UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

PETITION OF
THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
FOR APPROVAL OF PROPOSED RELIABILITY STANDARD PER-005-2 AND
RETIREMENT OF RELIABILITY STANDARD PER-005-1

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2] the North American Electric Reliability Corporation ("NERC")[3] hereby submits for Commission approval proposed Reliability Standard PER-005-2 – Operations Personnel Training. NERC requests that the Commission approve proposed Reliability Standard PER-005-2 (Exhibit A) as just, reasonable, not unduly discriminatory or preferential, and in the public interest.[4] NERC also requests approval of (i) the associated Implementation Plan (Exhibit B), (ii) the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (Exhibits A and E), (iii) the proposed NERC Glossary definitions for the terms "System Operator" and "Operations Support Personnel," and (iv) the retirement of currently effective Reliability Standard PER-005-1, as detailed in this Petition.

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1 16 U.S.C. § 824o (2006).

2 18 C.F.R. § 39.5 (2013).

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

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

As required by Section 39.5(a) of the Commission's regulations,[5] this Petition presents the technical basis and purpose of proposed Reliability Standard PER-005-2, a summary of the development history (Exhibit F) and a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672[6] (Exhibit C). The NERC Board of Trustees approved proposed Reliability Standard PER-005-2 and the retirement of PER-005-1 on February 6, 2014.

I. EXECUTIVE SUMMARY

The Personnel Performance, Training, and Qualifications ("PER") group of Reliability Standards is intended to help ensure the safe and reliable operation of the interconnected grid through the retention of suitably trained and qualified personnel in positions that can impact the reliable operation of the Bulk-Power System. Commission-approved Reliability Standard PER-005-1 requires Reliability Coordinators, Balancing Authorities, and Transmission Operators to: (1) establish a training program for their System Operators using a systematic approach to training, (2) verify each of their System Operators' capability to perform reliability-related tasks, and (3) provide emergency operations training to every System Operator. As System Operators have primary responsibility for the Real-time operation of the Bulk Electric System ("BES"), Reliability Standard PER-005-1 serves the important reliability goal of helping to ensure that System Operators performing Real-time, reliability-related tasks on the BES are adequately trained to competently perform those tasks and reliably operate the BES.

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5 18 C.F.R. § 39.5(a) (2013).

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

Consistent with FERC directives from Order Nos. 693[7] and Order No. 742,[8] the purpose of proposed Reliability Standard PER-005-2 is to improve upon PER-005-1 by expanding the scope of the Reliability Standard to include training requirements for the following personnel:

i. personnel of a Transmission Owner, excluding field switching personnel, who can act independently to operate or direct the operation of the Transmission Owner's BES transmission facilities in Real-time (i.e., local transmission control center operator personnel);

ii. Operations Support Personnel, which are proposed to be defined as "[i]ndividuals who perform current day or next day outage coordination or assessments, or who determine [System Operating Limits ("SOLs"), [Interconnection Reliability Operating Limits ("IROLs")], or operating nomograms, in direct support of Real-time operations of the Bulk Electric System;" and

iii. Generator Operator dispatch personnel at a centrally located dispatch center who receive direction from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner, and develop specific dispatch instructions for plant operators under their control.

As the Commission discussed in Order Nos. 693 and 742, these personnel perform or support Real-time operations on the BES and, in turn, could have a direct impact on BES reliability. Accordingly, it is important to expand the scope of the mandatory training requirements to require that such personnel receive adequate training to help maintain the reliable operation of the BES.

As is already required for System Operators, proposed Reliability Standard PER-005-2 requires the use of a systematic approach to develop and implement training requirements for local transmission control center operator personnel, Operations Support Personnel and the applicable Generator Operator dispatch personnel. As the Commission stated in Order No. 742, "[a] systematic approach to training is a widely-accepted methodology that ensures training is

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7 *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 72 FR 16416 (Apr. 4, 2007), FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

8 *See System Personnel Training Reliability Standards*, Order No. 742, 133 FERC ¶ 61,159 (2010).

efficiently and effectively conducted."[9] The concept of using a "systematic approach to training" refers to the use of a systematic method for establishing and maintaining training requirements that are directly related to the needs of the particular position. There are different models for using a systematic approach to training but any effective systematic approach to training method will determine: (1) the skills and knowledge necessary for the position in question; (2) the type of training needed to provide the trainee the identified skills and/or knowledge; (3) whether the trainee can competently perform his/her job function; and (4) whether the training is effective or requires adjustment.[10] Like PER-005-1, proposed Reliability Standard PER-005-2 does not mandate the use of a particular systematic approach to training model; rather it provides entities the discretion to determine the manner in which they will apply the principles of a systematic approach to training to develop and implement training requirements for their applicable personnel.

The proposed Reliability Standard also addresses the Commission's directive from Order No. 742 to develop an implementation period for those entities that may, at some time in the future, become subject to the requirement to provide emergency operations training using simulation technology.[11] Requirement R4, part 4.1 of the proposed Reliability Standard provides Reliability Coordinators, Balancing Authorities, Transmission Operators, and Transmission Owners 12 months from the date that they (1) gain operational authority or control over Facilities with established IROLs, or (2) establish protection systems or operating guides to mitigate IROL violations, to comply with the requirement to provide emergency operations training to their

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9 Order No. 693 at P 1382; Order No. 742 at P 25.

10 Systematic approaches to training are generally characterized by five distinct, yet interrelated phases: (1) analysis, (2) design, (3) development, (4) implementation, and (5) evaluation.

11 Order No. 742 at P 24.

applicable personnel using simulation technology. The 12-month period is designed to provide such entities sufficient time to acquire the necessary simulation technology and modify their training programs to account for the use of simulation technology.

Proposed Reliability Standard PER-005-2 also improves upon the prior version of the Reliability Standard by clarifying language in certain requirements and eliminating redundant or unnecessary requirements. For instance, PER-005-2 does not retain the obligation in Requirement R3 of PER-005-1 that Reliability Coordinators, Balancing Authorities, and Transmission Operators provide their System Operators at least 32 hours of emergency operations training every 12 months. As further explained below, the frequency and amount of emergency operations training for System Operators is most appropriately determined by each entity's training program developed in accordance with Requirement R1, rather than a uniform requirement applied to each entity regardless of its unique characteristics or reliability risk to the Bulk-Power System.

Finally, NERC proposes modifications to the definition of "System Operators" in the NERC Glossary. The purpose of the proposed modifications is to properly limit the definition to those operations personnel that have the independent authority to operate the BES in Real-time.

For the reasons discussed herein, NERC respectfully requests that the Commission approve proposed Reliability Standard PER-005-2, the proposed new and modified definitions used therein, and the retirement of PER-005-1.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[12]

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III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[13] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation's Bulk-Power System, and with the duty of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[14] of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[15] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability

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12 Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2013), to allow the inclusion of more than two persons on the service list in this proceeding.

13 16 U.S.C. § 824o (2006).

14 *Id.* § 824(b)(1).

15 *Id.* § 824o(d)(5).

Standard. Section 39.5(a)[16] of the Commission's regulations requires the ERO to file for Commission approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[17] and Section 39.5(c)[18] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[19] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[20] In its ERO Certification Order, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfies certain of the criteria for approving Reliability

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[16] 18 C.F.R. § 39.5(a) (2012).

[17] 16 U.S.C. § 824o(d)(2).

[18] 18 C.F.R. § 39.5(c)(1).

[19] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672 at P 334, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

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

Standards. The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders, and a vote of stakeholders and the NERC Board of Trustees is required to approve a Reliability Standard before the Reliability Standard is submitted for Commission approval.

C. History of PER Training Reliability Standards

1. <u>PER-002-0</u>

In Order No. 693, the Commission approved four PER Reliability Standards: PER-001-0, PER-002-0, PER-003-0, and PER-004-1.[21] PER-002-0, which has since been replaced by PER-005-1, as explained below, required each Transmission Operator and Balancing Authority to be staffed with adequately trained operating personnel. Specifically, PER-002-0 (1) directed each Transmission Operator and Balancing Authority to have a training program for all operating personnel who occupy positions that either have primary responsibility, directly or indirectly, for the Real-time operation of the Bulk-Power System or who are directly responsible for complying with the NERC Reliability Standards; (2) listed criteria that must be met by the training program; and (3) required that operating personnel receive at least five days of training in emergency operations each year using realistic simulations.

In Order No. 693, the Commission directed NERC to develop the following modifications to PER-002-0:

- identify the expectations of the training for each job function;
- develop training programs tailored to each job function with consideration of the individual training needs of the personnel;
- expand the applicability of the training requirements to include: (i) reliability coordinators, (ii) local transmission control center personnel, (iii) generator operators centrally-located at a generation control center with a direct impact on the reliable operation of the Bulk-

[21] Order No. 693 at PP 1330-1417.

Power System, and (iv) operations planning and operations support staff who carry out outage planning and assessments and those who develop SOLs, IROLs, or operating nomograms for Real-time operations;

- use a systematic approach to training methodology for developing new training programs; and

- include the use of simulators by Reliability Coordinators, Transmission Operators, and Balancing Authorities that have operational control over a significant portion of load and generation.[22]

The Commission also directed the ERO to determine whether it is feasible to develop meaningful performance metrics associated with the effectiveness of a training program required by currently effective Reliability Standard PER-002-0 and to consider whether personnel who support Energy Management System ("EMS") applications should be included in mandatory training pursuant to the Reliability Standard.[23]

While PER-002-0 addressed training requirements for Transmission Operators and Balancing Authorities, PER-004-1 applied to Reliability Coordinators. Specifically, PER-004-1 required:

- each Reliability Coordinator to be staffed with adequately trained, NERC-certified operators, 24 hours a day, seven days a week (Requirement R1); and

- Reliability Coordinator operating personnel to: (i) complete a minimum of five days of training in emergency operations each year using realistic simulations (Requirement R2), (ii) have a comprehensive understanding of the area of the Bulk-Power System for which they are responsible (Requirement R3), (iii) have an extensive understanding of the Balancing Authorities, Transmission Operators, and Generation Operators within their area (Requirement R4), and (iv) place particular attention on SOLs and IROLs and inter-tie facility limits (Requirement R5).

In Order No. 693, the Commission directed NERC to include formal training requirements for Reliability Coordinators similar to those in PER-002-0.[24]

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22 Order No. 693 at P 1393.

23 *Id*. at P 1394.

24 *Id*. at P 1415.

2. PER-005-1

In response to the Commission's directives in Order No. 693, NERC requested approval of proposed Reliability Standards PER-005-1 (System Personnel Training) and PER-004-2 (Reliability Coordination – Staffing) to replace PER-002-0 and PER-004-1, respectively. Reliability Standard PER-005-1, which superseded all of PER-002-0 as well as Requirements R2, R3, and R4 of PER-004-1, was designed to help ensure that System Operators performing reliability-related tasks on the North American BES are competent to perform those reliability-related tasks. PER-005-1 applies to Reliability Coordinators, Balancing Authorities, and Transmission Operators and contains the following three requirements:

1. Requirement R1 mandates that Reliability Coordinators, Balancing Authorities, and Transmission Operators "use a systematic approach to training to establish a training program for the BES company-specific reliability-related tasks performed by System Operators and implement the program." The requirement further requires applicable entities to create a list of company-specific, reliability-related tasks performed by their System Operators (R1.1); update the task list every calendar year (R1.1.1); and design and develop learning objectives and training materials based on the task list (R1.2). Finally, the requirement mandates that training be delivered (R1.3) and that the training program be evaluated on at least an annual basis to assess its effectiveness (R1.4).

2. Requirement R2 requires that Reliability Coordinators, Balancing Authorities, and Transmission Operators verify each of their System Operator's ability to perform the tasks identified in Requirement R1.1. The requirement also mandates that within six months of a modification to the task list, each System Operator's ability to perform those new or modified tasks must be verified.

3. Requirement R3 identifies the number of hours of emergency operations training (at least 32 hours) that a System Operator is required to receive every twelve months. Requirement R3.1 further requires that applicable entities that have operational authority or control over Facilities with established IROLs or have established operating guides or protection systems to mitigate IROL violations provide their System Operators emergency operations training using simulation technology, such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES during normal and emergency conditions.

Reliability Standard PER-004-2 modified PER-004-1 by deleting Requirements R2, R3, and R4, as these three requirements were incorporated into proposed PER-005-1. PER-004-2 simply carried forward, unchanged, the remaining provisions from PER-004-1.

The Commission approved Reliability Standards PER-005-1 and PER-004-2 in Order No. 742.[25] As discussed in that order, while Reliability Standard PER-005-1 addressed most of the Commission's directives from Order No. 693, NERC designated certain directives to be addressed in a subsequent Reliability Standards development project. In particular, Reliability Standard PER-005-1 did not address FERC's directives to expand the applicability of the training requirements to include: (1) local transmission control center operator personnel;[26] (2) certain Generator Operator dispatch personnel centrally-located at a generation control center;[27] and (3) operations and planning support personnel who carry out outage planning and assessments and those who develop SOLs, IROLs, or operating nomograms for real-time operations.[28] NERC also had yet to consider whether personnel who support EMS applications should be included in mandatory training requirements.[29] Consistent with NERC's commitment to address these directives in a future development project, FERC directed NERC to satisfy these unaddressed directives.[30] Additionally, the Commission directed NERC to consider the necessity of developing an implementation period for those entities that may become subject to the requirement to provide emergency operations training using simulation technology.[31]

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[25] Order No. 742 at P 1.

[26] *Id*. at PP 61-64.

[27] *Id*. at PP 74, 81, 83-85.

[28] *Id*. at PP 74, 81-2.

[29] Order No. 693 at P 1373.

[30] Order No. 742 at PP 64, 81-86.

[31] *Id*. at P 24.

The following section provides additional background on these outstanding Commission directives.

3. Outstanding Commission Directives

i. Local Transmission Control Center Operator Personnel

In Order No. 693, the Commission directed NERC to expand the applicability of Reliability Standard PER-002-0 to include local transmission control center operator personnel.[32] The Commission noted that decision making and implementation may be performed by separate groups in an Independent System Operator ("ISO") or Reliability Transmission Organization ("RTO") context, as well as other organizations that pool resources.[33] The Commission stated that the personnel of control centers and organizations that are necessary for the actual implementation of the decision or are needed for operation and maintenance made by the ISO, RTO or pooled resource organization should receive training under the standard.[34] Specifically, the Commission stated:

> Clearly, in a region where an RTO or ISO performs the transmission operator function, its personnel with primary responsibility for real-time operations must receive formal training pursuant to PER-002-0. In addition, personnel who are responsible for implementing instructions at a local control center also affect the reliability of the Bulk Power System. These entities may take independent action under certain circumstances, for example, to protect assets, personnel safety and during system restorations. Whether the RTO or the local control center is ultimately responsible for compliance is a separate issue addressed above, but regardless of which entity registers for that responsibility, these local control center employees must receive formal training consistent with their roles, responsibilities and tasks. Thus, while we direct the ERO to develop modifications to PER-002-0 to include formal training for local control center personnel, that training should be tailored to the needs of the positions.[35]

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[32] Order No. 693 at PP 1342-48.

[33] *Id*. at P 1342.

[34] *Id*. At 1342-43.

[35] *Id*. at P 1343.

The Commission further explained which type of control centers and personnel were subject to the directive. The Commission clarified that where a large utility within an RTO or ISO footprint has one centrally-located control center whose function is to supervise several distributed control centers, each with remote monitoring and control capability, the personnel of the centrally-located control center, not the personnel at the distributed control center, should receive formal training under the Reliability Standard.[36] Similarly, the Commission stated that where smaller entities have a single control center that implements operating instructions from its Transmission Operator (e.g., an RTO, ISO or pooled resource), the operators at these control centers should be trained under the Reliability Standards as they may also may take independent action to protect assets, safety and system restoration.[37] The Commission noted, however, that individuals who carry out field switching operations and station inspections at the direction of the local control center operators are not subject to the directive.[38] Lastly, the Commission noted that local control center operators need not be trained in the same manner, or to the same extent as System Operators at a Transmission Operator, Balancing Authority or Reliability Coordinator. Rather, the training program should be tailored to the functions of local control center operators.[39]

In Order No. 742, the Commission reiterated its conclusion that omitting such local transmission control center operator personnel from mandatory training requirements creates a reliability gap:

> The Commission understands that local transmission control center personnel exercise control over a significant portion of the Bulk-Power System under the supervision of the personnel of the registered transmission operator. This supervision may take the form of directing specific step-by-step instructions and at

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36 Order No. 693 at P 1344.

37 *Id*. at P 1345.

38 *Id*. at P 1346.

39 *Id*. at P 1348.

> other times may take the form of the implementation of predefined operating procedures. For example, ISO New England, Inc., PJM Interconnection, L.L.C., and New York Independent System Operator, Inc., are registered transmission operators who issue operating instructions that are carried out by local transmission control centers such as PSE&G, PPL Electric Utilities Corp., PECO Energy Company, Baltimore Gas and Electric Co., Consolidated Edison of New York, Inc., National Grid USA, and Long Island Power Authority, which are not registered transmission operators. The combined peak load of these three RTOs is in excess of 200 gigawatts. In all cases, the local transmission control center personnel must understand what they are required to do in the performance of their duties to perform them effectively on a timely basis. Thus, omitting such local transmission control center personnel from the PER-005-1 training requirements creates a reliability gap. The Commission believes that identifying these entities would be a valuable step in delineating the magnitude of that gap.[40]

Accordingly, in Order No. 742 the Commission reiterated its directive to develop training requirements for, and develop a definition of, local transmission control center operator personnel.[41]

ii. Generator Operator Dispatch Personnel

In Order No. 693, the Commission concluded that because a Generator Operator has the potential to directly impact the reliable operation of the Bulk-Power System, its personnel should be trained under NERC's Reliability Standards.[42] The Commission asserted that although Generator Operators take directions from Balancing Authorities and others, which limits their ability to impact reliability, it is essential that Generator Operator personnel have appropriate training to understand those instructions, particularly in an emergency situation in which instructions may be succinct and require immediate action.[43]

The Commission limited the directive to personnel of a Generator Operator that perform dispatch activities, namely, those dispatch personnel at a "centrally-located dispatch center that

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40 Order No. 742 at P 62.

41 *Id*. at PP 63-64.

42 Order No. 693 at P 1359.

43 *Id*. at P 1359.

receive[] direction and then develop[] specific dispatch instructions for plant operators under their control."[44] This group of personnel would include a Generator Operator's dispatch personnel where a single generator and dispatch center are located at the same site.[45] The Commission clarified that while plant operators located at the generator plant site also need to be trained, the responsibility for this training is outside the scope of the Reliability Standard.[46]

The Commission recognized, however, that "the experience and knowledge required by Transmission Operators about Bulk-Power System operations goes well beyond what is needed by Generation Operators."[47] Accordingly, the Commission stated that (1) the training for the applicable Generator Operator personnel "need not be as extensive as that required for Transmission Operators;" and (2) "the training requirements developed by the ERO should be tailored in their scope, content and duration so as to be appropriate to generation operations personnel and the objective of promoting system reliability."[48]

iii. Operations and Planning Support Personnel

The Commission also directed NERC to extend the training requirements to certain operations planning and operations support staff.[49] The Commission clarified that the applicable support staff are "those [individuals] who carry out outage coordination and assessments in accordance with Reliability Standards IRO-004-1 and TOP-002-2, and those who determine SOLs and IROLs or operating nomograms in accordance with Reliability Standards IRO-005-1 and

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44 Order No. 693 at P 1360; Order No. 742 at P 83.

45 Order No. 693 at P 1361; Order No. 742 at P 83.

46 *Id*. at PP 1360-61.

47 Order No. 693 at P 1363.

48 *Id*. at P 1363.

49 *Id*. at P 1372.

TOP-004-0."[50] The Commission concluded that the Reliability Standard should apply to these operations planning and operations support staff because they have a direct impact on the reliable operation of the Bulk-Power System. The Commission noted, however, that such personnel need not be trained on the responsibilities of System Operators; rather the training should be tailored to the needs of their functions, the tasks performed and personnel involved.[51]

iv. EMS Personnel

In its discussion of support personnel in Order No. 693, the Commission also stated that it "is aware that the personnel responsible for ensuring that critical reliability applications of the EMS, such as state estimator, contingency analysis and alarm processing packages, are available, up-to-date in terms of system data and produce useable results can also have an impact on the Reliable Operation of the Bulk-Power System."[52] Because the Commission was uncertain about the impact of EMS personnel on reliable operations, however, the Commission only directed NERC to consider whether EMS personnel should be included in a mandatory training requirement.

v. Implementation Period for Simulation Training

As noted above, Requirement R3.1 of PER-005-1 identifies the entities that must use simulation technology when providing emergency operations training. While the implementation plan for PER-005-1 addressed lead times for compliance based on governmental approval, the standard does not provide any lead times for compliance when an entity becomes subject to the requirement after the regulatory effective date of the standard. In Order No. 742, the Commission directed NERC to consider the necessity of developing an implementation period for those entities

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50 Order No. 693 at P 1372; Order No. 742 at P 82.

51 Order No. 693 at P 1375.

52 *Id*. at 1373.

that may become, in the future, subject to the simulator training requirement in Requirement R3.1 of PER-005-1.

D. Procedural History of NERC Project 2010-01 Training

The proposed Reliability Standard was developed as part of NERC Project 2010-01 Training, which was initiated to address the outstanding Commission directives from Order Nos. 693 and 742 related to Reliability Standard PER-005-1. Project 2010-01 Training arose from an informal development process that NERC began in February 2013 to review the outstanding directives. Participants in this informal development process were industry subject matter experts, NERC staff, and staff from FERC's Office of Electric Reliability.

The informal group met numerous times between February 2013 and July 2013 to discuss the outstanding FERC directives and, given their experience with Reliability Standard PER-005-1, ways to improve the standard. The informal group also conducted industry outreach to obtain feedback on approaches for responding to the outstanding directives and improving the standard. After considering this feedback, the informal participants drafted a revised Reliability Standard, PER-005-2, to address FERC's outstanding directives and improve the quality and content of the standard.

Project 2010-01 Training was formally initiated on July 18, 2013 with the posting of a Standard Authorization Request along with the draft of proposed PER-005-2 developed by the informal participants for a 45-day formal comment period and ballot. Following the July 18, 2013 posting, a standard drafting team was formed. As further described in Exhibit F hereto, drafts of the proposed Reliability Standard were posted for two additional comment periods and ballots. The third ballot received a quorum of 79.12% and an approval of 74.63%. Following approval of the proposed standard in a Final Ballot, the NERC Board of Trustees approved proposed PER-

005-2, the proposed new and modified definitions used therein, and the retirement of PER-005-1 on February 6, 2014.

IV. JUSTIFICATION FOR APPROVAL

As discussed below and in Exhibit C, proposed Reliability Standard PER-005-2 satisfies the Commission's criteria in Order No. 672 and is just, reasonable, not unduly discriminatory or preferential, and in the public interest. The following section provides: (1) the basis and purpose of the proposed Reliability Standard; (2) a discussion of the requirements in the proposed Reliability Standard, including an explanation of how each requirement improves upon the prior version of the Reliability Standard and, where applicable, satisfies outstanding Commission directives; (3) a discussion of the enforceability of the proposed Reliability Standard; and (4) an explanation of the proposed modifications to the definition of the term "System Operator."

A. Basis and Purpose of the Proposed Reliability Standard

The proposed Reliability Standard serves the vital reliability goal of helping to ensure that personnel who perform or support Real-time operations on the BES are adequately trained to maintain the reliable operation of the BES. Training individuals that both perform and support Real-time operations is an integral step in enhancing the reliability of the Bulk-Power System. It is important to train operators and their support personnel to, among other things, understand what they are required to do in the performance of their duties, particularly in emergency circumstances, and to perform those duties effectively and on a timely basis in support of reliable operations.

Proposed Reliability Standard PER-005-2 replaces and improves upon the prior version of the standard by addressing outstanding Commission directives from Order Nos. 693 and 742, clarifying language in certain requirements, and eliminating redundant or unnecessary requirements. First, the proposed Reliability Standard improves upon Reliability Standard PER-005-1 by expanding the scope of the Reliability Standard to include training requirements for: (1)

local transmission control center operator personnel; (2) Operations Support Personnel; and (3) certain Generator Operator dispatch personnel centrally-located at a generation control center. As noted above, currently effective Reliability Standard PER-005-1 is limited to requiring Reliability Coordinators, Balancing Authorities and Transmission Operators to train and verify the capabilities of their System Operators. As the Commission recognized in Order No. 693, however, while System Operators have primary responsibility for Real-time operations, there are other personnel – namely, local transmission control center operator personnel, certain planning and operations support personnel, and certain Generator Operator dispatch personnel – that perform or support Real-time operations on the BES and could directly impact BES reliability. As such, including mandatory training requirements for these personnel under NERC's Reliability Standard will serve to enhance the reliability of the BES.

As is already required for System Operators, proposed Reliability Standard PER-005-2 requires the use of a systematic approach to develop and implement training requirements for local transmission control center operator personnel, certain planning and operations support personnel, and certain Generator Operator dispatch personnel. The proposed Reliability Standard requires, consistent with the principles of an effective systematic approach to training, that the training for these personnel be tailored to the needs of the respective positions and their impact to BES reliability.

As explained further below, however, the standard drafting team determined, based on research conducted by the NERC Operating Committee's Event Analysis Subcommittee, that there was insufficient evidence at this time to warrant an extension of the mandatory training requirements to personnel that support EMS applications. The ERO will continue to assess the need for mandatory training of these personnel.

The proposed Reliability Standard further modifies the prior version of the standard to include an implementation period for those entities that may become subject, at some point in the future, to the requirement to provide emergency operations training using simulation technology. Consistent with FERC's directive, the implementation period is designed to provide such entities sufficient time to acquire the appropriate simulation technology and modify their training programs before they are required to comply with the requirement to use simulation technology.

In addition to modifying Reliability Standard PER-005-1 to address Commission directives, the standard drafting team sought to modify the standard to improve the clarity, quality and content of the Reliability Standard. The most substantive modification was the removal of the obligation from Requirement R3 of PER-005-1 that Reliability Coordinators, Balancing Authorities, and Transmission Operators provide their System Operators at least 32 hours of emergency operations training every 12 months. As further explained below, the frequency and amount of emergency operations training for System Operators is most appropriately determined by each entity's systematic approach to developing and implementing a training program tailored to the needs of its organization, rather than a uniform requirement applied to each entity regardless of the entity's unique characteristics or reliability risk to the Bulk-Power System.

B. Requirements of Proposed Reliability Standard PER-005-2

The proposed Reliability Standard contains six requirements that comprehensively address training requirements for System Operators, local transmission control center operators, Operations Support Personnel and applicable Generator Operator dispatch personnel. With the exception of removing the 32-hour emergency operations training requirement, the proposed

Reliability Standard carries over all of the requirements of Reliability Standard PER-005-1 and includes three new requirements to address Commission directives, as follows:[53]

- *Requirement R1* covers training requirements for System Operators and includes the same substantive requirements as those provided in PER-005-1, Requirement R1. The only modifications to Requirement R1 were non-substantive and designed to increase the clarity of the requirement.

- *Requirement R2* is a new requirement that covers training requirements for local transmission controls center operators. The requirements in Requirement R2 mirror those in Requirement R1 for System Operators.

- *Requirement R3*, which maps to Requirement R2 of PER-005-1, requires the verification of a System Operator's and a local transmission control center operator's ability to perform Real-time, reliability-related tasks. The only differences between proposed PER-005-2, Requirement R3 and PER-005-1, Requirement R2 is the inclusion of local transmission control center operators and certain minor changes to the language to provide additional clarity.

- *Requirement R4*, which maps to Requirement R3.1 of PER-005-1, identifies those entities that must provide emergency operations training using simulation technology. In contrast to Requirement R3.1 of PER-005-1, Requirement R4 of proposed PER-005-2, includes local transmission control center operators as personnel that may be required to receive emergency operations training using simulation technology. Additionally, Requirement R4, part 4.1 includes a 12-month implementation period for those entities that may become subject to the requirement at some point in the future.

- *Requirement R5* is a new requirement that requires Reliability Coordinators, Balancing Authorities and Transmission Operators to use a systematic approach to develop and implement training for Operations Support Personnel on how their job function(s) impact the Real-time reliability-related tasks which they support.

- *Requirement R6* is a new requirement that requires Generator Operators to use a systematic approach to develop and implement training for dispatch personnel at a centrally located dispatch center who receive direction from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator or Transmission Owner, and develop specific dispatch instructions for plant operators under their control.

The following is a more detailed discussion of each requirement in proposed Reliability Standard PER-005-2, including an explanation of how each requirement improves upon the prior

[53] Exhibit D to this Petition is a mapping document showing the translation of PER-005-1 to proposed PER-005-2. Additionally, Exhibit A includes a redline of the Reliability Standard comparing PER-005-1 and proposed PER-005-2.

version of the Reliability Standard and, where applicable, satisfies outstanding Commission directives.

Requirement R1 covers the development and implementation of training programs for System Operators, as follows:

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement a training program for its System Operators as follows:

1.1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology.

1.1.1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 1.1 each calendar year.

1.2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 1.1.

1.3. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall deliver training to its System Operators according to its training program.

1.4. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall implement the changes identified.

The language and structure of Requirement R1 are virtually the same as Requirement R1 of PER-005-1. There were no substantive changes to the obligations imposed upon Reliability Coordinators, Balancing Authorities, and Transmission Operators by the prior version of the requirement. Requirement R1 continues to require the training of System Operators using a systematic approach to training, which is a proven approach to: identify System Operator tasks and the associated skills and knowledge necessary to accomplish those tasks; determine the competency levels of each System Operator to carry-out those tasks; determine the competency gaps; and design, implement and evaluate a training plan to address each System Operator's competency.

The standard drafting team, however, sought to modify certain language in the requirement to provide additional clarity. Among others, the standards drafting team made the following modifications:

- Replacing the phrase "shall use a systematic approach to training to establish a training program" with "shall use a systematic approach to develop and implement a training program" to make the provision more readable and clarify the performance obligation ("develop and implement" vs. establish).

- Including the term "Real-time" before the phrase "reliability-related task" to clarify that the relevant tasks are those performed in Real-time.

- Including the phrase "based on a defined and documented methodology" in part 1.1 to clarify that the task list to be created must, consistent with a systematic approach to training, be based on a defined and documented methodology.

- Clarifying part 1.2 to state that the training material to be developed must be designed and developed based on the entity's BES company-specific Real-time reliability-related tasks, rather than some generic training materials.

- Replacing the phrase "an annual evaluation" with "an evaluation every calendar year" in part 1.4 to clarify the timeline for performing evaluations of the training program.

These modifications are designed to improve the strength and quality of the training delivered to System Operators in accordance with Requirement R1.

Requirement R2 is a new requirement designed to satisfy the Commission's directive to expand the training requirements to include local transmission control center operators. Requirement R2 mirrors the obligations in Requirement R1, as follows:

> **R2.** Each Transmission Owner shall use a systematic approach to develop and implement a training program for its personnel identified in Applicability Section 4.1.4.1 of this standard as follows:
>
> **2.1.** Each Transmission Owner shall create a list of BES company-specific Real-time reliability-related tasks based on a defined and documented methodology.

2.1.1. Each Transmission Owner shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 2.1 each calendar year.

2.2. Each Transmission Owner shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 2.1.

2.3. Each Transmission Owner shall deliver training to its personnel identified in Applicability Section 4.1.4.1 of this standard according to its training program.

2.4. Each Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement R2 to identify any needed changes to the training program and shall implement the changes identified.

Applicability Section 4.1.4.1 identifies Transmission Owner "[p]ersonnel, excluding field switching personnel, who can act independently to operate or direct the operation of the Transmission Owner's Bulk Electric System transmission Facilities in Real-time." The standard drafting team identified these personnel as the "local transmission control center operators" described in Order No. 693 and Order No. 742.[54] As provided in Order No. 742, it is Transmission Owners in RTO/ISO or other pooled resource contexts, "such as PSE&G, PPL Electric Utilities Corp., PECO Energy Company, Baltimore Gas and Electric Co., Consolidated Edison of New York, Inc., National Grid USA, and Long Island Power Authority, which are not registered transmission operators," that have local transmission control centers whose operators carry out the instructions issued by RTOs/ISOs or other pooled resource organization.[55]

As the Commission stated in Order No. 693, these personnel "may take independent action under certain circumstances, for example, to protect assets, personal safety and during system restorations."[56] As such, Applicability Section 4.1.4.1 focuses on Transmission Owner personnel

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54 Order No. 693 at pp 1342-46; Order No. 742 at p 62.

55 Order No. 742 at P 62.

56 Order No. 693 at P 1343. *See also* Order No. 693 at P 1347 ("…these operators maintain authority to act independently to carry out tasks that require real-time operation of the Bulk-Power System, including protecting

that may "act independently to operate or direct the operation" of the Transmission Owner's transmission facilities in Real-time. Field switching personnel are properly excluded in accordance with Order No. 693 as these personnel "are not involved with the transmission operator at the ISO or RTO or at organizations with pooled resources."[57]

Because of their authority to take independent action to carry out tasks that require Real-time operation of the Bulk-Power System, local transmission controls center operators are treated similarly to System Operators under the proposed Reliability Standard. Specifically, the training requirements in Requirement R2 mirror those required for System Operators under Requirement R1. Additionally, like System Operators, Transmission Owners must (i) verify the capabilities of their local control center operators under Requirement R3 and, (ii) for those Transmission Owners that meet the criteria specified in Requirement R4, provide emergency operations training to their local control center operators using simulation technology.

Consistent with the requirement to use a systematic approach to training, however, the actual training program for local transmission control center operators must be consistent with their roles, responsibilities and tasks, and would not necessarily cover the same topics, or be structured in the same manner, as the programs developed for System Operators pursuant to Requirement R1. As FERC stated in Order No. 742, training local control center operator personnel will further the reliability goal of helping to ensure that local transmission control center operators "understand what they are required to do in the performance of their duties to perform them effectively on a timely basis."[58]

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assets, protecting personal safety, adhering to regulatory requirements and establishing stable islands during system restorations.")

57 Order No. 693 at P 1346.

58 Order No. 742 at P 62.

Requirement R3 provides as follows:

> **R3.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1 or Requirement R2 part 2.1.
>
> **3.1.** Within six months of a modification or addition of a BES company-specific Real-time reliability-related task, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its personnel identified in Requirement R1 or Requirement R2 to perform the new or modified BES company-specific Real-time reliability-related tasks identified in Requirement R1 part 1.1 or Requirement R2 part 2.1.

As noted above, Requirement R3 carries over the obligation from Requirement R2 of PER-005-1 that Reliability Coordinators, Balancing Authorities and Transmission Operators verify the capabilities of each of their System Operators assigned to perform the Real-time reliability-related tasks identified in accordance with Requirement R1. Requirement R3 improves upon PER-005-1, Requirement R2 by requiring that Transmission Owners also verify the capabilities of each of their local transmission control center operators assigned to perform the Real-time reliability-related tasks identified in accordance with Requirement R2. In addition, the standard drafting team modified the language from the prior version of the standard to provide clarity.

Part 3.1 of Requirement R3 mirrors Requirement R2.1 of PER-005-1 in that it provides applicable entities six months to verify their applicable personnel's capability to perform a new or modified task added to the Real-time reliability related task list required by Requirement R1 part 1.1 or Requirement R2 part 2.1.

Requirement R4 identifies those entities that must provide emergency operations training using simulation technology, as follows:

> **R4.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations, shall

provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES.

4.1. A Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not previously meet the criteria of Requirement R4, shall comply with Requirement R4 within 12 months of meeting the criteria.

Requirement R4 carries over the obligation from Requirement R3.1 of PER-005-1 that Reliability Coordinators, Balancing Authorities, and Transmission Operators that have (1) operational authority or control over Facilities with established IROLs, or (2) established protection systems or operating guides to mitigate IROL violations, provide their System Operators emergency operations training using simulation technology. Requirement R4 improves upon Requirement R3.1 of PER-005-1 by also requiring that Transmission Owners that meet the above described criteria also use simulation technology when providing emergency operations training to their local transmission control center operators. While it is unlikely for a Transmission Owner to have operational authority or control over Facilities with an IROL, certain applicable Transmission Owners may have established protection systems or operating guides to mitigate IROL violations. In addition, the standard drafting team modified the language from the prior version of the standard to provide clarity.

Consistent with Commission directives, part 4.1 of Requirement R4 includes a 12-month implementation period for those entities that may, at some future time after the effective date of the proposed Reliability Standard, meet the criteria for having to comply with Requirement R4. The 12-month implementation period is necessary to provide such entities sufficient time to acquire the necessary simulation technology and modify their training programs before they are required to comply with the requirement to use simulation technology.

The proposed Reliability Standard does not retain the obligation from PER-005-1, Requirement R3 that Reliability Coordinators, Balancing Authorities, and Transmission Operators provide their System Operators at least 32 hours of emergency operations training every 12 months. The standard drafting team concluded that such a requirement is unnecessary and inconsistent with the obligation in Requirement R1 to use a systematic approach to develop and implement a training program for System Operators. As discussed above, inherent in any systematic approach to training method is an analysis of the skills and knowledge necessary for the position in question and the design, development and implementation of a training program based on that analysis. Because emergency operations are a significant component of many of the BES company-specific Real-time reliability-related tasks performed by System Operators, emergency operations training must be an integral part of any training program developed in accordance with Requirement R1. Specifically, Requirement R1 obligates Reliability Coordinators, Balancing Authorities, and Transmission Operators to:

- include all BES company-specific Real-time reliability-related tasks performed by System Operators, including those tasks involving emergency operations, in their list of tasks required by part 1.1;

- analyze the skills and knowledge necessary for their System Operators to competently perform those tasks;

- design and develop, in accordance with part 1.2, training materials and requirements for their System Operators, which must include the frequency and amount of emergency operations training necessary for System Operators to competently perform the tasks involving emergency operations.;

- provide emergency operations training to their System Operators in accordance with their training program, as required by part 1.3; and

- evaluate the effectiveness of their training program, including their emergency operations training, every calendar year to identify and implement any necessary changes, as required by part 1.4.[59]

[59] These same obligations would apply to Transmission Owners in developing training programs for their local control center operators under Requirement R2. Transmission Owners will be required to identify any Real-time reliability-related tasks involving emergency operations that are performed by their local control center operators and then design, develop and implement a training program that include emergency operations training. The frequency and amount of such training would be dictated by the analysis of the skills and knowledge necessary

The standard drafting team thus concluded that a generally applicable requirement mandating a minimum amount of emergency operations training, irrespective of the entity's unique characteristics or reliability risk to the Bulk-Power System, is unnecessary and inconsistent with the Commission-approved requirement to use a systematic approach to training methodology. To comply with Requirement R1, Reliability Coordinators, Balancing Authorities, and Transmission Operators will determine the frequency and amount of emergency operations training necessary to support reliable operation of the Bulk-Power System based on an analysis of the needs and risks of their particular organization and the position in question. As noted above, using a systematic approach to training methodology is a widely-accepted approach for developing efficient and effective training programs tailored to the needs and characteristics of the organization and personnel in question.

The proposal to remove the obligation to provide 32 hours of emergency operations training every 12 months does not eliminate the obligation to provide continual emergency operations training to System Operators. As the Commission recognized in Order No. 742, continual or repeated training is a fundamental part of any systematic approach to training and an enforceable requirement of the Reliability Standard:

> Based on NERC's and the majority of commenters' affirmation that continual training is a fundamental part of a systematic approach to training and an enforceable requirement of under PER-005-1, we find that any systematic approach to training, including the systematic approach to training mandated by Reliability Standard PER-005-1, would entail continual training to refresh System Operators' knowledge and to cover any new tasks relevant to the operation of the Bulk-Power System.[60]

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to help ensure that the local control center operators are competent to perform the tasks involving emergency operations.

60 Order No. 742 at P 34.

The deletion of Requirement R3 of PER-005-1 simply recognizes that the frequency and amount of emergency operations training is most appropriately determined by an entity as part of its systematic approach to developing and implementing a training program for its System Operators.

Requirement R5 addresses the Commission's directive to expand the scope of the Reliability Standard to include training requirements for "those [individuals] who carry out outage coordination and assessments in accordance with Reliability Standards IRO-004-1 and TOP-002-2, and those who determine SOLs and IROLs or operating nomograms in accordance with Reliability Standards IRO-005-1 and TOP-004-0."[61] Requirement R5 provides:

> **R5.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1.
>
> **5.1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training.

The proposed definition for Operations Support Personnel mirrors the Commission's description of the type of support personnel that may have a direct impact on reliable operations. Specifically, the term Operations Support Personnel is proposed to be defined as "[i]ndividuals who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms, in direct support of Real-time operations of the Bulk Electric System."

Requirement R5 serves the important reliability goal of helping to ensure that individuals that support the Real-time operation of the Bulk Electric System, even if not directly responsible for operating any BES Facilities, receive adequate training on how their job functions impact the

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61 Order No. 693 at P 1372; Order No. 742 at P 82.

Real-time reliability related tasks they support. To be clear, this requirement does not require that Operations Support Personnel be trained on the System Operator's responsibilities; rather, the requirement mandates that training be based on how the roles, responsibilities and tasks of Operations Support Personnel affect the tasks performed by System Operator. This approach is consistent with the use of a systematic approach to training because it requires the training to be directly related to the needs of the position in question.

As noted above, the standard drafting team concluded that it was not necessary, at this time, to expand the scope of the Reliability Standard to include personnel who support EMS applications. The standard drafting team relied on a May 2013 report provided by the NERC Operating Committee's Event Analysis Subcommittee. The report was issued in response to a request by NERC's Standards Committee that the Event Analysis Subcommittee consider which personnel, including EMS support personnel, should be trained under NERC's Reliability Standards. The Event Analysis Subcommittee concluded there was insufficient evidence to warrant extending mandatory training requirements of PER-005-1 to EMS support personnel.[62]

Specifically, the Event Analysis Subcommittee reviewed the reportable events in NERC's Event Analysis database to determine whether there was any evidence demonstrating a need to include EMS support personnel in NERC's mandatory training Reliability Standard. The Event Analysis database included the reportable events on the Bulk-Power System beginning in October 2010. As of May 2013, when the report was issued, the database included over 263 events, 208 of which were cause-coded to allow for trending and cluster analysis. The Event Analysis Subcommittee and NERC Event Analysis staff queried the 208 events for cause-codes that

[62] The Event Analysis Subcommittee is available at http://www.nerc.com/pa/Stand/PER%20Informal%20Development/NERC%20Event%20Analysis%20Subcommittee%20Response%20to%20Request%20for%20Research%20Updated%2010%20May%202013.pdf.

pertained to human error or lack of training. The query produced 44 events that identified human error or lack of training as a possible contributing factor in the event. A further analysis of those 44 events, however, indicated that human error or lack of training was a contributing factor in only 10 of those events. Six of those 10 events were related to the loss of EMS or Supervisory Control and Data Acquisition (SCADA) applications. The report also indicates that out of those six events, only two were deemed to be due to a lack of training. Based on that information, the Event Analysis Subcommittee concluded that while EMS support personnel should receive training, the evidence does not support a need for such personnel to be trained under Reliability Standard PER-005.

Requirement R6 addresses the Commission's directive to expand the scope of the Reliability Standard to include training requirements for certain Generator Operator dispatch personnel. Requirement R6 provides:

> **R6.** Each Generator Operator shall use a systematic approach to develop and implement training to its personnel identified in Applicability Section 4.1.5.1 of this standard, on how their job function(s) impact the reliable operations of the BES during normal and emergency operations.
>
> > **6.1.** Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R6 to identify and implement changes to the training.

Applicability Section 4.1.5.1 identifies Generator Operator "[d]ispatch personnel at a centrally located dispatch center who receive direction from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner, and may develop specific dispatch instructions for plant operators under their control." The description of the personnel identified in Applicability Section 4.1.5.1 mirrors the Commission's description of the type of Generator Operator dispatch personnel that may have a direct impact on reliable operations and should be included in the mandatory training Reliability Standard.[63] As the Commission recognized, although Generator Operators take directions from Balancing Authorities and others, which limits their ability to impact reliability, it is essential that these Generator Operator dispatch personnel have appropriate training to understand those instructions, particularly in an emergency situation in which instructions may be succinct and require immediate action.[64] Applicability Section 4.1.5.1 clarifies that, consistent with FERC's directive in Order No. 693, these personnel do not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who simply relay dispatch instructions without making any modifications.[65]

Because of the more limited impact that these Generator Operator dispatch personnel have on the reliable operation of the BES, Requirement R6 only requires that Generator Operators use a systematic approach to develop and implement training for its applicable personnel on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. While an entity may choose to develop a reliability-related task list and other documents typically developed as part of a systematic approach to training methodology, proposed Requirement R6 does not explicitly require them to do so. Nevertheless, applicable Generator Operators must be able to show that their training complies with the principles of a systematic approach to training, such as whether the entity assessed training needs, provided training based on that assessment, and evaluated the training activity.

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63 Order No. 693 at PP 1360-62; Order No. 742 at P 83.

64 Order No. 693 at P 1359.

65 *Id*. at PP 1360-61.

C. Enforceability of the Proposed Reliability Standards

The proposed Reliability Standard includes VRFs and VSLs. The VRFs and VSLs provide guidance on the way that NERC will enforce the requirements of the proposed Reliability Standard. The VRFs and VSLs for the proposed Reliability Standard comport with NERC and Commission guidelines related to their assignment. Exhibit E provides a detailed review of the VRFs, the VSLs, and the analysis of how the VRFs and VSLs were determined using these guidelines.

The proposed Reliability Standard also includes measures that support each requirement by clearly identifying what is required and how the requirement will be enforced. These measures help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[66]

D. Proposed Modifications to the Definition of "System Operator"

As part of NERC Project 2010-01 Training, the standard drafting team sought to respond to industry requests to modify the NERC Glossary definition of "System Operator" to more accurately describe the personnel the industry generally considers to be System Operators.[67] The current definition of "System Operator is as follows:

> An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time.

NERC is proposing the following definition:

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

[67] *See* Standard Authorization Request submitted by Thomas J. Bradish of RRI Energy on October 5, 2010 and accepted by the NERC Standards Committee on October 13, 2010, *available at* http://www.nerc.com/pa/Stand/Project%20201016%20Definition%20of%20System%20Operator%20DL/Project_2010-16_System_Op_Definition_SAR_approved_by_SC-Clean_UPDATED.pdf.

> An individual at a Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator who operates or directs the operation of the Bulk Electric System in Real-time.

The purpose of the proposed modification is to properly limit the definition to those operations personnel that have the independent authority to operate the Bulk Electric System in Real-time. The following is a discussion of each of the modifications to the definition.

First, the standard drafting team concluded that the phrase "operates or directs the operation of the Bulk Electric System in Real-time" more accurately depicts the function of a System Operator than the phrase "whose responsibility it is to monitor and control that electric system in real time." Specifically, the duty of a System Operator is to constantly monitor the BES and take the necessary action to operate the system in a reliable and economic manner based on varying system conditions. The System Operator is tasked with, among other things, reacting to varying system conditions by modifying system configurations, generator outputs, and transmission loadings, and directing field personnel to take various actions. The standard drafting team considered the words "monitor" and "control" to be too ambiguous and limiting. The standard drafting team used the phrase "operates or directs the operation" to better capture the duties performed by the System Operator. The standard drafting team also maintains that the phrase "operates or directs the operation" sufficiently limits the definition to the personnel in a Control Center who have the independent authority to operate the BES. Individuals that perform certain tasks under the direct supervision of the NERC-certified System Operator should not be considered to be "operating" the BES.[68]

[68] As noted in footnote 1 to Reliability Standard PER-003-1, "[n]on-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks."

The other significant change to the definition of System Operator was to remove reference to Generator Operators. The role of a Generator Operator is limited to operating generating units and performing the function of supplying energy and ancillary services to the grid. A Generator Operator is limited in the action it could take without instructions from its Reliability Coordinator, Balancing Authority or Transmission Operator. For instance, a Generator Operator cannot perform contingency analyses, institute switching orders, observe Real-time transmission line flows and status, or issue Transmission Loading Relief requests. Given this limited scope, the standard drafting team concluded it was not appropriate to categorize Generator Operator personnel as Systems Operators in the same manner as the operating personnel of a Reliability Coordinator, Balancing Authority and Transmission Operator. Removing references to Generator Operators from the definition is consistent with the manner in which the term is used in NERC's Reliability Standards. No Reliability Standard uses the NERC Glossary term "System Operator" to refer to Generator Operator personnel.

Lastly, the definition of System Operator was modified to capitalize the terms "Control Center" and "Real-time" so as to refer to the FERC-approved definition of these terms. Neither "Control Center" nor "Real-time" were FERC-approved defined terms when the current definition of "System Operator" was developed.

V. EFFECTIVE DATE

As described in the Implementation Plan, attached hereto as Exhibit B, NERC respectfully requests that the Commission approve the proposed Reliability Standard and new and modified NERC Glossary Terms effective on the first day of the first calendar quarter that is 24 months after Commission approval. This 24-month implementation period will provide sufficient time for the applicable entities to develop or modify their processes to comply with proposed PER-005-2. The standard drafting team determined that a 24-month implementation period was appropriate because proposed Reliability Standard PER-005-2 is applicable to functional entities (Transmission Owners and Generator Operators) that are not currently subject to PER-005-1. Transmission Owners and Generator Operators will for the first time be required to develop and implement a systematic approach to training process for their applicable personnel. The standard drafting team concluded that a 24-month implementation period is a sufficient amount of time to allow these entities to develop and implement a systematic approach to training process prior to the enforceability of the proposed standard. The proposed implementation period is consistent with the 24-month implementation period provided to Reliability Coordinators, Balancing Authorities and Transmission Operators under PER-005-1.

The proposed 24-month implementation period is also necessary to provide Reliability Coordinators, Balancing Authorities and Transmission Operators sufficient time to develop training for their Operations Support Personnel. Even though these entities are already subject to PER-005-1, the standard drafting team concluded that these entities will need a 24-month implementation period to modify their processes and training requirements to account for Operations Support Personnel. During the implementation period, Reliability Coordinators, Balancing Authorities and Transmission Operators must continue to comply with the requirements of PER-005-1 applicable to their System Operators.

As described in the proposed Implementation Plan, NERC also respectfully requests that the Commission approve the retirement of PER-005-1 effective 11:59:59 pm of the day immediately prior to the effective date for PER-005-2.

VI. <u>CONCLUSION</u>

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

- the proposed Reliability Standard and associated elements included in Exhibit A, effective as proposed herein;
- the proposed Implementation Plan included in Exhibit B;
- the proposed definitions for the terms "System Operator" and "Operations Support Personnel," effective as proposed herein; and
- the retirement of Reliability Standard PER-005-1, effective as proposed herein.

Respectfully submitted,

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Date: March 7, 2014

Exhibit A

Proposed Reliability Standard

A. Introduction

1. **Title:** **Operations Personnel Training**

2. **Number:** PER-005-2

3. **Purpose:** To ensure that personnel performing or supporting Real-time operations on the Bulk Electric System are trained using a systematic approach.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Reliability Coordinator

   4.1.2 Balancing Authority

   4.1.3 Transmission Operator

   4.1.4 Transmission Owner that has:

   4.1.4.1 Personnel, excluding field switching personnel, who can act independently to operate or direct the operation of the Transmission Owner's Bulk Electric System transmission Facilities in Real-time.

   4.1.5 Generator Operator that has:

   4.1.5.1 Dispatch personnel at a centrally located dispatch center who receive direction from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner, and may develop specific dispatch instructions for plant operators under their control. These personnel do not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions without making any modifications.

5. **Effective Date:**

   5.1. This standard shall become effective the first day of the first calendar quarter that is 24 months beyond the date that this standard is approved by an applicable governmental authority or is otherwise provided for in a jurisdiction where approval by an applicable authority is required for a standard to go into effect.

   Where approval by an applicable governmental authority is not required, this standard shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement a training program for its System Operators as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology.

1.1.1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 1.1 each calendar year.

1.2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 1.1.

1.3. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall deliver training to its System Operators according to its training program.

1.4. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall implement the changes identified.

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence of using a systematic approach to develop and implement a training program for its System Operators, as specified in Requirement R1.

M1.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection its methodology and its BES company-specific Real-time reliability-related task list, with the date of the last review, as specified in Requirement R1 part 1.1 and part 1.1.1.

M1.2 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection training materials, as specified in Requirement R1 part 1.2.

M1.3 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection System Operator training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R1 part 1.3.

M1.4 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation of its training program each calendar year, as specified in Requirement R1 part 1.4.

R2. Each Transmission Owner shall use a systematic approach to develop and implement a training program for its personnel identified in Applicability Section 4.1.4.1 of this standard as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall create a list of BES company-specific Real-time reliability-related tasks based on a defined and documented methodology.

2.1.1. Each Transmission Owner shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 2.1 each calendar year.

2.2. Each Transmission Owner shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 2.1.

2.3. Each Transmission Owner shall deliver training to its personnel identified in Applicability Section 4.1.4.1 of this standard according to its training program.

2.4. Each Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement R2 to identify any needed changes to the training program and shall implement the changes identified.

M2. Each Transmission Owner shall have available for inspection evidence of using a systematic approach to develop and implement a training program for its applicable personnel, as specified in Requirement R2.

M2.1 Each Transmission Owner shall have available for inspection its methodology and its BES company-specific Real-time reliability-related task list, with the date of the last review, as specified in Requirement R2 part 2.1.

M2.2 Each Transmission Owner shall have available for inspection training materials, as specified in Requirement R2 part 2.2.

M2.3 Each Transmission Owner shall have available for inspection training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R2 part 2.3.

M2.4 Each Transmission Owner shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation of its training program each calendar year, as specified in Requirement R2 part 2.4.

R3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1 or Requirement R2 part 2.1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

3.1. Within six months of a modification or addition of a BES company-specific Real-time reliability-related task, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its personnel identified in Requirement R1 or Requirement R2 to perform the new or modified BES company-specific Real-time reliability-related tasks identified in Requirement R1 part 1.1 or Requirement R2 part 2.1.

M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence to show that it verified the capabilities of each of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1 or Requirement R2 part 2.1. This evidence may be documents such as records showing capability to perform BES company-specific Real-time reliability-related tasks with the employee name and date; supervisor check sheets showing the employee name, date, and BES company-specific Real-time reliability-related task completed; or the results of learning assessments.

M3.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner shall present evidence that it verified the capabilities of applicable personnel to perform new or modified BES company-specific Real-time reliability-related tasks within 6 months of a modification or addition of a BES company-specific Real-time reliability-related task.

R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. A Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not previously meet the criteria of Requirement R4, shall comply with Requirement R4 within 12 months of meeting the criteria.

M4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that personnel identified in Requirement R1 or Requirement R2 completed

training that includes the use of simulation technology, as specified in Requirement R4.

M4.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that personnel identified in Requirement R1 or Requirement R2 completed training that included the use of simulation technology, as specified in Requirement R4, within 12 months of meeting the criteria of Requirement R4.

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence that Operations Support Personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training. Documentation of training shall include employee name and date of training.

M5.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation each calendar year, as specified in Requirement R5 part 5.1.

R6. Each Generator Operator shall use a systematic approach to develop and implement training to its personnel identified in Applicability Section 4.1.5.1 of this standard, on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R6 to identify and implement changes to the training.

M6. Each Generator Operator shall have available for inspection evidence that its applicable personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training. Documentation of training shall include employee name and date of training.

M6.1 Each Generator Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation each calendar year, as specified in Requirement R6 part 6.1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

Each Reliability Coordinator, Balancing Authority, Transmission Operator Transmission Owner, and Generator Operator shall keep data or evidence to show compliance for three years or since its last compliance audit, whichever time frame is greater, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator, Balancing Authority, Transmission Operator Transmission Owner, or Generator Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	None	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to review or update, if necessary, its BES company-specific Real-time reliability-related task list each calendar year. (1.1.1.) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator, failed to evaluate its training program each calendar year to identify needed changes to its training program(s). (1.4) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator, failed to implement the identified changes to the training program(s). (1.4.)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to use a systematic approach to develop and implement a training program. (R1) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to design and develop training materials based on the BES company-specific Real-time reliability-related task lists. (1.2)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to create a BES company-specific Real-time reliability-related task list. (1.1.) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to deliver training based on the BES company-specific Real-time reliability-related task lists. (1.3)
R2	Long-term Planning	Medium	None	The Transmission Owner failed to review or update, if necessary, its company-specific Real-time reliability-	The Transmission Owner failed to use a systematic approach to develop and implement a training program. (R2)	The Transmission Owner failed to create a BES company-specific Real-time reliability-related task list. (2.1.) OR

				related task list each calendar year. (2.1.1.) OR The Transmission Owner failed to evaluate its training program each calendar year to identify needed changes to its training program(s). (2.4) OR The Transmission Owner failed to implement the identified changes to the training program(s). (2.4.)	OR The Transmission Owner failed to design and develop training materials based on the BES company-specific Real-time reliability-related task lists. (2.2)	The Transmission Owner failed to deliver training based on the BES company-specific Real-time reliability-related task lists. (2.3)
R3	**Long-term Planning**	**High**	**None**	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of at least 90% but less than 100% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3)	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of at least 70% but less than 90% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner failed to verify the capabilities of its personnel identified in Requirements R1 or Requirement	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of less than 70% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3)

					R2 to perform each new or modified task within six months of making a modification to its BES company-specific Real-time reliability-related task list. (3.1)	
R4	**Long-term Planning**	**Medium**	**None**	**None**	**None**	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that meet the criteria of Requirement R4 did not provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. (R4) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner did not provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES within twelve months of meeting the criteria of Requirement R4. (R4.1)

R5	**Long-term Planning**	**Medium**	**None**	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to evaluate its training established in Requirement R5 each calendar year. (5.1)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to develop training for its Operations Support Personnel. (R5) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator developed training but failed to use a systematic approach. (R5)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to implement training for its Operations Support Personnel. (R5)
R6	**Long-term Planning**	**Medium**	**None**	The Generator Operator failed to evaluate its training established in Requirement R6 each calendar year. (6.1)	The Generator Operator failed to develop training for its personnel. (R6) OR The Generator Operator developed training but failed to use a systematic approach. (R6)	The Generator Operator failed to implement the training for its personnel identified in Requirement R6. (R6)

Guidelines and Technical Basis

Requirement R1 and R2:

Any systematic approach to training will determine: 1) the skills and knowledge needed to perform BES company-specific Real-time reliability-related tasks; 2) what training is needed to achieve those skills and knowledge; 3) if the learner can perform the BES company-specific Real-time reliability-related task(s) acceptably in either a training or on-the-job environment; and 4) if the training is effective, and make adjustments as necessary.

Reference #1: Determining Task Performance Requirements

The purpose of this reference is to provide guidance for a performance standard that describes the desired outcome of a task. A standard for acceptable performance should be in either measurable or observable terms. Clear standards of performance are necessary for an individual to know when he or she has completed the task and to ensure agreement between employees and their supervisors on the objective of a task. Performance standards answer the following questions:

How timely must the task be performed?

Or

How accurately must the task be performed?

Or

With what quality must it be performed?

Or

What response from the customer must be accomplished?

When a performance standard is quantifiable, successful performance is more easily demonstrated. For example, in the following task statement, the criteria for successful performance is to return system loading to within normal operating limits, which is a number that can be easily verified.

> Given a System Operating Limit violation on the transmission system, implement the correct procedure for the circumstances to mitigate loading to within normal operating limits.

Even when the outcome of a task cannot be measured as a number, it may still be observable. The next example contains performance criteria that is qualitative in nature, that is, it can be verified as either correct or not, but does not involve a numerical result.

> Given a tag submitted for scheduling, ensure that all transmission rights are assigned to the tag per the company Tariff and in compliance with NERC and NAESB standards.

Reference #2: Systematic Approach to Training References:
The following list of hyperlinks identifies references for the NERC Standard PER-005 to assist with the application of a systematic approach to training:

(1) DOE-HDBK-1078-94, A Systematic Approach to Training

http://www.publicpower.org/files/PDFs/DOEHandbookTrainingProgramSystematicApproach.pdf

(2) DOE-HDBK-1074-95, January 1995, Alternative Systematic Approaches to Training, U.S. Department of Energy, Washington, D.C. 20585 FSC 6910

http://www.catagle.com/112-1/download_php-spec_DOE-HDBK-1074-95_003254_1.htm

(3) ADDIE – 1975, Florida State University

http://www.nwlink.com/~donclark/history_isd/addie.html

(4) DOE Standard - Table-Top Needs Analysis
DOE-HDBK-1103-96

http://energy.gov/sites/prod/files/2013/06/f2/hdbk1103.pdf

Reference #3: Recognized Operator Training Topics
See Appendix A – Recognized Operator Training Topics within the NERC System Operator Certification Program Manual.
http://www.nerc.com/pa/Train/SysOpCert/Documents/SOC_Program_Manual_February_2012_Final.pdf

Reference #4: Definitions of Simulation and Simulators

Georgia Institute of Technology – Modeling & Simulation for Systems Engineering
http://www.pe.gatech.edu/conted/servlet/edu.gatech.conted.course.ViewCourseDetails?COURSE_ID=840

University of Central Florida – Institute for Simulation & Training
Just what is "simulation" anyway (or, Simulation 101)?
And what about "modeling"?
But what does IST do with simulations?
http://www.ist.ucf.edu/overview.htm

Rationale:

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

Rationale for System Operator:

The definition of the existing NERC Glossary Term “System Operator" has been modified to remove Generator Operator (GOP) in response to Project 2010-16.

The term “System Operator” contains another NERC Glossary term “Control Center”, which was approved by FERC on November 22, 2013. The inclusion of GOPs within the approved definition of Control Center does not bring GOPs into the System Operator definition. The System Operator definition specifies that it only applies to Balancing Authority (BA), Transmission Operator (TOP) or Reliability Coordinator (RC) personnel.

The modifications to the definition of “System Operator” do not affect other standards; see the PER-005-2 White Paper, which cross checks System Operator with other NERC Standards.

Rationale for Operations Support Personnel:

The term Operations Support Personnel is used to identify those support personnel of Reliability Coordinators (RC), Balancing Authorities (BA), or Transmission Operators (TOP) that FERC identified in Order No. 693.

Rationale for TO:

Extending the applicability to TOs is necessary to address the FERC directive that the ERO develop formal training requirements for local transmission control center operator personnel. In Order No. 742 at P 62, the Commission clarified its understanding that local control center personnel *“exercise control over a significant portion of the Bulk-Power System under the supervision of the personnel of the registered transmission operator. The supervision may take the form of directive specific step-by-step instructions and at other times may take the form of the implementation of predefined operating procedures. In all cases, the Commission continued, the local transmission control center personnel must understand what they are required to do in the performance of their duties to perform them effectively on a timely basis. Thus, omitting such local transmission control center personnel from the PER-005-1 training requirements creates a reliability gap.”* See FERC Order 693 at P 1343 and 1347.

Rationale for GOP:

Extending the applicability to Generator Operators (GOPs) that have dispatch personnel at a centrally located dispatch center is necessary to address the FERC directive that the ERO develop specific requirements addressing the scope, content and duration appropriate for certain GOP personnel. The Commission explains in Order No. 693 at P 1359 that “*although a generator operator typically receives instructions from a balancing authority, it is essential that generator operator personnel have appropriate training to understand those instructions,* *particularly in an emergency situation in which instructions may be succinct and require immediate action."* Order No. 742 further clarified that the directive "*applies to generator operator personnel at a centrally-located dispatch center who receive direction and then develop specific dispatch instructions for plant operators under their control. Plant operators located at the generator plant site are not required to be trained in PER-005-2."* Based on the FERC order, this applicability section clarifies which GOP personnel are subject to the standard.

Rationale for changes to R2:

Transmission Owners personnel at local transmission control centers have been added to the PER standard and are subject to Requirements R2, R3 and R4 of PER-005-2. The reason for adding Transmission Owners is to address Order No. 693 and Order No. 742 FERC directives to include local transmission control center operator personnel.

Rationale for R3:

This Requirement was brought forward from the previous version with the addition of Transmission Owners. It provides an entity with an opportunity to create a baseline from which to assess training needs as it develops a systematic approach.

Rationale for changes to R4:

The requirement mandates the use of specific training technologies. It does not require training on Interconnection Reliability Operating Limits (IROLs). The standard allows entities that gain operational authority or control over a Facility with IROLs or established protection systems or operating guides to mitigate IROL violations within 12 months to comply with Requirement R4 to provide them sufficient time to obtain simulation technology.

The requirement to provide a minimum of 32 hours of Emergency Operations training has been removed since the appropriate number of hours would be identified as part of the systematic approach in Requirement R1 and Requirement R2 through the analysis phase and outlined in a continuous education section of their training program. Any additional hours may be duplicative or repetitive for the entity in providing training to its personnel. Requirement R4.1 covers the FERC directive for the creation of an implementation plan for simulation technology.

Rationale for R5:

This is a new requirement applicable to Operations Support Personnel. In FERC Order No. 742, the Commission noted that NERC, in developing Reliability Standard PER-005-1, did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include operations planning and operation support staff who carry out outage planning and assessments and those who develop System Operating Limits (SOL), Interconnection Reliability Operating Limits (IROL), or operating nomograms for Real-time operations. This requirement contemplates that entities will look to the systematic approach already developed under Requirement R1. The entity can use the list created from Requirement R1 and select the BES company-specific Real-time reliability-related tasks with which Operations Support Personnel are involved.

Rationale for R6:

This requirement requires the training of certain GOP dispatch personnel on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. This requirement mandates the use of a systematic approach which allows for each entity to tailor its training to the needs of its organization.

This is a new requirement applicable to certain GOPs as described in the applicability section. In FERC Order No. 742, the Commission noted that in developing proposed Reliability Standard PER-005-1, NERC did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include GOPs centrally-located at a generation dispatch center with a direct impact on the reliable operation of the BES. The Commission acknowledged that the training for GOPs need not be as extensive as the training for TOPs and BAs. FERC also stated that the systematic approach to training methodology is flexible enough to build on existing training programs by validating and supplementing the existing training content, where necessary, using systematic methods.

Version History

Version	Date	Action	Change Tracking
1	2/10/2009	Adopted by the NERC Board of Trustees	
1	11/18/2010	FERC Approved	
1	8/26/2013	Updated VSLs based on June 24, 2013 approval.	
2	2/6/2014	Adopted by the NERC Board of Trustees	

A. Introduction

1. **Title:** ~~System~~**Operations Personnel Training**

2. **Number:** PER-005-~~1~~2

3. **Purpose:** To ensure that ~~System Operators~~personnel performing ~~real~~or supporting Real-time~~, reliability-related tasks~~ operations

~~3.~~ on the ~~North American~~ Bulk Electric System ~~(BES)~~ are ~~competent to perform those reliability-related tasks. The competency of System Operators is critical to the reliability of the North American Bulk Electric System~~trained using a systematic approach.

4. **Applicability:**

4.1. Functional Entities:

4.1.1 Reliability Coordinator~~.~~

4.1.2 Balancing Authority~~.~~

4.1.3 Transmission Operator~~.~~

4.1.4 ~~Proposed~~ Transmission Owner that has:

4.1.4.1 Personnel, excluding field switching personnel, who can act independently to operate or direct the operation of the Transmission Owner's Bulk Electric System transmission Facilities in Real-time.

4.1.5 Generator Operator that has:

4.1.5.1 Dispatch personnel at a centrally located dispatch center who receive direction from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner, and may develop specific dispatch instructions for plant operators under their control. These personnel do not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions without making any modifications.

5. **Effective Date** ~~**for Regulatory Approvals:**~~ **:**

5.1. ~~In those jurisdictions where regulatory approval is required, Requirement R1 and Requirement R2~~This standard shall become effective ~~on~~ the first day of the first calendar quarter~~, 24 months after applicable regulatory~~ that is 24 months beyond the date that this standard is approved by an applicable governmental authority or is otherwise provided for in a jurisdiction where approval by an applicable authority is required for a standard to go into effect.

~~**5.1.**~~ Where approval~~. In those jurisdictions where no regulatory approval is~~ by an applicable governmental authority is not required, ~~Requirement R1 and~~

~~Requirement R2 shall become effective on the first day of the first calendar quarter, 24 months after Board of Trustees adoption.~~

~~5.2.~~ ~~In those jurisdictions where regulatory approval is required, Requirement R3 shall become effective on the first day of the first calendar quarter after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirement R3~~this standard shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees ~~adoption.~~or as otherwise provided for in that jurisdiction.

~~5.3. In those jurisdictions where regulatory approval is required Sub-requirement R3.1 shall become effective on the first day of the first calendar quarter, 36 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the Sub-requirement R3.1 shall become effective on the first day of the first calendar quarter, 36 months after Board of Trustees adoption.~~

B. Requirements and Measures

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to ~~training to establish~~develop and implement a training program for ~~the BES company-specific reliability-related tasks performed by~~ its System Operators ~~and shall implement the program.~~as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

~~**R1.1.**~~**1.1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks ~~performed by its System Operators~~based on a defined and documented methodology.

~~**R1.1.1.**~~**1.1.1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks ~~performed by its System Operators~~identified in part 1.1 each calendar year~~to identify new or modified tasks for inclusion in training.~~.

~~**R1.2.**~~**1.2.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall design and develop ~~**learning objectives and**~~ training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in ~~**R1.**~~part 1.~~-~~1.

~~**R1.3.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall deliver the training established in R1.2.~~

1.3. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall deliver training to its System Operators according to its training program.

~~R1.4.~~1.4. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an ~~annual~~ evaluation each calendar year of the training program established in Requirement R1~~,~~ to identify any needed changes to the training program and shall implement the changes identified.

~~R2.~~ Each Reliability Coordinator, Balancing Authority ~~and Transmission Operator shall verify each of its System Operator's capabilities to perform each assigned task identified in R1.1 at least one time. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*~~

~~R2.1. Within six months of a modification of the BES company-specific reliability-related tasks, each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator's capabilities to perform the new or modified tasks.~~

~~R3. At least every 12 months each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each of its System Operators with at least 32 hours of emergency operations training applicable to its organization that reflects emergency operations topics, which includes system restoration using drills, exercises or other training required to maintain qualified personnel. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~

~~R3.1. Each Reliability Coordinator, Balancing Authority and Transmission Operator that has operational authority or control over Facilities with established IROLs or has established operating guides or protection systems to mitigate IROL violations shall provide each System Operator with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES during normal and emergency conditions.~~

~~C. Measures~~

M1. ~~Each Reliability Coordinator, Balancing Authority~~, and Transmission Operator shall have available for inspection evidence of using a systematic approach to ~~training to establish~~develop and implement a training program for its System Operators, as specified in Requirement R1.

M1.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection its methodology and its BES company-specific Real-time reliability-related task list, with the date of the last review ~~and/or revision~~, as specified in Requirement R1 part 1.1 and part 1.1.1.

M1.2 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection ~~its learning objectives and~~ training materials, as specified in ~~R1~~Requirement R1 part 1.2.

M1.3 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection System Operator training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in ~~R1~~Requirement R1 part 1.3.

M1.4 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an ~~annual~~evaluation of its training program ~~evaluation~~each calendar year, as specified in Requirement R1 part 1.4.

R2. Each Transmission Owner shall use a systematic approach to develop and implement a training program for its personnel identified in Applicability Section 4.1.4.1 of this standard as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall create a list of BES company-specific Real-time reliability-related tasks based on a defined and documented methodology.

2.1.1. Each Transmission Owner shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 2.1 each calendar year.

2.2. Each Transmission Owner shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 2.1.

2.3. Each Transmission Owner shall deliver training to its personnel identified in Applicability Section 4.1.4.1 of this standard according to its training program.

2.4. Each Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement R2 to identify any needed changes to the training program and shall implement the changes identified.

M2. Each Transmission Owner shall have available for inspection evidence of using a systematic approach to develop and implement a training program for its applicable personnel, as specified in Requirement R2.

M2.1 Each Transmission Owner shall have available for inspection its methodology and its BES company-specific Real-time reliability-related task list, with the date of the last review, as specified in Requirement R2 part 2.1.

M2.2 Each Transmission Owner shall have available for inspection training materials, as specified in Requirement R2 part 2.2.

M2.3 Each Transmission Owner shall have available for inspection training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R2 part 2.3.

M2.4 Each Transmission Owner shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation of its training program each calendar year, as specified in Requirement R2 part 2.4.

R3. Each Reliability Coordinator, Balancing Authority ~~and~~, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1 or Requirement R2 part 2.1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

3.1. Within six months of a modification or addition of a BES company-specific Real-time reliability-related task, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its personnel identified in Requirement R1 or Requirement R2 to perform the new or modified BES company-specific Real-time reliability-related tasks identified in Requirement R1 part 1.1 or Requirement R2 part 2.1.

~~M2.~~M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence to show that it verified ~~that each of its System Operators is capable of performing each assigned task identified in R1.1, as specified in R2.~~ the capabilities of each of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1 or Requirement R2 part 2.1. This evidence ~~can~~may be documents such as ~~training~~ records showing ~~successful completion of~~capability to perform BES company-specific Real-time reliability-related tasks with the employee name and date; supervisor check sheets showing the employee name, date, and BES company-specific Real-time reliability-related task completed; or the results of learning assessments.

~~M3.~~M3.1 Each Reliability Coordinator, Balancing Authority ~~and~~, Transmission Operator, or Transmission Owner shall ~~have available for inspection training records that provide~~ present evidence that ~~each System Operator has obtained 32 hours~~it verified the capabilities of ~~emergency operations training, as specified in R3~~applicable personnel to perform new or modified BES company-specific Real-time reliability-related tasks within 6 months of a modification or addition of a BES company-specific Real-time reliability-related task.

R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. A Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not previously meet the criteria of Requirement R4, shall comply with Requirement R4 within 12 months of meeting the criteria.

M4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission ~~Operator~~Owner shall have available for inspection training records that provide evidence that ~~each System Operator received emergency operations~~personnel identified in Requirement R1 or Requirement R2 completed training ~~using~~that includes the use of simulation technology, as specified in Requirement R4.

M4.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that personnel identified in Requirement R1 or Requirement R2 completed training that included the use of simulation technology, as specified in ~~R3~~Requirement R4, within 12 months of meeting the criteria of Requirement R4.

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence that Operations Support Personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training. Documentation of training shall include employee name and date of training.

M5.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation each calendar year, as specified in Requirement R5 part 5.1.

R6. Each Generator Operator shall use a systematic approach to develop and implement training to its personnel identified in Applicability Section 4.1.5.1 of this standard, on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R6 to identify and implement changes to the training.

M6. Each Generator Operator shall have available for inspection evidence that its applicable personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training. Documentation of training shall include employee name and date of training.

~~**M3.1**~~**M6.1** Each Generator Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation each calendar year, as specified in Requirement R6 part 6.1.

~~D.~~C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~For Reliability Coordinators and other functional entities that work for their Regional Entity,~~As defined in the ~~ERO shall serve as the~~ NERC Rules of Procedure, "Compliance Enforcement Authority~~.~~

~~For entities that do not work for~~" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the ~~Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority~~NERC Reliability Standards.

~~1.2. Compliance Monitoring Period and Reset~~

~~Not Applicable.~~

~~1.3. Compliance Monitoring and Enforcement Processes:~~

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Violation Investigations~~

~~Self-Reporting~~

~~Complaints~~

~~1.4.~~1.2. ~~Data~~Evidence Retention

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

Each Reliability Coordinator, Balancing Authority ~~and~~, Transmission Operator Transmission Owner, and Generator Operator shall keep data or evidence to show compliance for three years or since its last compliance audit, whichever time frame is ~~the greatest~~greater, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator, Balancing Authority ~~and~~, Transmission Operator Transmission Owner, or Generator Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

~~1.5.~~1.4. Additional Compliance Information

None~~.~~

~~2. Violation Severity Levels~~

~~R#~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
~~R1~~	~~N/A~~	~~The responsible entity failed to update its BES company-specific reliability-related task list to identify new or modified tasks each calendar year. (R1.1.1)~~ ~~OR~~ ~~The responsible entity failed to evaluate its training program to identify needed changes to its training program(s). (R1.4)~~ ~~OR~~ ~~An entity evaluated its training program and identified changes, but failed to implement them. (R1.4)~~	~~The responsible entity failed to design and develop learning objectives and training materials based on the BES company specific reliability related tasks. (R1.2)~~	~~The responsible entity failed to prepare a BES company-specific reliability-related task list. (R1.1)~~ ~~OR~~ ~~The responsible entity failed to deliver training based on the BES company specific reliability related tasks. (R1.3)~~
~~R2~~	~~N/A~~	~~The responsible entity failed to verify 5% or less of its System Operators' capabilities to perform each assigned task from its list of BES company-specific reliability-related tasks. (R2)~~	~~The responsible entity failed to verify more than 5% up to (and including) 10% of its System Operators' capabilities to perform each assigned task from its list of BES company-specific reliability-related tasks. (R2)~~ ~~OR~~ ~~The responsible entity verified its System Operator's capabilities to perform each new or modified task more than six months but fewer than twelve months after making a modification to its BES company-specific reliability-related task list. (R2.1)~~	~~The responsible entity failed to verify more than 10% of its System Operators' capabilities to perform each assigned task from its list of BES company-specific reliability-related tasks. (R2)~~ ~~OR~~ ~~The responsible entity failed to verify its System Operator's capabilities to perform each new or modified task within twelve months of making a modification to its BES company-specific reliability-related task list. (R2.1)~~
~~R3~~	~~N/A~~	~~The responsible entity failed to provide at least 32 hours of emergency operations training applicable to its organization, affecting 5% or less of their System Operators. (R3)~~	~~The responsible entity failed to provide at least 32 hours of emergency operations training applicable to its organization, affecting more than 5% and up to (and including) 10% of its System Operators. (R3)~~	~~The responsible entity failed to provide at least 32 hours of emergency operations training applicable to its organization, affecting more than 10% its System Operators (R3)~~ ~~OR~~

~~R#~~	~~Lower VSL~~	~~Moderate VSL~~	~~High VSL~~	~~Severe VSL~~
				~~The responsible entity did not include simulation technology replicating the operational behavior of the BES in its emergency operations training. (R3.1)~~

~~E.~~D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	None	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to review or update, if necessary, its BES company-specific Real-time reliability-related task list each calendar year. (1.1.1.) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator, failed to evaluate its training program each calendar year to identify needed changes to its training program(s). (1.4) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator, failed to implement the identified changes to the training program(s). (1.4.)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to use a systematic approach to develop and implement a training program. (R1) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to design and develop training materials based on the BES company-specific Real-time reliability-related task lists. (1.2)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to create a BES company-specific Real-time reliability-related task list. (1.1.) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to deliver training based on the BES company-specific Real-time reliability-related task lists. (1.3)
R2	Long-term Planning	Medium	None	The Transmission Owner failed to review or update, if necessary, its company-specific Real-time reliability-	The Transmission Owner failed to use a systematic approach to develop and implement a training program. (R2)	The Transmission Owner failed to create a BES company-specific Real-time reliability-related task list. (2.1.) OR

				related task list each calendar year. (2.1.1.) OR The Transmission Owner failed to evaluate its training program each calendar year to identify needed changes to its training program(s). (2.4) OR The Transmission Owner failed to implement the identified changes to the training program(s). (2.4.)	OR The Transmission Owner failed to design and develop training materials based on the BES company-specific Real-time reliability-related task lists. (2.2)	The Transmission Owner failed to deliver training based on the BES company-specific Real-time reliability-related task lists. (2.3)
R3	**Long-term Planning**	**High**	**None**	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of at least 90% but less than 100% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3)	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of at least 70% but less than 90% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner failed to verify the capabilities of its personnel identified in Requirements R1 or Requirement	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of less than 70% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3)

					R2 to perform each new or modified task within six months of making a modification to its BES company-specific Real-time reliability-related task list. (3.1)	
R4	**Long-term Planning**	**Medium**	**None**	**None**	**None**	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that meet the criteria of Requirement R4 did not provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. (R4) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner did not provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES within twelve months of meeting the criteria of Requirement R4. (R4.1)

R5	**Long-term Planning**	**Medium**	**None**	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to evaluate its training established in Requirement R5 each calendar year. (5.1)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to develop training for its Operations Support Personnel. (R5) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator developed training but failed to use a systematic approach. (R5)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to implement training for its Operations Support Personnel. (R5)
R6	**Long-term Planning**	**Medium**	**None**	The Generator Operator failed to evaluate its training established in Requirement R6 each calendar year. (6.1)	The Generator Operator failed to develop training for its personnel. (R6) OR The Generator Operator developed training but failed to use a systematic approach. (R6)	The Generator Operator failed to implement the training for its personnel identified in Requirement R6. (R6)

Guidelines and Technical Basis

Requirement R1 and R2:

Any systematic approach to training will determine: 1) the skills and knowledge needed to perform BES company-specific Real-time reliability-related tasks; 2) what training is needed to achieve those skills and knowledge; 3) if the learner can perform the BES company-specific Real-time reliability-related task(s) acceptably in either a training or on-the-job environment; and 4) if the training is effective, and make adjustments as necessary.

Reference #1: Determining Task Performance Requirements

The purpose of this reference is to provide guidance for a performance standard that describes the desired outcome of a task. A standard for acceptable performance should be in either measurable or observable terms. Clear standards of performance are necessary for an individual to know when he or she has completed the task and to ensure agreement between employees and their supervisors on the objective of a task. Performance standards answer the following questions:

How timely must the task be performed?

Or

How accurately must the task be performed?

Or

With what quality must it be performed?

Or

What response from the customer must be accomplished?

When a performance standard is quantifiable, successful performance is more easily demonstrated. For example, in the following task statement, the criteria for successful performance is to return system loading to within normal operating limits, which is a number that can be easily verified.

> Given a System Operating Limit violation on the transmission system, implement the correct procedure for the circumstances to mitigate loading to within normal operating limits.

Even when the outcome of a task cannot be measured as a number, it may still be observable. The next example contains performance criteria that is qualitative in nature, that is, it can be verified as either correct or not, but does not involve a numerical result.

> Given a tag submitted for scheduling, ensure that all transmission rights are assigned to the tag per the company Tariff and in compliance with NERC and NAESB standards.

Reference #2: Systematic Approach to Training References:

The following list of hyperlinks identifies references for the NERC Standard PER-005 to assist with the application of a systematic approach to training:

(1) DOE-HDBK-1078-94, A Systematic Approach to Training

http://www.publicpower.org/files/PDFs/DOEHandbookTrainingProgramSystematicApproach.pdf

(2) DOE-HDBK-1074-95, January 1995, Alternative Systematic Approaches to Training, U.S. Department of Energy, Washington, D.C. 20585 FSC 6910

http://www.catagle.com/112-1/download_php-spec_DOE-HDBK-1074-95_003254_1.htm

(3) ADDIE – 1975, Florida State University

http://www.nwlink.com/~donclark/history_isd/addie.html

(4) DOE Standard - Table-Top Needs Analysis
DOE-HDBK-1103-96

http://energy.gov/sites/prod/files/2013/06/f2/hdbk1103.pdf

Reference #3: Recognized Operator Training Topics

See Appendix A – Recognized Operator Training Topics within the NERC System Operator Certification Program Manual.
http://www.nerc.com/pa/Train/SysOpCert/Documents/SOC_Program_Manual_February_2012_Final.pdf

Reference #4: Definitions of Simulation and Simulators

Georgia Institute of Technology – Modeling & Simulation for Systems Engineering
http://www.pe.gatech.edu/conted/servlet/edu.gatech.conted.course.ViewCourseDetails?COURSE_ID=840

University of Central Florida – Institute for Simulation & Training
Just what is "simulation" anyway (or, Simulation 101)?
And what about "modeling"?
But what does IST do with simulations?
http://www.ist.ucf.edu/overview.htm

Rationale:

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

Rationale for System Operator:

The definition of the existing NERC Glossary Term "System Operator" has been modified to remove Generator Operator (GOP) in response to Project 2010-16.

The term "System Operator" contains another NERC Glossary term "Control Center", which was approved by FERC on November 22, 2013. The inclusion of GOPs within the approved definition of Control Center does not bring GOPs into the System Operator definition. The System Operator definition specifies that it only applies to Balancing Authority (BA), Transmission Operator (TOP) or Reliability Coordinator (RC) personnel.

The modifications to the definition of "System Operator" do not affect other standards; see the PER-005-2 White Paper, which cross checks System Operator with other NERC Standards.

Rationale for Operations Support Personnel:

The term Operations Support Personnel is used to identify those support personnel of Reliability Coordinators (RC), Balancing Authorities (BA), or Transmission Operators (TOP) that FERC identified in Order No. 693.

Rationale for TO:

Extending the applicability to TOs is necessary to address the FERC directive that the ERO develop formal training requirements for local transmission control center operator personnel. In Order No. 742 at P 62, the Commission clarified its understanding that local control center personnel *"exercise control over a significant portion of the Bulk-Power System under the supervision of the personnel of the registered transmission operator. The supervision may take the form of directive specific step-by-step instructions and at other times may take the form of the implementation of predefined operating procedures. In all cases, the Commission continued, the local transmission control center personnel must understand what they are required to do in the performance of their duties to perform them effectively on a timely basis. Thus, omitting such local transmission control center personnel from the PER-005-1 training requirements creates a reliability gap."* See FERC Order 693 at P 1343 and 1347.

Rationale for GOP:

Extending the applicability to Generator Operators (GOPs) that have dispatch personnel at a centrally located dispatch center is necessary to address the FERC directive that the ERO develop specific requirements addressing the scope, content and duration appropriate for certain GOP personnel. The Commission explains in Order No. 693 at P 1359 that "*although a generator operator typically receives instructions from a balancing authority, it is essential that generator operator personnel have appropriate training to understand those instructions,* *particularly in an emergency situation in which instructions may be succinct and require immediate action."* Order No. 742 further clarified that the directive "*applies to generator operator personnel at a centrally-located dispatch center who receive direction and then develop specific dispatch instructions for plant operators under their control. Plant operators located at the generator plant site are not required to be trained in PER-005-2."* Based on the FERC order, this applicability section clarifies which GOP personnel are subject to the standard.

Rationale for changes to R2:

Transmission Owners personnel at local transmission control centers have been added to the PER standard and are subject to Requirements R2, R3 and R4 of PER-005-2. The reason for adding Transmission Owners is to address Order No. 693 and Order No. 742 FERC directives to include local transmission control center operator personnel.

Rationale for R3:

This Requirement was brought forward from the previous version with the addition of Transmission Owners. It provides an entity with an opportunity to create a baseline from which to assess training needs as it develops a systematic approach.

Rationale for changes to R4:

The requirement mandates the use of specific training technologies. It does not require training on Interconnection Reliability Operating Limits (IROLs). The standard allows entities that gain operational authority or control over a Facility with IROLs or established protection systems or operating guides to mitigate IROL violations within 12 months to comply with Requirement R4 to provide them sufficient time to obtain simulation technology.

The requirement to provide a minimum of 32 hours of Emergency Operations training has been removed since the appropriate number of hours would be identified as part of the systematic approach in Requirement R1 and Requirement R2 through the analysis phase and outlined in a continuous education section of their training program. Any additional hours may be duplicative or repetitive for the entity in providing training to its personnel. Requirement R4.1 covers the FERC directive for the creation of an implementation plan for simulation technology.

Rationale for R5:

This is a new requirement applicable to Operations Support Personnel. In FERC Order No. 742, the Commission noted that NERC, in developing Reliability Standard PER-005-1, did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include operations planning and operation support staff who carry out outage planning and assessments and those who develop System Operating Limits (SOL), Interconnection Reliability Operating Limits (IROL), or operating nomograms for Real-time operations. This requirement contemplates that entities will look to the systematic approach already developed under Requirement R1. The entity can use the list created from Requirement R1 and select the BES company-specific Real-time reliability-related tasks with which Operations Support Personnel are involved.

Application Guidelines

Rationale for R6:

This requirement requires the training of certain GOP dispatch personnel on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. This requirement mandates the use of a systematic approach which allows for each entity to tailor its training to the needs of its organization.

This is a new requirement applicable to certain GOPs as described in the applicability section. In FERC Order No. 742, the Commission noted that in developing proposed Reliability Standard PER-005-1, NERC did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include GOPs centrally-located at a generation dispatch center with a direct impact on the reliable operation of the BES. The Commission acknowledged that the training for GOPs need not be as extensive as the training for TOPs and BAs. FERC also stated that the systematic approach to training methodology is flexible enough to build on existing training programs by validating and supplementing the existing training content, where necessary, using systematic methods.

Version History

Version	Date	Action	Change Tracking
1	2/10/2009	Adopted by the NERC Board of Trustees	
1	11/18/2010	FERC Approved	
1	8/26/2013	Updated VSLs based on June 24, 2013 approval.	
2	2/6/2014	Adopted by the NERC Board of Trustees	

Exhibit B

Implementation Plan

Implementation Plan

Project 2010-01 Operations Personnel Training

Implementation Plan for PER-005-2 – Operations Personnel Training

Approvals Required
PER-005-2 – Operations Personnel Training

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

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

System Operator: An individual at a Control Center of a Reliability Coordinator, Balancing Authority, or Transmission Operator who operates or directs the operation of the Bulk Electric System in Real-time.

Operations Support Personnel: Individuals who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms,[1] in direct support of Real-time operations of the Bulk Electric System.

Other Definitions Used within the Standard
None

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Operator

[1] Nomograms are used in the WECC Region to describe element operating limits.

- Transmission Owners that has personnel, excluding field switching personnel, who can act independently to operate or direct the operation of the Transmission Owner's Bulk Electric System transmission Facilities in Real-time
- Generator Operators that have dispatch personnel at a centrally located dispatch center who receive direction from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control. These personnel do not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions without making any modifications.

Applicable Facilities
None

Conforming Changes to Other Standards
None

Effective Dates
PER-005-2 shall become effective as follows:

> This standard shall become effective the first day of the first calendar quarter that is 24 months beyond the date that this standard is approved by an applicable governmental authority or is otherwise provided for in a jurisdiction where approval by an applicable authority is required for a standard to go into effect.
>
> Where approval by an applicable governmental authority is not required, this standard shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Actions to be Completed as of the Effective Date:
An implementation period provides time for an entity to become compliant with the standard prior to the standard becoming enforceable. This section describes the requirements that an entity must be compliant with as of the enforceable date of PER-005-2. This section does not address evidence of compliance; see measures, compliance input and RSAWs for further information regarding possible evidence.

<u>Requirement R1:</u>
Reliability Coordinators, Balancing Authorities, and Transmission Operators must have completed the requirements for PER-005-2 Requirement R1 as of the enforceable date of the standard as provided below. Note that these entities are subject to PER-005-1.

R1: Entities must have developed and implemented a training program for its System Operators using a systematic approach.

1.1: Entities must have defined and documented its methodology for creating a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks, and must have a list of these tasks.

1.1.1: Entities must have conducted a review of its tasks list once in the calendar year that this standard becomes enforceable.

Note: this review may be conducted either under the existing standard PER-005-1 or under PER-005-2 after it becomes enforceable, as long as the entity conducts one review during the calendar year.

1.2: An entity must have completed the design and development of training materials as necessary under its training program as of the enforceable date of PER-005-2. An entity is not obligated to have designed and developed training materials for all future training.

1.3: Entities must have delivered training in accordance with their training program as of the enforceable date of PER-005-2.

1.4: Entities must have conducted an evaluation once in the calendar year that PER-005-2 becomes enforceable.

Note: this may be conducted either under PER-005-1 or under PER-005-2 after it becomes enforceable, as long as the entity conducts one evaluation during the calendar year.

<u>Requirement R2:</u>

R2: Applicable Transmission Owners must have developed and implemented a training program for its applicable personnel using a systematic approach.

2.1: An applicable Transmission Owner must have defined and documented its methodology for creating a list of BES company-specific Real-time reliability-related tasks, and must have a list of these tasks as of the enforceable date of PER-005-2.

2.1.1: As applicable Transmission Owners were not previously subject to PER-005-1, they would not be required to have conducted a review prior to the enforceable date of the proposed standard or in the calendar year that the proposed standard becomes enforceable. The entity's first required evaluation would occur within the first calendar year following the enforceable date of PER-005-2.

2.2: An applicable Transmission Owner must have completed the design and development of training materials according to its training program as of the enforceable date of PER-005-2. An entity is not obligated to have designed and developed training materials for all future training.

2.3: As applicable Transmission Owners were not previously subject to PER-005-1, they must begin to implement training in accordance with its training program as of the enforceable date. Under the standard, these entities are not required to have delivered training prior to the enforceable date.

2.4: As applicable Transmission Owners were not previously subject to PER-005-1, they would not be required to have conducted an evaluation prior to the enforceable date of the proposed standard or in the calendar year that the proposed standard becomes enforceable. The entity's first required evaluation would occur within the first calendar year following the enforceable date of PER-005-2.

Requirement R3:

R3: Reliability Coordinators, Balancing Authorities, Transmission Operators and Transmission Owners must have verified the capabilities of its personnel identified in Requirements R1 and R2 to perform each of its assigned BES company-specific Real-time reliability-related tasks, at least once, as of the enforceable date of PER-005-2.

3.1: Reliability Coordinators, Balancing Authorities, and Transmission Operators that are already subject to PER-005-1 are required to, within six months of a change to its task list, have verified the capabilities of its personnel identified in Requirement R1 to perform each new or modified BES company-specific Real-time reliability-related tasks identified in Requirement R1 part 1.1. These entities will continue to have the time allotted to complete the verification under PER-005-1 after the enforceable date of PER-005-2.

Because Transmission Owners were not previously subject to PER-005-1, they are not expected to have verified the capabilities of its personnel identified in Requirement R2 to perform a new or modified BES company-specific Real-time reliability-related tasks identified under Requirement R2 part 2.1 prior to the enforceable date of the standard. This requirement pertains to BES company-specific reliability-related tasks that are newly identified or modified after the enforceable date of PER-005-2.

Requirement R4:

R4: Reliability Coordinators, Balancing Authorities, Transmission Operators and Transmission Owners must be providing training using the simulation technologies described in Requirement R4 according to its training program as of the date PER-005-2 becomes enforceable.

4.1: Entities that do not meet the criteria set forth in Requirement R4 prior to the enforceable date of the standard are required to comply with Requirement R4 within 12 months of meeting the criteria.

Requirement R5:

R5: Reliability Coordinators, Balancing Authorities, and Transmission Operators must have developed training, using a systematic approach, for their Operations Support Personnel on the impact of their job function(s) to those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1 and must have implemented that training according to its systematic approach as of the enforceable date of PER-005-2.

5.1: As Operations Support Personnel were not previously subject to PER-005-1, they would not be required to have conducted an evaluation prior to the enforceable date of the proposed standard or in the calendar year that the proposed standard becomes enforceable. The entity's first required evaluation would occur within the first calendar year following the enforceable date of PER-005-2.

Requirement R6:

R6: Generator Operators must have developed training, using a systematic approach, for their applicable personnel on the impact of their job function(s) to the reliable operations of the BES during normal and emergency operations and must have implemented that training according to its systematic approach as of the enforceable date of PER-005-2.

6.1: As Generator Operators were not previously subject to PER-005-1, they would not be required to have conducted an evaluation prior to the enforceable date of the proposed standard or in the calendar year that the proposed standard becomes enforceable. The entity's first required evaluation would occur within the first calendar year following the enforceable date of PER-005-2.

Justification

The 24-month period for implementation of PER-005-2 will provide sufficient time for the applicable entities to make necessary modifications to their systematic approach to training and, for entities not yet subject to the standard, time to develop a systematic approach to training that is compliant with the proposed standard. This time frame is consistent with the 24-month implementation period FERC approved for PER-005-1 to allow for Reliability Coordinators, Balancing Authorities, and Transmission

Operators to develop a systematic approach to training. The standard drafting team concluded that the same timeframe (24-months) should be provided to the new applicable entities and for the entities currently subject to PER-001-1 to development training for their Operations Support Personnel.

Retirements

PER-005-1 – System Personnel Training should be retired at 11:59:59 pm of the day immediately prior to the enforceable date of PER-005-2 in the particular jurisdiction in which the new standard is becoming enforceable. For entities that are completing actions under Requirement R3.1 of PER-005-1, this requirement will remain in effect until the time allotted under the requirement has expired.

Attachment 1
Approved Standards Incorporating the Term "System Operator"

EOP-005-2 — System Restoration from Blackstart Resources

EOP-006-2 — System Restoration Coordination

EOP-008-1 — Loss of Control Center Functionality

IRO-002-3 — Reliability Coordination – Analysis Tools

IRO-014-1 — Procedures, Processes, or Plans to Support Coordination between Reliability Coordinators

MOD-008-1 — TRM Calculation Methodology

MOD-020-0 — Providing Interruptible Demands and DCLM Data

PER-003-1 — Operation Personnel Credentials

PRC-004-WECC-1 – Protection System and Remedial Action Scheme Maintenance and Testing

PRC-023 -2 — Transmission Relay Loadability

Exhibit C

Order No. 672 Criteria

Order No. 672 Criteria

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

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

Proposed Reliability Standard PER-005-2 is designed to achieve the specific reliability goal of helping to ensure that personnel who perform or support Real-time operations on the Bulk Power System are adequately trained to maintain the reliable operation of Bulk-Power System. Training individuals that both perform and support Real-time operations is an integral step in enhancing the reliability of the Bulk-Power System. It is important to train operators and their support personnel to, among other things, understand what they are required to do in the performance of their duties, particularly in emergency circumstances, and to perform those duties effectively and on a timely basis in support of reliable operations.

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

[2] Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.

Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

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

The proposed Reliability Standard is clear and unambiguous as to what is required and who is required to comply. Proposed Reliability Standard PER-005-2 applies to Reliability Coordinators, Balancing Authorities, Transmission Operators, certain Transmission Owners and certain Generator Operators. The Transmission Owners subject to the proposed Reliability Standard are those that have personnel who can act independently to operate or direct the operation of the Transmission Owner's Bulk Electric System transmission Facilities in Real-time. The Generator Operators subject to the proposed Reliability Standard are those that have dispatch personnel at a centrally located dispatch center who receive direction from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner, and may develop specific dispatch instructions for plant operators under their control.

The actions that each entity must take to comply with the proposed Reliability Standard are clearly articulated.

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

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for the proposed Reliability Standard comports with NERC and Commission guidelines related to their

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[3] Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

[4] Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

assignment. The assignments of the severity levels for the VSLs are consistent with the corresponding requirements and will ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, and support uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed Reliability Standard includes clear and understandable consequences.

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

The proposed Reliability Standard contains measures that support the requirements by clearly identifying what is required and how the requirement will be enforced. These measures help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

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

The proposed Reliability Standard achieves the reliability goals effectively and efficiently. The proposed Reliability Standard requires applicable entities to use a systematic approach to training method. As the Commission stated in Order No. 742, "[a] systematic approach to training is a widely-accepted methodology that ensures training is efficiently and effectively conducted."[7]

6. Proposed Reliability Standards cannot be "lowest common denominator," *i.e.,* cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for

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

6 Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

7 Order No. 693 at P 1382; Order No. 742 at P 25.

smaller entities, but not at consequences of less than excellence in operating system reliability.[8]

The proposed Reliability Standard does not reflect a "lowest common denominator" approach. To the contrary, the proposed Reliability Standard represents an improvement over existing Reliability Standards by expanding the scope of the Reliability Standard to include training requirements for other individuals that could impact the reliable operation of the Bulk-Power System. In addition, as, noted above, the use of a systematic approach to training is a widely-accepted methodology for providing effective training.

7. **Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.**[9]

The proposed Reliability Standard applies throughout North America and does not favor one geographic area or regional model. The proposed Reliability Standard is drafted to accommodate the various practices across the continent.

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[8] Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although FERC will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

[9] Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

8. **Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.**[10]

Proposed Reliability Standard PER-005-2 has no undue negative effect on competition. The proposed Reliability Standard requires the same performance by each of the applicable Functional Entities in training its applicable personnel. The proposed Reliability Standard does not unreasonably restrict the available generation or transmission capability or limit use of the Bulk-Power System in a preferential manner.

9. **The implementation time for the proposed Reliability Standard is reasonable.**[11]

The proposed effective date for the proposed Reliability Standard is just and reasonable and appropriately balances the urgency in the need to implement the proposed Reliability Standard against the reasonableness of the time allowed for those who must comply to develop the necessary training materials. The proposed implementation periods will allow applicable entities adequate time to ensure compliance with the requirements. The proposed effective date is explained in the proposed Implementation Plan, attached as Exhibit B.

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[10] Order No. 672 at P 332. As directed by section 215 of the FPA, FERC itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

[11] Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, FERC will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[12]

The proposed Reliability Standard was developed in accordance with NERC's Commission-approved, ANSI-accredited processes for developing and approving Reliability Standards. Exhibit G includes a summary of the Reliability Standard development proceeding, and details the processes followed to develop the Reliability Standard. These processes included, among other things, multiple comment periods and balloting periods. Additionally, all meetings of the standard drafting team were properly noticed and open to the public. The initial and final ballots both achieved a quorum and exceeded the required ballot pool approval levels.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[13]

NERC has identified no competing public interests regarding the request for approval of the proposed Reliability Standard. No comments were received indicating the proposed Reliability Standard is in conflict with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[14]

No other factors relevant to whether the proposed Reliability Standards are just and reasonable were identified.

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[12] Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.

[13] Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

[14] Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.

Exhibit D

Mapping Document

Project 2010-01 Operations Personnel Training
PER-005-2 Mapping Document

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 **NERC Board Approved**	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
R1. Reliability Coordinator, Balancing Authority and Transmission Operator shall use a systematic approach to training to establish a training program for the BES company-specific reliability-related tasks performed by its System Operators and shall implement the program. **1.1.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall create a list of BES company-specific reliability-related tasks performed by its System Operators. **1.1.1.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall update its list of BES company-specific reliability-related tasks performed by its System Operators each calendar year to	Requirement R1 parts 1.1.1., 1.1., 1.2., 1.3., and 1.4.	**R1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement a training program for its System Operators as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **1.1** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology. **1.1.2** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 1.1 each calendar year.

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 **NERC Board Approved**	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
identify new or modified tasks for inclusion in training. **1.2.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall design and develop learning objectives and training materials based on the task list created in R1.1. **1.3.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall deliver the training established in R1.2. **1.4**. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall conduct an annual evaluation of the training program established in R1, to identify any needed changes to the training program and shall implement the changes identified.		**1.2** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 1.1. **1.3** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall deliver training to its System Operators according to its training program. **1.4** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall implement the changes identified.
R2. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator's capabilities to perform each assigned task identified in R1.1 at least one time.	The old Requirement R2 is now Requirement R3.	**R3.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
2.1. Within six months of a modification of the BES company-specific reliability-related tasks, each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator's capabilities to perform the new or modified tasks.		Requirement R1 part 1.1 or Requirement R2 part 2.1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]* **3.1** Within six months of a modification or addition of a BES company-specific Real-time reliability-related task, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its personnel identified in Requirement R1 or Requirement R2 to perform the new or modified BES company-specific Real-time reliability-related tasks identified in Requirement R1 part 1.1 or Requirement R2 part 2.1.
R3. At least every 12 months each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each of its System Operators with at least 32 hours of emergency operations training applicable to its organization that reflects emergency operations topics, which includes system	This Requirement has been updated with deleting R3 and moving 3.1 from the approved standard to be the new R4. Part 4.1 in the proposed standard it	**R4.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1 or

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
restoration using drills, exercises or other training required to maintain qualified personnel. **3.1.** Each Reliability Coordinator, Balancing Authority and Transmission Operator that has operational authority or control over Facilities with established IROLs or has established operating guides or protection systems to mitigate IROL violations shall provide each System Operator with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES during normal and emergency conditions.	addresses the implementation of simulation technology.	Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **4.1.** A Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not previously meet the criteria of Requirement R4, shall comply with Requirement R4 within 12 months of meeting the criteria.
	This requirement is new to PER-005-2.	**R2.** Each Transmission Owner shall use a systematic approach to develop and implement a training program for its personnel identified in Applicability Section 4.1.4.1 of this standard as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
		2.1 Each Transmission Owner shall create a list of BES company-specific Real-time reliability-related tasks based on a defined and documented methodology. **1.1.2** Each Transmission Owner shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 2.1 each calendar year. **2.2** Each Transmission Owner shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 2.1. **2.3** Each Transmission Owner shall deliver training to its personnel identified in Applicability Section 4.1.4.1 of this standard according to its training program. **2.4** Each Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement R2 to identify any needed changes to the training program and shall implement the changes identified.

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
	This requirement is new to PER-005-2.	**R5.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **5.1** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training.

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
	This requirement is new to PER-005-2.	**6.** Each Generator Operator shall use a systematic approach to develop and implement training to its personnel identified in Applicability Section 4.1.5.1 of this standard, on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **6.1.** Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R6 to identify and implement changes to the training.

Exhibit E

Analysis of Violation Risk Factors and Violation Security Levels

Violation Risk Factor and Violation Severity Level Justifications

PER-005-2 – Operations Personnel Training

This document provides the Standard Drafting Team's (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PER-005-2 – Operations Personnel Training. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project. To review the VRFs and VSLs for PER-005-2, please go to the standards webpage (PER-005-2 Standard Webpage link).

NERC Criteria - Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

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

Lower Risk Requirement

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

FERC Violation Risk Factor Guidelines

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

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

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

• Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) – Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

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

Guideline (5) –Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria - Violation Severity Levels

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

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

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

FERC Order of Violation Severity Levels

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

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

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

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

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

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

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

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

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justification – PER-005-2 Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is consistent with the NERC VRF definition. Requirement R1 requires that Reliability Coordinators (RCs), Balancing Authorities (BAs) and Transmission Operators (TOPs) train their System Operators using a systematic approach to training method. While a violation of this requirement is unlikely to directly lead to Bulk Electric System instability, separation, or a cascading sequence of failures, a failure to adequately train System Operators could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. Additionally, the Medium VRF is consistent with the prior version of Requirement R1 in the currently effective version of the standard, PER-005-1. PER-005-1 will be retired upon the effective date of PER-005-2.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: While the Blackout report identified training for operator personnel as important for reliable operations, a violation of Requirement R1 is unlikely to directly lead to bulk power system instability, separation or cascading failures or hinder restoration to a normal condition. Therefore, the Medium VRF assignment is appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The Medium VRF is applicable to all parts of Requirement R1 and is consistent with other requirements in the Reliability Standard.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with the prior version of Requirement R1 in the currently effective version of the standard, PER-005-1. PER-005-1 will be retired upon the effective date of PER-005-2.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs:

	The VRF is consistent with the NERC definition because a violation of this requirement is unlikely to lead to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This VRF has one objective – to develop and implement training using a systematic approach - and thus does not co-mingle multiple objectives. It appropriately has one VRF for its single objective.

VSL Justification – PER-005-2 Requirement R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines, the VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered by the proposed Medium VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

Guideline 2b: VSL Assignments that contain ambiguous language	
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirements.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justification – PER-005-2 Requirement R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is consistent with the NERC VRF definition. Requirement R2 requires Transmission Owners to train their local control center operator personnel using a systematic approach to training method. A violation of this requirement is unlikely to lead to BES instability, separation, or a cascading sequence of failures.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: While the Blackout report identified training for operator personnel as important for reliable operations, a violation of Requirement R2 is unlikely to directly lead to bulk power system instability, separation or

	cascading failures or hinder restoration to a normal condition. Therefore, the Medium VRF assignment is appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The VRF is applicable for all of the parts within Requirement R2 and thus are consistent with one another. Requirement R2 contains the similar requirements as Requirement R1 but applies to Transmission Owners. Therefore, to be consistent within the Reliability Standard, the VRF for Requirement R2 reflects the VRFs of Requirement R1.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with Requirement R1 of the FERC approved prior version of the standard, PER-005-1. PER-005-1 will be retired upon the effective date of PER-005-2.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition because a violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This VRF has one objective – to develop and implement training for local control center operators using a systematic approach - and thus does not co-mingle multiple objectives. It appropriately has one VRF for its single objective.

VSL Justification – PER-005-2 Requirement R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines, the VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering	There is no prior compliance obligation related to the subject of this standard.

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

Not on A Cumulative Number of Violations	

VRF Justification – PER-005-2 Requirement R3	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of high is consistent with the NERC VRF definition. Requirement R3 requires Reliability Coordinators, Balancing Authorities, Transmission Operators and Transmission Owners to verify the capabilities of their System Operators or local control center operators. If such personnel are not able to complete their tasks, the situation could lead to BES instability, separation or cascading failures or hinder restoration to a normal condition. Additionally, the High VRF is consistent with the requirement in the currently effective version of the standard, PER-005-1, addressing verification of System Operator personnel capabilities. PER-005-1 will be retired upon the effective date of PER-005-2.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: The High VRF is consistent with the Blackout Report listing of operator personnel training as a critical impact area. Requirement R3 mandates that applicable entities verify the capabilities of its personnel identified in Requirement R1 and Requirement R2 to perform assigned tasks. Failure of operating personnel to competently perform assigned reliability-related tasks could lead to bulk power system instability, separation or cascading failures or hinder restoration to a normal condition.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The VRF for all of the parts within Requirement R3 are consistent with one another.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The High VRF is consistent with other requirements containing actions identified in the Blackout report.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition of VRFs because it is important that personnel are capable of performing each of the BES company-specific Real-time reliability-related tasks. Failure of operating personnel

	to competently perform assigned reliability-related tasks could lead to BES instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This VRF has one objective – to verify the capabilities of an entity's applicable personnel to perform reliability-related tasks – and thus does not co-mingle multiple objectives. It appropriately has one VRF for its single objective.

VSL Justification – PER-005-2 Requirement R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines, the VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

"Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL level is consistent with the requirement.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on cumulative number of violations.

VRF Justification – PER-005-2 Requirement R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is consistent with the NERC VRF definition. Requirement R4 requires that entities use simulation technology to conduct such training. Failure to provide emergency operations training using simulation technology is unlikely to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report:

	While the Blackout report identified training for operator personnel as important for reliable operations, a failure to use simulation technology is unlikely to directly lead to instability, separation, or Cascading. NERC staff believes that the Medium VRF assignment was appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: All of the parts within Requirement R4 are consistent with one another and are commensurate with Requirements R1 and Requirement R2.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with Requirement R3 of the FERC approved prior version of the standard, PER-005-1. PER-005-1 will be retired upon the effective date of PER-005-2.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition because it is important to provide emergency operations training using simulation technology. However, a violation of this Requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This VRF has one objective – to provide emergency operations training using technology that replicates the operational behavior of the BES – and thus does not co-mingle multiple objectives. It appropriately has one VRF for its single objective.

VSL Justification – PER-005-2 Requirement R4	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines, the VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering	The current level of compliance is not lowered with the proposed VSL.

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

Not on A Cumulative Number of Violations	

VRF Justification – PER-005-2 Requirement R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is consistent with the NERC VRF definition. Requirement R5 requires that RCs, BAs, and TOPs train their Operations Support Personnel using a systematic approach to training method. A violation of this requirement is unlikely to lead BES instability, separation, or a cascading sequence of failures. However, a failure to adequately train Operations Support Personnel on the impact of their job functions on Real-time reliability-related tasks could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: While the Blackout report identified training for operator personnel as important for reliable operations, a failure to use a systematic approach to develop and implement training for Operations Support Personnel is unlikely to lead to bulk power system instability, separation or cascading failures or hinder restoration to a normal condition. Therefore, the Medium VRF assignment was appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The VRF is applicable to all of the parts within Requirement R5 and thus are consistent with one another. The VRF is consistent with the VRFs for Requirements R1, R2 and R6, which require training for other categories of personnel.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with Requirement R1 of the FERC approved prior version of the standard, PER-005-1 to use a systematic approach to training. PER-005-1 will be retired upon the effective date of PER-005-2. Although this is a new requirement to PER-005-2, it requires the similar actions for a different functional entity.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs:

	The VRF is consistent with the NERC definition because a violation is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This VRF has one objective – to develop and implement training for its Operations Support Personnel using a systematic approach – and thus does not co-mingle multiple objectives. It appropriately has one VRF for its single objective.

VSL Justification – PER-005-2 Requirement R5	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines, the VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

"Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL level is consistent with the requirement.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on cumulative number of violations.

VRF Justification – PER-005-2 Requirement R6	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is consistent with the NERC VRF definition. Requirement R6 requires that Generator Operators train certain of their dispatch personnel using a systematic approach to training method. A violation of this requirement is unlikely to lead to BES instability, separation, or a cascading sequence of failures. However, a Generator Operator's failure to adequately train its applicable personnel on the impact of their job functions on the reliable operations of the BES could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES

FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: While the Blackout report identified training for operator personnel as important for reliable operations, a failure to use a systematic approach to develop and implement training for applicable Generator Operator personnel is unlikely lead to bulk power system instability, separation or cascading failures or hinder restoration to a normal condition. Therefore, the Medium VRF assignment was appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The VRF is applicable for all of the parts within Requirement R6 and thus are consistent with one another. The VRF is consistent with the VRFs for Requirements R1, R2 and R5, which require training for other categories of personnel.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with Requirement R1 of the FERC approved prior version of the standard, PER-005-1. PER-005-1 will be retired upon the effective date of PER-005-2. Although this is a new requirement to PER-005-2, it requires the similar actions for a different functional entity.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition because a violation is unlikely to lead to bulk electric system instability, separation, or cascading failures
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This VRF has one objective – to develop and implement training for applicable Generator Operator personnel using a systematic approach – and thus does not co-mingle multiple objectives. It appropriately has one VRF for its single objective.

VSL Justification – PER-005-2 Requirement R6	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines, the VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not	There is no prior compliance obligation related to the subject of this standard.

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

Not on A Cumulative Number of Violations	

Exhibit F

Summary of Development History and Complete Record of Development

Summary of Development History

The development record for proposed Reliability Standard PER-005-2 is summarized below.

I. Overview of the Standard Drafting Team

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

II. Standard Development History

A. Standard Authorization Request Development

A Standard Authorization Request ("SAR") was submitted on July 18, 2013 and accepted by the Standards Committee ("SC") on July 18, 2013. A revised version of the SAR was posted on September 25, 2013 in response to industry comment.

B. First Posting

Proposed Reliability Standard PER-005-2 was posted for a 45-day public comment period from August 23, 2013 through September 3, 2013. There were 71 sets of comments, including comments from approximately 235 individuals from approximately 130 companies representing 9 of the 10 industry segments. The proposed Reliability Standard received a quorum of 75.25% and an approval of 34.46%.

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1 Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d)(2) (2006).

The standard drafting team considered stakeholder comment regarding proposed Reliability Standard PER-005-2 and made the following modifications based on those comments:

Definitions and Applicability

- The standard drafting team added the term “Operations” to the proposed defined terms “Support Personnel” to provide clarity on the type of support personnel subject to the standard.

- The standard drafting team also expanded the definition of “Operations Support Personnel” to clarify that the functional entities (Reliability Coordinators, Balancing Authorities, Transmission Operators, and Transmission Owners) must identify their Operations Support Personnel.

- The standard drafting team modified the definition of “Operations Support Personnel” to mirror language from FERC Order Nos. 693 and 742.

- In response to comments requesting clarification as to which Transmission Owners are subject to the proposed PER-005-2 standard, the standard drafting team modified the applicability section to clarify which Transmission Owners are subject to the standard and to better describe their local control center personnel.

- The standards drafting tem updated the applicability section to clarify which Generator Operators are subject to the PER-005-2 standard.

Requirement R1

- The standard drafting team removed the acronym “SAT” for the phrase systematic approach to training to avoid any implication that there is only one model of a systematic approach.

- The standard drafting team added the phrase “if necessary” to Requirement R1.1.1 to clarify that changes to the list of Real-time reliability-related tasks are to be made only if updates are necessary.

- In response to comments that Measure M1 and Requirement R1 did not align, the standard drafting team revised Measure M1 to reflect Requirement R1.

- In response to a comment regarding the word “annual” in Measure M1.4, the standard drafting replaced “annual” with the phrase “each calendar year.”

Requirement R2

- The standard drafting team added the phrase "Real-time reliability-related tasks" to Requirement R2 and R2.1 to make it clear that it is Real-time reliability-related tasks that require verification of performance capability.

Requirement R3

- In response to comments asserting that six months is insufficient time to obtain simulation technology, the standard drafting team changed the time frame from six to 12 months.

Requirements R4

- In response to comments that the Operations Support Personnel do not perform the Real-time reliability-related tasks, the standards drafting team modified the requirement to clarify that the training for Operations Support Personnel is on the impact of their job functions on the Real-time reliability-related tasks performed by System Operators.

- The standard drafting team added Requirement R4.1 to clarify that conducting a systematic approach to training includes completing an evaluation.

- The standard drafting team added the phrase "systematic approach to training" to Requirement R4 to clarify that a systematic approach to training must be used.

Requirement R5

- The standard drafting team modified Requirement R5 to clarify that training for Generator Operators is to be on the impact of their job functions on reliable operations of the BES.

- The standard drafting team added Requirement R5.1 to clarify that conducting a systematic approach to training includes completing an evaluation.

- The standard drafting team removed the phrase "coordination with other applicable entities" from the standard.

C. Second Posting

Proposed Reliability Standard PER-005-2 was posted for a second 45-day public comment period from September 27, 2013 through November 12, 2013. There were 63 sets of responses, including comments from 35 companies representing 9 of the 10 industry segments.

Proposed Reliability Standard PER-005-2 received a quorum of 76.23% and an approval of 56.48%.

The standard drafting team considered stakeholder regarding proposed Reliability Standard PER-005-2 and made the following modifications based on those comments:

Definitions and Applicability

- In response to comments that the definition of the term "System Operator" should retain the phrase "monitors and controls" instead of the new "operates or directs," the standard drafting team clarified that it used the phrase "operates or directs" to more accurately reflect the duties performed by the System Operator.

- In response to comments requesting the standard-only term "Operations Support Personnel" be moved to the NERC Glossary, the standard drafting team modified the definition so that it could be moved to the NERC Glossary.

- The proposed term "System Personnel" was been removed due to comments that it was redundant and unnecessary.

- In response to comments regarding the list of examples in the description of the applicable Transmission Owner personnel, the standard drafting team removed the list of examples and modified the applicability to clearly define which Transmission Owners are subject to PER-005-2.

Requirement R1

- The standard drafting team included a new consistent term to describe the tasks to be identified under Requirement R1: "Bulk Electric System (BES) company-specific, Real-time reliability-related tasks."

Requirement R2 (Now Requirement R3)

- The standard drafting team modified the requirements to use the new term for tasks: "BES company-specific, Real-time reliability-related tasks."

Requirement R3 (Now Requirement R4)

- The standard drafting team reworded the requirement to further clarify that the requirement is applicable to those entities with authority or control over Interconnection Reliability Operating Limits (IROLs) or those with operating guides or protections systems used to mitigate IROL violations.

Requirement R4 (Now Requirement R5)

- In response to comments, the standard drafting team clarified that the applicable Operations Support Personnel are those that support System Operators and, in turn, removed Transmission Owners from the requirement.
- In response to comments raised that the VSLs were inconsistent between Requirements R1, R4, and R5 in regard to the use of a systematic approach, the standard drafting team modified the VSLs to be consistent.

D. Third Posting

Proposed Reliability Standard PER-005-2 was posted for a third 45-day public comment period and ballot from December 4, 2013 through January 17, 2014. There were 45 sets of comments, including comments from approximately 126 individuals from approximately 82 companies representing 9 of the 10 industry segments. Proposed Reliability Standard PER-005-2 received a quorum of 79.12% and an approval of 74.63%.

The standard drafting team considered stakeholder comments and made the following observations and modifications based on those comments:

- In response to comments regarding local control center operators having the ability to act independently, the standard drafting team included the word "can" in section 4.1.4.1 to reflect that ability.
- The standard drafting team created a separate requirement for local control center operators (Requirement R2), which were originally included in Requirement R1.
- The standard drafting team included the phrase "current and next day studies" to provide clarity to the FERC directive from Order 693 P 1393, which required that PER-005 be extended to include "…operations planning and operations support staff who carry out outage planning and assessments and those who develop SOLs and IROLs or operating nomograms for real-time operations".

E. Final Ballots

Proposed Reliability Standard PER-005-2 was posted for a 10-day final ballot period from January 27, 2014 through February 5, 2014. The proposed Reliability Standard received a quorum of 84.02% and an approval rating of 77.06%.

F. Board of Trustees Approval

Proposed Reliability Standards PER-005-2 was approved by the NERC Board of Trustees on February 6, 2014.

Complete Record of Development

Project 2010-01 Training

Related Files

Status:
A **final ballot** for **PER-005-2 – Operations Personnel Training** concluded at **8 p.m. Eastern on Wednesday, February 5, 2014**. The NERC Board of Trustees adopted the standard on February 6, 2014. The standard will be filed with applicable regulatory authorities.

Background:
The "PER" initiative is focused on closing out five outstanding directives from FERC Order 693 and 742 with regards to reliability standards. The standards involved are" PER-002 Operating Personnel Training (PER-005 – System Personnel Training).

The PER ad hoc group is suggesting a pro forma standard (PER-005-2) extending the applicability to certain GOPs, support personnel, and TOs, excluding EMS support personnel. The 32-hour requirement has been suggested for removal as it is inherent to the systematic approach to training that training hours should be left up to each entity. The requirement for 32 hours of training meets the Paragraph 81 criteria for redundancy and was further not a results-based requirement and considered unnecessarily prescriptive. A new requirement R3.1 was created to develop the implementation of the simulation technology requirement.

The pro forma standard was drafted to provide maximum flexibility to industry while addressing the reliability concerns in the FERC directives. Under the pro forma standard, each entity has the ability to identify its reliability-related tasks, determine which of its personnel conduct those tasks, and determine the appropriate training and level of training for each employee. The ad hoc group understood the concerns from industry regarding the systematic approach to training, and each requirement has been left up to the entity to decide which approach should be used.

If you have any questions, please contact sarcomm@nerc.net.

Draft	Action	Dates	Results	Consideration of Comments
PER-005-2 Clean (62) | Redline to last posting (63) Implementation Plan Clean (64)| Redline to last posting (65) **Supporting Materials:** SAR Clean (66) | Redline	Final Ballot Info>> (75) Vote>>	01/27/14 - 02/05/14	Summary>> (76) Ballot Results>> (77)	

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Mapping Document
Clean (68) | Redline to last posting (69)

Compliance Input
Clean (70) | Redline (71)

Technical White Paper (72)

Draft Reliability Standard Audit Worksheet (73)

VRF VSL Justifications (74)</td><td></td><td></td><td></td><td></td></tr>
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Clean (39) | Redline to last posting (40)

Implementation Plan
Clean (41) | Redline to last posting (42)

Supporting Materials:
Unofficial Comment Form (Word) (43)

SAR
Clean (44) | Redline (45)

Mapping Document
Clean (46) | Redline to last posting (47)

Compliance Input
Clean (48)| Redline (49)</td><td>Additional Ballot and Non-Binding Poll
Updated Info>> (54)

Info>> (55)

Vote>>

(Extended and additional day)</td><td>01/08/14 - 01/22/14</td><td>Summary>> (57)

Ballot Results>> (58)

Non-Binding Poll Results>> (59)</td><td></td></tr>
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Info>> (56)

Submit Comments>></td><td>12/04/13 - 01/22/14</td><td>Comments Received>> (60)</td><td>Consideration of Comments>> (61)</td></tr>
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Technical White Paper (50) Proposed Timeline for the Formal Development (51) Draft Reliability Standard Audit Worksheet (52) VRF/VSL Justifications (53)				
PER-005-2 Clean (19) | Redline to last posting (20) Implementation Plan Clean (21) | Redline to last posting (22) **Supporting Materials:** Unofficial Comment Form (Word) (23) SAR Clean (24) | Redline (25) Mapping Document Clean (26) | Redline to last posting (27) Compliance Input Clean (28) | Redline (29) Technical White Paper (30) Proposed Timeline for the Formal Development (31)	Additional Ballot and Non-binding Poll Updated Info>> November 1, 2013 (33) Updated Info>> (34) Vote>>	11/01/13 - 11/12/13 Non-Binding Poll has been extended 1 additional day ending 11/13/13 (closed)	Summary>> (36) Ballot Results>> (37) Non-Binding Poll Results>> (38)	
	Comment Period Updated Info>> (35) Submit Comments>>	09/27/13 - 11/12/13 (closed)	Comments Received>> (39)	Consideration of Comments Summary>> (40)

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PER-005-2 (3)

Implementation Plan (4)

Standard Authorization Request (5)

Supporting Materials:
Unofficial Comment Form (Word) (6)

Technical White Paper (7)

Mapping Document (8)

Compliance Input (9)

Proposed Timeline for the Formal Development (10)

Background Write-up (11)</td><td>PER-005-2

Ballot and Non-binding Poll
Updated Info>> (12)

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

Non-binding Poll has been extended 1 additional day ending 09/04/13

(closed)</td><td rowspan="2">Summary>> (14)

Ballot Results>> (15)

Non-binding Results>> (16)

Comments Received>> (17)</td><td rowspan="4">Consideration of Comments Summary>> (18)</td></tr>
<tr><td>Comment Period Info>> (13)

Submit Comments>></td><td>07/19/13 - 09/03/13

(closed)</td></tr>
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(closed)</td><td rowspan="2"></td></tr>
<tr><td>Info>> (1)

Submit Nomination>>

Unofficial Nomination Form>> (2)</td><td>07/24/13 - 08/02/13(closed)</td></tr>
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Standards Announcement

Standard Drafting Team Nominations

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

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

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

Background

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

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

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

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

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

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

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

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

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

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

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

Standards Process

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

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

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

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Nomination Form

Standard Drafting Team Members

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

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

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

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

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

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

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

Please briefly describe your experience and qualifications to serve on the selected Standard Drafting Team:

If you are currently a member of any NERC drafting team, please list each team here:

☐ Not currently on any active SAR drafting team, standard drafting team, standard review team, or informal ad hoc group.

☐ Currently a member of the following SAR, standard drafting team(s), standard review team(s), or informal ad hoc group:

If you previously worked on any NERC drafting team please identify the team(s):

☐ No prior NERC SAR or standard drafting team experience.

☐ Prior experience on the following team(s):

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

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

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	

Provide the name of your immediate supervisor if not provided above:			
Name:		Telephone:	
Organization:		E-mail:	

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

Standard Development Timeline

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

Development Steps Completed

1. SAR posted for comment (Dates of posting TBD).

Description of Current Draft

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	July 2013
15-day Formal Comment Period with Parallel Ballot	September 2013
Recirculation ballot	October 2013
BOT adoption	November 2013

Definitions of Terms Used in Standard

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

System Operator: An individual at a ~~c~~Control ~~c~~Center ~~(Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control~~ that operates or directs the operation of the Bulk ~~e~~Electric ~~s~~System in ~~r~~Real~~-~~-time.

The following terms are defined for use only within PER-005-2, and should remain with the standard upon approval rather than being moved to the NERC Glossary of Terms:

System Personnel: System Operators of a Reliability Coordinator, Transmission Operator or Balancing Authority, and the Transmission Owner personnel described in the Applicability Section of this standard.

Support Personnel: Individuals who carry out outage coordination and assessments, or determine SOLs, IROLs or operating nomograms[1] for Real-time operations.

[1] Nomograms are used in the WECC region to describe element operating limits.

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

A. Introduction

1. **Title:** **Operations Personnel Training**

2. **Number:** PER-005-2

3. **Purpose:** To ensure that personnel performing or supporting Real-time, reliability-related tasks on the Bulk Electric System are competent to perform those tasks.

4. **Applicability:**

4.1. Functional Entities:

4.1.1 Reliability Coordinator

4.1.2 Balancing Authority

4.1.3 Transmission Operator

Rationale for Transmission Owner: Extending the applicability to Transmission Owners is necessary to address the FERC directive that the ERO develop formal training requirements for local transmission control center operator personnel. In Order No. 742 at P 62, the Commission clarified its understanding that local control center personnel *exercise control over a significant portion of the Bulk-Power System under the supervision of the personnel of the registered transmission operator. The supervision may take the form of directive specific step-by-step instructions and at other times may take the form of the implementation of predefined operating procedures. In all cases, the Commission continued, the local transmission control center personnel must understand what they are required to do in the performance of their duties to perform them effectively on a timely basis. Thus, omitting such local transmission control center personnel from the PER-005-1 training requirements creates a reliability gap.*

4.1.4 Transmission Owner that has:

4.1.4.1 Personnel in a transmission control center who operate a portion of the Bulk Electric System at the direction of its Transmission Operator.

Rationale for Generator Operator: Extending the applicability to Generator Operators at a centrally located dispatch center is necessary to address the FERC directive that the ERO develop specific requirements addressing the scope, content and duration appropriate for generator operator personnel. The Commission explains in Order No. 693 at P 1359 that *although a generator operator typically receives instructions from a balancing authority, it is essential that generator operator personnel have appropriate training to understand those instructions, particularly in an emergency situation in which instructions may be succinct and require immediate action.* Order No. 742 further clarified that the directive *applies to generator operator personnel at a centrally-located dispatch center who receive direction and then develop specific dispatch instructions for plant operators under their control. Plant operators located at the generator plant site are not required to be trained in PER-005-2.*

4.1.5 Generator Operator that has:

4.1.5.1 Personnel at a centrally located dispatch center who receive direction from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control.

4.1.5.1.1 Personnel at a centrally located dispatch center who relay dispatch instructions, without making any modifications, are excluded.

5. Effective Date:

5.1. Requirement R1, Requirement R2, Requirement R3 part 3.1, Requirement R4 and Requirement R5 shall become effective the first day of the first calendar quarter that is 24 months beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, Requirement R1, Requirement R2, Requirement R3 part 3.1, Requirement R4 and Requirement R5 become effective the first day of the first calendar quarter that is 24 months beyond the date this standard is approved by the NERC Board of Trustees', or as otherwise made pursuant to the laws applicable to such ERO governmental authorities.

5.2. Requirement R3, with the exclusion of part 3.1, shall become effective the first day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, Requirement R3 becomes effective the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees', or as otherwise made pursuant to the laws applicable to such ERO governmental authorities.

Rationale for changes to requirements in the PER Standard related to Transmission Owners and Calendar Year:

- Transmission Owners personnel at local transmission control centers have been added to the PER standard and are subject to all the Requirements of PER-005-2. The reason for adding Transmission Owners is to address Order No. 693 and Order No. 742 FERC directives to include local transmission control center operator personnel.
- To address industry input, the term *annual* has been changed to *each calendar year*.
- PER-005-2 provides a requirement for training, but does not create a requirement for certification.

B. Requirements and Measures

R1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall use a systematic approach to training (SAT) to develop and implement a training program for its System Personnel as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall create a list of BES company-specific Real-time reliability-related tasks.

1.1.1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall review and update its list of tasks identified in part 1.1 each calendar year.

1.2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall design and develop training materials based on the task list created in part 1.1 and part 1.1.1.

1.3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall deliver the training established in part 1.2 to System Personnel.

1.4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall implement the changes identified.

M1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall review and update its list of tasks identified in part 1.1 each calendar year.

M1.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection its company-specific Real-time reliability-related task list, with the date of the last update, as specified in Requirement R1 parts 1.1 and 1.1.1.

M1.2 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training materials, as specified in Requirement R1 part 1.2.

M1.3 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection System Personnel training records showing the names of the people trained, the title of the training delivered and the dates of delivery to show that it delivered the training, as specified in Requirement R1 part 1.3.

M1.4 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an annual training program evaluation, as specified in Requirement R1 part 1.4.

R2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its System Personnel identified to perform each assigned task in Requirement R1 parts 1.1 and 1.1.1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

Rationale for changes to R2: A change from System Operator to System Personnel is used to capture Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner in one term versus spelling each term out a second time in the requirement.

2.1. Within six months of a modification or addition of Bulk Electric System company-specific Real-time reliability-related tasks, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its System Personnel to perform the new or modified tasks identified in Requirement R1 part 1.1.1.

M2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence to show that it verified the capabilities of each of the System Personnel identified to perform each assigned task in Requirement R1 parts 1.1 and 1.1.1, as specified in Requirement R2. This evidence can be documents such as training records showing successful completion of tasks with the employee name and date; supervisor check sheets showing the employee name, date, and task completed; or the results of learning assessments.

Rationale for changes to R3: The 32 hours of Emergency Operations training has been removed since this training should be covered as part of the systematic approach to training process in Requirement R1. The 32 hours is inherent to the systematic approach to training process and a legacy to the 2003 blackout. The removal of 32 hours is also considered to be a paragraph 81 concept due to it being redundant to the systematic approach to training process. Requirement R3.1 also covers the FERC directive for the creation of an implementation plan for simulation technology.

R3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that has operational authority or control over Facilities with established IROLs or has established operating guides or protection systems to mitigate IROL violations shall provide its System Personnel with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the Bulk Electric System. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that gains operational authority or control over a Facility with an established IROL or establishes operating guides or protection systems to mitigate IROL violations shall comply with Requirement R3 within 6 months of gaining that authority, control or establishing such operating guides or protection systems.

M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that System Personnel completed training that includes the use of simulation technology, as specified in Requirement R3.

M3.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that System Personnel completed training that included the use of simulation technology, as specified in Requirement R3, within 6 months of gaining that authority, control or establishing such operating guides or protection systems.

Rationale for R4: This is a new requirement applicable to Support Personnel as defined above in the definition section. In FERC Order No. 742, the Commission noted that NERC, in developing Reliability Standard PER-005-1, did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include operations planning and operation support staff who carry out outage planning and assessments and those who develop System Operating Limits (SOL), Interconnection Reliability Operating Limits (IROL), or operating nomograms for Real-time operations. This requirement does not require that entities create a new, comprehensive systematic approach to training (SAT) process for training support personnel. Rather, the requirements contemplate that entities will look to the SAT process already developed for System Operators. The entity can use the list created from requirement R1 and select the reliability-related tasks that support personnel conduct and therefore should be trained on.

R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall establish and implement training for Support Personnel specific to those Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1 and part 1.1.1 that relate to the Support Personnel's job function. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training materials and training records that provide evidence that Support Personnel completed training. This evidence can be documents such as training records showing successful completion of training with the employee name and date.

Rationale for R5: This is a new requirement applicable to Generator Operators described in the applicability section. In FERC Order No. 742, the Commission noted that in developing proposed Reliability Standard PER-005-1, NERC did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include generator operators centrally-located at a generation control center with a direct impact on the reliable operation of the Bulk-Power System. The Commission acknowledged that the training for GOPs need not be as extensive as the training for TOPs and BAs. FERC also stated that the systematic approach to training methodology is flexible enough to build on existing training programs by validating and supplementing the existing training content, where necessary, using systematic methods. It is important that the relevant generator operator personnel receive the necessary training. This requirement does not necessitate an SAT process that is as comprehensive as that used for TOPs, RCs and BAs. R5 also acknowledges that in order to provide the necessary training applicable to GOPs, GOPS will need to coordinate with their RC, BA, TOP and TO to understand the training topics that each GOP should be trained on.

R5. Each Generator Operator shall use a systematic approach to training to establish and implement training for its personnel described in applicability section 4.1.5. The training shall also include topics identified as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. Each Generator Operator shall coordinate with its Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner to identify training topics that address the impact of the decisions and actions of a Generator Operator's personnel as it pertains to the reliability of the Bulk Electric System during normal and emergency operations.

5.1.1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall provide input as requested by the Generator Operator.

M5. Each Generator Operator shall have available for inspection training materials and training records that provide evidence that its applicable personnel completed training. This evidence can be documents such as training records showing successful completion of training with the employee name and date.

M5.1 Each Generator Operator shall have available for inspection evidence, such as an email or attestation that it coordinated with the Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner in establishing the training requirements.

M5.1.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence, such as an email or attestation, that it provided input to the Generator Operator.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

Each Reliability Coordinator, Balancing Authority, Transmission Operator Transmission Owner, and Generator Operator shall keep data or evidence to show compliance for three years or since its last compliance audit, whichever time frame is the greatest, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator, Balancing Authority, Transmission Operator Transmission Owner, or Generator Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

1.3. Compliance Monitoring and Assessment Processes:

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

1.4. Additional Compliance Information

None

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**Medium**	**None**	The Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner, failed to provide evidence that it updated its company-specific Real-time reliability-related task list to identify new or modified tasks each calendar year (1.1.2) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner, failed to provide evidence of evaluating its training program each calendar year to identify needed changes to its training program(s). (1.4)	The Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner failed to design and develop training materials based on the task lists. (1.2)	The Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner failed to prepare a task list (1.1 or 1.1.1.) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner failed to deliver training based on the task lists. (1.3)
R2	**Long-term Planning**	**High**	**None**	The Reliability Coordinator, Balancing Authority, Transmission Operator, and	The Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner	The Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner verified less

				Transmission Owner verified at least 90% but less than 100% of its System Personnel capabilities to perform each assigned task from its tasks list. (R2)	verified at least 70% but less than 90% of its System Personnel capabilities to perform each assigned task from its task lists (R2) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner failed to verify its System Personnel capabilities to perform each new or modified task within six months of making a modification to its task list of the tasks in Real-time. (2.1)	than 70% of its System Personnel capabilities to perform each assigned task from its task lists. (R2)
R3	**Long-term Planning**	**Medium**	**None**	**None**	**None**	The Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner did not provide its System Personnel with any form of simulation technology training (R3) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner did not verify its System Personnel capabilities to perform each new or modified task within six months of making a modification to its task list. (R3.1)

R4	**Long-term Planning**	**Medium**	**None**	**None**	**None**	The Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner failed to establish training for its Support Personnel (R4) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner failed to implement training for its Support Personnel. (R4)
R5	**Long-term Planning**	**Medium**	**None**	**None**	The Generator Operator failed to use a systematic approach to training to establish training requirements as defined in Requirement R5.	The Generator Operator failed to coordinate with its Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner to identify training topics as defined in Requirement R5 part 5.1 OR The Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner failed to provide the requested input as defined in Requirement R5 part 5.1.1. OR The GOP failed to implement the training as defined in Requirement R5.

Guidelines and Technical Basis

Requirement R1:

Any systematic approach to training will: 1) determine the skills and knowledge needed to perform tasks, 2) determine what training is needed to achieve those skills and knowledge, 3) determine how to assess the acquisition of those skills and knowledge by the learner, 4) should determine if the learner can perform the task(s) acceptably in either a training or on-the-job environment, 5) determine if the training is effective, and make adjustments as necessary.

Reference #1: Determining Task Performance Requirements
The purpose of this reference is to provide guidance in writing a performance standard that describes the desired outcome of a task. A standard for acceptable performance should be in either measurable or observable terms. Clear standards of performance are necessary for an individual to know when he or she has completed the task and to ensure agreement between employees and their supervisors on the objective of a task. Performance standards answer the following questions:

How timely must the task be performed?

Or

How accurately must the task be performed?

Or

With what quality must it be performed?

Or

What response from the customer must be accomplished?

When a performance standard is quantifiable, successful performance is more easily demonstrated. For example, in the following task statement, the criteria for successful performance is to return system loading to within normal operating limits, which is a number that can be easily verified.

> Given a System Operating Limit violation on the transmission system, implement the correct procedure for the circumstances to mitigate loading to within normal operating limits.

Even when the outcome of a task cannot be measured as a number, it may still be observable. The next example contains performance criteria that is qualitative in nature, that is, it can be verified as either correct or not, but does not involve a numerical result.

> Given a tag submitted for scheduling, ensure that all transmission rights are assigned to the tag per the company Tariff and in compliance with NERC and NAESB standards.

Reference #2: Systematic Approach to Training References:
The following list of hyperlinks identifies references for the NERC Standard PER-005 to assist with the application of a systematic approach to training:

(1) DOE-HDBK-1078-94, A Systematic Approach to Training
http://www.hss.energy.gov/NuclearSafety/techstds/standard/hdbk1078/hdbk1078.pdf

(2) DOE-HDBK-1074-95, January 1995, Alternative Systematic Approaches to Training, U.S. Department of Energy, Washington, D.C. 20585 FSC 6910
http://www.hss.energy.gov/NuclearSafety/techstds/standard/hdbk1074/hdb1074.html

(3) ADDIE – 1975, Florida State University
http://www.nwlink.com/~donclark/history_isd/addie.html

(4) DOE Standard - Table-Top Needs Analysis
DOE-HDBK-1103-96
http://hss.energy.gov/NuclearSafety/techstds/standard/hdbk1103/hdbk1103.pdf

Requirement R2:

Requirement R3:

Requirement R4:

Requirement R5:

Implementation Plan

Project 2010-01 Operations Personnel Training

Implementation Plan for PER-005-2 – Operations Personnel Training

Approvals Required

PER-005-2 – Operations Personnel Training

Prerequisite Approvals

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

Revisions to Glossary Terms

The following definitions shall become effective when PER-005-2 becomes effective:

System Operator: An individual at a Control Center that operates or directs the operation of the Bulk Electric System in real-time.

The following terms are defined for use only within PER-005-2, and should remain with the standard upon approval rather than being moved to the NERC Glossary of Terms:

System Personnel: System Operators of a Reliability Coordinator, Transmission Operator or Balancing Authority, and the Transmission Owner personnel described in the Applicability Section of this standard.

Support Personnel: Individuals who carry out outage coordination and assessments, or determine SOLs, IROLs or operating nomograms for Real-time operations.

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Operator
- Transmission Owner that has personnel in a Transmission control center who operate a portion of the Bulk Electric System at the direction of its Transmission Operator
- Generator Operator that has personnel at a centrally located dispatch center who receive direction from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control.

Applicable Facilities
None

Conforming Changes to Other Standards
None

Effective Dates
PER-005-2 shall become effective as follows:

- Requirement R1, Requirement R2, Requirement R3 part 3.1, Requirement R4 and Requirement R5 shall become effective the first day of the first calendar quarter that is 24 months beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, Requirement R1, Requirement R2, Requirement R3 part 3.1, Requirement R4 and Requirement R5 become effective the first day of the first calendar quarter that is 24 months beyond the date this standard is approved by the NERC Board of Trustees', or as otherwise made pursuant to the laws applicable to such ERO governmental authorities.
- Requirement R3, with the exclusion of part 3.1, shall become effective the first day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, Requirement R3 becomes effective the first day of the first calendar quarter beyond the date this standard is approved by the NERC Board of Trustees', or as otherwise made pursuant to the laws applicable to such ERO governmental authorities.

Rationale for changes to requirements in the PER Standard related to Transmission Owners and Calendar Year:
- Transmission Owners personnel at local transmission control centers have been added to the PER standard and are subject to all the Requirements of PER-005-2. The reason for adding Transmission Owners is to address Order No. 693 and Order No. 742 FERC directives to include local transmission control center operator personnel.
- To address industry input, the term *annual* has been changed to *each calendar year*.
- PER-005-2 provides a requirement for training, but does not create a requirement for certification.

Justification
The 24-month period for implementation of PER-005-2 will provide ample time for the applicable entities to make necessary modifications to existing or creation of new systematic approach to training programs for compliance.

Retirements
PER-005-1 – System Personnel Training should be retired at midnight of the day immediately prior to the effective date of PER-005-2 in the particular jurisdiction in which the new standard is becoming effective.

Attachment 1

Approved Standards Incorporating the Term "System Operator"

EOP-005-2 — System Restoration from Blackstart Resources
EOP-006-2 — System Restoration Coordination
EOP-008-1 — Loss of Control Center Functionality
IRO-002-3 — Reliability Coordination – Analysis Tools
IRO-014-1 — Procedures, Processes, or Plans to Support Coordination between Reliability Coordinators
MOD-008-1 — TRM Calculation Methodology
MOD-020-0 — Providing Interruptible Demands and DCLM Data
PER-003-1 — Operation Personnel Credentials
PER-005-1 — System Personnel Training
PRC-023 -2 — Transmission Relay Loadability

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Form

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

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

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Operations Personnel Training		
Date Submitted:	July 18, 2013		
SAR Requester Information			
Name:	Jordan Mallory		
Organization:	NERC		
Telephone:	404-446-9733	E-mail:	Jordan.mallory@nerc.net
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
Resolve FERC directives, modify System Operator definition (project 2010-16), and to incorporate initiatives such as results-based, performance-based, Paragraph 81, etc.

SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):
• Modify System Operator Definition (Project 2010-16) • Define applicable entities to address outstanding FERC Directives from Order No. 693 and Order No. 742. • Modify existing PER-005-1 requirements for additional applicable entities and personnel. • Remove existing PER-005-1 R3 prescriptive 32 hours of emergency operations as it is covered under the Systematic Approach to Training and thus is repetitive. In Paragraph 81 of the March 15, 2012 Order (link), FERC provided an opportunity for the ERO to remove requirements that did little to protect to the BPS pursuant to specific criteria. The requirement for 32 hours of training meets the Paragraph 81 criteria for redundancy. It further is not a results-based requirement, as it is unnecessarily prescriptive.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
This project will be addressing the following FERC directives. In addition, the project will be reviewing the present standard to eliminate in ambiguity within the standard. 1. This SAR is needed to address outstanding FERC Directives from Order No. 693 and Order No. 742. The following is a summary of the FERC Directives to the ERO: ▪ Develop specific Requirements addressing the scope, content and duration appropriate for generator operator personnel. A new requirement R5 has been suggested as an addition to a revised PER-005-1 capturing Generator Operators Personnel at a centrally located dispatch center who receive direction from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control. Personnel at a centrally located dispatch center who relay dispatch instructions, without making any modifications, are excluded. ▪ Include personnel who carry out outage coordination and assessments in accordance with IRO-004-1 and TOP-002-2 and determine SOLs and IROLs or operating nomograms in accordance with IRO-005-1 and TOP-004-0. A new requirement R4 has been suggested as an addition to a revised PER-005-1 capturing operation support and support staff personnel for training. The term Support Personnel has been created with a definition solely for the revised PER-005-1 standard. ▪ Consider whether personnel responsible for ensuring that critical reliability applications of the EMS, such as state estimator, contingency analysis and alarm processing packages are available, up-to-date in terms of system data and produce useable results should be included in a mandatory training standard. (Technical Justification) ▪ Consider the necessity of developing a similar implementation plan with respect to PER-005-1, Requirement R3.1. (simulation technology) ▪ Develop a definition of "local transmission control center" for developing the training requirements for local transmission control center operator personnel. The group thought it would be a better path to define local transmission control center through extending the

SAR Information
applicability to Transmission Owners versus creating a new term for the NERC Glossary. Transmission Owner in the PER standard is defined as “Personnel in a transmission control center who operate a portion of the Bulk Electric System at the direction of its Transmission Operator.” Transmission Owner has been added to all the requirements of the suggested revised PER-005-1 standard. 2. Revise definition of System Operator in glossary of terms to address industry concerns for clarity. 3. Implement Paragraph 81 by identifying Reliability Standards requirements that either: (a) provide little protection to the BPS; (b) are unnecessary or (c) are redundant.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Detailed description of this project can be found in the Technical White Paper, of this SAR submittal package.

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator’s wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.

Reliability Functions		
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems

Reliability and Market Interface Principles	
	reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☒	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

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

Related Standards	
Standard No.	Explanation

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	None
FRCC	None
MRO	None
NPCC	None
RFC	None
SERC	None
SPP	None
WECC	None

Unofficial Comment Form

Project 2010-01 PER Revisions

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the draft PER-005-2 standard. The electronic comment form must be completed by 8:00 p.m. ET on **Tuesday, September 3, 2013**.

If you have questions please contact Jordan Mallory via email or by telephone at 404-446-29733.

The project page may be accessed by clicking here.

Background Information

On March 16, 2007 the Federal Energy Regulatory Commission (FERC) issued Order No. 693, *Mandatory Reliability Standards for the Bulk-Power System* and on November 18, 2010 FERC issued Order No. 742, *System Personnel Training Reliability Standards.* Five outstanding directives remain from those two orders (3 from Order No. 693 and 2 from Order No. 742), which are explained in detail in the PER White Paper contained in the SAR package.

The informal consensus building for PER began in February 2013. Specifically, the ad hoc group engaged stakeholders on how best to address the FERC directives, paragraph 81 candidates and results-based approaches (see page 4 of the PER White Paper regarding the paragraph 81 candidate). A discussion of the ad hoc group's consensus building and collaborative activities are included in the PER White Paper (see SAR package).

Based on stakeholder outreach, the PER ad hoc group has developed one revised proposed reliability standards (PER-005-2) that address the FERC directives and recommendations for improving PER-005-1, which included creating results-based requirements and considering paragraph 81 criteria to ensure that the standards proposals did not include requirements that meet those criteria. A discussion of the ad hoc group's consensus building and collaborative activities are included in the technical white paper.

This posting is soliciting comment on a pro forma standard and a Standard Authorization Request (SAR).

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

Question

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

☐ Yes
☐ No

Comments:

2. Please specify if you have comments or proposed changes to any of the Requirements of the pro forma standard.

Comments:

3. Do you support the revised NERC Glossary Term System Operator? If no, please indicate in the comment section what suggested changes would put you in favor of the new glossary term.

☐ Yes
☐ No

Comments:

4. Do you support the revised PER-005-2 standard? If no, please indicate in the comment section what suggested changes would put you in favor of the new revised standard.

☐ Yes
☐ No

Comments:

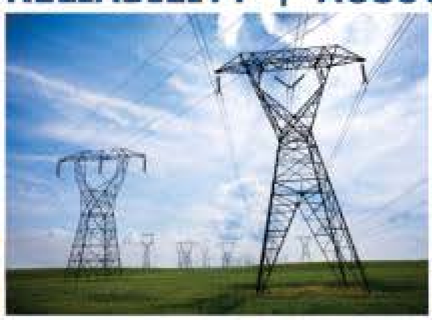
NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

PER-005 Standards White Paper

July 18, 2013

RELIABILITY | ACCOUNTABILITY



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Executive Summary

A Personnel, Performance, Training, and Qualifications (PER) ad hoc group was formed to work with industry stakeholders to address five outstanding Federal Energy Regulatory Commission (FERC) directives.

The five outstanding FERC directives are as follows:

1. The Commission directs the Electric Reliability Organization (ERO) to develop specific requirements addressing the scope, content, and duration appropriate for Generator Operator (GOP) personnel (Order No. 693, P. 1363).
2. The Commission directs the ERO to develop a modification to PER-002-0 to require training of operations planning and operations support staff of Transmission Operators (TOPs) and Balancing Authorities (BAs) who have a direct impact on the reliable operation of the Bulk-Power System (BPS) (Order No. 693, P. 1372).
3. The Commission directs the ERO to consider personnel responsible for ensuring that critical reliability applications of the EMS, such as state estimator, contingency analysis and alarm processing packages, are available, up to date in terms of system data and produce useable results that can also have an impact on the reliable operation of the BPS (Order No. 693, P. 1373).
4. The Commission directs the ERO to consider the necessity of developing a similar implementation plan with respect to PER-005-1, Requirement R3.1 (Order No. 742, P. 24).
5. The Commission directs the ERO to develop through a separate reliability standards development project formal training requirements for local transmission control center operator personnel, and to develop a definition of "local transmission control center" in the standards development project (Order No. 742, P. 64).

The ERO is required to comply with FERC directives unless there is an equally effective and efficient method of addressing the reliability concern, or if there is evidence that the directive has been overcome by events or is no longer needed. These five directives were challenging due to the variance of industry opinion.

The PER informal development project reviewed the FERC directives, conducted outreach to industry stakeholders, and developed the pro forma standard. There were differing opinions from industry; some stated that the directives should be complied with while others stated there was sufficient justification as to why the directives were no longer needed. Although persuasive, the majority of the arguments as to why the directives were no longer needed had been addressed by FERC in prior orders as outlined in Appendix A. The discussion for each of the above directives are summarized as follows.

First, discussions were held regarding GOP dispatchers at a local control center. Through industry feedback, it became apparent that stakeholders needed a better understanding of the types of GOPs FERC was including in the directive. Initially it appeared that the directive would apply only to those GOPs that make independent decisions; however, FERC had addressed that narrow reading in FERC Order 693 P. 1359. The group's final determination was that even though GOPs at a local control center receive direction from their BA or TOP, those that take direction and then develop dispatch instructions for their plant operators are the specific GOPs the FERC Orders are attempting to capture. Therefore, the pro forma standard expanded the applicability in PER-005 to include these specific types of GOPs.

Second, the ad hoc group received strong feedback from industry that operations planning and operations support staff should not be included in the PER standard. Some of the reasons presented were: the System Operator is the one who impacts the Bulk Electric System (BES) and not the support personnel; support personnel do not make any Real-time decisions on BES operations; mandating training would distract training staff from the more critical functions of training System Operators; and this would create an administrative burden and would be too costly of a task on industry for the reliability protection it offers. Through further research it was determined that these were the same arguments previously presented and responded to by FERC in Orders 693 and 742 (see Appendix A). Therefore, as the informal development effort was not able to provide an argument that had not previously been rejected by FERC, the ad hoc group continued with the inclusion of support personnel in PER-005.

The third major discussion was in regard to the directive for the ERO to consider including personnel responsible for ensuring that critical reliability applications of the EMS, such as state estimator, contingency analysus and alarm processing packages, are available, up-to-date in terms of system data and produce useable results can also have an impact on the reliable operation of the BPS. Similar to the previously described discussions, many of the arguments had been addressed by FERC, but there was new evidence in this area. The argument for not including EMS personnel in the training standard at this time is based on a report provided by the Event Analysis Subcommittee (EAS). The EAS worked with the NERC Event Analysis (EA) staff to review the events that have been cause-coded since October 2010. The database has over 263 events; 208 of them were cause-coded to allow for trending and cluster analysis. The EAS and NERC EA staff queried the 208 events and looked in particular for cause codes that pertain to human errors and training that were less than adequate. The query produced 44 events that had the possibility for human errors or training being a contributing factor in the event. An analysis of those 44 events indicated that only 10 had human error or training as a contributing factor. Six of those 10 events were related to the loss of EMS or SCADA. Out of the six events, only two were deemed to be a training issue. Therefore, based on the information, the EAS and PER ad hoc group do not believe it is necessary at this time to require EMS support personnel to receive the level of training required of a BA, Reliability Coordinator (RC), and TOP by NERC standard PER-005.

Fourth, the ad hoc group and industry stakeholders agreed with the Commission on developing an implementation plan with respect to the simulation technology requirement. The ad hoc group determined that six months would suffice for an entity to become compliant with the simulation technology requirement in PER-005. No feedback has been received thus far from industry regarding this suggested change.

Last, the group addressed the local transmission control center directive by expanding the PER-005 applicability section to Transmission Owners (TO) and creating a standard-only definition. The group defined “local transmission control center” in the standard as *personnel in a transmission control center who operate a portion of the Bulk Electric System at the direction of its Transmission Operator.* This term will not become a part of the NERC Glossary of Terms used in NERC Reliability Standards at this time.

In summary, the PER ad hoc group created a pro forma standard (PER-005-2) extending the applicability to certain GOPs, support personnel, and TOs, excluding EMS support personnel. The 32-hour requirement has been removed as it is inherent to the systematic approach to training that training hours should be left up to each entity. The requirement for 32 hours of training meets the Paragraph 81 criteria for redundancy and was further not a results-based requirement and considered unnecessarily prescriptive. A new requirement R3.1 was created to develop the implementation of the simulation technology requirement.

The pro forma standard was drafted to provide maximum flexibility to industry while addressing the reliability concerns in the FERC directives. Under the pro forma standard, each entity has the ability to identify its reliability-related tasks, determine which of its personnel conduct those tasks, and determine the appropriate training and level of training for each employee. The ad hoc group understood the concerns from industry regarding the systematic approach to training, and each requirement has been left up to the entity to decide which approach should be used.

Purpose

The purpose of the PER-005 white paper is to provide the issues, rationale, and support for the revisions to the PER-005 standard. This white paper provides an explanation of how each of the FERC directives was addressed, including the issues that were raised during informal development and the rationale for proceeding or not proceeding with each. This paper will also provide technical justification and support for the revisions to the standard. The contents in this paper will provide the standard drafting team with the basis for the pro forma standard so they can begin the formal standard development process.

History of the PER-005 Informal Development

In February 2012, the North American Electric Reliability Corporation (NERC) Board of Trustees (Board) formed the Standards Process Input Group (SPIG) to address the widespread frustration with the duration of the standards development process.[1] In May 2012, SPIG submitted a report to the NERC Board recommending improving both the timeliness and quality of the standards. The process manual changes were approved by the Board in February 2013.[2] Since then, the Board issued a resolution requesting SPIG, the Members Representative Committee (MRC), NERC staff, and industry stakeholders to reform their standards development paradigm. Changes were integrated into the 2013–15 Reliability Standards Development Plan (RSDP) and Standards Committee (SC) Strategic Plan.[3]

The evolving standards process includes an informal development period in which NERC Standards developers work with an ad hoc group to gather information up front from industry regarding the FERC directives or other standards development project. There are three approaches to consider when addressing FERC directives: comply with the FERC directive, present an equally and effective alternative, or provide technical justification as to why the directive is no longer needed.

A PER ad hoc group was formed in January of 2013 to work with industry stakeholders to address five outstanding FERC directives. The ad hoc group addressed each directive through informal development, with the goal of filing a revised standard with FERC by December 31, 2013.

The PER ad hoc group held its first informal development meeting February 25–27, 2013, in Atlanta, Georgia. A small ad hoc group of industry subject matter experts (SMEs) representing RCs', BAs', GOPs', TOPs', and TOs' participated in discussions about the FERC directives and possible resolutions to address them. The ad hoc group created the first draft of a pro forma standard to address each directive. The ad hoc group conducted conference calls, workshops, and, to reach additional industry participants, two webinars: a March 15 informational webinar and an April 4 industry feedback webinar requesting feedback from industry regarding the PER ad hoc group suggestions. Multiple conference calls were held with the ad hoc group to keep all members aware of feedback received.

A second informal meeting was held April 22–23, 2013, at NERC's Atlanta office. The meeting was a continuation of the efforts of the first meeting with the addition of discussion on the information received through the outreach efforts. The ad hoc group discussed issues raised by industry and revised the pro forma standard based on that information. The group presented the revised pro forma standard to industry at the May 31 industry feedback webinar and other conference calls. During the webinar, polling questions were presented to participants, and 147 out of 323 people participated in the polling. The purpose of this polling was to gauge industry's support of the suggested PER-005 standard.

The last informal development meeting was held June 20–21, 2013 to develop the materials necessary to move into the formal process. This will entail submitting a Standard Authorization Request (SAR), the pro forma standard, input to a reliability standards audit worksheet (RSAW), an implementation plan, a mapping document, and a technical white paper to the NERC Standards Committee (SC).

A complete list of entities that participated during the informal development can be located in Appendix B.

[1] May 9, 2012 NERC Board minutes: http://www.nerc.com/gov/bot/Agenda%20Minutes%20and%20Highlights%20DL/2012/BOT_050912m_complete.pdf
[2] August 16, 2012 NERC Board minutes: http://www.nerc.com/gov/bot/Agenda%20Minutes%20and%20Highlights%20DL/2012/0-BOT08-12a-complete.pdf
[3] 2013–15 Reliability Standards Development Plan: http://www.nerc.com/pa/Stand/Standards%20Development%20Plan%20Library/2013-2015_RSDP_BOT_Approved_12-19-12.pdf

Outstanding FERC Directives and Technical Discussions

There are five outstanding FERC directives from Order 693[4] and Order 742.[5] Each directive was discussed in detail during the informal development stage, and below are the summaries of the discussions.

Applicability of the PER Standard to GOP Dispatchers

FERC Order 693 ¶ 1360-1361, 1363

P. 1360. We agree with FirstEnergy and others that some clarification is required regarding which generator operator personnel should be subject to formal training under the Reliability Standard. As noted above, a generator operator typically receives instructions from a balancing authority. Some generator operators are structured in such a way that they have a centrally-located dispatch center that receives direction and then develops specific dispatch instructions for plant operators under their control. For example, a balancing authority may direct a centrally-located dispatch center to deliver 300 MW to the grid, and the dispatch center would determine the best way to deliver that generation from its portfolio of units. In this type of structure, it is the personnel of the centrally located dispatch center that must receive formal training in accordance with the Reliability Standard. Plant operators located at the generator plant site also need to be trained but the responsibility for this training is outside the scope of the Reliability Standard.

P. 1361. Other generator operators may be structured in such a way that the dispatch center and the single generation plant are at the same site. In this structure as well, some personnel will perform dispatch activities while others are designated as plant operators. Again, it is the dispatch personnel that must receive formal training in accordance with the Reliability Standard. Plant operators also need to be trained but the responsibility for this training is outside the scope of the Reliability Standard.

P. 1363. Further, the Commission agrees with MidAmerican, SDG&E and others that the experience and knowledge required by transmission operators about Bulk-Power System operations goes well beyond what is needed by generation operators; therefore, training for generator operators need not be as extensive as that required for transmission operators. Accordingly, the training requirements developed by the ERO should be tailored in their scope, content and duration so as to be appropriate to generation operations personnel and the objective of promoting system reliability. Thus, in addition to modifying the Reliability Standard to identify generator operators as applicable entities, we direct the ERO to develop specific Requirements addressing the scope, content and duration appropriate for generator operator personnel.

FERC Order 742 ¶ 83-84

P. 83. EPSA requests clarification of several statements in the NOPR regarding the Order No. 693 directive related to expanding the applicability of the system operator training Reliability Standard to include certain generator operators. First, EPSA expresses concern that the NOPR discussion broadly addresses generator operator personnel in a way that could be construed as subjecting all generator operator personnel, regardless of the disposition of the generating unit and how it fits into the grid and the topology of the grid, to the system operator training requirements. Therefore EPSA seeks clarification that the Commission did not intend for the NOPR to expand the Order No. 693 directives. We confirm that we have not modified the scope of applicability of the Order No. 693 directive regarding generator operator training. As described in Order No. 693, the directive applies to generator operator personnel at a centrally-located dispatch center who receive direction and then develop specific dispatch instructions for plant operators under their control. Those generator operator personnel must receive formal training of the nature provided to system operators under PER-005-1. As clarified in Order No. 693, this group of personnel would include a generator operator's dispatch personnel where a single generator and dispatch center are located at the same site.

P. 84. EPSA also seeks clarification regarding the statement in the NOPR that: "[I]n the event communication is lost, the generator operator personnel must have had sufficient training to take appropriate action to ensure reliability of the Bulk-Power System." EPSA expresses concern that this statement suggests that if communication is lost with the grid operator, the generator operator must take unilateral action for which it requires training. EPSA notes that generator operators do not take such unilateral action nor do they have access to information to make such decisions. Therefore, EPSA asks the Id. Commission to make clear that while communication should be addressed in training requirements for centrally located generator operator dispatch employees, the Commission is not extending related responsibilities or training requirements to generator operator employees. We grant the requested clarification, and affirm that we are not modifying the Order No.

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[4] *Mandatory Reliability Standards for the Bulk-Power System*, 118 FERC ¶ 61,218, FERC Stats. & Regs. ¶ 31,242 (Order No. 693), *order on reh'g, Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 (Order No. 693-A) (2007).

[5] FERC Order 742 PP 83-84

693 directive regarding training for certain generator operator dispatch personnel, nor are we expanding a generator operator's responsibilities.

Consideration of Directive

The PER ad hoc group considered all options (such as complying with the FERC directive, presenting an equally and effective alternative, or providing technical justification as to why the directive is no longer needed) when addressing GOPs at a centrally located dispatcher center who receive direction and then develop specific dispatch instructions for plant operators under their control.[6] The ad hoc group suggested a revised PER-005-1 standard that expands the applicability section to these specific GOPs, leaving it up to the entity to identify the reliability-related tasks its GOP personnel should be trained on. The group attempted to draw a bright line of GOPs that make independent decisions. Through subsequent discussions with FERC's OER staff, the group learned that this bright line, per the FERC orders, would not address the FERC directive. It appears that the intent of the FERC order is for GOPs at a control center who receive direction from their BAs or TOPs to develop specific dispatch instructions (not just that make an independent decision) for their plant operator. These are the people who should be captured under the standard. The group considered and suggested a revised PER-005 that extends applicability to these specific GOPs. The standard language allows the entity to decide which systematic approach to training should be used when training GOPs and includes coordination on training topics with the entity's RC, BA, TOP, and TO.

Technical Discussions

Many technical discussions were held regarding increasing the applicability of the PER standard to GOP dispatchers. The feedback provided in the list below are the reasons provided by industry as to why this directive was no longer needed for GOP dispatchers.

- All decisions that GOPs make that impact the reliability of the BES must be approved by the BA, TOP, or RC. Even in the case of an emergency situation, the GOP will not make any decisions until approved by the BA, TOP, or RC. It was further explained that there are GOPs that do not develop dispatch instruction and simply take the information received from the BA, TOP, or RC and relayed information directly to the plant operator.
- FERC limited emergency shutdowns of generation to occur at the plant level, not the dispatch level; at this time, the FERC order does not require plant operators to be trained.
- The NERC Functional Model was stated many times as a reason to show that GOP dispatchers follow the direction of the BA or TOP. The NERC Functional Model for GOPs states that GOPs in Real time:
    - Provide Real-time operating information to the Transmission Operators and the required Balancing Authority.
    - Adjust real and reactive power as directed by the Balancing Authority and Transmission Operators.[7]
- When a GOP would be making decisions that impact reliability, they are also registered as the BA or TOP.

Entities that agreed with GOPs being added to the standard made the following comments:

- Consider including some criteria regarding various sizes of generation like in CIP Version 5.
- Consider creating a new standard addressing GOP dispatchers.
- PPL Electric Utilities Corp., Louisville Gas and Electric Co., and PPL Generation LLC stated that the TOP or BA should prepare the GOP training modules since the goal is to ensure that dispatchers do what the TOP or BA wants in emergency situations.

The arguments provided above constitutes the same arguments that FERC rejected in Order Nos 693 and 742 (see Appendix A).

[6] FERC Order 742 P 83.
[7] NERC functional model: http://www.nerc.com/pa/Stand/Resources/Documents/FunctionalModelTechnicalDocumentV5Clean2009Dec1.pdf

FERC Order 693 P. 1393 clearly states that GOP dispatchers need to be trained using the systematic approach to training methodology.

> 1393. Accordingly, the Commission approves Reliability Standard PER-002-0. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to PER-002-0 through the Reliability Standards development process that: (1) identifies the expectations of the training for each job function; (2) develops training programs tailored to each job function with consideration of the individual training needs of the personnel; (3) expands the Applicability section to include (a) reliability coordinators, (b) local transmission control center operator personnel (as specified in the above discussion), **(c) generator operators centrally-located at a generation control center with a direct impact on the reliable operation of the Bulk-Power System and** (d) operations planning and operations support staff who carry out outage planning and assessments and those who develop SOLs, IROLs or operating nomograms for Real-time operations; **(4) uses the Systematic Approach to Training (SAT) methodology in its development of new training programs** and (5) includes the use of simulators by reliability coordinators, transmission operators and balancing authorities that have operational control over a significant portion of load and generation.[8]

The pro forma standard is written to require the use of a Systematic Approach to Training, but provides the entity the ability to determine the reliability-related tasks GOP dispatchers need to be trained on and the method of how the GOP dispatchers are trained.

There were discussions regarding whether training for GOPs should be in a separate standard, however the current PER-005 is a systematic approach to training based standard and thus it is logical to include the GOP dispatchers within the current standard.

Because the ad hoc group received the same feedback that was provided in FERC Order Nos. 693 and 742; the ad hoc group suggested expanding the applicability section in PER-005 to capture these certain GOP dispatchers using the systematic approach to training, which is left up to the entity.

Applicability of the PER Standard to Operations Planning and Operations Support Staff

FERC Order 693 ¶ 1366

P. 1366. As mentioned above, the Commission proposed in the NOPR to direct the ERO to develop a modification to PER-002-0 to require training of operations planning and operations support staff of transmission operators and balancing authorities who have a direct impact on the reliable operation of the Bulk-Power System.[9]

FERC Order 742 ¶ 82

P. 82. Associated Electric expressed concern that the NOPR definition of the "operations planning and operations support staff" who should receive training pursuant to the Order No. 693 directive is "broad and will encompass operations planning and operation support staff who engage in tasks that do not directly affect the reliable operation of the bulk electric system." The Commission clarifies that the scope of the Reliability Standard or modification to a Reliability Standard to address training for "operations planning and operations support staff" is limited by the qualifications stated in Order No. 693. Specifically, in Order No. 693, the Commission directed the ERO to develop a modification to PER-002-0 that extends applicability of the training requirements to the operations planning and operations support staff of transmission operators and balancing authorities. The Commission further clarified that such directive applies only to operations planning and operations support personnel who: "carry out outage coordination and assessments in accordance with Reliability Standards IRO-004-1 and TOP-002-2, and those who determine SOLs and IROLs or operating nomograms in accordance with Reliability Standards IRO-005-1 and TOP-004-0." The NOPR did not expand or alter the scope of this directive as set forth in Order No. 693.[10]

[8] FERC Order 693 P 1363.
[9] FERC Order 693 P 1366.
[10] FERC Order 742 P 82.

Consideration of Directive

The PER ad hoc group held multiple discussions regarding the impact that operations planning and operations support staff have on the BES. The feedback received from industry regarding this topic was deemed to be the same arguments provided in the NOPR and rejected in FERC Orders 693 and 742 (see Appendix A). Therefore, the ad hoc group group revised PER-005-1 to incorporate operations planning and support personnel in the standard.

Technical Discussions

Industry provided the following information regarding operations planning and operations support staff about why training is not needed for support personnel:

- Training will provide no reliability benefit because of the administrative burden on entities and costly burden on industry with uncertain benefits.
- Training will provide no reliability impact because System Operators make the final decision, and support personnel do not make Real-time decisions.
- Operations planning and planning support staff is ambiguous and should be clarified.
- Entities appear to already train their support personnel; therefore, it should not be a mandatory requirement.

Again, the feedback received was deemed to be the same arguments provided on FERC Orders 693 and 742; therefore, the ad hoc group revised PER-005-1 to incorporate operations planning and support personnel in the standard.

Applicability of the PER Standard to EMS Personnel
FERC Order 693 ¶ 1373

1373. In addition, the Commission is aware that the personnel responsible for ensuring that critical reliability applications of the EMS, such as state estimator, contingency analysis and alarm processing packages, are available, up-to-date in terms of system data and produce useable results can also have an impact on the Reliable Operation of the Bulk-Power System. Because these employees' impact on Reliable Operation is not as clear, we direct the ERO to consider, through the Reliability Standards development process, whether personnel that perform these additional functions should be included in mandatory training pursuant to PER-002-0.[11]

Consideration of Directive

Through discussion with industry, the ad hoc group determined that the report provided by the Event Analysis Subcommittee (EAS) serves as rationale for why EMS personnel should not be included in the PER standard at this time. The technical discussion section below provides more in-depth information regarding this determination.

Technical Discussions

As background, in Orders 693 and 742, the Commission directed NERC to consider whether there is a need to include EMS personnel in the training standard. In contrast to the directive for GOPs and operations support personnel, FERC did not conclude that it was necessary to include EMS personnel in the standard; rather, it directed the ERO to consider EMS personnel inclusion. The ad hoc group discussed the issue with industry stakeholders and concluded that the data does not support a need to include EMS personnel in the standard at this time.

Based on the information in the EMS report on cause-coded events, the EAS and PER ad hoc group do not believe it is necessary at this time to require EMS support personnel to receive the level of training required of a BA, Reliability Coordinator (RC), and TOP by NERC Reliability Standard PER-005.

Lastly, the EMS events will continue to be monitored, and if EMS events begin to indicate that training is a root or contributing cause, NERC will readdress inclusion of EMS personnel to PER-005. A request will be submitted to the Operating Committee (OC) to produce an EMS guideline for training EMS personnel.

[11] FERC Order 693 P 1373.

New Simulation Technology Implementation Plan
FERC Order 742 ¶ 24

With respect to EEI's comment regarding the effective date for entities that may become subject to the simulator training requirement in PER-005-1 R3.1, the Commission believes that this issue should be considered by the ERO. We note that, with respect to the Critical Infrastructure Protection (CIP) Reliability Standards, NERC has developed a separate implementation plan that essentially gives responsible entities some lead time before newly acquired assets must be in compliance with the effective CIP Reliability Standards. **We direct NERC to consider the necessity of developing a similar implementation plan with respect to PER-005-1, Requirement R3.1.**[12]

Consideration of Directive

The PER ad hoc group was in agreement that a new subrequirement 3.1 should be developed in the PER-005 standard to address entities that may become subject to simulator training in the future. Further discussion was held regarding the best time frame for entities to become compliant, and the general consensus was that six months is a reasonable timeframe. This information was presented at webinars, conferences, and face-to-face meetings, and no feedback was received regarding the implementation plan of simulator training for entities.

Technical Discussions

The ad hoc group did not receive feedback regarding the implementation plan for simulation technology.

Applicability of the PER Standard to Local Transmission Control Center
FERC Order 742 ¶ 64

Accordingly, we adopt our NOPR proposal and direct the ERO to develop through a separate Reliability Standards development project formal training requirements for local transmission control center operator personnel. Finally, given the numerous comments stating that term "local transmission control center" should be defined, we direct NERC to develop a definition of "local transmission control center" in the standards development project for developing the training requirements for local transmission control center operator personnel. We will not evaluate Associated Electric's proposed definition but, rather, leave it to the ERO to develop an appropriate definition that reflects the scope of local transmission control centers. The Commission will not opine on the appropriate definition of local transmission control center, as this definition can be addressed first using NERC's Reliability Standards Development Procedures.

Consideration of Directive

The ad hoc group considered whether to define local transmission control center in the NERC Glossary of Terms or create a standard-only definition. The group defined "local transmission control center" by extending the PER standard applicability to TOs and developing a definition that only applies to the PER standard. The suggested TO standard-only definition is *personnel in a transmission control center who operate a portion of the BES at the direction of its Transmission Operator*.

Technical Discussions

The group did not receive many comments regarding expanding formal training for local transmission control center operator personnel and defining local transmission control center. The group suggested a revision to PER-005-1 and created a standard-only definition of "local transmission control center."

Other Issues

Inconsistent usage of "each calendar year," "annual," and "at least every twelve months"

The PER ad hoc group changed all terms (such as "annual" and "at least every twelve months") to "each calendar year" due to "each calendar year" being better defined than the other two terms.

Definitions

System Operator

A SAR was submitted for GOPs to be removed from the System Operator definition. The ad hoc group removed the term and suggested a revised definition. The suggested definition is as follows: *An individual at a ~~c~~Control ~~c~~Center ~~(Balancing~~*

[12] FERC Order 742 P 64

~~Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control~~ who operates or directs the operation of the Bulk ~~e~~Electric ~~s~~System in Real time.

System Personnel

The term "System Personnel" was created as a standard-only definition for PER-005. The purpose of this definition is to capture certain applicable entities within the requirement instead of having to type each one out individually, multiple times, in a requirement. The suggested definition is as follows: *System Operators of a Reliability Coordinator, Transmission Operator, or Balancing Authority, and the Transmission Owner personnel described in the Applicability Section of this standard.*

Support Personnel

The term "System Personnel" was created as a standard-only definition for PER-005. The purpose of this definition is to capture certain applicable personnel within the requirement as a group for clarity. The suggested definition is as follows: *Individuals who carry out outage coordination and assessments, or determine SOLs, IROLs, or operating nomograms for Real-time operations.*

Conclusion

The informal development initiative provided key discussions regarding the outstanding PER FERC directives. This white paper encapsulates all of the components of what is needed for the Standards Committee to act on, discuss, and ultimately authorize the PER Standard Authorization Request.

Appendix A: Industry Arguments and FERC Responses

The below table shows initial arguments received from industry regarding FERC Orders 693 and 742. Also shown below are the arguments received from industry to-date that are deemed to be the same arguments found in both orders.

EXTENDING APPLICABILITY TO GOPS				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comment**
<u>Clarification of Applicable GOPs</u> Many commenters requested clarification as to which GOPs needed to be trained: 1) FirstEnergy supported GOP training but noted there was some confusion over the GOP classification, which is sometimes used to refer to dispatch personnel (or fleet operators at a control center) and other times used to refer to a plant or unit operator. FirstEnergy requested that the Commission direct NERC to recognize this distinction. 2) California PUC, Nevada Companies, Reliant, Dynegy, MISO, and Wisconsin Electric all presented various arguments as to why training should not be extended to plant operators. These entities did not argue against application of the training standard to dispatch personnel.	Order No. 693 at PP. 1350, 1352-54	FERC clarified that the directive to train GOPs only applies to GOPs located at a dispatch center that receives direction and then develops specific dispatch instructions for plant operators under their control. FERC clarified that plant operators need not be trained under the standard.	Order No. 693 at PP. 1360-61 See also Order No. 742 at P. 83.	

EXTENDING APPLICABILITY TO GOPS				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comment**
<u>Decision-Making Arguments</u> A number of commenters, including Xcel, argued that GOPs need not be trained because they do not make independent decision. They argued that GOPs simply take their direction from Transmission Operators, Balancing Authorities, and Reliability Coordinators, which limits their ability to exercise independent action impacting the reliability of the Bulk-Power System.	Order No. 693 at PP. 1351; 1354	FERC rejected this argument, stating: "Xcel and others oppose extending the applicability of PER-002-0 to generator operators, because they take directions from balancing authorities and others, which limits their ability to impact reliability. Although a generator may be given direction from the balancing authority, it is essential that generator operator personnel have appropriate training to understand those instructions, particularly in an emergency situation in which instructions may be succinct and require immediate action. Further, if communication is lost, the generator operator personnel should have had sufficient training to take appropriate action to ensure reliability of the Bulk-Power System. Thus, we direct the ERO to develop a modification to make PER-002-0 applicable to generator operators.	Order No. 693 at P. 1359	<u>Decision-Making Arguments</u> A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that all decisions that GOPs make that impact the BES must be approved by BA, TOP, or RC have the final say in the decisions being made.

EXTENDING APPLICABILITY TO GOPS				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comment**
No Reliability Benefit Argument Entergy, Xcel and Nevada companies further argued that generator operator training will provide limited benefit. Entergy further stated that that expanding the applicability to generator operators would provide little benefit to those personnel in the performance of their own functions, and could distract them from those functions.	Order No. 693 at P. 1351; 1357	FERC disagreed, stating that with the limitation of training to dispatch personnel, "the benefits to the Bulk-Power System will be maximized and the cost of formal training limited."	Order No. 693 at P. 1362	No Reliability Benefit Argument Creating training for GOPs will be costly and provide no benefit.
Scarcity of Resources and Cost Argument Entergy argued that training would be extremely costly and would divert necessary resources from more important reliability objectives. TAPS also opposed the expanded applicability, especially in the case of small systems, because it believes that the requirement would be costly with no benefits to reliability.	Order No. 693 at P. 1351; 1357	See above. FERC rejected these arguments, stating that the limitation to dispatch personnel would limit the cost of training.	Order No. 693 at P. 1362	Scarcity of Resources and Cost Argument A number of commenters, through verbal conversations and the chat feature during PER webinars stated that it will be costly to train GOPs. Smaller entities state it will be a costly to provide training to their GOPs and no major benefits will appear.
Scope of Training Arguments Many commenters discussed the scope of training for GOPs, arguing that the scope, content, and duration needs to be limited and tailored to their functions.	Order No. 693 at P. 1356	FERC agreed, stating that training for Generator Operators need not be as extensive as that required for Transmission Operators, and the training requirements developed by the ERO should be tailored in their scope, content, and duration so as to be appropriate to Generation Operations personnel and the objective of promoting system reliability.	Order No. 693 at P. 1363	Scope of Training Arguments Concerns about GOPs that do not develop dispatch instructions will be captured regardless.

EXTENDING APPLICABILITY TO GOPS				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comment**
Size Limitation Arguments APPA, TAPS, and the Process Electricity Committee requested a size limitation, arguing that while a generator plays an important role in the reliable operations of the Bulk Electric System, the Generator Operator takes commands from the Rransmission Operator, Balancing Authority, or Reliability Coordinator. Without a size limitation, the standard would require many small generators to enroll in a training program.	Order No. 693 at P. 1357	FERC responded that concerns regarding the need for a size limitation on Generator Operators should be satisfied by FERC's determination that the applicability of particular entities should be determined based on the ERO compliance registry criteria.	Order No. 693 at P. 1357	Size Limitation Arguments Comments received stated that a size limitation needs to be captured like CIP V5.
In response to the Order No. 742 NOPR, a number of commenters challenged the need for the directive.	Order No. 742 at P. 79	FERC rejected these arguments as beyond the scope of Order No. 742 and as collateral attacks on the ruling in Order No. 693 and refused to address the arguments again.	Order No. 742 at PP. 79, 81	

EXTENDING APPLICABILITY TO GOPS				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comment**
EPSA Clarification EPSA sought clarification regarding the statement in the NOPR, "[I]n the event communication is lost, the generator operator personnel must have had sufficient training to take appropriate action to ensure reliability of the Bulk-Power System." EPSA expressed concern that this statement suggests that if communication is lost with the grid operator, the Generator Operator must take unilateral action for which it requires training. EPSA notes that Generator Operators do not take such unilateral action, nor do they have access to information to make such decisions. EPSA asks the Commission to make clear that while communication should be addressed in training requirements for centrally located Generator Operator dispatch employees, the Commission is not extending related responsibilities or training requirements to Generator Operator employees.	Order No. 742 at P. 84	FERC granted the requested clarification and affirmed that it did not modify the Order No. 693 directive regarding training for certain Generator Operator dispatch personnel, nor expand a Generator Operator's responsibilities.	Order No. 742 at P. 84	

EXTENDING APPLICABILITY TO SUPPORT PERSONNEL				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comments**
No Reliability Benefit EEI states that the extension of the applicability to "operations support personnel" could result in a dramatic expansion of industry training requirements with uncertain benefits to system reliability.	Order No. 693 at P. 1368	FERC stated that because it is limiting training of support personnel to those who carry out outage coordination and assessments and those who determine SOLs and IROLs or operating nomograms, the directive is limited to those with a direct impact on reliability.	Order No. 693 at P. 1374	No Reliability Benefit A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that expanding PER-005 applicability to support personnel will capture a variety of people who do not impact the BES.
TOP makes decision Entergy argued that it is unnecessary to require all staff supporting the Transmission Operator to be trained in the Transmission Operator's Reliability Standards responsibilities, because as long as the supporting personnel work under the direction of a NERC-certified Transmission Operator, there is no need for duplicative training for supporting personnel.	Order No. 693 at P. 1370	FERC stated that because it is limiting training of support personnel to those who carry out outage coordination and assessments and those who determine SOLs and IROLs or operating nomograms, the directive is limited to those with a direct impact on reliability.	Order No. 693 at P. 1374	TOP makes decision A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that decisions are made by the NERC-Certified System Operators.
Administrative Burden APPA expressed concern about expanding the applicability to operations planning and operations support staff, especially if the Commission adopts its proposed interpretation of the Bulk Electric System, because this would become quite onerous for small utilities.	Order No. 693 at P. 1368	FERC limited the scope of what support personnel must be trained and clarified that training for support personnel should be tailored to the functions they perform and need not be trained to the same extent as Transmission Operators.	Order No. 693 at P 1375	Administrative Burden A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that this would be a huge administrative burden regarding the SAT process.

EXTENDING APPLICABILITY TO SUPPORT PERSONNEL				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comments**
Directive is Ambiguous Wisconsin Electric argued that the Commission's proposal does not address how to identify the operations planning and operations support personnel who would be subject to the Reliability Standard and how to develop compliance measures for them. It contended that the proposed modification is ambiguous and should not be implemented. Northern Indiana also argued that the terms "operations planning" and "operations support staff" should be clarified.	Order No. 693 at P. 1368	FERC clarified that the support personnel who need to be trained are those who carry out outage coordination and assessments in accordance with Reliability Standards IRO-004-1 and TOP-002-2, and those who determine SOLs and IROLs or operating nomograms in accordance with Reliability Standards IRO-005-1 and TOP-004-0. FERC said that because the reliability impact of EMS personnel are unclear, it directed NERC to consider whether such personnel need to be trained.	Order No. 693 at P. 1372	Directive is Ambiguous A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that "operations planning" and "operations support" are too broad.
Scope of Training Entergy commented that if training is required, it should focus on the functions operations planning and operations support staff must perform, not on the functions that others perform.	Order No. 693 at P. 1370	FERC clarified that training for support personnel should be tailored to the functions they perform and need not be trained to the same extent as transmission operators.		Scope of Training

EXTENDING APPLICABILITY TO SUPPORT PERSONNEL				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comments**
No Reliability Benefit In response to the Order No. 742 NOPR, a number of commenters challenged the need for the directive. For example, Associated Electric urged the Commission to direct NERC to adopt a definition of “operations planning” and “operations support staff” that more narrowly identifies those personnel who will be subject to the training standard. Associated Electric stated that the directive in Order No. 693 is broad and will encompass operations planning and operation support staff who engage in tasks that do not directly affect the reliable operation of the Bulk Electric System. GSOC and GTC do not support expanding the applicability of the PER-005-1 training requirements to any other personnel and argue that time spent expanding training requirements to other personnel will take away from their job of supporting their operating personnel—a use of time and resources that could actually decrease reliability.	Order No. 742 at P. 80	FERC rejected these arguments as beyond the scope of Order No. 742 and as collateral attacks on the ruling in Order No. 693 and refused to address the arguments again.	Order No. 742 at PP. 79, 81	No Reliability Benefit A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that tasks performed by support personnel do not directly affect the BES. Support personnel may guide, but do not operate.

Appendix B: Entity Participants

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

Table 2: Entity Participation in PER Informal Development

ACES Power	CPS Energy	IESO	NV Energy	Southern Co.
AECI	CSU	IMPA	OGE	STEC
AEP	CWLP	Integry Group	OMU	Sunflower
AES	DC PUD	IREA	ORU	Sycamore
ALCOA	Detroit Renewable	ISO-NE	OUC	TID
Alliant Energy	Direct Energy	ITC	OXY	Tri-State G&T
Ameren	Dominion	KCPL	PacifiCorp	TVA
AMP Partners	DTE Energy	KUA	PEPCO	
APS	Duke Energy	LCEC	PGE	
ATC	Dynegy	LCRA	PGN	**Regional Entities**
Austin Energy	Energy GRP	LES	PJM	FRCC
Blackhills Corp	Entergy	LGE-KU	PNM	MRO
BPA	EP Electric	Luminant	PNM Resources	NPCC
Brazos Electric	ERCOT	MGE	PPL	RFC
Brownsville PUD	Essential Power LLC	MidAmerican	Seattle Power & Light	SERC
CAISO	Exelon Corp	Minnkota Power	Sempra Utilities	SPP
CB Power	FMTN	MISO Energy	Sharyland	TRE
Center Point Energy	FPL	NaturEner	SMEPA	WECC
Chelan PUD	GASOC	NIPSCO	SMMPA	
City of Tacoma	GC Pud	Northwestern	SMUD	
City Utilities	Hydro Manitoba	NRECA	Snohomish PUD	
Cleco Corporation	Hydro-Quebec	NU	South Westgen	

Table 3: Presentations and Events

NERC Operating Committee	FRCC Compliance Workshop
NERC EAS	WECC Operations Training Subcommittee
NERC Standards and Compliance Workshop	WECC Standing Committees
NERC News	TRE Standards Discussion Forum

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2010-01 Operations Personnel Training
PER-005-2 Mapping Document

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 **NERC Board Approved**	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
R1. Reliability Coordinator, Balancing Authority and Transmission Operator shall use a systematic approach to training to establish a training program for the BES company-specific reliability-related tasks performed by its System Operators and shall implement the program. **1.1.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall create a list of BES company-specific reliability-related tasks performed by its System Operators. **1.1.1.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall update its list of BES company-specific reliability-related tasks performed by its System	Requirement R1 parts 1.1.1., 1.1.	**R1.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall review and update its list of tasks identified in part 1.1 each calendar year. **1.1.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall review and update its list of tasks identified in part 1.1 each calendar year. **1.1.1.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall design and develop training materials based on the task list created in part 1.1 and part 1.1.1 **1.2.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall deliver the training established in part 1.2 to System Personnel. **1.3.** Each Reliability Coordinator, Balancing Authority,

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
Operators each calendar year to identify new or modified tasks for inclusion in training. **1.2.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall design and develop learning objectives and training materials based on the task list created in R1.1. **1.3.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall deliver the training established in R1.2. **1.4**. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall conduct an annual evaluation of the training program established in R1, to identify any needed changes to the training program and shall implement the changes identified.		Transmission Operator, and Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement R1, to identify any needed changes to the training program and shall implement the changes identified.
R2. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator's capabilities to perform each assigned task identified in R1.1 at least one time.	Requirement R2	**R2:** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify at least once, the capabilities of its System Personnel identified to perform each assigned task in Requirement R1

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 **NERC Board Approved**	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
2.1. Within six months of a modification of the BES company-specific reliability-related tasks, each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator's capabilities to perform the new or modified tasks.		parts 1.1 and 1.1.1. **2.1.** Within six months of a modification or addition of Bulk Electric System company-specific Real-time reliability-related tasks, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its System Personnel to perform the new or modified tasks identified in Requirement R1 part 1.1.1.
R3. At least every 12 months each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each of its System Operators with at least 32 hours of emergency operations training applicable to its organization that reflects emergency operations topics, which includes system restoration using drills, exercises or other training required to maintain qualified personnel.	This Requirement has been updated with deleting R3 and moving 3.1 from the approved standard to be the new R3. Part 3.1 in the proposed standard it addresses the implementation of simulation technology.	**R3.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that has operational authority or control over Facilities with established IROLs or has established operating guides or protection systems to mitigate IROL violations shall provide its System Personnel with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the Bulk Electric System.

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
3.1. Each Reliability Coordinator, Balancing Authority and Transmission Operator that has operational authority or control over Facilities with established IROLs or has established operating guides or protection systems to mitigate IROL violations shall provide each System Operator with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES during normal and emergency conditions.		**3.1.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that gains operational authority or control over a Facility with an established IROL or establishes operating guides or protection systems to mitigate IROL violations shall comply with Requirement R3 within 6 months of gaining that authority, control or establishing such operating guides or protection systems.
	This requirement is new to PER-005-2.	**R4.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall establish and implement training for Support Personnel specific to those Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1 and part 1.1.1 that relate to the Support Personnel's job function.
	This requirement is new to PER-005-2.	**R5.** Each Generator Operator shall use a systematic approach to training to establish and implement training for its personnel described in applicability section 4.1.5 as follows: *[Violation Risk Factor: Medium] [Time Horizon:*

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
		Long-term Planning] **5.1** Each Generator Operator shall coordinate with its Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner to identify training topics that address the impact of the decisions and actions of a Generator Operator's personnel as it pertains to the reliability of the Bulk Electric System during normal and emergency operations. **5.1.1.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall provide input as requested by the Generator Operator.

Compliance Operations

Draft Reliability Standard Compliance Guidance for PER-005-2
July 1, 2013

Introduction

The NERC Compliance department (Compliance) worked with the PER-005 informal ad hoc group (PER Group) in a review of pro forma standard PER-005-2. The purpose of the review is to discuss the requirements of the pro forma standard to obtain an understanding of its intended purpose and the evidence necessary to support compliance. The purpose of this document is to address specific questions posed by the PER Group and Compliance in order to aid in the drafting of the requirements and provide a level of understanding regarding evidentiary support necessary to demonstrate compliance. However, this document makes no assessment as to the enforceability of the standard.

While all testing requires levels of auditor judgment, participating in these reviews allows Compliance to develop training and approaches to support a high level of consistency in audits conducted by the Regional Entities. The following questions and answers are intended to both assist the PER Group in further refining the standard and to serve as a resource in the development of training for auditors.

PER-005-2 Questions

Question 1

For Requirement 1, what criteria would an auditor use to determine if a registered entity uses a systematic (SAT) approach to develop training?

Compliance Response to Question 1

Without a definition of, or reference to, a specific SAT, it would be difficult for auditors to assess an entity's training development program because no benchmark is provided within the standard. Compliance recommends the PER Group consider referencing a specific SAT process for registered entities to follow in developing training.

Question 2

Is an auditor to assess a registered entity based on a SAT for the support personnel referenced in requirement 4?

Compliance Response to Question 2

No, since the requirement does not specify use of a SAT, then Compliance will not require training be developed based on a SAT for requirement 4.

Question 3

Since requirement 5 does not include the same sub-requirements as requirement 1 to define a SAT, do entities have to adhere to the requirement 1 sub-requirements for requirement 5?

Compliance Response to Question 3

As with requirement 1, without a definition of, or reference to, a specific SAT, it would be difficult for auditors to assess an entity's training development program because no benchmark is provided within the standard. Compliance recommends the PER Group consider referencing a specific SAT process for registered entities to follow in developing training. Compliance Operations also notes that requirement 5 does not include the sub-requirements found in requirement 1 and is noting the inconsistency.

Conclusion

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

Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training. Attachment A represents the version of the pro forma standard requirements referenced in this document.

Attachment A

Requirements and Measures

R1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall use a systematic approach to training (SAT) to develop and implement a training program for its System Personnel as follows *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall review and update its list of tasks identified in part 1.1 each calendar year.

1.1.1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall review and update its list of tasks identified in part 1.1 each calendar year.

1.2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall design and develop training materials based on the task list created in part 1.1 and part 1.1.1.

1.3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall deliver the training established in part 1.2 to System Personnel.

1.4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement R1, to identify any needed changes to the training program and shall implement the changes identified.

M1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall

M1.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection its company-specific Real-time reliability-related task list, with the date of the last update, as specified in Requirement R1 parts 1.1 and 1.1.1.

M1.2 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training materials, as specified in Requirement R1 part 1.2.

M1.3 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection System Personnel training records showing the names of the people trained, the title of the training delivered and the dates of delivery to show that it delivered the training, as specified in Requirement R1 part 1.3.

M1.4 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an annual training program evaluation, as specified in Requirement R1 part 1.4.

R2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify at least once, the capabilities of its System Personnel identified to perform each assigned task in Requirement R1 parts 1.1 and 1.1.1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. Within six months of a modification or addition of Bulk Electric System company-specific Real-time reliability-related tasks, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its System Personnel to perform the new or modified tasks identified in Requirement R1 part 1.1.1.

M2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence to show that it verified the capabilities of each of the System Personnel identified to perform each assigned task in Requirement R1 parts 1.1 and 1.1.1, as specified in Requirement R2. This evidence can be documents such as training records showing successful completion of tasks with the employee name and date; supervisor check sheets showing the employee name, date, and task completed; or the results of learning assessments.

R3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that has operational authority or control over Facilities with established IROLs or has established operating guides or protection systems to mitigate IROL violations shall provide its System Personnel with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that gains operational authority or control over a Facility with an established IROL or establishes operating guides or protection systems to mitigate IROL violations shall comply with Requirement R3 within 6 months of gaining that authority, control or establishing such operating guides or protection systems.

M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that System Personnel completed training that includes the use of simulation technology, as specified in Requirement R3.

M3.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that System Personnel completed training that included the use of simulation technology, as specified in Requirement R3, within 6 months of gaining that authority, control or establishing such operating guides or protection systems.

R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall establish and implement training for Support Personnel specific to those Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1 and part 1.1.1 that relate to the Support Personnel's job function. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training materials and training records that provide evidence that Support Personnel completed training. This evidence can be documents such as training records showing successful completion of training with the employee name and date.

R5. Each Generator Operator shall use a systematic approach to training to establish and implement training for its personnel described in applicability section 4.1.5 as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. Each Generator Operator shall coordinate with its Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner to identify training topics that address the impact of the decisions and actions of a GOP's personnel as it pertains to the reliability of the Bulk Electric System during normal and emergency operations.

5.1.1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall provide input as requested by the Generator Operator.

M5. Each Generator Operator shall have available for inspection training materials and training records that provide evidence that its applicable personnel completed training. This evidence can be documents such as training records showing successful completion of training with the employee name and date.

M5.1 Each Generator Operator GOP shall have available for inspection evidence, such as an email or attestation, that it coordinated with the RC, BA, TOP, and TO in establishing the training requirements.

M5.1.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence, such as an email or attestation, that it provided input to the Generator Operator.

Proposed Timeline for the Project 2010-01 Standard Drafting Team (SDT)		
Anticipated Date	**Location**	**Event**
July 2013	-	SC Authorizes SAR and Pro Forma Standard for Posting
July 2013		Conduct Nominations for Project 2012-05 SDT
July 2013	-	Post SAR and Pro Forma standard for 45-Day Comment Period
August 2013	-	Conduct Ballot
September 2013	-	45-Day Comment Period and Ballot Closes
September 2013	San Francisco	PER Standard Drafting Team Face to Face Meeting to Respond to Initial Comments and Make Possible Revisions
September 2013	-	Conduct Final Ballot
November 7, 2013	-	NERC Board of Trustees Adoption
December 31, 2013	-	NERC Files Petition with the Applicable Governmental Authorities

PER Informal Development Project

Requested Action

1. Authorize the concurrent posting of the PER Standards Authorization Request (SAR) for a 45-day informal comment period (given it is addressing FERC directives) along with the revised PER reliability standards (proposed PER-005-2), VRFs/VSLs, and associated implementation plan for a 45-day comment period with a ballot pool formed during the first 30 days of the comment period, and a ballot and non-binding poll conducted during the last ten days of that comment period; and
2. Approve the posting for a 10-day solicitation for nominations for Standard Drafting Team members for MOD B's formal development.

The PER project is assigned the project number 2010-01. Additionally, a redlined of the revised PER-005-1 will not be provided due to the significant amount of changes made to the standard. The rationale boxes provided in the standard will explain the changes.

Background

On March 16, 2007 the Federal Energy Regulatory Commission (FERC) issued Order No. 693, *Mandatory Reliability Standards for the Bulk-Power System* and on November 18, 2010 FERC issued Order No. 742, *System Personnel Training Reliability Standards.* Five outstanding directives remain from those two orders (3 from Order No. 693 and 2 from Order No. 742), which are explained in detail in the PER White Paper contained in the SAR package.

The informal consensus building for PER began in February 2013. Specifically, the ad hoc group engaged stakeholders on how best to address the FERC directives, paragraph 81 candidates and results-based approaches (see page 4 of the PER White Paper regarding the paragraph 81 candidate). A discussion of the ad hoc group's consensus building and collaborative activities are included in the PER White Paper (see SAR package).

Based on stakeholder outreach, the PER ad hoc group has developed one revised proposed reliability standards (PER-005-2) that address the FERC directives and recommendations for improving PER-005-1, which included creating results-based requirements and considering paragraph 81 criteria to ensure that the standards proposals did not include requirements that meet those criteria. A further discussion of this topic is included in the SAR package (see page 4 of the "PER White Paper" document).

The goal is to present the PER standard to the NERC Board of Trustees (Board) during its November 2013 meeting, and for the Board adopted PER Reliability Standard to be filed with the applicable regulatory authorities by the end of 2013.

Standard Drafting Team

The PER drafting team is proposed to consist of a maximum of 10 members. Since this project is a continuation of informal development, several drafting team members will be selected from members of the informal group and the remainder from industry. A confidential slate of candidates with recommendations for appointment will be provided following the public solicitation. The purpose of this appointment/solicitation approach is to ensure a smooth transition from the informal to formal standards development process for MOD B, while also providing an opportunity for solicitation of new members to help provide a well-rounded perspective to moving MOD B forward. The public solicitation shall request that standard drafting team members have experience in one or more of the following areas: training and operations. In addition, team members with experience in compliance, legal, regulatory, and technical writing are desired. Previous drafting team experience is beneficial, but not a requirement.

Quality Review
A quality review was coordinated by NERC Staff for the posting of the PER reliability standard, implementation plan, VRFs and VSLs, and other associated documents.

Project Schedule
The drafting team is expected to facilitate meeting the proposed schedule contained in the SAR package.

Standards Announcement

Project 2010-01 Training
PER-005-2

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

Now Available

A ballot for **PER-005-2** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels is open through **8 p.m. Eastern on Tuesday, September 3, 2013.**

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

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

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

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

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

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

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Standards Announcement

Project 2010-01 Training
PER-005-2

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

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

Now Available

A 45-day formal comment period for **PER-005-2** is open through **8 p.m. Eastern on Tuesday, September 3, 2013.** The standard authorization request (SAR) for this project is also posted for comment. Additional supporting documents are posted for information. A ballot pool is being formed and the ballot pool window is open through 8 a.m. Eastern on **Monday, August 19, 2013** *(please note that ballot pools close at 8 a.m. Eastern and mark your calendar accordingly).*

This project began with an informal development process to address outstanding FERC directives from Orders 693 and 742, and other issues based on operational lessons learned. The informal effort resulted in the revision of PER-005-1. The informal development also included a review for Paragraph 81 principles, and this resulted in one of the sub-requirement is being recommended for retirement. The goal is to present the standard to the NERC Board of Trustees in November 2013.

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

Instructions for Joining Ballot Pool(s)

Ballot pools are being formed for **PER-005-2** and the associated non-binding poll in this project. Registered Ballot Body members must join the ballot pools to be eligible to vote in the balloting and submit an opinion for the non-binding polls of the associated VRFs and VSLs. Registered Ballot Body members may join the ballot pools at the following page: Join Ballot Pool

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

Ballot: bp-2010-01_PER-005-2_in@nerc.com
Non-Binding poll: bp-2010-01_PER-005-2_NB_in@nerc.com

Instructions for Commenting

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

Next Steps

A ballot for PER-005-2 and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) will be conducted as previously outlined.

Standards Development Process

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

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

North American Electric Reliability Corporation
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Suite 600, North Tower
Atlanta, GA 30326
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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2010-01 Training
PER-005-2

Ballot and Non-Binding Poll Results

Now Available

A ballot for **PER-005-2** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) concluded at **8 p.m. Eastern on Tuesday, September 3, 2013.**

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

Approval	Non-binding Poll Results
Quorum: 75.25% Approval: 34.46%	Quorum: 80.45% Supportive Opinions: 34.24%

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

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

Standards Development Process
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-Ballot Pools
-Current Ballots
-Ballot Results
-Registered Ballot Body
-Proxy Voters

Home Page

Ballot Results	
Ballot Name:	Project 2010-01 Training PER-005-2 August 2013
Ballot Period:	8/23/2013 - 9/3/2013
Ballot Type:	Initial
Total # Votes:	298
Total Ballot Pool:	396
Quorum:	**75.25 % The Quorum has been reached**
Weighted Segment Vote:	34.46 %
Ballot Results:	**The drafting team will review comments received.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	106	1	27	0.346	51	0.654	0	4	24
2 - Segment 2	9	0.9	1	0.1	8	0.8	0	0	0
3 - Segment 3	90	1	19	0.302	44	0.698	0	4	23
4 - Segment 4	31	1	4	0.19	17	0.81	0	0	10
5 - Segment 5	91	1	18	0.316	39	0.684	0	7	27
6 - Segment 6	53	1	12	0.293	29	0.707	0	2	10
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	5	0.3	2	0.2	1	0.1	0	0	2
9 - Segment 9	2	0.2	1	0.1	1	0.1	0	0	0
10 - Segment 10	9	0.7	6	0.6	1	0.1	0	0	2
Totals	**396**	**7.1**	**90**	**2.447**	**191**	**4.653**	**0**	**17**	**98**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - AEP)

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

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

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

1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Texas Municipal Power Agency	Brent J Hebert		
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Negative	COMMENT RECEIVED
1	Westar Energy	Allen Klassen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Westar Energy, Tiffany Lake)
1	Western Area Power Administration	Lloyd A Linke	Negative	SUPPORTS THIRD PARTY COMMENTS - (US Bureau of Reclamation)
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Xcel Energy - Alice Ireland)
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC/Standards Review Committee)
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRC)
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Kathleen Goodman	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC)
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New York Independent System Operator	Gregory Campoli	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC/SRC & NPCC)
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	COMMENT RECEIVED
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz from American Electric Power)
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Abstain	
3	American Public Power Association	Nathan Mitchell	Negative	SUPPORTS THIRD PARTY COMMENTS - (Allen Mosher - APPA)
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	

3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Negative	COMMENT RECEIVED
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	COMMENT RECEIVED
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Negative	COMMENT RECEIVED
3	City of Redding	Bill Hughes		
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	City Water, Light & Power of Springfield	Roger Powers		
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	SUPPORTS THIRD PARTY COMMENTS - (support NPCC group comments)
3	Consumers Energy Company	Gerald G Farringer	Negative	COMMENT RECEIVED
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Negative	COMMENT RECEIVED
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
3	Entergy	Joel T Plessinger	Abstain	
3	FirstEnergy Corp.	Cindy E Stewart	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Negative	COMMENT RECEIVED
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel		
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	COMMENT RECEIVED
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lincoln Electric System	Jason Fortik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)

3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Negative	COMMENT RECEIVED
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF comments and SPP comments)
3	New York Power Authority	David R Rivera		
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (NIPSCO)
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Electric Utility	David Anderson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC group comments)
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Comments)
3	Pacific Gas and Electric Company	John H Hagen		
3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker		
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
3	Puget Sound Energy, Inc.	Erin Apperson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Denise Lietz)
3	Rutherford EMC	Thomas M Haire		
				COMMENT

3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	RECEIVED
3	Salt River Project	John T. Underhill	Abstain	
3	Santee Cooper	James M Poston	Negative	COMMENT RECEIVED
3	Seattle City Light	Dana Wheelock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase (Seattle City Light))
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole comments)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (New York Power Authority)
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group)
3	Tacoma Public Utilities	Travis Metcalfe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Mike Hill)
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
3	Westar Energy	Bo Jones	Negative	COMMENT RECEIVED
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tony Jankowski)
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Negative	SUPPORTS THIRD PARTY COMMENTS - (Xcel Energy via Alice Ireland)
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	COMMENT RECEIVED
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel		
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Gerald Farringer)
4	Detroit Edison Company	Daniel Herring	Negative	COMMENT RECEIVED
4	Flathead Electric Cooperative	Russ Schneider		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Fort Pierce Utilities Authority	Cairo Vanegas		
				SUPPORTS THIRD PARTY

4	Georgia System Operations Corporation	Guy Andrews	Negative	COMMENTS - (GSOC's comment)
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	North Carolina Electric Membership Corp.	John Lemire	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (New York Power Authority)
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	COMMENT RECEIVED
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase (Seattle City Light))
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative, Inc.)
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	SUPPORTS THIRD PARTY COMMENTS - (Mike Hill, Tacoma Power)
4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Regional Standards Committee)
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (We Energies)
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz – American Electric Power)
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Arkansas Electric Cooperative Corporation	Brent R Carr		
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar		
5	Boise-Kuna Irrigation District/dba Lucky	Mike D Kukla		

	peak power plant project			
5	Bonneville Power Administration	Francis J. Halpin	Negative	COMMENT RECEIVED
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	COMMENT RECEIVED
5	City of Redding	Paul A. Cummings		
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Negative	COMMENT RECEIVED
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC group comments)
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jerry Farringer)
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Detroit Edison Company	Alexander Eizans		
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	El Paso Electric Company	Gustavo Estrada	Affirmative	
5	Electric Power Supply Association	John R Cashin	Abstain	
5	Entergy Services, Inc.	Tracey Stubbs	Negative	SUPPORTS THIRD PARTY COMMENTS - (NAGF)
5	Essential Power, LLC	Patrick Brown	Negative	COMMENT RECEIVED
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Florida Municipal Power Agency (FMPA))
5	Liberty Electric Power LLC	Daniel Duff	Negative	SUPPORTS THIRD PARTY COMMENTS - (Generator Forum Standards Review Team)
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)
5	MidAmerican Energy Co.	Neil D Hammer		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	NiSource	Huston Ferguson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NIPSCO)
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES and SERC OC)
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Leo Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	COMMENT RECEIVED
5	Orlando Utilities Commission	Richard K Kinas		
5	PacifiCorp	Bonnie Marino-Blair	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kelly Cumiskey, PacifiCorp)
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway		
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	SUPPORTS THIRD PARTY COMMENTS - (NAGF)
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	COMMENT RECEIVED
5	Raven Power	Scott A Etnoyer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Negative	COMMENT RECEIVED
5	Salt River Project	William Alkema	Abstain	
5	Santee Cooper	Lewis P Pierce	Negative	COMMENT

				RECEIVED
5	Seattle City Light	Michael J. Haynes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase, Seattle City Light)
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (New York Power Authority)
5	South Feather Power Project	Kathryn Zancanella	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Mike Hill)
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
5	Westar Energy	Bryan Taggart	Negative	COMMENT RECEIVED
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS - (Matthew Beilfuss) - (Tony Jankowski)
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland)
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz (AEP))
6	Alabama Electric Coop. Inc.	Ron Graham		
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Negative	COMMENT RECEIVED
6	City of Austin dba Austin Energy	Lisa L Martin	Negative	COMMENT RECEIVED
6	City of Redding	Marvin Briggs		
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC group comments)
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
6	Duke Energy	Greg Cecil		

6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY COMMENTS - (First Energy)
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF/ACES)
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm		
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS - (NIPSCO Comments)
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Mahmood Safi)
6	PacifiCorp	Kelly Cumiskey	Negative	COMMENT RECEIVED
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Public Service Enterprise Group)
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Negative	COMMENT RECEIVED
6	Salt River Project	Steven J Hulet	Abstain	
6	Santee Cooper	Michael Brown	Negative	COMMENT RECEIVED
6	Seattle City Light	Dennis Sismaet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Paul Haase)
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	COMMENT RECEIVED

6	Snohomish County PUD No. 1	Kenn Backholm	Negative	SUPPORTS THIRD PARTY COMMENTS - (New York Power Authority)
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	COMMENT RECEIVED
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Negative	COMMENT RECEIVED
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Negative	SUPPORTS THIRD PARTY COMMENTS - (Lloyd Linke)
6	Wisconsin Public Service Corp.	David Hathaway	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Negative	SUPPORTS THIRD PARTY COMMENTS - (Alice Ireland, Xcel Energy)
8		Edward C Stein		
8		Merle Ashton		
8		Roger C Zaklukiewicz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Northeast Utilties, ISO-NE)
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Negative	COMMENT RECEIVED
10	Florida Reliability Coordinating Council	Linda Campbell		
10	Midwest Reliability Organization	Russel Mountjoy		
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Non-binding Poll Results

Project 2010-01 PER-005-2

Non-binding Poll Results	
Non-binding Poll Name:	Project 2010-01 Training PER-005-2 Non-binding Poll
Poll Period:	8/23/2013 - 9/4/2013
Total # Opinions:	288
Total Ballot Pool:	358
Summary Results:	80.45% of those who registered to participate provided an opinion or an abstention; 34.24% of those who provide dan opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

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

1	CPS Energy	Richard Castrejana	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy		
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	El Paso Electric Company	Pablo Onate	Affirmative	
1	Entergy Transmission	Oliver A Burke	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group)
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Georgia Transmission Corporation	Jason Snodgrass	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC)
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS (NPCC)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
1	JDRJC Associates	Jim D Cyrulewski	Negative	SUPPORTS THIRD PARTY COMMENTS -NIPSCO - (MISO)
1	JEA	Ted Hobson		
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lincoln Electric System	Doug Bantam	Abstain	
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)

1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Group Comments)
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	David Boguslawski	Negative	COMMENT RECEIVED
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (NIPSCO)
1	NorthWestern Energy	John Canavan	Negative	COMMENT RECEIVED
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	COMMENT RECEIVED
1	Omaha Public Power District	Doug Peterchuck	Negative	COMMENT RECEIVED
1	Oncor Electric Delivery	Jen Fiegel	Abstain	
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Negative	SUPPORTS THIRD PARTY COMMENTS - (Northeast Power Coordinating Council group comments)
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	PacifiCorp	Ryan Millard	Abstain	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments submitted under the title 'PPL NERC Registered Affiliates')
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	COMMENT RECEIVED
1	Rochester Gas and Electric Corp.	John C. Allen	Negative	COMMENT RECEIVED
1	Sacramento Municipal Utility District	Tim Kelley	Negative	COMMENT RECEIVED
1	Salt River Project	Robert Kondziolka	Abstain	
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson		
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Snohomish County PUD No. 1	Long T Duong	Negative	SUPPORTS THIRD PARTY COMMENTS - (New York Power Authority)
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group)
1	South Carolina Public Service Authority	Shawn T Abrams	Negative	COMMENT RECEIVED
1	Southern California Edison Company	Steven Mavis	Affirmative	

1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Texas Municipal Power Agency	Brent J Hebert	Affirmative	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Westar Energy, Tiffany Lake)
1	Western Area Power Administration	Lloyd A Linke	Negative	SUPPORTS THIRD PARTY COMMENTS - (US Bureau of Reclamation)
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC/Standards Review Committee)
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRC)
2	Independent Electricity System Operator	Barbara Constantinescu	Negative	COMMENT RECEIVED
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	COMMENT RECEIVED
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	COMMENT RECEIVED
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		

NERC

3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	SUPPORTS THIRD PARTY COMMENTS - (support NPCC group comment)
3	Consumers Energy Company	Gerald G Farringer	Negative	COMMENT RECEIVED
3	CPS Energy	Jose Escamilla	Abstain	
3	Detroit Edison Company	Kent Kujala	Negative	COMMENT RECEIVED
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger	Abstain	
3	FirstEnergy Corp.	Cindy E Stewart	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Negative	COMMENT RECEIVED
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel		
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	COMMENT RECEIVED
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lincoln Electric System	Jason Fortik	Abstain	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Negative	COMMENT RECEIVED
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera		
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (NIPSCO)
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC group comments)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Comments)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Abstain	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Denise Lietz)
3	Rutherford EMC	Thomas M Haire		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	COMMENT RECEIVED
3	Salt River Project	John T. Underhill	Abstain	
3	Santee Cooper	James M Poston	Negative	COMMENT RECEIVED
3	Seminole Electric Cooperative, Inc.	James R Frauen	Abstain	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Negative	SUPPORTS THIRD PARTY COMMENTS - (New York Power Authority)
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC Review Group)
3	Tacoma Public Utilities	Travis Metcalfe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Mike Hill)
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
3	Westar Energy	Bo Jones	Negative	COMMENT RECEIVED
3	Wisconsin Electric Power Marketing	James R Keller		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City Utilities of Springfield, Missouri	John Allen	Abstain	
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Gerald Farringer)
4	Detroit Edison Company	Daniel Herring	Negative	COMMENT RECEIVED

4	Flathead Electric Cooperative	Russ Schneider	Abstain	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Negative	SUPPORTS THIRD PARTY COMMENTS - (GSOC's Comments)
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	North Carolina Electric Membership Corp.	John Lemire		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Negative	SUPPORTS THIRD PARTY COMMENTS - (New York Power Authority)
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	COMMENT RECEIVED
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Abstain	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	SUPPORTS THIRD PARTY COMMENTS - (Mike Hill, Tacoma Power)
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (We Energies)
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Arkansas Electric Cooperative Corporation	Brent R Carr		
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar		
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	COMMENT RECEIVED
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		

5	Cleco Power	Stephanie Huffman	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Negative	SUPPORTS THIRD PARTY COMMENTS - (NAGF Standard's Review Team)
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC group comments)
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jerry Farringer)
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Detroit Edison Company	Alexander Eizans	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kathleen Black)
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	El Paso Electric Company	Gustavo Estrada	Affirmative	
5	Electric Power Supply Association	John R Cashin	Abstain	
5	Entergy Services, Inc.	Tracey Stubbs	Negative	SUPPORTS THIRD PARTY COMMENTS - (NAGF)
5	Essential Power, LLC	Patrick Brown	Negative	COMMENT RECEIVED
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Negative	SUPPORTS THIRD PARTY COMMENTS - (Generator Forum Standards REveiw Team)
5	Lincoln Electric System	Dennis Florom	Abstain	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Negative	SUPPORTS THIRD PARTY COMMENTS - (SMUD)

5	MidAmerican Energy Co.	Neil D Hammer		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver		
5	NiSource	Huston Ferguson	Negative	COMMENT RECEIVED
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES and SERC OC)
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Leo Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	COMMENT RECEIVED
5	Orlando Utilities Commission	Richard K Kinas		
5	PacifiCorp	Bonnie Marino-Blair	Abstain	
5	Pattern Gulf Wind LLC	Grit Schmieder-Copeland	Negative	COMMENT RECEIVED
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway		
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey		
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	SUPPORTS THIRD PARTY COMMENTS - (NAGF Standard's Review Team)
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	COMMENT RECEIVED
5	Raven Power	Scott A Etnoyer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Negative	COMMENT RECEIVED
5	Salt River Project	William Alkema	Abstain	
5	Santee Cooper	Lewis P Pierce	Negative	COMMENT RECEIVED
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Abstain	
5	Snohomish County PUD No. 1	Sam Nietfeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (New York Power Authority)
5	South Feather Power Project	Kathryn Zancanella	Abstain	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Mike Hill)
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED

5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
5	Wisconsin Electric Power Co.	Linda Horn		
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Negative	COMMENT RECEIVED
6	Cleco Power LLC	Robert Hirchak	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC group comments)
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY COMMENTS - (First Energy)
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF/ACES)
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Abstain	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm		
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS - (NIPSCO Comments)
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Mahmood Safi)
6	PacifiCorp	Kelly Cumiskey	Abstain	
6	Platte River Power Authority	Carol Ballantine	Abstain	

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

Individual or group. (71 Responses)
Name (40 Responses)
Organization (40 Responses)
Group Name (31 Responses)
Lead Contact (31 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (10 Responses)
Comments (71 Responses)
Question 1 (54 Responses)
Question 1 Comments (61 Responses)
Question 2 (0 Responses)
Question 2 Comments (61 Responses)
Question 3 (52 Responses)
Question 3 Comments (61 Responses)
Question 4 (59 Responses)
Question 4 Comments (61 Responses)

Group
Lower Colorado River Authority Transmission Services Corporation
Steve Rainwater
Yes
In the rationale for R4 it is stated that no new tasks are required for support personnel; rather it says that tasks already created for System Operators can be "cherry-picked" to provide tasks for support personnel. This does not, at face value at least, make much sense. Support personnel do not perform System Operator tasks and vice-versa. R4 is highly confusing. The applications, processes, and thus the knowledge, required to perform Network Analysis or to develop SOL's or IROL's can be quite different from the knowledge required for System Operator tasks. For example, System Operators respond and mitigate SOL's, but have little or no input into their creation. Conversely, creating an SOL is far different from responding to one. Is it possible that the intent of R4 is to provide Support Personnel with insight into the tasks System Operators perform? If so, the wording of R4 could be greatly simplified leading to better understanding. From R4: "The entity can use the list created from requirement R1 and select the reliability-related tasks that support personnel conduct and therefore should be training on". Again, Support Personnel do not perform those tasks. Does not make any sense to train and evaluate them on tasks they simply do not perform. Is an entity exempt from R4 if it attests that its support personnel do not perform System Operator tasks? In addition, the definition of "Support Personnel" is far too vague: "Individuals who carry out outage coordination and assessments, or determine SOLs, IROLs..." What exactly does "determine SOL's mean? There can be quite a few people involved in that process. Does everyone that inputs into that process fall under the requirement? Engineers determine SOL's

for the most part at this organization, but display and database specialists contribute as well. Are they to be included as well? For outage coordination: how far upstream must one go? Coordinating transmission outages at the LCRA involves more than just one person. Various LCRA groups (maintenance, construction, project management, etc.) provide input into that process along with our wholesale power customers. Where is the demarcation point?
see previous comment
Yes
No
R4, as previously stated, would not accomplish much since it is, in a de facto fashion, saying that Support Personnel positons are not different from System Operator positions. The explanation for R4 in the grey box above it essentially says that support positions are comprised of system operator tasks. This simply is not true. If the intent is to ensure Support Personnel are trained to perform tasks, then PER-005-2 falls short since it does not include any application of SAT to those positions. It should suffice that if an individual has earned a BSEE, and possibly a professional engineering license as well, that they are qualified to conduct studies, determine SOL/IROL, etc. as the schooling they received did just that. R4 does make it somewhat clear as to what is expected, but the text box above it makes an error in that it attempts to say that no new tasks are required. I do not see how that could possibly be the case.
Individual
Thomas Foltz
American Electric Power
Yes
“Control Center” is not capitalized within the SAR.
4.1.5.1 – The term “dispatch center” should be replaced by the capitalized term “Control Center”. It appears that there is a peridocity lacking in R5 in that it could be interpreted as requiring contact only once. We do not believe that is the intent of the drafting team.
No
AEP does not recommend using terms defined only within a standard and not including them in the NERC Glossary of Terms. This is especially troubling given that the “local term” references “global terms” which *are* specified in the NERC glossary. The definition provided for Support Personnel is a concern as its scope is not well defined. Instead, we recommend the proposed definition be changed to the following : “…individuals who have direct contact with the System Personnel and who carry out outage coordination and outage assessments, or determine SOLs, IROLs or operating nomograms…” . This concern is also extended to any proposed requirements which are directed at Support Personnel.
No
Improvements are needed so that the applicability of the requirements is not greater than

what is actually intended (see response to Question #3). The terms System Personnel and Support Personnel appear similar enough to potentially cause confusion when interpreting the standard. This is illustrated by the awkwardnesss in how R4 points back to R1, appearing to be redundant. AEP's negative vote on this standard is driven by its concerns regarding the proposed definition for Support Personnel, and for the lack of clear periodicity of R5.
Group
Arizona Public Service Company
Janet Smith
No
See comments for Question 4
Yes
No
APS has no Generator Operators that "develop specific dispatch instructions" so the new GOP requirement will not have an impact at APS in our current configuration. APS does have Support Personnel who "carry out outage coordination and assessments" and also individuals who "determine SOLs, IROLs for operating nomograms for Real-time operations". However, industry feedback that these personnel do not make real-time decisions on BES operations is reasonable, as these decisions are the responsibility of System Operators. The ad hoc committee decision that EMS support personnel do not perform tasks that jeopardize the reliability of the BES makes sense in light of the evidence. The proposed timeline for implementation of the simulation technology requirements is six months. APS would meet this target , but this timeline is unattainable for many small utilities who have few resources to develop this solution. Eighteen months would be a reasonable target. The standard-only definition regarding the role of Transmission Owners in conducting operations on the BES does not apply to APS in its current configuration. Replacing the current "32-hours per calendar year" Emergency Operations training requirement with an approach that enables each utility to employ a Systematic Approach to Training that identifies training requirements is appropriate.
Group
Northeast Power Coordinating Council
Guy Zito
Yes
The SAR should not be posted with the Standard. The intent of posting a SAR for comment is to seek industry's input on the need and scope of a proposed standard's development or revision. Posting the Standard for comments and ballot means that the SAR is "water under the bridge", and that industry's input on SAR doesn't mean anything. In the proposed Purpose

of the Standard the words “performing or” should be deleted. A more results oriented Purpose statement would read as follows: To ensure that personnel supporting Real-time reliability tasks are trained and competent.
What is the basis for assigning a Long-Term Planning Time Horizon to the five requirements of a Standard that addresses training for operating personnel and support personnel? As suggested by a number of Requirements in the Standard, training is delivered at least annually, if not more frequently, and the training program needs to be reviewed and revised once a year. This is much shorter than the Long-term Planning time frame. The intent of the Time Horizon is to indicate the general time frame to correct a non-compliance with a requirement. We do not see how a non-compliance of any of the requirements should wait for more than a year to mitigate, in view of the time frame stipulated in the Requirements. We suggest to change the Time Horizons to Operations Planning. Control Center should be capitalized throughout the Standard. Regarding the Standard’s Introduction-- In 4.1.4.1 what is the intention of the use of the word “operate”? Does operate mean giving or executing instructions? 4.1.4.1 reads “Personnel in a transmission control center who operate a portion of the Bulk Electric System at the direction of its Transmission Operator.” Propose changing the second occurrence of the word “a” to “any”. 4.1.5.1 is ambiguous. What is a centrally located dispatch center? It is not defined. Suggest repeating 4.1.5.1.1 section for Transmission Owner 4.1.4.1. Make a “4.1.4.2 Personnel in a centrally located dispatch center who relay instructions without making any modifications, are excluded”. 4.1.5.1.1--“…who relay dispatch instructions,…” is not clear. What is the “relay” intended to convey? Consider changing “relay” to “communicate” if that better explains the intent. Regarding Requirement R1-- Regarding R1 part 1.4, specify that the delay for completing the annual program evaluation should be done once the calendar year is over. For example, to evaluate the 2013 training program, wait until the end of the year on December 31, 2013, and then, do the annual program evaluation. R1 part 1.1--What in R1 is “BES company specific”? Is BES a modifier of the word “company” or a modifier of the word “tasks” in this sentence? The Requirement is ambiguous. R1 part 1.1.1--This requirement is inconsistent with the prior one as to the use of the word “tasks”. It should repeat “Real-time reliability-related tasks” in the task update obligation to be consistent with R1.1. R1 part 1.3--Is this one time training? If not, where is the refreshing interval specified? Can the person perform their job before they receive this training? Regarding Requirement R2-- R2--Does the verification of System personnel capabilities apply to each task in the SAT? Is the proposed standard designing and specifying the personnel testing here? Should it be? Regarding Requirement R3-- R3--“Emergency” can be removed. R3 part 3.1--Focusing on the words “gains operational authority”, no RC, BA, TOP or TO should gain operational authority until after all its staff are trained. Regarding Requirement R4-- Requirement R4 is unclear regarding Real-time reliability-related tasks. The proposed definition of Support Personnel is: Individuals who carry out outage coordination and assessments, or determine SOLs, IROLs or operating nomograms for Real-time operations. This definition clearly indicates that these personnel do not perform any Real-time tasks, although their tasks produce results that are applied in Real-time operations. R4 stipulates that: Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall establish and implement training for

Support Personnel specific to those Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1 and part 1.1.1 that relate to the Support Personnel's job function. Should Support Personnel be trained for Real-time tasks? R4 references Requirement R1 parts 1.1 and 1.1.1 which specifically refer to "Real-time reliability-related tasks". If R4 means tasks that are related to Real-time reliability, then outage coordination and assessment and determination of SOLs, IROLs, etc. will certainly meet such criteria and therefore the Support Personnel will need to be trained on the "related" Real-time task. The question then becomes who exactly are the Support Personnel that need to be trained? And trained in what? As written, Responsible Entities will not have a clear understanding of what their obligations are with respect to the who to train and the topics to be including in the training program for Support Staff. We are unable to suggest any specific wording to clarify the definition for Support Personnel and/or Requirement R4 since we do not know what training objective the Standard Drafting Team intends for Support Personnel. Requirement R5-- Regarding R5 and M5, the words ''Systematic approach to training'' should be replaced by ''training'' as it is written in R4. This is what is explained in the Rationale Box for R5. It is not necessary to include "applicability section 4.1.5" in R5. R5 part 5.1.1--The expectations and results desired from the RC, BA, TO and TOP are not clear. What constitutes input? Is a comment an input? It is agreed that the GOP should receive input from its Reliability Coordinator (RC), Balancing Authority (BA) and Transmission Operator (TOP). A method that would be sufficient to accomplish that would be to have the RC, BA or TOP post its PRC-005-2 input for GOPs on its website and that the GOPs incorporate the input into their training. The TO should not have to provide input. Transmission Owners and Generator Operators either have contractual, tariff or integrated relationships which forego the need for additional input, and, moreover, the operational Reliability Standards that drives the need for training under PRC-005-2 are relationships between BA,s TOPS, RCS and GOPs – not TOs and GOPs. Recommend that references to TOs be deleted from PER-005-2 R5 and its sub requirements. A suggestion to be considered is to combine R5 and part 5.1 for better efficiency. The wording of R5 could be changed to: Each GOP shall establish and implement training for its personnel which includes coordinating with its RC, BA, TOP, and TO to identify training topics that address the impact of the decision and actions of a GOP's personnel as it pertains to the reliability of the BES during normal and emergency operations. Part 5.1.1 should be made a separate Requirement because it stipulates requirements for entities other than the GOP. Suggested language for a new R6: Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall provide input to a Generator Operator's training program established under R5 as requested by the Generator Operator. It should be noted that at the bottom of page 19 of the White Paper, FERC's response: ''training for support personnel should be tailored to the functions they perform and need not be trained to the same extent as Transmission Operators." Because training for personnel other than TOPs, RCs, and BAs need not be as comprehensive, we would suggest to delete the words "Transmission Owner" from R1, R2 and R3, and instead, create a new requirement for ''Transmission Owner'', similar to R4.
No
The revised definition of "System Operator" potentially expands the applicable population

subject to the Standard's training requirements to beyond what was originally intended (e.g. the System Operator). We agree that System Operators and personnel with that authority regardless of title issuing orders for changes in the state of BES Elements should be included in the definition. However, the proposed definitions lack clarity of scope. It is not clear which personnel at the Transmission Owner (TO) might be identified as System Operators. FERC Order 742 only identifies “local transmission control center operator personnel.” Yet, the definition is sufficiently broad and subject to interpretation that other personnel could, inadvertently, unintentionally and unnecessarily, also be swept into the definition including: (a) downstream personnel at substations or district offices who implement directives from “local transmission control center operator personnel,” but who do not initiate, monitor or control changes in the state of BES Elements, and/or (b) upstream personnel at headquarters and elsewhere who provide administrative supervision of “local transmission control center operator personnel,” but who do not directly monitor or control the state of BES Elements. These individuals do not personally monitor or control changes in the state of BES Elements. Proposed Alternate Wording: System Operator: An individual at a Control Center that monitors, directs and controls the operation of the Bulk Electric System (BES) in Real- time. Per FERC’s directive, System Operators should both (1) be located at a “local transmission control center,” and (2) “exercise control” over changes in the state of BES Elements (see the Rationale for 4.1.4). Other personnel who either do not reside at the “local transmission control center” and/or do not “exercise control” over changes in the state of BES Elements are excluded. Other concerns with the revision to the defined term “System Operator” to replace the current NERC Glossary term. The revised System Operator definition incorporates the “Control Center” definition that is embodied in the CIP v5 filing in Docket No. RM13-5-000 and which is under consideration at this time by FERC: “Control Center: One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.” In Paragraph 80 of its NOPR issued in the CIP v5 docket, FERC asked whether the phrase “generation Facilities at two or more locations” intended to include two or more units at one generation plant and/or two or more geographically dispersed units. Therefore, whether this definition will be remanded for further clarification is undetermined at this time. In addition, when the term “System Operator” is used within PER-005-2, it is used in the “System Personnel” definition that is only used within PER-005-2 (i.e., it will not be a NERC Glossary term and will only be used within PER-005-2). Within the System Personnel definition, System Operators are limited to “System Operators of a Reliability Coordinator, Transmission Operator, or Balancing Authority:” Generator Operators, even those GOPs that are subject to the applicability of PER-005-2, are excluded. While the existing System Operator definition uses the language “monitor and control,” that language is replaced with the phrase “operates or directs the operation” in the proposed new definition. Whether GOPs are intended to be included in the new System Operator definition has not been made clear. The Standard begins by defining the terms System Operator, System Personnel and Support Personnel, but then applies for GOPs only the word “personnel.” It is not clear whether or not

this differentiation was intentional, particularly since Applicability paragraph 4.1.5 appears to describe GOP dispatchers who are System Operators. It would seem that they should have been included in the System Personnel definition.
No
The proposed definition of Support Personnel is intended to respond to a FERC Order 742 Directive. However, the proposed definition lacks clarity of scope. The definition is sufficiently broad and subject to interpretation that other personnel could, inadvertently, unintentionally and unnecessarily, also be swept into the definition. We recommend tighter wording which more closely parrots the FERC Directive. Proposed Alternate Wording: Support Personnel: Individuals who carry out outage coordination and assessments in accordance with IRO-004 and TOP-002, or determine SOLs, IROLs or operating nomograms1 for Real-time operations in accordance with IRO-005 and TOP-004. This definition includes: (i) Reliability Coordinator personnel who conduct Contingency analysis studies to identify potential interface and other SOL and IROL violations (IRO-004), and who identify the cause of any potential or actual SOL or IROL violations (IRO-005); and/or (ii) Transmission Operator personnel who perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs (TOP-002 and TOP-004) ; The specific FERC Order 742 Directive wording was: "… [Who] carry out outage coordination and assessments in accordance with Reliability Standards IRO-004-1 and TOP-002-2, and those who determine SOLs and IROLs or operating nomograms in accordance with Reliability Standards IRO-005-1 and TOP-004-0." There is an inconsistency between the VSLs for R1 and R5. Both R1 and R5 require that the Responsible Entity use a systematic approach to training to develop a training program (note that in R5, it's training only, not a training program) for their personnel. The VSL for R1 does not have a level for failure to demonstrate that the Responsible Entity used the SAT to develop the training program. However, a Responsible Entity is assigned a High VSL for failing to use a systematic approach to training to establish training requirements as defined in Requirement R5. The two VSL sets should be consistent with respect to the requirement for using SAT. We suggest the SDT to revise the VSL for R1 to include this violation condition. Refer to the response to Question 2 that references the Rationale Box for R5. Because of the issues mentioned above concerning the proposed definition of "System Operator", unless it is withdrawn or until the PER team revises it to specifically include only Reliability Coordinators, Transmission Operators, and Balancing Authorities we cannot support the Standard. The scope changes, the changes proposed for requirements above, and the discussions regarding R5 are essential to make the standard "results based" and to meet quality review requirements for use.
Individual
John Brockhan
CenterPoint Energy Houston Electric LLC.
No

Yes
No
CenterPoint Energy appreciates the efforts of addressing the remaining Directives outlined by FERC for the Personnel Training Standard. We believe the Standard as it is proposed, however, has ambiguity that may be left up to the auditor's professional judgment for interpretation of the intent of the requirements. The definition of Support Personnel incorporates "Individuals who carry out outage coordination and assessments". CenterPoint Energy believes that the umbrella of personnel that could be covered by this generalized title could erroneously encompass long term, mid-term, and short term outage coordination personnel, which would broaden the scope of the requirements further than the intent of the Directive. CenterPoint Energy suggests modifying the definition of Support Personnel to clarify the scope of outage coordination personnel and proposes the following change: System Personnel: Individuals who carry out next day study outage coordination and assessments, or determine SOLs, IROLs or operating nomograms for Real time Operations. CenterPoint Energy also believes that R2.1 offers the industry a window of flexibility for verifying the capabilities of its System Personnel "Within six months". It is unclear as to whether the training and verification should be performed before or after the modification or addition of the reliability related tasks.
Group
Southwest Power Pool Regional Entity
Emily Pennel
No
No
Glossary changes should be approved through a separate project. Glossary terms are used in other standards and should not be changed by SDTs as part of one project, as that may adversely impact another SDT's work that pivots on the current Glossary definition. SDTs should conform to the approved Glossary rather then SDTs making changes to the Glossary for their own projects.
Yes
Individual
Brian Reich
Idaho Power Company
No

Requirement 5.1 requires that the Generator Operator have evidence that the Generator Operator coordinated with the RC, BA,TO, or TOP. However Requirement 5.1.1 requires the RC, BA, TO or TOP to have available for inspection evidence that the GO coordinated as well. This subrequirement is redundent of Requirement 5.1. System reliability is not improved by verifying that both entities have an email for coordination. Recommend removing requirement 5.1.1.
Yes
Yes
Group
Tennessee Valley Authority
Brandy Spraker
Yes
Comments: Without better clarification of real time, other non-intended personnel might be determined by auditors as being held to this standard. The term 'Support Personnel' could be clarified to show that both parts of the sentence refers to real-time operations personnel only. Suggested wording: Support Personnel: Pertaining to Real-time operations only for individuals who carry out outage coordination and assessments, or determine SOLs, IROLs or operating nomograms.
Yes
Yes
Individual
John Bee
Exelon and its' affiliates
Yes
Exelon supports the concept of developing Compliance Guidance concurrently with the Standard development because it makes sense to develop audit explanations and tools while the intent and information is fresh and under development. In addition, this is very useful for Registered Entities to understand how compliance will be judged. However, it is not clear how development of Compliance Input is to be conducted. The Compliance Input should evolve as the Standard language evolves through the standards development process and must ultimately reflect the actual language in the final, approved standard. Understanding that no ballot is associated with Compliance Input, it would be very useful for NERC to post Compliance Input with a separate comment form for stakeholder input. Some of the project

SARs cite development of an RSAW. Stakeholder Review and comment on RSAWs and Compliance Input prior to the final ballot of a proposed standard will be mutually beneficial.
Yes
Individual
Jonathan Appelbaum
The United Illuminating Company
Yes
Order 742 was issued prior to the new definition of BES being developed. In order 742 FERC used examples of Transmission Owners in the Northeast who were operating the BES but were not TOPs. This situation is being remedied with the new definition of BES and the transition of Transmission Owners to Transmission Operators. The rationale for adding local control centers has changed.
In R3 the term - that has operational authority or control over Facilities - is used. Does the word operational modify the word control? If a Transmission Owner does not have the operational authority to operate a breaker, but can control the breaker would R3 apply? This is important because it would require an investment to purchase the required simulation technology. It would seem a waste of resources since the Transmission owner is not supposed to issue a control to a Transmission element without the permission of the Transmission Operator. Without a proper EMS model and contingency analysis engine there is no safe way for such a transmission owner to reliably issue a control. In fact the training a Transmission Owner would provide the operator is to never issue such a control. Still on R3, if a Transmission Owner is directed to install a protection system that mitigates an IROL this requirement then states the control room personnel would be subject to R3 even though they have no authority to take an action independent of the Transmission operator’s direction.
Yes
No
I believe the facts around Order 742 have changed. This standard will require a Transmission owner that lacks operational authority but can issue a control to have a SAT for answering the phone, using 3-part communication, and following directives. It is beneficial to train on these topics but using SAT is overkill. The R3 requirement for simulation training is unneeded when a Transmission Owner cannot take independent action, cannot redispatch generation, and lacks visibility into the outside world.
Individual
Nazra Gladu
Manitoba Hydro

No
(1) Purpose - for clarity, specify which “personnel” are being refferd to - System or Support personnel for example? (2) R3 - for clarity, define IROL and include its bracketed acronym, since this is the first instance of the word in the standard.
Yes
(1) Yes, the new definition simplifies the NERC Glossary Term System Operator.
Yes
(1) Manitoba Hydro is in support of the revised PER-005-2 standard. Our training section administration is already largely compliant with this standard and although our reliability task list is a work in progress,incorporating support personnel and accommodating their training requirements shouldn’t impose too much of an additional burden on our current training structure.
Individual
Gerald G Farringer
Consumers Energy
No
None
No
If the definition of System Operator relates only to the operating personnel of the RC,TOP,BA then state so in the definition. Remove redline in this definition.
No
The extention to the Generation Operator (GOP) is not required. If it must be done however the obligation to define the topics or material that needs to be covered in a training program should rest with the RRO, RC,BA or TOP. To make it a requirement for the GOP to request to get this information from these entities is backwards. The training developed should be done with all stakeholder input but it is the RC,BA and TOP that can best define the needs for the GOP.
Individual
Scott Bos
Muscatine Power and Water
No
As there is no direction for how often training is to be delivered in R4 and R5, is there a requirement for capability verification for both these groups of personnel that they can

perform these tasks at least one time. Is training to be delivered at some frequency of more than one time? For personnel covered in R4 and R5, suggest to add a training framework for receiving training at least one time on those real-time reliability-related tasks identified by the entity pursuant to Requirement R1. Adding requirements and measures for proof of coordination in R5 is not "results based", is not practical and will be an administrate compliance burden. The MP&W believes that this is a paragraph 81 issue.
No
The proposed definition could be interpreted as any individual in a Control Center. The definition of System Operator should be reworded to read: "Any NERC-certified individual at a Control Center that operates or directs the operation of the Bulk Electric System in Real Time in the capacity of BA, TOP or RC."
No
Update Support Personnel definition to read: Support Personnel: "Individuals who carry out, in Real-time, planned or forced outage coordination and assessments, or determine SOLs, IROLs or operating nomograms for Real-time operations." MP&W appreciates the efforts of the SDT for removing the undefined term "learning objectives" from R1.2. This allows the focus of R1.2 to be on the development of training materials based on the task list created in R1.1 and R1.1.1 and not on the unbounded "learning objectives" from the previous version of PER-005.
Individual
David Thorne
Pepco Holdings Inc.
No
Yes
Yes
Group
PacifiCorp
Kelly Cumiskey
No
Per FERC Order 693, Support Personnel has been described as, "Personnel who carry out outage coordination and assessments in accordance with Reliability Standards IRO-004-1 and TOP-002-2, and those who determine SOLs and IROLs or operating nomograms in accordance

with Reliability Standards IRO-005-1 and TOP-004-0.” PacifiCorp agrees that personnel who determine SOLs and IROLs or operate nomograms in accordance with IRO- 005-1 and TOP-004-0, would maintain a level of independent decision making regarding the operation of the BES. However, the inclusion of personnel who “carry out outage coordination and assessments” would expand the scope of responsibility to those who do not make independent decisions regarding system operations. At minimum, PacifiCorp believes that the definition of Support Personnel should be amended to provide more clarity. Specifically, PacifiCorp seeks clarification of the type of outage coordination intended to be within scope of the Support Personnel definition. Under 4.1.5.1 of the Applicability Section the Generator Operator is defined as: “Personnel at a centrally located dispatch center who receive direction from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control.” PacifiCorp maintains that the word “may” implies that even if the aforementioned personnel don’t develop specific dispatch instructions for plant operators under their control, they are still applicable to the standard. This conflicts with the intent of the FERC directive. The PER-005-2 development team has indicated at several PER conference meetings that the training requirements are intended to target personnel providing dispatch instruction. PacifiCorp recommends removing the word “may” to reduce ambiguity. Furthermore, under 4.1.5.1 PacifiCorp seeks further clarity of the term “Modification” in order to understand which “modification” actions performed by “Personnel at a centrally located dispatch control” would no longer exclude those personnel as part of the Generator Operator applicability.
Yes
No
As expressed in the response to question #2, PacifiCorp does not support the proposed standard as it is presently written. PacifiCorp appreciates the opportunity to provide input for this project and looks forward to the next step in the process.
Group
MRO NERC Standards Review Form (NSRF)
Russel Mountjoy
No
Adding requirements and measures for proof of coordination in R5 is not "results based", is not practical and will be an administrate compliance burden. The NSRF believes that this is a paragraph 81 issue.
No
The definition could be interpreted as any individual in a Control Center. The definition of System Operator should be reworded to read: “A NERC-certified individual at a Control Center that operates or directs the operation of the Bulk Electric System in Real Time in the capacity

of BA, TOP or RC.
No
The NSRF appreciates the efforts of the SDT for removing the undefined term “learning objectives” from R1.2. This allows the focus of R1.2 to be on the development of training materials based on the task list created in R1.1 and R1.1.1 and not on the unbounded “learning objectives” from the previous version of PER-005. R4. Recommend that either the rational box or within the background document, clearly state that support personnel’s training is predicated of the entity’s list of BES company-specific Real-Time reliability-related tasks for a BA, RC and or TOP. The NSRF also recommends that the definition of “Support Personnel” to be rewtitten as: Support Personnel: Individuals who carry out, in Real-time, planned or forced outage coordination and assessments, or determine SOLs, IROLs or operating nomograms1 for Real-time operations.
Individual
John Seelke
Public Service Enterprise Group
Agree
NAGF SRT (North American Generator Forum Standards Review Team)
Individual
Matthew Beilfuss
Wisconsin Electric
Yes
PER-005-2, Requirement 5: The GOP is required to use a systematic approach to training (SAT) and take input from the RC, BA, TOP, and TO to identify training topics impacting reliability of the Bulk Electric System during normal and emergency operations. Presumably, other Standards that require the GOP to perform specific training would be a third source of training topics. The framework in Requirement 5 results in three separate processes for GOPs to establish training content subject to compliance review. However, the reliability related training tasks identified will likely be a small subset of the tasks that GOP personnel perform. As an alternative approach, current standards that explicitly require GOP personnel to conduct training (e.g. EOP 005-2 R17) provide a more focused approach. The approach to discreetly identify within the Standards real-time reliability tasks completed by GOP personnel is more “results focused” than requiring the creation of an all-encompassing “program” subject to compliance review. Making the standard applicable to a sub-set of GOP personnel (those located at a centrally located dispatch center that relay dispatch instructions), in some ways amends the NERC functional model and compliance framework established by the reliability standards. We’re not certain of the full implications of this type of role re-definition.
The language in Requirement 1 and Subsection 1.1. limit the scope of the training program for System Personnel to BES company-specific reliability related tasks. No such scope limitation exists in Requirement 5 for GOP personnel. As written, Requirement 5 and Subsection 5.1 establish scope limitations on the (1) GOP personnel subject to the standard and (2) training

topics identified by the RCs, BA, TOP, TO. However, the language includes no scope limitation on the tasks identified by the SAT. We presume the intent of the standard is to only address BES company-specific reliability related tasks? Requirement 5 could be modified as follows: “Each Generator Operator shall use a systematic approach to training to establish and implement training for its personnel described in applicability section 4.1.5. The training shall also include topics identified as follows: 5.1 Each Generator Operator shall create a list of BES company-specific Real-time reliability-related tasks completed by personnel described in 4.1.5.
Yes
No
Existing standards that explicitly identify training tasks for the GOP are sufficient. The requirement to establish a SAT subject to compliance review creates a large and complex program, when the concern is a relatively small sub-set of reliability related tasks executed by a sub-set of GOP personnel creating dispatch instructions.
Individual
Tiffany Lake
Westar Energy
No
Westar Energy supports the scope of the proposed SAR and the removal of EMS personnel and plant control room operators from the scope.
We question the justification of the removal of the 32 hours of emergency operations training and what impact that has on the classification of emergency operations training in general. We request the SDT to provide clarification regarding whether or not entities will still be required to conduct emergency operations training and what, if any, metric will be used to demonstrate compliance. System Operators will always have Real-time reliability related tasks. However, Support Personnel may not. Each entity should be required to first determine whether or not its Support Personnel are performing Real-time reliability related tasks. We suggest revising the proposed R4 language with the following: R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall determine if the entity’s Support Personnel perform Real-time reliability-related tasks and establish and implement training for Support Personnel specific to those Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1 and part 1.1.1 that relate to the Support Personnel’s job function.
Yes
No
Although we support the intent of PER-005-2, we do not support the existing language in R3 and R4. Refer to the comments above in question 2.

Individual
Ronnie Hoeinghaus
City of Garland
No
R1.1.2 – “shall design and develop training materials” requires the registered entity to internally perform this requirement – registered entities (especially smaller entities) should have the option to hire a 3rd party company to perform this task
No
The glossary terms should not be specific to the this standard but added to the NERC Glossary. This will help avoid confustion. Then, regardless of where the terms are used (such as NERC standards, NERC Committee Guideline, NERC Committee white paper, etc), everyone will have the same definition
No
R1.1.2 – “shall design and develop training materials” requires the registered entity to internally perform this requirement – registered entities (especially smaller entities) should have the option to hire a 3rd party company to perform this task The glossary terms should not be specific to the this standard but added to the NERC Glossary. This will help avoid confustion. Then, regardless of where the terms are used (such as NERC standard, NERC Committee Guideline, NERC Committee white paper, etc), everyone will have the same definition
Individual
Silvia P. Mitchell
NextEra Energy
No
NextEra Energy in general supports PER-005-2 with the exception of the manner in which R5 is drafted. While NextEra agrees with the concept that the Generator Operator (GOP) should receive input from its Reliability Coordinator (RC), Balancing Authority (BA) and Transmission Operator (TOP), it does not agree with the method set forth to achieve this goal. Instead, NextEra believes it is sufficient that the RC, BA or TOP post its PER-005-2 input for GOPs on its website and that the GOPs incorporate the input into their training. Nor does NextEra agree that there is a need for input from the Transmission Owner (TO). One, Transmission Owners and Generator Operators generally either have contractual, tariff or integrated relationships which forego the need for additional input, and, moreover, the operational Reliability Standards that drives the need for training under PER-005-2 are relationships between BAs TOPs, RCs and GOPs – not TOs and GOPs. Thus, NextEra recommends that references to TOs be deleted from PER-005-2 R5 and its sub requirements. To effectuate the changes set forth

above, NextEra has revised PER-005-2 R5 as follows: R5. Each Generator Operator shall use a systematic approach to training to establish and implement training for its personnel described in applicability section 4.1.5. The training shall also include topics identified by its Reliability Coordinator, Balancing Authority and Transmission Operator. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] 5.1. Each Reliability Coordinator, Balancing Authority and Transmission Operator, and Transmission Owner shall post on its website training topics related to their interaction with Generator Operator personnel to maintain the reliability of the Bulk Electric System during normal and emergency operations.
Yes
Yes
NextEra Energy in general supports PER-005-2 with the exception of the manner in which R5 is drafted.
Individual
John Canavan
NorthWestern Energy
No
NorthWestern Energy (NWE) objects to the assignment of responsibility to each Balancing Authority and Transmission Operator, that has or gains operational authority over facilities with IROLs, for “training using simulation technology . . . that replicates the operational behavior of the Bulk Electric System,” contained in R3 and R3.1. As was shown by the Southwest blackout of 9/8/2011, an IROL may develop from an SOL based upon real-time conditions or events outside the footprint of the BA or TOP that controls a particular facility. The RC has been tasked with maintaining a wide-area view to identify and respond to threatening conditions that may be outside the visibility of an individual BA or TOP. NWE believes that training on and simulation of IROLs should be the responsibility of the RC who has the wide-area view and the capability of recognizing interactions between events occurring in different BA or TOP areas. A requirement to share this training and simulation with affected BAs and TOPs (similar to requirements EOP-006-2, R10, and EOP-005-2, R12) may be appropriate. NorthWestern Energy (NWE) believes that the Rationale for R4 is deceptive and potentially harmful to the training process (systematic approach) in that it suggests that the tasks performed by Support Personnel will be defined by the job analysis performed for real-time system operators. Systematic analysis of the job functions of real-time operators and Support Personnel will identify the different responsibilities of each with regard to a single operational process (e.g., mitigate a violation of an SOL). NWE believes the language of R4 should be clarified to define the extent of the job analysis that will be required for Support Personnel and the extent of the training that will be required for Support

Personnel under this standard.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
We question the need to ask this question when the consolidated standard is already posted for commenting and balloting. The intent of posting a SAR for comment is to seek industry's input on the need and scope of a proposed standard development/revision project. Posting the standard for balloting at the same time suggests that there is already a foregone conclusion on the need and the scope for this project , and that the industry's input on SAR would seem irrelevant. The IESO understands that posting a SAR and the draft standards for comment at the same time can improve standard development efficiency, and we support it to the extent that sufficient technical information has been obtained to facilitate the development of a draft standard at the informal outreach stage. However, we are very concerned about the fact that the industry was asked to ballot the draft standard when the need and scope of the draft standard have not been commented on and supported by the industry, and the standard itself has not been drafted by a formal standard drafting team. Such an approach appears to: a. Deviates from the normal standards development process as presented in the Standards Process Manual (SPM); b. Contradicts and perhaps violates the intent of the established standard development process and ANSI principles to have new and revised standard formally developed through an open and inclusive process before being presented to the RBB for balloting. The industry is being asked to ballot a set of standards that has not been formally developed. This concept appears to be fundamentally flawed. We propose that the SDT convey our concern to the NERC senior management and the Standards Committee. We further suggest that NERC and the SC evaluate alternative approaches or make revisions to the SPM to provide the needed flexibility that can further improve the efficiency in standard development if certain elements in the existing SPM are assessed to restrict such improvements.
a) There appears to be an inconsistency between the definition of Support Personnel and Requirement R4, or an unclear definition or an unclear requirement or both as it relates to Real-time reliability-related tasks. The proposed definition of Support Personnel is: Individuals who carry out outage coordination and assessments, or determine SOLs, IROLs or operating nomograms for Real-time operations. This definition clearly indicates that these personnel do not perform any Real-time tasks, although their tasks produce results that are applied in Real-time operations. R4 stipulates that: Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall establish and implement training for Support Personnel specific to those Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1 and part 1.1.1 that relate to the Support Personnel's job function. R4 is unclear as to whether or not the Responsible Entities need to establish and implement training for Support Staff on Real-time tasks. If R4 means tasks that are related to Real-time reliability, then outage coordination and assessment and determination of SOLs,

IROLs, etc. will certainly meet such criteria and therefore the Support Personnel will need to be trained on the “related” Real-time task. However, such an interpretation will mean that almost every task in a Control Centre is related to Real-time operation. The question becomes: who exactly are the Support Personnel that need to be trained? If only those personnel that perform tasks as indicated in the definition, then why would they need to be trained on Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1 and part 1.1.1, and what does it mean by “that related to the Support Personnel’s job function”? The above questions and interpretations reflect that Requirement R4 and its relation to the definition of Support Personnel are unclear. As written, Responsible Entities will not have a clear understanding of what their obligations are with respect to who to train and the topics to be included in the training program for Support Staff. Much clarity is needed in Requirement R4 or the proposed definition for Support Personnel or both. We are unable to suggest any specific wording to clarify the definition for Support Personnel and/or Requirement R4 since we do not know what the objective (the kind of training) the SDT has in mind when it comes to providing training to the Support Personnel. b) Intuitively, we have difficulty understanding the basis for assigning a Long-Term Planning Time Horizon to the five requirements of a standard that addresses training for operating personnel and support personnel. As suggested by a number of requirements in the standard, training is delivered at least annually, if not more frequently, and the training program needs to be reviewed and revised once a year. This is much shorter than the Long-term Planning time frame. The intent of the Time Horizon is to indicate the general time frame to correct a non-compliance with a requirement. We do not see how a non-compliance of any of the requirements should wait for more than a year to mitigate, in view of the time frame stipulated in the requirements. We suggest to change the Time Horizons to Operations Planning.
Yes
No
We are unable to support this standard as presented, for the reason as cited in Comment (a) under Question 2, above. In addition, there is an inconsistency between the VSLs for R1 and R5. Both R1 and R5 require that the Responsible Entity use a systematic approach to training to develop a training program (note that in R5, it’s training only, not a training program) for their personnel. The VSL for R1 does not have a level for failure to demonstrate that the Responsible Entity used the systematic approach to develop the training program. However, a Responsible Entity is assigned a High VSL for failing to use a systematic approach to training to establish training requirements as defined in Requirement R5. The two VSL sets should be consistent with respect to the requirement for using systematic approach. We suggest the SDT to revise the VSL for R1 to include this violation condition.
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
Agree

Northeast Power Coordinating Council (NPCC) - All comments
Individual
Mahmood Safi
Omaha Public Power District
No
Please see comments provided by MRO NSRF.
No
Please see comments provided by MRO NSRF.
No
This standard is proposing adding operating support personnel to receive training for the tasks they provide support to the operators. Operating support personnel such EMS and or engineering support personnel and the support they provide is in their areas of expertise. We believe adding these personnel, who are experts in their fields, is adding additional layers of compliance and the risk associated with maintaining compliance. We propose removing operating support personnel from training requirement under PER-005-2. In order to address FERC's directive related to operating personnel training, the standard should proposed that the Registered Entity's training program under the current PER-005-1 should determine who in addition to the operators would be required to receive training on the specific task a support personnel provide. The blanket requirement as proposed in PER-005-2, as mentioned above, is creating additional compliance burden without providing any benefit to the reliability of the BES.
Group
Bonneville Power Administration
Jamison Dye
No
BPA requests that the drafting team revise the applicability section to provide additional clarity to the 'Generator Operator' section. Within the 'rationale' section for applicability 4.1.5 of the draft standard there is a statement 'Plant operators located at the generator plant site are not required to be trained in PER-005-2.' BPA suggests that this statement be included in the final standard text to provide the additional clarity necessary.
Yes
No
BPA requests that the drafting team revise the applicability section to provide additional clarity to the 'Generator Operator' section. Within the 'rationale' section for applicability 4.1.5

of the draft standard there is a statement ‘Plant operators located at the generator plant site are not required to be trained in PER-005-2.’ BPA suggests that this statement be included in the final standard text to provide the additional clarity necessary.
Group
Oklahoma Gas & Electric
Terri Pyle
Yes
We have some concern regarding what appears to be creep in scope associated with personel training in PER-005-2. We are concerned that as this scope continues to expand and include non-certified personnel on the fringes of the functionality of the operating desk, maintaining compliance with the standard could become a burdensome task to the industry as well as create an equally increased risk of non-compliance for an issue that has very little impact on the reliability of the BES. While we realize that the drafting team has attempted to address issues directed by FERC, perhaps there is an alternative solution to the proposed standard as the team found with the inquiry into including EMS support personnel in the standard.
The 6-month lead-time for simulator training in R3 may not be adequate depending upon whether the entity has access to a simulator. Unless the entity has its own simulator, the simulation provided would be of a generic nature. To obtain more customized, specific simulator training may require acquisition of a simulator and providing for staff to develop and implement simulator training. This would require much more than 6-months lead-time. We are also concerned with the openness of the ‘relate to’ phrase in R4 and would suggest the following replacement for R4: Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall establish and implement training for Support Personnel who perform Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1 and part 1.1.1.
Yes
No
We recommend changing Requirement 4 to remove the obligation to train all support personnel with language that only requires training for support personnel who actually perform the company specific reliability-related tasks.
Group
Hydro One
Sasa Maljukan
Agree
We'd like to support NPCC RSC Comments. Additionally Hydro One would like to note that in R3 we don't understand how R1's Systematic Approach to Traiing would cover 32 hour requirement. We believe that the Systematic Approach to Training is a methodology for managing training. It does not set criteria. Regulations, Instructions, etc. will set out the

criteria and guidelines that are to be followed for operation of the power system. The 32 hours of EOPs should not be removed from R3 unless they will/are showing up in other NERC documentation.
Individual
Brett Holland
Kansas City Power & Light
Agree
SPP & North American Generator Forum
Individual
Ed Mackowicz, David Austin, Shawn White, Bernard Horvath, Huston Ferguson
NIPSCO
No
Justification: • Standards should be written clearly and easily interpretable. We don't feel this one is as the need for "rationale" statements clearly points out. • As written we perceive a wide range of "interpretation" variances between entities and or auditors which is in contradiction to FERC's and NERC's intent. • We oppose the introduction of new terms or the use of Functional Entities or relationships that don't exist in the NERC Glossary of Terms or the NERC Functional Model to show or explain clear relationships and interactions. • PER-005-1 "System Personnel Training" was deployed to address training for System Operators performing real-time reliability-related tasks on the BES. We believe this standard to be necessary and adequate for its purpose. The proposed PER-005-2 "Operations Personnel Training" reaches past the System Operators (NERC Definition) to additional personnel not called out or properly defined in the functional model to be included in this standard. If NERC needs to address specific loop holes that are being leveraged or entity structural organization issues with respect to BES operations it should be outside of this standard. • Training requirements for those performing RTRR tasks are far different than those performing "support" for or around those tasks. As written, we believe training will be imposed that is unsupported in the model and open to interpretation as to what level it should extend. • We acknowledge we need to provide maximum flexibility to the industry while addressing the reliability concerns in the FERC directives. We just don't know if it does that and or oversteps FERC's intentions.
No
System operator should remain as it has been. The proposed new definition allows for expanded interpretation that we may not agree with.
No
Clarity in the requirements that wouldn't necessitate "rationale" comments for understanding. Definitions and terms should be consistant with the NERC Functional model and be consistant across all standards, not utilized or created for one standard alone. Support

personnel are not "Operators" and shouldn't be viewed as such for training requirements.
Group
Tacoma Power
Michael Hill
Yes
Real time roles they are depicting (System Personnel) are unclear. Not sure how to take our current task list that we defined for system operators and just qualified them on in April 2013 and then over lay it on these additional job descriptions (System Personnel). Our fear is that we would need to significantly change our current task list to meet this proposed standard as written, which is a huge under taking. That being said we would still need them to clarify who these other real time people would be. 2. PER-005-1 R3.1 has not yet been implemented nor is it enforceable until April 01, 2014. 3. Better clarify the specific intent of PER-005-2 R5. At Tacoma this “generator operator” is what we refer to as our Senior System Operator who does start and stop Tacoma’s generation from a central control center, however definition seems unclear. My recommendation would be to vote No at this time. We need the drafting team to give better clarification on above said statements.
PER-005-1 R3.1 has not yet been implemented nor is it enforceable until April 01, 2014.
Yes
Better clarify the specific intent of PER-005-2 R5. At Tacoma this “generator operator” is what we refer to as our Senior System Operator who does start and stop Tacoma’s generation from a central control center, however definition seems unclear.
No
Refer to above comments
Individual
Kenneth A Goldsmith
Alliant Energy
Yes
Support personnel should be defined as those supporting "reliability" outage coordination and assesments.
Alliant Energy believes the Emergency Training should include a set number of hours. By leaving it as written, it is up to the discretion of the Regional Entity as to what is "Adequate" and leaves the Registered Entity open to findings after any sort of event.
Yes
No
In general, we support the revisions, however, as noted in our comments, there are apecific areas that we believe need to be revised prior to the standard being acceptable.

Group
Dominion
Mike Garton
No
Requirement 4 – Suggest it be revised as follows “Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall provide training to their Support Personnel according to a systematic approach to training (SAT). Such an approach must include the following minimum elements: a list of job tasks performed by Support Personnel that relate specifically to the reliability of the BES and support real-time operation, learning objectives tied to those tasks, training content tied to the objectives, delivery and evaluation of the training.” Requirement R5 – Suggest that the requirement be revised as follows “Each Generator Operator shall provide training to its applicable personnel according to a systematic approach to training (SAT). Such an approach must include the following minimum elements: a list of job tasks performed by applicable Generator Operator personnel that relate specifically to the reliability of the BES and support real-time operation, learning objectives tied to those tasks, training content tied to the objectives, delivery and evaluation of the training. R5.1 The Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall provide input as requested by the Generator Operator.”
No
: Dominion does not agree with this change and suggests that only Control Center be capitalized. Our reasons for opposing modification of the existing term are primarily due to the authority that this term has historically bestowed upon those who carried out the functions (BA, RC and TOP), the fact that the term is used in many other existing standards (most of which explicitly point to BA, RC and TOP) and the fact that NERC currently has a certification program (see portion of webpage below) appropriately called the System Operator Certification and Continuing Education. [http://www.nerc.com/pa/Train/SysOpCert/Pages/default.aspx] Excerpt: “System Operator Certification In support of NERC’s mission, the System Operator Certification Program’s promotes reliability of the North American bulk power system by ensuring that employers have a workforce of system operators that meet minimum qualifications. These industry accepted qualifications are set through internationally recognized processes and procedures for agencies that certify persons. Goverance The Personnel Certification Committee (PCGC) is a NERC standing committee that provides oversight to the policies and processes used to implement and maintain the integrity and independence of the NERC System Operator Certification program. The PCGC provides reports to the NERC Board of Trustees and NERC President regarding the governance and administration of the System Operator Certification Program.“] Further Dominion believes that the proposed defined term System Personnel adequately includes all operating personnel that operate or direct the operation of the Bulk Electric System in Real- time given these personnel consist of System Operators (in BA, RC and TOP Control Centers) as well as Transmission Owner personnel described in 4.1.4.1.

No
Individual
Scott McGough
Georgia System Operations Corporation
Yes
The current PER-005-1 standard applies to System Operators. The new personnel (generation operator, local control center personnel, and support personnel) that are proposed, could be added to the current standard but leave the current requirements and definition of System Operator alone since they are currently well defined. The SDT should define the local control center. This should be done in the way currently proposed as it has added confusion to who is defined as a System Operator.
Do not change the definition of "System Operator." There is no problem with it. Define "Local Control Center" as "a control center of a Transmission Owner that has personnel who operate a portion of the Bulk Electric System at the direction of its Transmission Operator and a centrally located dispatch center of a Generator Operator that has personnel who receive direction from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control. Generator Operator dispatch centers with personnel who relay dispatch instructions, without making any modifications, and generator plant control rooms are excluded." Change the definition of "System Personnel" to "System Operators of a Reliability Coordinator, Transmission Operator or Balancing Authority, and Transmission Owner Local Control Center personnel who operate a portion of the Bulk Electric System at the direction of its Transmission Operator. Change the definition of "Support Personnel" to "Individuals, other than System Operators, who carry out outage coordination and assessments, or determine SOLs, IROLs or operating nomograms for Real-time operations. Change Applicability to 4.1. Functional Entities: 4.1.1 Reliability Coordinator 4.1.2 Balancing Authority 4.1.3 Transmission Operator 4.1.4 Transmission Owners that have Local Control Centers 4.1.5 Generator Operators that have Local Control Centers Change R5 to "Each Generator Operator that has a Local Control Center shall use a systematic approach to training to establish and implement training for its Local Control Center personnel who receive direction from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control. The training shall also include topics identified as follows:" Delete R5.1 and R5.1.1. Generator Operators that have Local Control Centers should develop their own training topics and should not be required to coordinate with other entities. Other entities should not be required to coordinate with Generator Operators that have Local Control Centers.
No
The proposed definition of System Operator utilizes the pending regulatory approval definition of Control Center. The definition of Control Center states "facilities hosting

operating personnel that monitor and control the Bulk Electric System in real-time to perform the reliability tasks". The proposed definition for System Operator states "operates or directs the operation of Bulk Electric Ssytem in Real-time". These two definitions should match. FERC directed NERC to define local control center. The proposed method of NERC to define a local control center does not seem to address the concerns of FERC.
No
We do not support the revised PER-005-2 because of the change in definition of System Operator, the lack of a definition for a local control center, the definitions of System Personnel and Support Personnel, the applicability section, and R5. We do not support it because it is not clear and is very confusing.
Group
Florida Municipal Power Agency
Frank Gaffney
No
Adding R5 requirements and measures for "proof of coordination" is not results based and not practical. The added requirements for "coordination" in R5 are really routine matters that will occur regardless of whether there is a requirement specified. Having measures requiring "proof" only creates an administrative compliance burden. If you consider how many "pieces" of paper will have to exchange hands amongst so many registered entities, especially in larger systems, it will be untenable. R5.1 & 5.1.1 and M5.1 & 5.1.1 should be deleted. R5.1. Each Generator Operator shall coordinate with its Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner to identify training topics that address the impact of the decisions and actions of a Generator Operator's personnel as it pertains to the reliability of the Bulk Electric System during normal and emergency operations. R5.1.1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall provide input as requested by the Generator Operator. M5.1 Each Generator Operator shall have available for inspection evidence, such as an email or attestation that it coordinated with the Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner in establishing the training requirements. M5.1.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence, such as an email or attestation, that it provided input to the Generator Operator.
No
Definition of System Operator can be interpreted to mean any individual in a Control Center. Proposed definition is as follows: System Operator: An individual at a Control Center that operates or directs the operation of the Bulk Electric System in Real Time. This can be interpreted in two ways: : 1) any individual, such as cleaning people, in a Control Center where the Control Center has the capability to operate or direct (certainly not the intent); or 2) to an individual who has the authority to operate or direct who is located at a Control

Center (certainly the intent). FMPA suggests a minor modification to remove this ambiguous reference.. System Operator: An individual, at a Control Center, that operates or directs the operation of the Bulk Electric System in Real Time.
No
See comments to questions 2 and 3 above. In addition FMPA has the following comments: The applicability to Transmission Owners is too broad and not necessary to address the FERC directive. Proposed Standard language adds the following applicability for Transmission Owners. 4.1.4 Transmission Owner that has: 4.1.4.1 Personnel in a transmission control center who operate a portion of the Bulk Electric System at the direction of its Transmission Operator. This applicability language will apply to all Transmission Owners regardless of whether they have a thousand breakers or one breaker. It is clear by the language in the order at P62, that FERC was concerned with large entities with significant control and impact on the BES. Order 742 at P62. The Commission understands that local transmission control center personnel exercise control over a significant portion of the Bulk-Power System under the supervision of the personnel of the registered transmission operator. This supervision may take the form of directing specific step-by-step instructions and at other times may take the form of the implementation of predefined operating procedures. For example, ISO New England, Inc., PJM Interconnection, L.L.C., and New York Independent System Operator, Inc., are registered transmission operators who issue operating instructions that are carried out by local transmission control centers such as PSE&G, PPL Electric Utilities Corp., PECO Energy Company, Baltimore Gas and Electric Co., Consolidated Edison of New York, Inc., National Grid USA, and Long Island Power Authority, which are not registered transmission operators. The combined peak load of these three RTOs is in excess of 200 gigawatts. In all cases, the local transmission control center personnel must understand what they are required to do in the performance of their duties to perform them effectively on a timely basis. Thus, omitting such local transmission control center personnel from the PER-005-1 training requirements creates a reliability gap. The Commission believes that identifying these entities would be a valuable step in delineating the magnitude of that gap. (emphasis added) The directive in the order 742 did not direct that all Transmission Owners be included in the training requirements, but only directed that local transmission control center operator personnel have training requirements and to define “local transmission control center”. 64. Accordingly, we adopt our NOPR proposal and direct the ERO to develop through a separate Reliability Standards development project formal training requirements for local transmission control center operator personnel. Finally, given the numerous comments stating that term “local transmission control center” should be defined, we direct NERC to develop a definition of “local transmission control center” in the standards development project for developing the training requirements for local transmission control center operator personnel. (emphasis added) The SDT should abandon the approach of adding the broad Transmission Owners applicability that will include any Transmission Owner regardless of size or impact to the BES and/or to prove they are excluded. Instead, the SDT should establish some boundaries and criteria around a “local transmission control center” definition as directed by FERC. Possibly MW’s controlled by the control center or other criteria, such as those within the CIP v5

brightlines, may be appropriate. The RSAW has not been developed so it is difficult to understand how the standard will be enforced. In order to better assess and evaluate a standard, a draft RSAW should be available to understand what the compliance and enforcement expectations are regarding evidence, documentation, attestations, etc. The Compliance Operations Guidance provided on the Project page for the most part simply repeats back the measures in the standards and does not provide added insights. So it is premature to ballot the standard without such information.
Individual
Scott Berry
Indiana Municipal Power Agency
Indiana Municipal Power Agency (IMPA) does not agree with requirement R5.1. with the need for the GOP to “coordinate” with its RC, BA, TOP, and TO. First, this requirement is not “results based” and it is an administrative compliance burden. It is also not practical because it is placing a GOP’s compliance on another entity’s action with the use of “coordinate”. If the SDT wants the GOP to have a training program, let the GOP have control over what is in it and be completely responsible for it. However, IMPA believes this requirement should be deleted along with requirement R5.1.1..
No
The definition could mean every person in the Control Center is a System Operator, including the cleaning person. It is not clear if the definition is applying the last part of the definition (“that operates or directs the operation of the Bulk Electric System in Real Time”) to the individual or the Control Center.
No
1. IMPA does not support this standard due to the comments in questions 2 and 3. IMPA would also like to see the RSAW to understand how this standard will be enforced. 2. In addition, it is not clear what the GOP will have to provide to show its decision when it comes to deciding its applicability under section 4.1.5.
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
No
These comments are submitted on behalf of the following PPL NERC Registered Affiliates (PPL): Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC, PPL Generation, LLC, PPL Montana, LLC and PPL Susquehanna, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.

PPL thanks the SDT and agrees with the inclusion of Generator Operator as defined in the applicability section of the standard. PPL request that the SDT consider removing the Transmission Owner (TO) from the list of entities included in Requirement 5. The inclusion of the TO in the applicability section limits the scope to “personnel in a transmission control center who operate a portion of the Bulk Electric System at the direction of its Transmission Operator. Thus, the TOP is in the best position to provide adequate and complete input as to the GOP training topics. The obligation to coordinate with the TO as well as the TOP appears to be redundant or unnecessary, as the NERC functional model assigns the Reliability Coordinator as the entity with the wide area view, situational awareness, and responsibility to issue corrective actions and emergency procedure directives in coordination with the Balancing Authority and Transmission Operator.
No
PPL has several concerns with the revision to the defined term “System Operator” to replace the current NERC Glossary term. 1. The revised System Operator definition incorporates the “Control Center” definition that is embodied in the CIP v5 filing in Docket No. RM13-5-000 and which is under consideration at this time by FERC: “Control Center: One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.” In Paragraph 80 of its NOPR issued in the CIP v5 docket, FERC asked whether the phrase “generation Facilities at two or more locations” intended to include two or more units at one generation plant and/or two or more geographically dispersed units. Therefore, whether this definition will be remanded for further clarification is undetermined at this time. 2. In addition, when the term “System Operator” is used within PER-005-2, it is used in the “System Personnel” definition that is only used within PER-005-2 (i.e., it will not be a NERC Glossary term and will only be used within PER-005-2). Within the System Personnel definition, System Operators are limited to “System Operators of a Reliability Coordinator, Transmission Operator, or Balancing Authority:” Generator Operators, even those GOPs that are subject to the applicability of PER-005-2, are excluded. 3. Furthermore, while the existing System Operator definition uses the language “monitor and control,” that language is replaced with the phrase “operates or directs the operation” in the proposed new definition. Whether GOPs are intended to be included in the new System Operator definition has not been made clear by the PER team. 4. The standard begins by defining the terms System Operator, System Personnel and Support Personnel, but then applies for GOPs only the word “personnel.” It is not clear whether or not this differentiation was intentional, particularly since Applicability para. 4.1.5 appears to describe GOP dispatchers who are System Operators. It would seem in this case, though, that they should have been included in the System Personnel definition.
No
PPL has identified issues in response to Questions 2 and 3 above that they believe should be addressed in a future version of this standard.

Group
Iberdrola USA
John Allen
No
No
NYSEG/RGE/CMP are concerned that the change in System Operator definition is vague and opens the standard to a wider range of interpretations than that of the previous definition. We request clarification of this new definition to better understand the scope of the change. Additionally, as this term is used in other standards (e.g. PER-003) a change in this definition needs to be properly vetted per NERC Standards Process Manual Section 5 to ensure that there is no change in the intent of that standard: "If a term has already been defined, any proposal to modify or delete that term shall consider all uses of the definition in approved Reliability Standards, with a goal of determining whether the proposed modification is acceptable, and whether the proposed modification would change the scope or intent of any approved Reliability Standards."
No
The addition of R4 and Support Personnel could significantly expand the scope and cost of training programs. The plane language of R4 appears to be less prescriptive than R4 taken with the rationale. Without the rationale, the plane language could be interpreted to apply only to traditional system operations personnel. The rationale expands this to planning personnel. Training of planning personnel should be separate than for System Operators.
Individual
John Taylor
Individual consumer
No
R4 in the Pro Forma Standard requires training for Support Personnel. R5 Requires training for Generator Operators using SAT. NERC Compliance stated in their Draft Reliability Standard Compliance Guideline for PER-005-2 in their answer to Question 2 that "Without a definition of, or reference to, a specific SAT, it would be difficult for auditors to assess an entity's training program because no benchmark is provided within the standard." So, in effect, training for Support Personnel would not be subject to SAT. The Pro Forma Standard draft includes an explanation for the omission of specifically mentioning SAT from R4. That explanation basically says that the entities would look to the list of reliability related tasks already developed for System Operators, and that training would be on those System Operator tasks that Support Personnel perform. Support Personnel don't perform System

Operator tasks. System Operators perform System Operator tasks. Even if the intent is that Support Personnel are trained on those their functions that support System Operator tasks, that does not identify Support Personnel tasks that impact company specific real time reliability related tasks. How are these identified? How are the Support Personnel functions identified if not through some sort of analysis (part of a SAT process). If the guidance of NERC Compliance Operations is followed in audit PER-005-2 as written SAT will not be required for Support Personnel training. Training done not following SAT is not valid training for tasks and will never make it past FERC. The FERC Order does say that Support Personnel need not be trained to the extent of transmission operators on transmission operator tasks, but that does not imply that SAT need not be used to develop and deliver their training. EMS personnel were excluded from the Pro Forma Standard based on a NERC Events Analysis determination using TADS and GADS data on, I believe, based on relay operations data. Breaker operations happen all the time and are not "Events" that necessarily result in mis-operations and are irrelevant in deciding if training is needed for EMS personnel. The relevancy of the data should be verified and applicable data used since EMS personnel training was one of the major contributors to the 2003 blackout.
Yes
No
Change R4 to include SAT for Support Personnel, and verify the relevancy of the data used by the Events Analysis Subcommittee to exclude MES personnel from the standard.
Group
Bureau of Reclamation
Erika Doot
Yes
The Bureau of Reclamation (Reclamation) suggests that the drafting team should include all definitions proposed in the standard in the NERC Glossary. Reclamation believes that standard-specific definitions further complicate an already complex regulatory framework. Reclamation also requests that the drafting team clarify the term “local transmission control center” because it appears to suggest that Transmission Owners are always Transmission Operator or System Operators. The definition of “local transmission control center” is confusing because it incorporates the phrase “transmission control center” without defining it or incorporating the NERC definition of Control Center. It is unclear whether a generator owner and operator (GO/GOP) that is also a transmission owner (TO) would be considered to have a “transmission control center” under the proposed definition. It is not uncommon for GO/GOP/TOs to have a limited number of bulk electric system transmission facilities that they operate in coordination with the local Transmission Operator (TOP) and Balancing Authority (BA). Reclamation does not believe that these facilities should be considered “transmission control centers” because these facilities do not generally have a view of or control the local transmission system. The proposed definition of “local transmission control centers” is not

detailed enough to determine whether a GO/GOP/TO control center would be considered a "transmission control center" in addition to a generation Control Center. Reclamation understands that the drafting team is attempting to address the FERC directive but believes that the current proposal is not sufficiently clear.
Reclamation recommends that GOPs should be free to develop their own training programs under a systematic approach to training. Reclamation suggests that if coordination of GOP training topics with Reliability Coordinators (RCs), Bas, and TOPs is necessary for BES reliability, the RC should be required to lead this coordination. RCs would be more appropriate to lead this effort than GOPs so that consistent training is suggested to GOPs, and so that RC concerns expressed to generators are understood, coordinated, and concurred with by BAs and TOPs who generally communicate with GOPs. Reclamation also suggests that training topic coordination with TOs should not be required because TOs do not generally develop instructions for individuals at GOP Control Centers who operate or direct the operations of the Bulk Electric System in Real-Time. If the drafting team determines that training topic coordination is necessary for BES reliability and should be retained in the standard, Reclamation recommends that the drafting team specify the required frequency of training topic coordination in R5, perhaps every two to three years. If the periodicity is not specified, Reclamation requests that the drafting team clarify whether it is meant to be an annual requirement? Reclamation also requests that the drafting team clarify whether GO/GOP/TO entities with limited BES transmission assets are meant to be included in the R4 required training for Support Personnel. The definition of Support Personnel applies to "Individuals who carry out outage coordination and assessments." GO/GOP/TO entities generally submit outages and therefore engage in outage coordination, and may conduct assessments of outage impacts on generator operations, but they generally do not conduct assessments of outage impacts on the BES, so it appears that GO/GOP/TO entities would not have "Support Personnel" or be required to comply with R4. Reclamation requests that the drafting team clarify whether support personnel subject to the standard must conduct assessments of outage impacts on the BES. As described in Q1, Reclamation also requests that the drafting team clarify the definition of "local transmission control center."
No
Reclamation requests that the drafting team clarify whether GOPs can be considered "System Operators" under the revised definition. Although GOPs operate BES-qualifying facilities that may include some qualifying transmission elements, Reclamation does not consider these operations to constitute "operating the Bulk Electric System" like a Transmission Operator, Balancing Authority, or Reliability Coordinator with a wide-area view of a transmission system. Reclamation does not believe that GOPs should be included in the definition of System Operator, but by incorporating the definition of Control Center which includes GOP Control Centers into the definition of System Operator, the ad hoc team appears to be suggesting that GOPs at Control Centers may be System Operators.
No
Reclamation recommends that GOPs should be free to develop their own training programs under a systematic approach to training. Reclamation suggests that if coordination regarding

GOP training topics needs to occur with the RC, BA, and TOP, then the RC should be required to lead the coordination. Reclamation suggests that TOs should be removed from R5.1 because they do not typically participate in the development of operating instructions for GOPs. Reclamation suggests that the drafting team clarify that GO/GOP/TOs who operate BES transmission equipment under the direction of TOPs do not develop dispatch instructions and therefore do not operate “local transmission control centers.”
Individual
Texas Reliability Entity, Inc.
Texas Reliability Entity, Inc.
Yes
The SAR has Generator Owner selected but the Standard makes no reference to a Generator Owner. This training standard should be expanded to apply to key GO operating personnel who control significant generation installations.
No
The “Control Center” term constrictively limits the definition. For instance, the most severe single contingency could be a single generating facility and the individuals operating that facility (on-site GO personnel) would be exempt from the Standard. Consider adding GO personnel to the applicability, perhaps limited to the personnel “that operate or direct the operation of a portion of the Bulk Electric System” or something similar, as was done with the TO in the applicability section.
No
The Standard is not supportive of reliability. The training is dependent upon a self-determined list which may or may not include significant “company-specific Real-time reliability-related tasks”. There is no delivery requirement on any periodic basis (only have to verify capabilities “once” and changes within 6 months.) As written a “company-specific Real-time reliability-related task” could be system restoration and the actions needed to restore the system could change but the task itself not change on the list. The change in actions may not be considered a modification of the task by the responsible entity and therefore no training would be required. There are no mandatory criteria by which the quality or effectiveness of an entity’s training program can be evaluated, and there is no basis for the CEA to identify a deficiency based on an incomplete task list or an ineffective training program. An entity can fully satisfy the proposed requirements by designing and delivering an ineffective program. The newly defined term “Support Personnel” is inclusive of the FERC order comments explicitly but fails to capture many of the “BES company-specific Real-time reliability related tasks”determined in R1. Why limit the training for the Support Personnel to a few basic comments by FERC? Additionally in Order No. 742 there is the Paragraph 5 statement “In Order No. 693, the Commission also directed the ERO to determine whether it is feasible to develop meaningful performance metrics associated with the effectiveness of a training program required by currently effective Reliability Standard PER-002-0 and to consider whether personnel who

support Energy Management System (EMS) applications should be included in mandatory training pursuant to the Reliability Standard". Why was that not considered? The rationale for removal of 32 hours of Emergency Operations is ambiguous and troublesome. What "should" be part of a systematic approach is dependent upon who develops the approach. Basic requirements such as 32 hours of Emergency Operations training were provided to appropriately shape the systematic approach. Does the SDT believe that each entity (Registered and Regional) has a consistent understanding of a SAT? The guidelines provide some reference but no requirements for a SAT. If the 32 hours is redundant per Paragraph 81, indicate where the redundancy exists. There are no periodic training requirements for the GOP personnel (no calendar year reference, no "once" requirement, no modification or new requirement.) Depending on when a company is audited, the personnel may not have been trained or had the training material delivered per R1.3 which has no timing requirement. This makes the VSL for R2 troublesome and does not take into consideration training schedules. If an entity has a three year timeline for the systematic approach to training, then R2 is unenforceable. The Severe VSL for Requirement 3 (specifically the "or" language associated with Requirement 3.1) does not reflect or represent the language within the Requirement.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Agree
SERC OC Review Group comments
Individual
Anthony Jablonski
ReliabilityFirst
ReliabilityFirst has a comments related to Requirement R5, Part 5.1.1 Q2 - The parent Requirement R5 is only applicable to the Generator Operator while the associated sub Part 5.1.1 is applicable to the Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner. Reliability standard requirements need to state the Applicable entity within each parent requirement and are not allowed to designate different Applicable entities within the associated sub-parts. ReliabilityFirst recommends making Part 5.1.1 a new separate, stand alone, requirement applicable to the Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner.
Yes
ReliabilityFirst offers the following comments related to certain Violation Severity Levels: 1. Requirement R1 VSL - a. The first moderate VSL references Part 1.1.2 and there is no corresponding Part 1.1.2. ReliabilityFirst recommends the SDT review the standard requirements and VSLs to ensure they are consistent. b. The second Moderate VSL indicates "…failed to provide evidence…" and within Part 1.4 there is no requirement to "provide

evidence”. Providing evidence is simply a means of complying with a requirement and does not indicate the degree to which an entity failed to comply. ReliabilityFirst recommends the following for consideration, “The Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner, failed to conduct an evaluation of its training program each calendar year to identify needed changes to its training program(s). (1.4)” c. The second Severe VSL is inconsistent with Requirement R1, Part 1.3. Part 1.3 does not require the entity to “deliver training” rather it requires the design and development of training materials. ReliabilityFirst recommends the following for consideration, “The Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner failed to design and develop training materials based on the task lists.” 2. Requirement R3 VSL - For consistency with the language in R3, ReliabilityFirst recommends the following for consideration for the first Severe VSL, “The Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner failed to provide its System Personnel with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the Bulk Electric System.”
Individual
Grit Schmieder-Copeland
Pattern
No
In addition to supporting the comments submitted by NAGF SRT to R5 I am submitting the following comments: One of the major flaws from a practice point of view appears to be that the GOP shall be required to coordinate training topics with RC, BA, TO and TOP to develop training. We manage a number of assets, each registered in its own rights as GO/GOP. As a result we currently would have to contact 4 RCs, 7 TOs, 7 BAs and 10 TOPs (ISOs registered as TOP as well as the local TOP for some of the assets) to create training for one central control room and to be compliant for each assets. This makes no practical sense at all. GOP with a control room should already know what training topics need to be covered just alone by reviewing the GOP responsibilities under the standards. I also foresee that RCs, BAs and TOs and TOPs would be overwhelmed with requests. The current draft just feels a bit like “fill in the gap standards” resulting in the GOP possibly not being (fully)compliant because the GOP depends on the (qualitative good) input from a third party that may or may not be provided (regardless if the standard requires these entities to do so). As of today, we haven’t made the best experience with a number of these registered entities providing the feedback we already are asking – the requirments as drafted just seems to add on to the already exisiting rather administrative burden of being compliant and more paperwork. In addition, if and when a GOP would not get a response (or useful response) from each of the 4 listed registered entities, the GOP is already in risk of being non-compliant position because training might be developed without the required input from at least 4 parties. Would it not result in a more consistent approach and be much more effective if the standard would already call out the required minimum training topics rather than requiring the GOP to request input from not

only one but at least 4 parties? Also, the GOP - RC interaction is rather limited (typically to emergency situation) as most of the real-time coordination takes place through the BA and TOPs. Therefore, I believe the training coordination should only take place between the parties involved where actual real –time and most of the emergency coordination takes place. In addition, I don't know many GOPs that have useful contact info for the RC other than the real-time desk. Considering the GOP - TO interaction – this standard is applicable for GOP operators located in the control room; therefore, training focuses on real-time and emergency operation. From the top of my head I don't' recall any requirements for real-time or emergency operation that involves the TO, therefore, why would a GOP need to ask the TO for input on its training for control room operators?
No
I am referring to the comments provided by NAGF SRT as I am supporting the submission. In addition, the standard still leaves room for interpretation when it would truly apply to a GOP control room and when not. Ultimately, no decision is made by a GOP control room regarding the BES w/o approval from TOP/BA and ultimately the RC nor should any directive received from a RC, BA and TOP communciated from control room to plant operator be altered. Otherwise why would we need three way communications when internally operator communication would maybe develop dispatch instructions rather than relaying the instruction? Or the question becomes: what defines a "dispatch instruction" that is not relaying a directive? Also, how would a GOP prove it control room operators develop specific dispatch instructions or only relays them?
No
Because GOP control room operators typically do not make operating decisions towards the BES, but rather monitor and relay operational information to TOP/BA and indirectly RC and where the resulting actions typically require approval of any of the three registered entities anyway, it is not obvious that a standard mandated training is necessary. However, should GOP training be mandated, then the standard should call out the overall topics to allow for consistent training requirements and to avoid unnecessary administrative burden (coordination effort) or refer to the real-time and emergency operating requirements in the NERC standards for a GOP to determine the scope. (For reasons see comments to question #2)
Individual
Kathleen Goodman
ISO New England, Inc
Agree
ISO/RTO Standards Review Committee (SRC)
Group
seattle city light
paul haase

No
Seattle finds the revised definitions of System Operator and System Personnel to add possibility of confusion in an area for which the term "System Operator" is well-defined and well-understood by industry. The term has been in long use and should not be changed for this single Standard. Seattle suggests the following change: Modify explanation of applicability to Transmission Owners as follows: (i) add new "Transmission Owner Personnel" definition (defined analogously to "Support Personnel" using information from Applicability Section 4.1.4.1, i.e. "Personnel in a transmission control center who operate a portion of the Bulk Electric System at the direction of its Transmission Operator"); delete all changes to "System Operator" definition; and delete new "System Personnel" definition entirely. (ii) change 4.1.4 to "Transmission Owner" and delete 4.1.4.1 entirely. (iii) Replace "System Personnel" with "System Operator and Transmission Owner Personnel" throughout all Requirements and Measures of PER-005-2.
No
Seattle expects to support draft PER-005-2 with two changes. The first is to revise potentially confusing definitions as discussed above (or similarly). The second is ensure that all "blue box" text included in the draft to explain and clarify the changes and intent of the Standard be preserved and formally recorded along with the Standard to ensure consistency of audit approach. It is not sufficient to retain this information in the NERC Standards Development archives, which are not easily accessible at NERC.com (there is no drop-down link to archives, for example; rather one must remember the old project number and other information to access a prior project, nor is there any promise that this important information will be retained as the archives are updated).
Individual
Mike Hirst
Cogentrix Energy Power Management
Agree
NAGF Standard's Review Team
Individual
Bret Galbraith
Seminole Electric Cooperative, Inc.
No
(1) In Requirement R4, Support Personnel are required to receive training. This Requirement and Measure read similar to the training Requirement in FAC-003-1 which is deleted from FAC-003-2 due to vagueness. Please describe how this Requirement and Measure are

different from the Requirement in FAC-003-1. (2) In the Applicability Section for Transmission Owner, we request the SDT to insert the word “significant” in front of “portion” to be in line with FERC Order No. 742. As written, any TO that operates a portion of the BES at the direction of a TOP is covered, however, it appears the intent of FERC via Order No. 742 was to only have those TOs that operated a “significant” portion of the BES. We request the term “significant” be inserted along with factors that described what is covered by a “significant” portion of the BES, i.e., please clarify the applicability for TOs. (3) In the Applicability Section for a Transmission Owner, please clarify what “transmission control center” involves. For instance, what is the lower voltage limit for transmission before it becomes distribution or are there other factors involved? (4) In the Applicability Section for a Generator Operator, please provide additional guidance on what entails a centrally located dispatch center. (5) In the Applicability Section for Generator Operator, please include the sentence from the notes that states “[p]lant operators located at the generator plant site are not required to be trained in PER-005-2.” Seminole would prefer to see this language in the Standard instead of the Guidelines Section.
Individual
Bill Temple
Northeast Utilities
Yes
Standard is unclear on the definition of "Support Personnel"
No
Clarify Support personnel. Consider the burden on training staff to complete all training documentation and whether expanding the scope of personnel that are required to participate in training directly supports reliability.
Group
DTE Electric
Kathleen Black
No
R4 - Applicability - Do not agree that GOP be included in this standard. Under rational, it states "applicability of training requirements to include operations planning and operation support staff who carry out outage planning and assessments and those who develop SOLS, IROLs, or operating nomograms for Real-time operations". Clarification is needed regarding outage planning and assessments. Is this transmission outages, distribution outages or generation outages? R4 & R5 - Why inconsistency in trianing requirements for Support Personnel and GOP? It is our opinion that GOP shall use training to establish and implement

training and get rid of "SAT based training" verbage. R5 & R5.1 - There is no periodicity in coordination - Each GOP shall coordinate with its RC, BA, TO, but how often? If the standard becomes effective, what if the GOP coordinates with RC one time and never has to do it again - what is the point - it is a waste of our time. R5.1.1 - R5.1.1 States that each RC, BA, TO and TOP shall provide input as requested by the GOP. This puts the GOP "on the hook" to make random requests or establish intervals for requests (which may leave reliability gaps between requests). After initial request (initial coordination required by R5.1), only the RC, BA, TO and TOP know when a change would occur in their areas that a GOP would need to consider for training topics. Obviously, any changes to training required by GOP side changes would be handled internally by GOP. Suggest R5.1.1 language be changed to require RC, BA, TO and TOP notify GOP of any suggested additions/changes to training topics after initial identification in R5.1 within "some reasonable time frame (30 days)."
Yes
We did appreciate your hard work on this definition - good job.
No
Please see comments suggested in Quesiton 2.
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Pamela Hunter
Yes
For the definition of “Support Personnel”, we recommend replacing “Individuals” with “Operating Personnel” to emphasize that it is personnel within an operations organization that perform these tasks to support real-time operations and not be confused with individuals in planning organizations. R4 is targeted to support personnel (R4)
Southern suggests to insert “if necessary” after the word “update” in R1 part 1.1.1. The list of tasks should be reviewed, but only updated if there was a need to do so based on some change. If no changes were identified, there is not a need to update. Measure M1 does not align with Requirement 1. M1 should state the following: M1. Each Reliability Coordinator, Balancing Authority Transmission Operator, and Transmission Owner shall have available for inspection evidence of using a systematic approach to training to establish and implement a training program, as specified in R1. Measure M1.1 should be modified to incorporate our comments regarding R1.1.1 above. It should include the date of the last review and/or revision and not update. There may be instances where the list is reviewed with no changes thus not requiring an update. M1.1 should state the following: M1.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator and Transmission Owner shall have available for inspection its company-specific reliability-related task list, with the date of the last review and/or revision, as specified in R1.1.
Yes

Yes
Southern suggests adding 'learning objectives' to the language in R1.2 because entities should be required to develop learning objectives and because training is tied to learning objectives. The Measure should have a corresponding change. Proposed change: R1.2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall design and develop learning objectives and training materials based on the task list created in part 1.1 and part 1.1.1. Southern suggests rewording R1.1 to be consistent with the wording in the purpose statement; change to 'reliability related task that perform or support real time operations'. The Measure should have a corresponding change. Proposed change: 1.1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall create a list of BES company-specific reliability related tasks that perform or support real-time operations.
Individual
Jason Snodgrass
Georgia Transmission Corporation
Georgia System Operations Corporation
Yes
The current PER-005-1 standard applies to System Operators. The new personnel being proposed (generation operator, local control center personnel, and support personnel), could be added to the current standard while leaving the current requirements and definition of System Operator in place since they are currently well defined. GTC suggest the SDT should define the local control center and applicable TO personnel or GOP personnel. This would minimize the unintended added confusion to who is defined as a System Operator if the SDT proceeds with modifying this clear definition.
Do not change the definition of "System Operator." There is no problem with it. Define "Local Control Center" as "1) a centrally located facility owned by a Transmission Owner that host operating personnel to remotely operate a portion of the Bulk Electric System at the direction of its Transmission Operator. This does not include switching stations or substations; or 2) a centrally located dispatch center of a Generator Operator that has personnel who receive direction from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control. Generator Operator dispatch centers with personnel who relay dispatch instructions, without making any modifications, and generator plant control rooms are excluded." Change the definition of "System Personnel" to "System Operators of a Reliability Coordinator, Transmission Operator or Balancing Authority; and Local Control Center Transmission Owner personnel. Change the definition of "Support Personnel" to "Operations Support Personnel: Operations planning and/or operation support staff, other than System Operators, who carry out outage coordination and assessments, or determine SOLs, IROLs or operating nomograms for Real-time operations. Change Applicability to 4.1. Functional Entities: 4.1.1 Reliability Coordinator 4.1.2 Balancing Authority 4.1.3 Transmission Operator

4.1.4 Transmission Owners that have Local Control Centers 4.1.5 Generator Operators that have Local Control Centers
No
The proposed definition of System Operator utilizes the pending regulatory approval definition of Control Center. The definition of Control Center states “facilities hosting operating personnel that monitor and control the Bulk Electric System in real-time to perform the reliability tasks”. The proposed definition for System Operator states “operates or directs the operation of Bulk Electric Ssytem in Real-time”. These two definitions should match relationally. FERC directed NERC to define local control center. The proposed method of NERC does not seem to address the concerns of FERC.
No
We do not support the revised PER-005-2 because of the change in definition of System Operator, the lack of a definition for a local control center, the definitions of System Personnel and Support Personnel, the applicability section, and R5. We do not support it because it is not clear and is very confusing.
Group
SERC OC Review Group
Sammy Roberts
Yes
The SDT should be commended for reviewing the Event Analysis Subcommittee report and working with the NERC EA staff to identify appropriate incidents and make the determination to omit EMS personnel. In order to further address industry concerns over the scope and applicability to GOPs and Support Personnel, the SDT is urged to halt the current standard development process to perform a similar analysis using the EAS report to properly categorize the risk level associated with GOPs and Support Personnel.
In regard to R3 part 3.1, what is the basis for the 6 month period to provide simulation technology if an entity gains operational authority or control over a Facility with an established IROL or establishes operating guides or protection systems to mitigate IROL violations? Purchasing, installing, and implementing simulator technologies for training system operators on these types of facilities would likely take longer than 6 months if for an entity that gains control over one of these facilities. Entities that gain control over these facilities should be allowed to implement enhanced training until such time that simulation technologies can be in place, not to exceed 12 months (a more reasonable timeframe). In addition, please clarify what it meant by virtual technology and other technology that replicates the operational behavior of the Bulk Electric System. Is this meant to include offline analysis of these IROL facilities with tools such as PSSE or other tools?
No
The primary concern centers on R5 and the inclusion of Generator Operator. Additionally, including “Support Personnel” in the proposed standard should be further clarified. The

comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Individual
Wayne Sipperly
New York Power Authority
Agree
Northeast Power Coordinating Council (NPCC)
Individual
Michael Moltane
ITC
Agree
SPP Standards Group
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
No
The proposed language in PER-005-2 R4 is unclear regarding the relationship between the Real-time reliability-related tasks identified by an entity under R1 and the Support Personnel's job function. The proposed Support Personnel definition includes personnel performing outage coordination and assessments. Since outage coordination and current-day, next-day and seasonal assessments are not Real-time tasks (i.e. they are future time, not present time, oriented), it is unclear how the applicable entity described in R4 will identify any relationship between these Support Personnel and Real-time reliability-related tasks under R4. It would help commenters if the drafting team would provide examples of this relationship to Real-time reliability-related tasks or undertake a rewrite of R4 to bring clarity. To add clarity, ATC suggests the definition of “Support Personnel” be rewritten as: Support Personnel: Individuals who carry out, in Real-time, planned or forced outage coordination and assessments, or determine SOLs, IROLs or operating nomograms1 for Real-time operations.
No
The term “directs” in the proposed definition of System Operator creates ambiguity. Directing the operation of the Bulk Electric System (BES) could be interpreted to include managerial personnel or those in a position of authority in a Control Center, for example. Another interpretation is the direct actions taken by the System Operator to monitor and control the operation of the BES, including the issuance of switching orders to field personnel or directives to System Operators in other Control Centers. The latter interpretation would seem to be captured in the term “operates” negating the need to include the term “directs” in the System Operator definition.

No
Please see the response to Question #2 for suggested changes.
Individual
Brian Shanahan
Transmission Operations
National Grid USA
No
No.
No
We support the NPCC RSC's comments on this standard and specifically offer this comment and suggested wording relative to the term "System Operator": The revised definition of "System Operator" potentially expands the applicable population subject to the Standard's training requirements to beyond what was originallyintended (e.g. the System Operator). I agree that System Operators and personnel with that authority regardless of title issuing orders for changes in the state of BES Elements should be included in the definition. However, the proposed definitions lack clarity of scope. It is not clear which personnel at the Transmission Owner (TO) might be identified as System Operators. FERC Order 742 only identifies “local transmission control center operator personnel.” Yet, the definition is sufficiently broad and subject to interpretation that other personnel could, inadvertently, unintentionally and unnecessarily, also be swept into the definition including: (a)downstream personnel at substations or district offices who implement directives from “local transmission control center operator personnel,” but who do not initiate, monitor or control changes in the state of BES Elements, and/or(b) upstream personnel at headquarters and elsewhere who provide administrative supervision of “local transmission control center operator personnel,” but who do not directly monitor or control the state of BES Elements. These individuals do not personally monitor or control changes in the state of BES Elements. Proposed Alternate Wording: System Operator: An individual at a Control Center that monitors, directsand controls the operation of the Bulk Electric System (BES) in Real- time.
No
Refer to comment provided to question #3.
Group
Puget Sound Energy
Denise Lietz
No
No
The proposed rewrite of the System Operator definition will result in a major expansion of the

people that will be considered to be System Operators because the term "operate" is so broad. For instance, Puget Sound Energy (PSE) has personnel located in its control center who remotely operate some generation units and relay dispatch instructions to other units at the direction of PSE's certified Power Dispatchers. Based on FERC's direction and the drafting team's approach, PSE understands it would be required to consider whether these operators are subject to requirement R5 of the revised standard. However, with the proposed definition of System Operator, these personnel will probably also be subject to requirement R1. The fact that R1 does not apply to the Generator Operator function probably does not help because PSE is a Balancing Authority and a Transmission Operator, so both R1 and the definition of System Personnel would apply to those personnel because they would be "System Operators of a ... Transmission Operator or Balancing Authority...". In addition, as identified in the Implementation Plan, this proposed change would affect the application of PER-003-1 and several other standards. Over time, other entities may move personnel to control centers to take advantage of the efficiencies that increased automation provides. Even if these personnel will not have independent authority to carry out tasks that affect the reliability of the BES in real-time, the proposed definition of System Operator will subject them to requirement R1 of PER-005. As a result, it seems that careful consideration of the definitions for System Operator and Control Center is advisable at this time. And, since the key to whether an operator needs training is his or her ability to independently affect the BES in real-time, the drafting team should consider defining a term "Reliability-Related Task" and then basing the System Operator definition on that term. This way the term "System Operator" would be based on the tasks assigned to a control center position and the resulting ability for the position to affect the BES in real-time.
Group
ACES Standards Collaborators
Jason Marshall
Yes
(1) In the purpose or goal section, the SAR indicates that PER-005-1 R3 was removed because it is redundant to the Systematic Approach to Training (SAT) required in R1. R3 compelled responsible entities to provide 32 hours of emergency operations training to their System Operators. Because the SAR states that are R1 is redundant, is the SAR implying that the 32 hours of emergency operations training is required in R1 also or that the SAT will identify the appropriate number of hours of training that is required whether it is 32 hours, 16 hours, 64 hours or some other number? If the answer is the latter, please modify the SAR and standard to state more directly that the SAT will identify the necessary number of required training hours. Otherwise, we are concerned that auditors will interpret the new Requirement R1 to require 32 hours of emergency operations training even though a responsible entity may view that only 20 hours are necessary.
(1) We do not believe that sufficient technical justification has been provided for including Support Personnel such as operations engineers who perform next day transmission security

studies or outage coordination. We understand that NERC must comply with the FERC directive and will support them doing so but we simply do not see the technical justification for including these types of personnel. We would like to see the drafting team provide technical justification or state that there is no technical justification and include this in the compliance filing along with the necessary requirements that are responsive to the FERC directive. This will allow the technical record to stand on its own merit. (2) We disagree with the use of the phrase "that relate" in Requirement R4. It is vague, ambiguous, will lead to multiple interpretations, and will result in inconsistent application in the enforcement process. Many reliability-related tasks that System Operators or System Personnel perform will relate to a Support Personnel job function. For instance, transmission switching may result in the transmission topology change which relates to the Support Personnel's job function. Outage coordinators will need to include such topology reconfigurations in their studies and EMS support staff will need to ensure the breaker statuses related to switching orders are telemetered into the state estimator model appropriately. Obviously, it relates to both Support Personnel positions but neither should be required to participate in training on implementing and writing switching orders unless they are actually performing those two tasks. We suggest that it would be better to implement straight forward language that clarifies that the Support Personnel have primary responsibility for performing the task. Thus, if conducting next-day transmission security studies is identified as a reliability related task and operations engineers perform that function, then the entity would be responsible for providing appropriate training that is directly related to that job function. Thus, we suggest incorporating the following language: "Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall establish and implement training for only those specific Real-time reliability-related tasks identified by the responsible entity pursuant to Requirement R1 part 1.1 and part 1.1.1 for which Support Personnel have primary responsibility." (3) The definition of Support Personnel should be modified as it is currently vague and could unintentionally include transmission planners. It states "Individuals who carry out… assessments" which could draw in transmission planning personnel since no time frame is associated with the assessments. The TPL standards require PC and TPs to conduct assessments of the transmission system which could be viewed as applicable assessments. There is a well-defined and FERC-approved NERC glossary term that would be more appropriate: Operational Planning Analysis (OPA). Thus, we suggest replacing "outage coordination and assessment" with OPA in the Support Personnel definition as it more appropriately applies to the near-term operation and, thus, focuses training on those tasks in a time frame with greatest reliability impact. (4) We do not see how the System Personnel definition is necessary. While the rationale box for R2 states it is necessary to capture RC, BA, TOP and TO without spelling out these terms a second time, we do not see why System Operator cannot simply replace System Personnel. The requirement is only applicable to the RC, BA, TOP, and TO so it can only apply to their System Operators. There is no need to list those entities a second time when using the System Operator definition. Ultimately, we think adding this definition will only cause confusion when System Operator is already a well defined term. (5) We suggest that R5 should be modified to require the RC to deliver the training to the GOP's applicable personnel. All of the supporting documents (e.g. whitepaper and Severe VSL for RC failing to provide input) and the requirement itself seem to indicate that the SDT does not believe the GOP can deliver the necessary training required in the FERC directive without the assistance of the TOP, BA, and RC. If this is the case, it would make more sense to require the RC to develop and deliver the training, and it would be unreasonable to compel the GOP to perform a task that the SDT does not believe it is capable of performing. The RCs already know what they require of the GOP and have well-established formal training programs that could easily be utilized to deliver the training to the GOP's applicable personnel. This would most likely result in lower costs to industry and would lessen the cost impacts on the end-use customers and would also result in the most reliable solution. (6) If the drafting team does not modify R5 to require the RC to deliver training, we suggest that Parts 5.1 and 5.1.1 should be modified to require the RC to provide training topics and supporting training materials for the GOP to deliver to its own personnel. (7) If the drafting team does not modify the R5 to require the RC to deliver training, Part 5.1 should be modified to describe exactly what actions are required to coordinate. Requirements that compel coordination are notoriously difficult to comply with because the meaning of coordination is ambiguous. What one person believes are reasonable efforts to comply may not be what another person believes is reasonable. Thus, this introduces too much of an opportunity to require auditor judgment that likely will not be consistent and will result in inconsistent enforcement. (8) We disagree with the inclusion of Transmission Owner into the standard. This is a registration and audit issue. If the Transmission Owner is truly carrying out TOP functions, they should be registered as a TOP. If they are carrying out delegated functions from another TOP, they could still be registered as a TOP through a CFR. Finally, if there is no CFR but only a delegation agreement, the TOP should ultimately be responsible for demonstrating compliance with the requirements including ensuring that the delegated tasks are carried out by an appropriately trained System Operator. The TOP should be able to demonstrate this by working with the TO. (9) We recommend moving the six month grace period in Part 3.1 regarding newly identified IROLs to the implementation plan and effective date/applicability sections for consistency with other standards. CIP standards have a newly identified critical asset plan that could be used as guidance. PRC-023 is another standard that has an implementation plan with applicability contingent upon something else occurring. (10) Please provide technical justification for the percentages that are used in the VSLs for R3. Why does 90 percent start the threshold for Moderate VSL and not a Lower VSL? Why use a 10 percent range for Moderate and a 20 percent range for High? (11) Please modify the first part of the Severe VSL for R3 to include "for IROLs". Simulation training is only required for IROLs and the VSLs do not reflect this important distinction. Thus, the VSL could be viewed as inconsistent with the requirement which would be contrary to the FERC Guideline 3 (from the June 19, 2008) order that the VSL cannot change the requirement. (12) The VSLs for R3, R4, and R5 are not consistent with VSLs for R1 contrary to FERC Guideline 2 (from the June 19, 2008 order). FERC Guideline 2 requires that penalty determination must be uniform and consistent. R2 has graduated VSLs based on the number of System Personnel that have been verified capable of performing the reliability related tasks. Requirement R3 deals with the capability of the System Personnel to perform newly identified reliability-related tasks, which is similar to R2 since it deals with existing reliability-related tasks. Yet, the VSLs for R3 are not

graduated based on the number of System Personnel that have been verified capable of performing the task. So while one System Personnel out of ten not verified capable of performing all existing reliability related tasks would result in a Moderate VSL for R2, the VSL for R3 would be Severe if the reliability related tasks were new (i.e. R3 applies). This would clearly result in an inconsistent outcome of penalties. R4 and R5 would have similar issues because a failure by a GOP to train one applicable employee or a failure by a RC, BA, or TOP to train one Support Personnel would be a Severe VSL. This creates an imbalanced compliance burden on smaller entities. Please provide graduated VSLs based on the number of System Operators/applicable employees similar to R2 for R3, R4, and R5. (13) VSLs for Requirement R1 and R5 are inconsistent contrary to FERC Guideline 2 which requires penalty determinations to be uniform and consistent. R5 has a VSL for failure to use SAT while R1 does not. Since SAT is required in both requirements shouldn't each requirement have a similar VSL at the same level? (14) We do not understand how failure for a TOP, BA, and TO to provide input to the GOP on their training tasks per R5 warrants a Severe violation. It does not prevent the GOP from developing and delivering the training that is required. It might make it more difficult for the GOP but does not keep the majority of the requirement from being met. At best, we believe this warrants a Lower VSL per the NERC guidelines.
No
We cannot support the modification to the System Operator definition until the impact to other applicable standards has been presented. System Operator is used in EOP-005-2, EOP-006-2, EOP-008-1, IRO-002-3, IRO-014-1, MOD-008-1, PER-003-1, PRC-004-WECC-1, and PRC-023-2. The SDT should perform an in-depth analysis and provide a written explanation for why the modifications to the definition do not impact the meaning, enforceability and compliance obligations of these other applicable standards.
No
(1) We do not support this standard at this juncture for several reasons. (2) First, we believe the standards process was not followed correctly and that this standard should not have been posted for ballot at the same time the standard was posted for comment. Based on the nomination period and representation in the materials, this standard is clearly the work of the ad hoc team and is not the work of the standards drafting team. While we understand the standards drafting team does not have to make changes to the standard proposed by the ad hoc team and that may ultimately be the case here since the majority of the SDT are the ad hoc team members, the simple reality is that there was not sufficient time for the new members to thoroughly review and agree with the standard. Furthermore, given that the nomination period did not commence until aft ether comment period started and the timeline posted shows a single ballot followed by the Final Ballot, it is clear the intent that that new members to the drafting team are intended to validate the work of the ad hoc team without any substantial modifications. Furthermore, the purpose statement on page 5 of the white paper clarifies the intent of the whitepaper is to provide a basis to the SDT for the pro forma standard so they can begin formal standard development. After all, the significant modifications are not allowed between a ballot and Final Ballot. (3) Second, we are concerned the quality of some of the materials posted may indicate a lack of quality in the standard.

There has been a haste to post this project and rush it through the ballot process as evidenced by the parallel initial posting of the standard for comment and ballot prior to formation of the SDT and the unrealistic posting schedule that anticipates no successive ballots (which would be very unusual). For example, PER-005-2 R1 in the mapping document does not match the standard. Which requirement is intended? We assume it is the one in the standard but cannot be sure since the mapping document is inconsistent. (4) Third, the Support Personnel definition needs modification as it is currently vague and could unintentionally include transmission planners. It states "Individuals who carry out… assessments" which could draw in transmission planning personnel since no time frame is associated with the assessments. The TPL standards require PCs and TPs to conduct assessments of the transmission system which could be viewed as applicable assessments. There is a well-defined and FERC approved glossary term that would be more appropriate: Operational Planning Analysis (OPA). Thus, we suggest the Support Personnel definition should replace "outage coordination and assessment" with OPA as it more appropriately applies on the near-term operation and, thus, focuses training on those tasks in a time frame with greatest reliability impact. (5) Fourth, the impact to other standards of the change to the definition of a System Operator has not been presented. System Operator is used in EOP-005-2, EOP-006-2, EOP-008-1, IRO-002-3, IRO-014-1, MOD-008-1, PER-003-1, PRC-004-WECC-1, and PRC-023-2. The SDT should perform an in-depth analysis and provide a written explanation for why the modifications to the definition do not impact the meaning, enforceability and compliance obligations of these standards. (6) Fifth, requirement R5 should be modified to require the RC to provide the necessary training or, at least provide the training materials to the GOP. Please see our related comments in question 2. (7) Sixth, the compliance input has not been addressed by the drafting team. While we disagree with some of the compliance input such as the suggestion to require a specific SAT, there is no documentation provided by the drafting team indicating the reason for not following this input and the compliance ramifications. (8) Thank you for the opportunity to comment.
Group
Duke Energy
Michael Lowman
Yes
Duke Energy continues to question the necessity and technical justification for expanding the currently effective PER-005-1. In fact, the NERC Events Analysis Subcommittee (EAS) reviewed existing EA reports that might point to the need of a standard for generator operators, EMS technicians, and for engineering support personnel at the request of the NERC Operating Committee (OC). Based on the EA reports in the database, the EAS and NERC EA staff concluded that training was not a root cause/driving factor in the EMS related events, and no events occurred where the generator operators or engineering support staff were involved. The fact that no events exist is a data point that a standard is not needed.
See response to Question 4
No

See response to Question 4
No
Duke Energy does not support the revised PER-005-2 for the following reasons. Before this question can be addressed, Duke Energy believes that a reliability based technical justification should be provided to the industry detailing the need for the proposed expansion of this standard. PER-005-1 is a standard that has only been in effect and enforceable for approximately 4 months, and required a 2 year phased in implementation plan. The industry has had little time to review the current PER-005-1 in order to: 1) determine whether this standard is in need of a revision; and 2) gain consensus regarding any expansion or revisions such as is being proposed. Duke Energy suggests that rather than unnecessarily expanding or revising PER-005, NERC should consider explaining to FERC why the expansion of PER-005 is no longer needed. For example, Duke Energy, as a TO with a local transmission control center, is required by the TOP to have their System Operators adhere to PER-005-1 in order to perform BES related tasks. Again, Duke Energy would like to reiterate the comment mentioned above that the NERC Events Analysis Subcommittee has performed a technical review of the reported EA submissions and has concluded that training is not a root cause factor and that additional training of Engineering Support personnel is not necessary. The current version of the PER-005 standard is very clear as to the responsibilities of a System Operator and the impact they can have on the reliability of the BES. Duke Energy believes that this expansion creates ambiguity and this ambiguity could lead to a reliability gap. Duke Energy will continue to reevaluate its position regarding this project. We look forward to working with the SDT and NERC in this effort.
Individual
Catherine Wesley
PJM Interconnection
Yes
Order 742 categorized any challenge to the scope of the proposed standard as a “collateral attack” but did say “such issues should be vetted” and “raised in comments in a future Commission proceeding”. PJM feels this is appropriate as this proposed standard assumes and mandates a training solution for job positions without any supporting data from a job and needs analysis. In doing so it conflicts with the Systematic Approach to Training Order 693 put in place. There are warnings in the DOE training references (along with references from other training industry sources) that warn against this. For instance, DOE-HDBK-1103-96, on page 5 states, “Much of today’s training has been developed based on a facility’s perceived training need rather than an analytically determined training need. Therefore, the training developed does not always address the training issue, yet training programs are developed at tremendous cost. A needs analysis can often not only limit the amount of unnecessary training developed, but also provide possible solutions to performance problems other than training. “ For these new requirements to be just and reasonable, they should be supported by data that has analytically determined the need.

PJM supports retaining a 32 hour minimum training threshold in R3. While applicable entities may exceed that level in their systematic training program, PJM believes it is important for the standard to identify minimum training hours. Without this bright line requirement, it is unclear as to how an entities continuing training program will be evaluated during an audit. PJM recommends that R4 be more prescriptive regarding who should receive the training and be based on industry analysis to determine the key positions to be included. PJM does not support R5 remaining in the standard specific to applicability to GOPs. Within the present structure of BES operations, a GOP does not make decisions regarding real time operations without the direction of their BAs and TOPs. The responsibilities and requirements for the GOPs are included in a number of standards, for example, EOP-005-2 and COM-002-2. Typically, GOPs make commercial or market based decisions. Rather than create training requirements for the few (if any) GOPs that make unilateral decisions, a requirement should be developed to prevent GOP unilateral action. Most GOPs will be faced with the task of proving a negative – that they do not take unilateral action and therefore are not subject to the training requirements.
No
The inclusion of the NERC glossary term “Control Center” in the new “System Operator” term would indirectly re-define a Generation Operator as a System Operator. This would make the new System Operator definition incorrect. Generation Operators receive and carry out “dispatch” instructions from the BA, RC, TOP’s or BES “System Operators”, but are themselves not responsible and do not have the authority to make unilateral reliability related operating decisions. Before the revised “System Operator” definition is accepted, the “Control Center” definition should be changed to remove Generation Operator.
No
While PJM supports robust training programs for all support staff, PJM does not support this standard as drafted. PJM is supportive of standards that advance safe and reliable operation of the BES and mitigate a similar occurrence happening again. PJM finds this draft standard to limit applicable entities’ flexibility to fully utilize its staff in the support functions. There will be an additional burden to provided operations training without detailed analysis that identifies training as the best solution for Support Personnel. PJM is strong supporter of the Systematic Approach to Training (SAT) which includes a detailed analysis to determine if additional training or a revision to existing training are appropriate solutions. PJM also supports the application of NERC EAS or similar data in the future that establishes the need to add support perosnnel as a mandatory requirement. This standard does not utilize this methodology to determine the specific Support Personnel for which operations training is warranted. It is not clear what is meant by “Support Personnel” in this standard. “Individuals who carry out outage coordination and assessments” could cast a very wide net and potentially include not only operations planning personnel but also system planning and markets personnel. Generalization of Support Personnel could result in training for training sake and miss a stronger corrective action such as revisions to operating procedures, policies and tools. This includes tools that provide the System Operator with, not static, but dynamically generated ratings and the ability to do real time assessments and analysis, thus making Operators less

dependent on support personnel for real time decisions. Also, the grey “Rationale box” for R4 seems to contradict the definition of Support Personnel by saying that the same reliability related task list developed for R1 for System Operators can be used for Support Personnel. Task lists developed in R1 are specific to operating positions and do not include tasks conducted by Support Personnel. PJM is supportive of excluding plant operators from applicability to this standard.
Individual
Diane Barney
New York State Department of Public Service
No
No
It is premature to be voting at all for the standard at this point in the process. Two major pieces of information are missing. First, the SAR has not been adopted, so we do not know if the proposed standard conforms to an adopted SAR. Second, the proposed standard was drafted by a small team of subject matter experts and has not yet been subject to a NERC wide critical review. Therefore, we do not yet know if there is a fatal flaw in the standard for some system(s) across NERC not represented by the SMEs, or if there is an outstanding idea to improve the draft standard.
Individual
Andrew Gallo
City of Austin dba Austin Energy
No
Austin Energy (AE) offers the following suggestions: (1) M1.4 should use the phrase “each calendar year” instead of “annual.” (2) M3 and M3.1 should include language to note that the associated requirements do not apply to all RCs, BAs, TOPs and TOs, but only those “that [have] operational authority or control over Facilities with estabilished IROLs or [have] established operating guides or protection systems to mitigate IROL violations.” Adding the word “applicable" after “Each” and before “Reliability Coordinator” will help. This comment also applies to the VRFs for R3. (3) The VRF for R3.1 appears to go with Requirement R2.1. R3.1’s VRF should reflect the use of simulation training within six months of gaining such operational authority. (4) R5 should not use the phrase “systematic approach to training” but instead should use language similar to R4, “shall establish and implement training.” This would better match the intent stated in the Rationale box: “The Commission acknowledged that the training for GOPs need not be as extensive as training for TOPs and BAs.... This

requirement does not necessitate an SAT process that is as comprehensive as that used for TOPs, RCs and BAs.”
Yes
No
AE’s comment regarding the use of the term “systematic approach to training” in R5 prevents us from voting Affirmative. The remaining comments in Question 2 above are clean-up.
Group
FirstEnergy
Doug Hohlbaugh
No
R1 - FirstEnergy (FE) believes revisions are needed to Requirement R1 to clarify that collaborative efforts already completed by separately registered TOP and TO organizations, such as RTO/ISO organizations, may be utilized. For example, PJM (TOP) and its member TO companies have already invested a significant amount of time and resources to jointly and consistently implement a systematic approach to training (SAT) for applicable transmission operations personnel. As part of the implemented SAT, a detailed job task analysis was performed collaboratively, resulting in a common approach for the established set of reliability-related tasks. Requirement R1 should be clarified to recognize and maintain these coordinated efforts. Based on the above comments, FE recommends that text “jointly or independently” after the word “shall” in requirement R1. As revised the text would read “R1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall independently or jointly use a systematic approach to training (SAT) …” R5 – FE agrees with the North American Generation Forum that consideration should be given to combine R5 and R5.1 for efficiency. However, we propose a modified version of their proposal as we believe that the applicable Transmission Owner as described in the standard is not needed or appropriate for the GOP coordination described within R5. In the TOP/TO LCC format, the TOP has primary responsibility for the transmission system under its purview and provides direction to the TO and GOP connected to its system. FE believes the TOP entity is better suited to coordinate with the GOP entity in applicable training tasks it believes is needed to ensure reliable transmission system operations. Based on the above comments FE proposes the following revised text for requirement R5: “R5. Each Generator Operator shall use a systematic approach to training to establish and implement training for its personnel described in applicability section 4.1.5, including coordination with its Reliability Coordinator, Balancing Authority and Transmission Operator to identify training topics that address the impact of the decisions and actions of a Generator Operator’s personnel as it pertains to the reliability of the Bulk Electric System during normal and emergency operations.” With our proposed change, sub-requirement R5.1.1 should be renumbered to R5.1.
Yes

No
For the above reasons, FirstEnergy does not support the proposed PER-005-2 at this time. We appreciate the hard work of the drafting team and their consideration of our comments.
Group
IRC/Standards Review Committee
Gregory Campoli
Yes
During the PER Industry Feedback Webinar, given by the PER Ad Hoc Group on April 4, 2013, the PER Ad Hoc Group requested Industry input on whether PER-related FERC Directives should be addressed by a New Standard, a Revised Standard or a Guideline. We have highlighted below why added or changed Standard requirements are no longer needed to address FERC's directives. There were five FERC Directives to the ERO in Order 693: (1) Develop specific Requirements addressing the scope, content and duration appropriate for generator operator personnel – This directive should be addressed through a Generator-specific, results-based Standard on Generator performance obligation. (2) Include in PER-002-0, personnel who: (2a) carry out outage coordination and assessments in accordance with IRO-004-1 and TOP-002-2 and (2b) determine SOLs and IROLs or operating nomograms in accordance with IRO-005-1 and TOP-004-0 – since Order 693, NERC's enforcement of the results-based Standards relating to operational reliability serve to address the Commission's core concerns that outage coordination and IROL/SOL management be improved and are reliable. Moreover, review of the Notices of Penalties and Lessons Learned shows that the industry has not experienced repeated compliance issues with IRO-004, IRO-005, TOP-002 or TOP-004, we no longer believe this is a Reliability Risk. (3) Consider through the Reliability Standards development process, whether personnel that perform functions having an impact on the reliability of the BES, should be included in mandatory training pursuant to PER-002-0; (3b) Personnel responsible for ensuring that critical reliability applications of the EMS, such as state estimator, contingency analysis and alarm processing packages, are available, up-to-date in terms of system data and produce useable results – since Order 693, NERC's enforcement of the results-based Standards relating to operational reliability that serve to address the Commission's core concerns that outage coordination and IROL/SOL management be improved and are reliable. Moreover, review of the Notices of Penalties and Lessons Learned shows that the industry has not experienced repeated compliance issues with IRO-004, IRO-005, TOP-002 or TOP-004, we no longer believe this is a Reliability Risk.. Additionally, the post-Blackout initiative has sufficiently addressed any shortcomings in the support area, including implementation of Change Management structures within the real-time IT community. There were two FERC Directives to the ERO in Order 742: (1) Direct NERC to consider the necessity of developing a similar implementation plan with respect to PER-005-1, Requirement R3.1. (simulation technology) –NERC has addressed this directive, because industry and the NERC BOT considered such issues in the development and approval of PER-005 and its Implementation Plan. (2) Direct NERC to develop a definition of "local transmission control

center” in the standards development project for developing the training requirements for local transmission control center operator personnel – The ERO appears to have addressed this issue through its registration and compliance monitoring programs. Through both programs, the ERO has assessed the role different Transmission companies play in BES operations and if or how they need to be trained. Given the different approaches registered entities take in registering as Transmission Operators, if more is needed here, a good first step would be to draft an operating guideline. We have captured the relevant Blackout “Recommendations,” “Causes” and “Other Deficiencies,” as published on NERC’s website. Following each is a dispensation. In addition, and of note, in October 2003, before the Task Force had issued its reports, NERC requested CEOs of all Reliability Coordinators and Control Areas to initiate organizational self-assessments and certify that their organizations were in compliance with NERC and regional reliability council standards and good utility practices. This request focused in particular on problem areas identified in preliminary findings from the Blackout investigation. From http://www.nerc.com/docs/docs/blackout/Report_to_US-Can_TF_on_Status_of_Blackout_Recommendations-071405.pdf “Status of August 2003 Blackout Recommendations” dated July 14, 2005 Recommendation 5. Track implementation of recommended actions to improve reliability. • Completed in 2005. Recommendation 18. Support and strengthen NERC’s Reliability Readiness Audit Program. • NERC clarified the standards defining Reliability Coordinator (RC) and Control Area functions, responsibilities, capabilities, and authorities. NERC conducted Readiness Audits on all RC, CA entities. Recommendation 19. Improve near-term and long-term training and certification requirements for operators, reliability coordinators, and operator support staff. • With respect to Recommendation 19.A, NERC addressed this requirement for training of “back room” personnel through its organization certification standards. Recommendation 22. Evaluate and adopt better real-time tools for operators and reliability coordinators. • NERC created a Real-time Tools Best Practices Task Force (RTBPTF) to identify best practices for building and maintaining real-time networks, and develop guidelines based on these practices. This Task Force presented recommendations in 2005 for specific, auditable requirements for inclusion in new standards concerning real-time tools for operators. From http://www.nerc.com/docs/docs/blackout/section5.pdf “August 14, 2003, Blackout, Final NERC Report, Section V, Conclusions and Recommendations” Causes Cause 1a: FE had no alarm failure detection system. Cause 1b: FE computer support staff did not effectively communicate the loss of alarm functionality to the FE system operators after the alarm processor failed at 14:14, nor did they have a formal procedure to do so. • Cause 1a and 1b have been addressed by incorporating detection tools and having such capability confirmed during Readiness Audits. Cause 1c: FE control center computer support staff did not fully test the functionality of applications, including the alarm processor, after a server failover and restore. Cause 1d: FE operators did not have an effective alternative to easily visualize the overall conditions of the system once the alarm processor failed. Cause 3a: MISO was using non-real-time information to monitor real-time operations in its area of responsibility. Cause 3b: MISO did not have real-time topology information for critical lines mapped into its state estimator. • Causes 1c, 1d, 3a and 3b have been addressed by adopting the Real-Time Tools Best Practices Task Force (http://www.nerc.com/filez/rtbptf.html) recommendations and

confirming such during Readiness Audits. Other Deficiencies Problems identified in studies of prior large-scale blackouts were repeated on August 14, including deficiencies in vegetation management, operator training, and tools to help operators better visualize system conditions. Reliability coordinators and control areas have adopted differing interpretations of the functions, responsibilities, authorities, and capabilities needed to operate a reliable power system. FE did not have the ability to transfer control of its power system to an alternate center or authority during system emergencies. FE operational planning and system planning studies were not sufficiently comprehensive to ensure reliability because they did not include a full range of sensitivity studies based on the 2003 Summer Base Case. FE did not perform adequate hour-ahead operations planning studies after Eastlake 5 tripped off-line at 13:31 to ensure that FE could maintain a 30-minute response capability for the next contingency. FE did not perform adequate day-ahead operations planning studies to ensure that FE had adequate resources to return the system to within contingency limits following the possible loss of their largest unit, Perry 1. MISO did not have additional monitoring tools that provided high-level visualization of the system. • The other Deficiencies have been addressed through (1) individual entities' mitigation plan completion and confirmation thereof by NERC and FERC; (2) Implementing the Readiness Audits (pre-enforcement) for organizational certification; and (3) Adopting and enforcement of NERC Reliability Standards (post-enforcement). It should be noted that ERCOT does not support this comment, and any subsequent comments that reference this comment.
a) There appears to be an inconsistency between the definition of Support Personnel and Requirement R4, or an unclear definition or an unclear requirement or both as it relates to Real-time reliability-related tasks. The proposed definition of Support Personnel is: Individuals who carry out outage coordination and assessments, or determine SOLs, IROLs or operating nomograms for Real-time operations. This definition clearly indicates that these personnel do not perform any Real-time tasks, although their tasks produce results that are applied in Real-time operations. R4 stipulates that: Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall establish and implement training for Support Personnel specific to those Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1 and part 1.1.1 that relate to the Support Personnel's job function. R4 is unclear as to whether or not the Responsible Entities need to establish and implement training of Support Staff on Real-time tasks. If R4 means tasks that are related to Real-time reliability, then outage coordination and assessment and determination of SOLs, IROLs, etc. will certainly meet such criteria and therefore the Support Personnel will need to be trained on the "related" Real-time task. However, such an interpretation will mean that almost every task in a Control Centre is related to Real-time operation. The question becomes: who exactly are the Support Personnel that need to be trained? If only those personnel that perform tasks as indicated in the definition, then why would they need to be trained on Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1 and part 1.1.1, and what will does it mean by "that related to the Support Personnel's job function"? The above questions and interpretations reflect that Requirement R4 and its relation to the definition of Support Personnel are unclear. As written, Responsible Entities will not have a clear understanding of what their obligations are with respect to the

who to train and the topics to be including in the training program for Support Staff. Much clarity is needed in Requirement R4 or the proposed definition for Support Personnel or both. We are unable to suggest any specific wording to clarify the definition for Support Personnel and/or Requirement R4 since we do not know what the objective (the kind of training) the SDT has in mind when it comes to providing training to the Support Personnel. b) Intuitively, we have difficulty understanding the basis for assigning a Long-Term Planning Time Horizon to the five requirements of a standard that addresses training for operating personnel and support personnel. As suggested by a number of requirements in the standard, training is delivered at least annually, if not more frequently, and the training program needs to be reviewed and revised once a year. This is much shorter than the Long-term Planning time frame. The intent of the Time Horizon is to indicate the general time frame to correct a non-compliance with a requirement. We do not see how a non-compliance of any of the requirements should wait for more than a year to mitigate, in view of the time frame stipulated in the requirements. We suggest to change the Time Horizons to Operations Planning.
Yes
We support the change, however, we believe Control Center definition should also be changed to make it more consistent with the revised definition of System Operator.
No
We support the elimination of the 32 hours of Emergency Operations training. However, we are unable to support this standard as presented, for the reason as cited in Comment (a) under Question 1 and 2, above. In addition, there is an inconsistency between the VSLs for R1 and R5. Both R1 and R5 require that the Responsible Entity use a systematic approach to training to develop a training program (note that in R5, it's training only, not a training program) for their personnel. The VSL for R1 does not have a level for failure to demonstrate that the Responsible used the SAT to develop the training program. However, a Responsible Entity is assigned a High VSL for failing to use a systematic approach to training to establish training requirements as defined in Requirement R5. The two VSL sets should be consistent with respect to the requirement for using SAT. We suggest the SDT to revise the VSL for R1 to include this violation condition.
Group
Santee Cooper
S. Tom Abrams
Santee Cooper votes negative based on the proposed changes to PER-005-2 requirement R4 "Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall establish and implement training for Support Personnel specific to those Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1 and part 1.1.1 that relate to the Support Personnel's job function." The current version of PER-005 R1.1 requires each Reliability Coordinator, Balancing Authority, Transmission Operator to

create a list of BES company-specific reliability-related tasks performed by its System Operators, not the Support Personnel. We feel that these tasks are not applicable to the Support Personnel because the list is solely focused on the System Controller position. Santee Cooper also feels that while the Support Personnel may perform tasks that support our System Controllers they are not done in real-time; they are done for the day-ahead and ultimately the System Controllers, make the final decisions for all real-time operations. Therefore decisions from day-ahead studies performed by Support Personnel do not have an impact on real time operations.
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.
No
Requirement 1.3 states training shall be delivered to System Personnel. We believe System Operator should be added, and prefer it be used in place of the new term System Personnel. In requirement 4 the Support Personnel's job function should clearly identify the actual training needs for tasks associated with Real-time Reliability Related tasks. The requirement should not obligate Support Personnel to meet the same criteria as the System Operator. Currently the ad hoc group has some useful rationale for Generator Operator under 4.1.5. However, once the standard gets approved the rationale box will be removed and the applicability to plant operators will not be clear. Therefore Tri-State requests that the last sentence from the "Rationale for Generator Operator" box stating "Plant operators located at the generator plant site are not required to be trained in PER-005-2" should be added as the last sentence in the Applicability Section 4.1.5.1.
Yes
No
We do not believe the new defined term "System Personnel" is needed. Maintaining the System Operator definition is adequate. When the term "System Operator" is used within PER-005-2, it is used in the "System Personnel" definition that is defined for use only within PER-005-2 which is not intended to be a NERC Glossary definition. Within the "System Personnel" definition, "System Operators" are limited to those from entities that are RCs, TOPs, BAs, and TOs. GOPs are not listed, and therefore are excluded as it is written. The PER team did not make it clear whether GOPs are going to be included in the proposed "System Personnel" definition. Support Personnel needs to be defined more clearly and in more detail. We question the need to extend the applicability of the standard to Transmission Owners. Local transmission control centers that operate portions of the BES meet the definition of a System Operator, therefore meeting the conditions required to register as a Transmission

Operator.
Group
APPA Staff
Allen Mosher
No
No
APPA agrees with the intent of the Commission’s directives in Order No. 742 that the ERO develop formal training requirements for local transmission control center operator personnel that exercise control over a significant portion of the Bulk-Power System under the supervision of the personnel of the registered transmission operator. However, the Commission’s directive appears to be targeted at ensuring proper training of system operators that are employed by large TOs that operate under the direction of RTOs and other large TOP entities. These large TOPs direct the real time operation of the BES within their regional footprints by sending instructions to Transmission Owner control center personnel. TO control center operators then execute these directives for elements within their local areas. APPA staff’s review of the NERC Compliance Registry as of September 3, 2013, indicates that there are 176 entities registered as Transmission Owners that are NOT also registered as Transmission Operators. These non-TOP Transmission Owners are widely distributed across all NERC regions. These non-TOP TOs are not confined to areas within RTOs that perform the RC, BA and TOP functions for large footprints. The breakdown by regions is as follows: FRCC-8, MRO-19, NPCC-22, RFC-25, SERC–28, SPP-26, TRE-16, WECC-32. APPA is concerned that the Applicability section of the draft standard could be read to make the proposed Requirements R1, R2, R3, and R4 applicable to many and potentially all 176 non-TOP Transmission Owners that have either (a) multi-function control centers (e.g., distribution control centers that also control limited BES transmission elements used primarily to serve load) or (b) small transmission control centers with only limited capabilities that are commensurate with the limited BES elements they operate. Transmission control center is not a defined term. Also, it is possible that only intermittent or occasional directions by the Transmission Operator to a small Transmission Owner might be deemed to have triggered the Applicability of PER-005. 4.1.4 Transmission Owner that has: … 4.1.4.1 Personnel in a transmission control center who operate a portion of the Bulk Electric System at the direction of its Transmission Operator. Thus, it is critically important that the SDT’s proposed language addressing Applicability be crystal clear as to which TOs are subject to the proposed standard.
Group
NAGF Standards Review Team
Patrick Brown

1. The SRT believes R5 and R5.1 should be combined for efficiency. The SRT recommends the language for R5 be changed to: “Each GOP shall establish and implement training for its personnel described in Applicability Section 4.1.5 which includes coordinating with its RC, BA, TOP, and TO to identify training topics that address the impact of the decision and actions of a GOP’s personnel as it pertains to the reliability of the BES during normal and emergency operations.” 2. R5.1.1 should be a separate R6 since it stipulates requirements for those other than the GOP. The SRT recommends the languge for this new R6 be: “Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall provide input to a Generator Operator’s training program established under R5 as requested by the Generator Operator.”
No
We have several concerns with the revision to the defined term “System Operator” to replace the current NERC Glossary term. 1. The revised System Operator definition incorporates the “Control Center” definition that is embodied in the CIP v5 filing in Docket No. RM13-5-000 and which is under consideration at this time by FERC: “Control Center: One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.” In Paragraph 80 of its NOPR issued in the CIP v5 docket, FERC asked whether the phrase “generation Facilities at two or more locations” intended to include two or more units at one generation plant and/or two or more geographically dispersed units. Therefore, whether this definition will be remanded for further clarification is undetermined at this time. 2. In addition, when the term “System Operator” is used within PER-005-2, it is used in the “System Personnel” definition that is only used within PER-005-2 (i.e., it will not be a NERC Glossary term and will only be used within PER-005-2). Within the System Personnel definition, System Operators are limited to “System Operators of a Reliability Coordinator, Transmission Operator, or Balancing Authority:” Generator Operators, even those GOPs that are subject to the applicability of PER-005-2, are excluded. 3. Furthermore, while the existing System Operator definition uses the language “monitor and control,” that language is replaced with the phrase “operates or directs the operation” in the proposed new definition. Whether GOPs are intended to be included in the new System Operator definition has not been made clear by the PER team. 4. The standard begins by defining the terms System Operator, System Personnel and Support Personnel, but then applies for GOPs only the word “personnel.” It is not clear whether or not this differentiation was intentional, particularly since Applicability para. 4.1.5 appears to describe GOP dispatchers who are System Operators. It would seem in this case, though, that they should have been included in the System Personnel definition.
No
Because if the issues above, we cannot support PER-005-2 until the proposed definition of “System Operator” is withdrawn or until the PER team revises it to specifically include only

Reliability Coordinators, Transmission Operators, and Balancing Authorities.
Group
SPP Standards Review Group
Robert Rhodes
Yes
We have some concern regarding what appears to be creep in scope associated with personnel training in PER-005-2. We are concerned that as this scope continues to expand and include non-certified personnel on the fringes of the functionality of the operating desk, maintaining compliance with the standard could become a burdensome task to the industry as well as create an equally increased risk of non-compliance for an issue that has very little impact on the reliability of the BES. While we realize that the drafting team has attempted to address issues directed by FERC, perhaps there is an alternative solution to the proposed standard as the team found with the inquiry into including EMS support personnel in the standard.
The 6-month lead-time for simulator training in R3 may not be adequate depending upon whether the entity has access to a simulator. Unless the entity has its own simulator, the simulation provided would be of a generic nature. To obtain more customized, specific simulator training may require acquisition of a simulator and providing for staff to develop and implement simulator training. This would require much more than 6-months lead-time for many entities due to budgetary constraints as well as staffin and acquisition processes. We are also concerned with the openness of the 'relate to' phrase in R4 and would suggest the following replacement for R4: Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall establish and implement training for Support Personnel who perform Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1 and part 1.1.1.
Yes
No
Please refer to our comments in Questions 1 and 2 above.
Group
Western Area Power Administration
Lloyd A. Linke
Agree
US Bureau of Reclamation.

Additional comments received from SMUD:

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

☐ Yes
☒ No

Comments:

2. Please specify if you have comments or proposed changes to any of the Requirements of the pro forma standard. SEE BELOW:

Comments:

3. Do you support the revised NERC Glossary Term System Operator? If no, please indicate in the comment section what suggested changes would put you in favor of the new glossary term.

☒ Yes
☐ No

Comments: To avoid any confusion or misapplications we suggest that the definitions of "System Personnel"and "Support Personnel" be included in the NERC Glossary of Terms to provide consistency and standard usage.

4. Do you support the revised PER-005-2 standard? If no, please indicate in the comment section what suggested changes would put you in favor of the new revised standard.

☐ Yes
☒ No

Comments:

The blue text box "Rationale" statements includes language that excludes generator plant site operators from the training requirements. This exclusion should be reflected in the Applicability Section to make it clear that "Plant operators located at the local generator plant site who receive dispatch instructions from the GOP of a centrally located dispatch center are excluded ".

We believe the following concepts should be included in the Requirement R4:

1. R4 should be consistent with Requirement R3.1. by specifying the training intervals and frequency required for support personnel; and, by specifying that similar training protocols be established for new support personnel.

2. For consistency, R4 should stipulate that training be provided for support personnel as well as System Operators within 6 months of implementing Reliability-related tasks and/or procedures that have changed.
3. Please provide clarifying language that specifies that Requirement R1 applies to developing and implementing a training program that addresses the subset of real-time Reliability-related tasks, as opposed to the entire scope of the support personnel job function.

Additional comments received from Xcel:

Question

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

☐ Yes

X☐ No

Comments: NONE

2. Please specify if you have comments or proposed changes to any of the Requirements of the pro forma standard.

Comments:

1) Support Personnel definition: suggest enhancing the definition to clarify which assessments (and individuals who perform them) are subject to this. Suggest the following language for Support Personnel:

"Individuals who carry out outage coordination, outage assessments, or determine SOLs, IROLs or operating nomograms[1] used in the Real-time operation of the Bulk Electric System".

2) capitalize "Control Center" throughout the standard

3) the description of the Functional Entities for Transmission Owner and Generator Operator seems overly complicated. We recommend that be simplified. For example, would "Transmission Owner that has System Operators" suffice?

4) R3: recommend modifying the requirement to say " …shall provide its System Personnel with ***IROL*** emergency operations training…" to indicate the training requirement is limited to the IROL.

5) R4: what is meant by "pursuant to R1 Part 1.1…"? Restate those requirements here if needed, to eliminate confusion. It is also not clear if there is a minimum training quantity/frequency for Support Personnel or is it established by the entity.

6) R4: As written, there is confusion between the definition for Support Personnel and what training is required for them in Requirement 4. Most utilities have defined “real-time” as occurring within the moment, the next hour, or within an operating day. The tasks identified in the definition for Support Personnel are all planning tasks that are not considered “real-time” functions. For example, the development of SOLs and IROLs is a long-term process that is done on a day-ahead basis at the soonest and more likely on a seasonal basis. Moreover, requirement R4 refers to training of Support Personnel specific to those Real-time reliability-related tasks identified in the initial System Operator task lists which were created to comply with R1. These initial task lists do not include any of the tasks provided in the definition of Support Personnel.

This confusion is amplified by the use of ambiguous and contradictory terminology in Requirement 4. The rationale for R4 suggests entities select the “real-time” reliability related tasks that Support Personnel conduct. From this perspective, there would be no training required of Support Personnel since they don’t conduct any real-time tasks. This is unlikely the intent because the SDT wouldn’t have included a Requirement that basically tells the entity to do nothing. The language in the Requirement 4 states to implement training specific to real-time reliability-tasks that “relate to the Support Personnel’s job function”. This is in direct conflict with the rationale statement because now it opens up required training to Support Personnel on tasks that are not currently included in the real-time reliability-related tasks. Given this contradiction, it leaves the entities wondering what the SDT is expecting. The rationale statement for R4 says one thing and the R4 requirement says almost the complete opposite.

If the intent of R4 is to mandate training of real-time reliability-related tasks to Support Personnel on those tasks for which they support so that they better understand the real-time operational task; I do not believe this is necessary and think there are better ways to accomplish this goal. Xcel Energy is not against conducting training for its operations support personnel, but it wants to ensure required training has added value in furthering the reliability of the bulk electric system. In many cases, Xcel Energy’s operational Support Personnel is providing guidance used to formulate the real-time reliability-related tasks that operators are then trained on. By mandating training to Support Personnel on those same tasks, this standard is asking entities to train their Support Personnel on tasks that they were directly involved in helping to develop. As such, they already have a solid understanding of the task and any training would be unnecessary review of information that they already know. Therefore, there is little benefit in requiring this training be conducted. Further, Xcel Energy encourages Support Personnel to engage with the real-time operators when performing their job function to ensure that they understand the real-time operational impact of their work. In addition, Xcel Energy has an operator acceptance process on any new or revised real-time reliability-related task that allows them to provide feedback to Support Personnel which opens a dialogue between operators and Support Personnel so that Support Personnel better understand the operational impact of said task. I believe this is a more effective way to ensure Support Personnel understand the real-time tasks and further the reliability of the BES than mandated training.

For example, PER-005-2 suggests that Support Personnel be trained on the real-time reliability task of managing power flows and voltages within their SOLs and mitigating SOL exceedances. Support Personnel determine the SOLs as required by TOP Standards. However, in addition, Support Personnel develop guidance for how to mitigate exceedances of those SOLs and provide that guidance to operators in the form of operating guides or operating procedures. The guides and procedures are then reviewed by the operators to ensure they are viable in the real-time operation of the system. By determining SOL mitigation guidance, Support Personnel are directly involved in the real-time reliability-task that PER-005-2 is requiring they be trained on.

7) R5: Please clarify if there is a required quantity/frequency for the training and coordination with entities or if that is intended to be established by the entity.

8) R5.1: how does each GOP identify "its" TOP and TO? Is there a mapping or hierarchy of GOPs to TOPs and TOs?

3. Do you support the revised NERC Glossary Term System Operator? If no, please indicate in the comment section what suggested changes would put you in favor of the new glossary term.

X☐ Yes

☐ No

Comments: None.

4. Do you support the revised PER-005-2 standard? If no, please indicate in the comment section what suggested changes would put you in favor of the new revised standard.

☐ Yes

X☐ No

Comments: See comments provided above.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

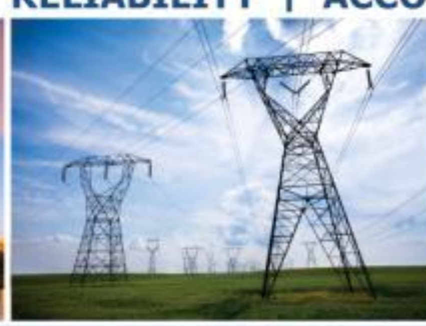
Consideration of Comments Summary

Project 2010-01 Training (PER)

September 27, 2013

RELIABILITY | ACCOUNTABILITY



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Introduction

The Project 2010-01 drafting team thanks everyone who submitted comments on the draft PER-005-2 standard. This standard was posted for a 45-day public comment period from August 23, 2013, through September 3, 2013. NERC asked Stakeholders to provide feedback on the standard and associated documents through a special electronic comment form. There were 71 sets of responses, including comments from approximately 235 people from approximately 130 companies, representing 9 of the 10 Industry Segments, as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact Vice President and Director of Standards Mark Lauby at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Consideration of Comments

Purpose

The PER standards drafting team (SDT) appreciates industry's comments on the PER-005-2 standard. The SDT reviewed all comments carefully and made changes to the standard accordingly; however, the new Standards Process Manual (SPM) does not require the SDT to respond to each comment if a successive ballot is needed. The following pages are a summary of the comments received and how the PER SDT addressed them. If a specific comment was not addressed in the summary of comments, please contact the NERC standards developer or one of the SDT members to discuss. (See Attachment A for the SDT contact information.)

Administrative

The SDT removed the acronym for the systematic approach to training (SAT) to avoid the implication that there is only one model of a systematic approach. There are many ways that an entity can implement a systematic approach to training.

Standards Authorization Request (SAR)

The SDT received a few comments about unchecking "Generator Owner" and as a result modified the SAR to uncheck the term. Based on another comment, the SDT modified the discussion of the 32 hour training obligation from Requirement R3. The language was modified to state: *"Remove from existing PER-005-1, Requirement R3 the requirement to provide at least 32 hours of emergency operations training as it no longer meets criteria set forth in the standard for utilizing a systematic approach to training. The appropriate amount of such training should be determined "by the applicable entities" through the analysis phase of a systematic approach to training and outlined in a continuous education section of their training program. Any additional hours may be duplicative or repetitive for the entity in providing training to their personnel."*

NERC Glossary Term "System Operator"

One commenter asked the SDT not to change the NERC Glossary term "System Operator" from the current NERC Glossary definition. The intent in modifying the definition, however, was to remove the term "Generator Operators" and to make the language clearer.

The SDT also received several comments regarding the capitalization of "Control Center" within the System Operator definition. The term "control center" has been lower-cased since it has not yet been approved by FERC.

Lastly, the SDT reviewed other standards that contain the NERC Glossary term "System Operator." The proposed change in the term "System Operator" does not affect other standards that use the term. The PER Implementation Plan has a copy of which standards use the term "System Operator."

Definition of Terms Used in Standard

The terms provided below are defined for use only within PER-005-2 and, upon approval of the standard, will not be moved to the NERC Glossary of Terms.

System Personnel

Several commenters questioned the use of "System Personnel" throughout the standard. One suggestion was to replace the term with "System Operator." The term "System Personnel" includes more applicable entities than that of "System Operator." The term "System Personnel" was created to allow the standard to be more concise by preventing repetition of the long description ("Reliability Coordinators, Balancing Authorities, Transmission Operators, and Transmission Owners") throughout the standard. Additionally, the term "System Personnel" was created to include Transmission Owners with local control center personnel.

Operations Support Personnel

Comments stated that the term "Support Personnel" was unclear. The SDT added the term "Operations" to the standard-specific defined term to make it "Operations Support Personnel." The SDT also expanded the definition to clarify that the functional entities (Reliability Coordinators, Balancing Authorities, Transmission Operators, and Transmission Owners) must identify Operations Support Personnel. The SDT modified the definition to use the exact language from FERC Order Nos. 693 and 742. Additionally, the language describing Transmission Owners comes directly from FERC Order No. 693, paragraphs 1343 and 1347.

Applicability Section

The SDT received several comments requesting clarification of which Transmission Owners are subject to the PER-005-2 standard. As a result, the SDT modified the applicability section to clarify the Transmission Owners subject to the standard and better define the local control center personnel as required by the FERC directive. The Transmission Owner applicability section now states: "Transmission Owner that has personnel at a facility, excluding field-switching personnel, who act independently to carry out tasks that require Real-time operation of the Bulk Electric System (BES) including protecting assets, protecting personnel safety, adhering to regulatory requirements, and establishing stable islands during system restoration."

Based on comments received, the SDT updated the applicability section to clarify which Generator Operators are applicable to the PER-005-2 standard. The now states that only Generator Operators that havethe following personnel are subject to the standard: "Dispatch personnel at a centrally located dispatch center who receive direction from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control. This does not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions without making any modifications."

Requirement R1

The SDT removed the acronym for the systematic approach to training (SAT) to avoid the implication that there is only one model of a systematic approach. There are many ways that an entity can implement a systematic approach to training.

The SDT added the phrase "if necessary" to Requirement R1.1.1 to clarify that changes to the list of Real-time reliability-related tasks are to be made if necessary. If no change is necessary, an entity is still expected to document that the Real-time reliability-related tasks have been reviewed each calendar year.

An additional comment regarding the phrase "shall design and develop training materials" (Requirement R1.2) said that the requirement seems to require the registered entity to internally perform this requirement and precludes the option to hire a third-party company to perform this task. The entity has the responsibility for the design and development of the training materials. Who actually does the work is irrelevant.

The SDT updated Measure M1 to reflect Requirement R1 based on comments saying the two did not align. Additionally, a commenter requested that the word "annual," located in Measure M1.4, be replaced with the phrase "each calendar year." This modification was made.

Requirement R2

The majority of the comments on Requirement R2 dealt with VRFs and VSLs. Responses to VRFs and VSLs can be found their respective sections in this document.

The SDT added the phrase "Real-time reliability-related tasks" to Requirements R2 and R2.1 to make it clear that it is Real-time reliability-related tasks that require verification of performance capability.

Requirement R3

Commenters stated that six months is insufficient when an entity does not have simulation technology, so after discussion, the SDT changed the time frame from six to 12 months.

Requirement R4

Many comments said that Operations Support Personnel do not perform the Real-time reliability-related tasks, so the SDT modified the requirement to clarify that the training for Operations Support Personnel is on the impact of their job functions on the Real-time reliability-related tasks—not on the Real-time reliability-related tasks performed by the System Operator. In response to other comments, the SDT added Requirement R4.1 to clarify that conducting a systematic approach to training includes completing an evaluation.

Additionally, one comment asked if Requirement R4 had to do with a systematic approach to training. The intent of Requirement R4 was for a systematic approach to training to be used, so the SDT added the phrase "systematic approach to training" to Requirement R4.

Requirement R5

Commenters requested clarity for the training requirements for Generator Operators. The SDT modified Requirement R5 to clarify that training for Generator Operators is to be <u>on the impact of their job functions</u> on the reliable operations of the BES. The SDT added Requirement R5.1 to clarify the requirement for completing an evaluation. In addition, although it may be beneficial for Generator Operators to request assistance from their RCs, BAs, and TOPs to understand their impact on Reliable Operation, the SDT removed "coordination with other applicable entities" from the standard as many commenters indicated that Generator Operators were capable of determining the training needs of their personnel. Removing the coordination requirement reduces the administrative compliance burden for the applicable entities.

Violation Risk Factors (VRFs)

There were comments regarding concerns with the VRFs. All VRFs have been reviewed and modified as necessary.

Violation Severity Levels (VSLs)

There were comments regarding concerns with the VSLs. All VSLs have been reviewed and modified as necessary.

Time Horizon

The SDT received several comments regarding the time horizon being long-term planning for the PER-005-2 standard. A systematic approach to training is a continuous activity; therefore, the horizon does not need to be changed to near-term planning. Additionally, the time horizon has gone through the process and has been FERC-approved.

Mapping Document

There was a comment that "R" within the PER-005-2 mapping document does not match the standard. The SDT appreciates the commenter's careful review and has updated the mapping document to match the requirement.

Compliance Input

The SDT received comments regarding a Reliability Standards Audit Worksheet (RSAW). The Compliance department will not provide the RSAW until six months before the standard is implemented. In the meantime, a document titled "Compliance Input" is provided, along with the posted standard, to explain the contents of the RSAW.

Process

Several commenters expressed concern that the simultaneous posting of the Standards Authorization Request (SAR) and the pro forma standard for initial comment and ballot was outside the scope of the Standards Process Manual (SPM). The SDT notes that, although this action was authorized by the NERC Standards Committee, NERC received an appeal of the SPM, which has been resolved. The SDT notes the process issue is outside the purview of the SDT.

Attachment A – SDT Members Contact Information

Table 7: Standard Drafting Team Member Contact Information			
	Participant	**Entity**	**Phone Number**
Chair	Patti Metro	NRECA	(571)334-8890
Vice Chair	Lauri Jones	PG&E	(415)973-0918
Member	Charles Abell	Ameren	(314)554-3817
Member	Sam Austin	TVA	(423)751-2935
Member	Jim Bowles	ERCOT	(512)248-3942
Member	Jeff Gooding	FP&L	(305)442-5804
Member	Mark Grear	Constellation	(410)470-4380
Member	Venona Greaff	OXY	(713)552-8575
Member	John Rymer	MISO	(317)249-5698
NERC Staff	Stanley Winbush	American Electric Power	(614)413-2489
NERC Staff	Jordan Mallory	NERC	(404)446-9733
NERC Staff	Darrel Richardson	NERC	(609)613-1848

Standard Development Timeline

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

Development Steps Completed

1. SAR and supporting package posted for comment (July 19, 2013 – September 3, 2013).
2. Draft standard posted for comments and ballot. (August 19, 2013 – September 3, 2013).
3. Draft standard posted for additional comments and ballot (September 25, 2013 – November 9, 2013).

Description of Current Draft

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Ballot	July 2013
Additional 45-day Formal Comment Period with Ballot	September 2013
Final ballot	November 2013
BOT adoption	December 2013

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved.

Glossary Term:

When the standard becomes effective, this defined term will be removed from the individual standard and added to the Glossary.

Rationale for System Operator: The definition of the existing NERC Glossary Term "System Operator" has been modified to remove Generator Operator (GOP). The term control center was not capitalized as the proposed NERC Glossary Term "Control Center" is not consistent with the applicability of this standard.

System Operator: An individual at a control center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System in Real-time.

Standard Only Terms:

The following terms are defined for use only within PER-005-2 and, upon approval, will not be moved to the NERC Glossary of Terms:

Rationale for System Personnel: The term "System Personnel" has been created to identify specific personnel with applicable entities, and allows the standard to be more concise by preventing repetition of the long description throughout the standard.

System Personnel: System Operators of a Reliability Coordinator, Transmission Operator or Balancing Authority, and the Transmission Owner personnel described in the Applicability Section of this standard.

Rationale for Operations Support Personnel: This definition uses language from the FERC Orders 693 and 742 to define those operations support personnel subject to the standard. The definition clarifies that functional entities (Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), and Transmission Owner (TO)) identify "Operations Support Personnel."

Operations Support Personnel: Individuals, as identified by the Reliability Coordinators, Balancing Authorities, Transmission Operators, or Transmission Owners, who perform outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms,[1] in direct support of Real-time, reliability-related tasks performed by System Operators.

[1] Nomograms are used in the WECC Region to describe element operating limits.

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

A. Introduction

1. **Title:** **Operations Personnel Training**
2. **Number:** PER-005-2
3. **Purpose:** To ensure that personnel performing or supporting Real-time, reliability-related tasks on the Bulk Electric System are trained using a systematic approach to training.
4. **Applicability:**

4.1. Functional Entities:

4.1.1 Reliability Coordinator

4.1.2 Balancing Authority

4.1.3 Transmission Operator

Rationale for TO: Extending the applicability to TOs is necessary to address the FERC directive that the ERO develop formal training requirements for local transmission control center operator personnel. In Order No. 742 at P 62, the Commission clarified its understanding that local control center personnel *"exercise control over a significant portion of the Bulk-Power System under the supervision of the personnel of the registered transmission operator. The supervision may take the form of directive specific step-by-step instructions and at other times may take the form of the implementation of predefined operating procedures. In all cases, the Commission continued, the local transmission control center personnel must understand what they are required to do in the performance of their duties to perform them effectively on a timely basis. Thus, omitting such local transmission control center personnel from the PER-005-1 training requirements creates a reliability gap."* See FERC Order 693 at P 1343 and 1347. The word facility was intentionally left lower-case as there may be a facility that is not included in the NERC glossary term "Facility".

4.1.4 Transmission Owner that has:

4.1.4.1 Personnel at a facility, excluding field switching personnel, who act independently to carry out tasks that require Real-time operation of the Bulk Electric System, including protecting assets, protecting personnel safety, adhering to regulatory requirements and establishing stable islands during system restoration.

Rationale for GOP: Extending the applicability to GOPs that have dispatch personnel at a centrally located dispatch center is necessary to address the FERC directive that the ERO develop specific requirements addressing the scope, content and duration appropriate for certain GOP personnel. The Commission explains in Order No. 693 at P 1359 that "*although a generator operator typically receives instructions from a balancing authority, it is essential that generator operator personnel have appropriate training to understand those instructions, particularly in an emergency situation in which instructions may be succinct and require immediate action.* Order No. 742 further clarified that the directive *applies to generator operator personnel at a centrally-located dispatch center who receive direction and then develop specific dispatch instructions for plant operators under their control. Plant operators located at the generator plant site are not required to be trained in PER-005-2."* Based on the FERC order, this applicability section clarifies which GOP personnel are not subject to the standard.

4.1.5 Generator Operator that has:

4.1.5.1 Dispatch personnel at a centrally located dispatch center who receive direction from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control. This personnel does not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions, without making any modifications.

5. Effective Date:

5.1. This standard shall become effective the first day of the first calendar quarter that is 24 months beyond the date that this standard is approved by an applicable governmental authority or is otherwise provided for in a jurisdiction where approval by an applicable authority is required for a standard to go into effect.

Where approval by an applicable governmental authority is not required, this standard shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall use a systematic approach to training to develop and implement a training program for its System Personnel[2] as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology.

1.1.1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall review, and update if necessary, its list of Real-time reliability-related tasks identified in part 1.1 each calendar year.

1.2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall design and develop training materials according to its

[2] As used in this standard, the term "System Personnel" is defined as System Operators of a Reliability Coordinator, Transmission Operator or Balancing Authority, and the Transmission Owner personnel described in the Applicability Section of this standard.

training program, based on the Real-time reliability-related task list created in part 1.1.

1.3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall deliver training to its System Personnel according to its program.

1.4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall implement the changes identified.

M1. Each Reliability Coordinator, Balancing Authority, Transmission Operator and Transmission owner shall have available for inspection evidence of using a systematic approach to training to establish and implement a training program, as specified in Requirement R1.

M1.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection its methodology and its company-specific Real-time reliability-related task list, with the date of the last review, as specified in Requirement R1 part 1.1.

M1.2 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training materials, as specified in Requirement R1 part 1.2.

M1.3 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection System Personnel training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R1 part 1.3.

M1.4 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed a training program evaluation each calendar year, as specified in Requirement R1 part 1.4.

Rationale for changes to R2: System Personnel, as opposed to System Operator, is used to capture specific personnel of a Transmission Owner in addition to the Reliability Coordinator, Balancing Authority, and Transmission Operator in one term.

R2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its System Personnel assigned to perform each of the Real-time reliability-related tasks identified under

Requirement R1 part 1.1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. Within six months of a modification or addition of BES company-specific Real-time reliability-related tasks, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its System Personnel to perform the new or modified Real-time reliability-related tasks identified in Requirement R1 part 1.1.

M2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence to show that it verified the capabilities of each of its System Personnel assigned to perform each of the Real-time reliability-related task identified under Requirement R1 part 1.1, as specified in Requirement R2. This evidence may be documents such as records showing capability to perform Real-time reliability-related tasks with the employee name and date; supervisor check sheets showing the employee name, date, and Real-time reliability-related task completed; or the results of learning assessments.

Rationale for changes to R3: The requirement mandates the use of specific training technologies. It does not require training on Interconnection Reliability Operating Limits (IROLs). The standard allows entities that gain operational authority or control over a facility a 12 month period to comply with the requirements of Requirement R3 to provide them sufficient time to obtain simulation technology.

The requirement to provide a minimum of 32 hours of Emergency Operations training has been removed since the appropriate time would be identified as part of the systematic approach to training process in Requirement R1 through the analysis phase of a systematic approach to training and outlined in a continuous education section of their training program. Any additional hours may be duplicative or repetitive for the entity in providing training to their personnel. Requirement R3.1 also covers the FERC directive for the creation of an implementation plan for simulation technology.

R3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs) or has established operating guides or protection systems to mitigate IROL violations shall provide its System Personnel with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES, according to its training program. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. When a Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not have an IROL gains operational authority or control over a Facility with an established IROL or establishes operating guides or protection systems to mitigate IROL violations, it shall comply with Requirement R3 within 12 months of gaining that authority or control, or establishing such operating guides or protection systems.

M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that System Personnel completed training that includes the use of simulation technology, as specified in Requirement R3.

M3.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that System Personnel completed training that included the use of simulation technology, as specified in Requirement R3, within 12 months of gaining that authority or control, or establishing such operating guides or protection systems.

Rationale for R4: The requirement requires the training of Operations Support Personnel on the impact of their job function to the Real-time reliability-related tasks identified under Requirement R1. It does not require training on the actual Real-time reliability-related tasks conducted by the System Operator.

This is a new requirement applicable to Operations Support Personnel as defined herein. In FERC Order No. 742, the Commission noted that NERC, in developing Reliability Standard PER-005-1, did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include operations planning and operation support staff who carry out outage planning and assessments and those who develop System Operating Limits (SOL), IROLs, or operating nomograms for Real-time operations. This requirement does not require that entities create a new, comprehensive systematic approach to training process for training Operations Support Personnel. Rather, the requirements contemplate that entities will look to the systematic approach to training process already developed for System Operators. The entity may use the list created from requirement R1 part 1.1 and select the reliability-related tasks that Operations Support Personnel support and therefore should be trained on.

R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall use a systematic approach to training to develop and implement training for its Operations Support Personnel[3] on the impact of their job function(s) to those Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

4.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall conduct an evaluation each calendar year of the training established in Requirement R4 to identify and implement changes to the training.

M4 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence that Operations Support Personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training with the employee name and date.

M4.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course

[3] As used in this standard, the term "Operations Support Personnel" is defined as Individuals, as identified by the Reliability Coordinators, Balancing Authorities, Transmission Operators, or Transmission Owners, who perform outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms, in direct support of Real-time, reliability-related tasks performed by System Operators.

evaluations, learning assessments, or internal audit results) that it performed a training program evaluation each calendar year, as specified in Requirement R4 part 4.1.

Rationale for R5: The requirement requires the training of certain GOP dispatch personnel on their job function(s) as it pertains to the reliable operations of the BES. This requirement mandates the use of a systematic approach to training which allows for each entity to tailor its training program to the needs of its organization. This requirement does not necessitate a systematic approach to training process that is as comprehensive as that used for RCs, BAs, and TOPs.

This is a new requirement applicable to certain GOPs as described in the applicability section. In FERC Order No. 742, the Commission noted that in developing proposed Reliability Standard PER-005-1, NERC did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include GOPs centrally-located at a generation dispatch center with a direct impact on the reliable operation of the BES. The Commission acknowledged that the training for GOPs need not be as extensive as the training for TOPs and BAs. FERC also stated that the systematic approach to training methodology is flexible enough to build on existing training programs by validating and supplementing the existing training content, where necessary, using systematic methods.

R5. Each Generator Operator shall use a systematic approach to develop and deliver training to its personnel described in Applicability Section 4.1.5 of this standard on the impact of their job function(s) as it pertains to reliable operations of the BES during normal and emergency operations. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1 Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training.

M5. Each Generator Operator shall have available for inspection evidence that its applicable personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training with the employee name and date.

M5.1 Each Generator Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed a training program evaluation each calendar year, as specified in Requirement R5 part 5.1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

Each Reliability Coordinator, Balancing Authority, Transmission Operator Transmission Owner, and Generator Operator shall keep data or evidence to show compliance for three years or since its last compliance audit, whichever time frame is the greatest, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator, Balancing Authority, Transmission Operator Transmission Owner, or Generator Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

1.3. Compliance Monitoring and Assessment Processes:

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

1.4. Additional Compliance Information

None

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	None	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner, failed to review its company-specific Real-time reliability-related task list to identify new or modified Real-time reliability-related tasks each calendar year. (1.1.1.) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner, failed to implement the identified changes to the Real-time reliability-related task. (1.1.1.) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner, failed to evaluate its training program each calendar year to identify needed changes to its training program(s). (1.4)	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner failed to design and develop training materials based on the Real-time reliability-related task lists. (1.2)	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner failed to prepare a Real-time reliability-related task list. (1.1 or 1.1.1.) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner failed to deliver training based on the Real-time reliability-related task lists. (1.3)

R2	**Long-term Planning**	**High**	**None**	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified at least 90% but less than 100% of its System Personnel's capabilities to perform all of their assigned Real-time reliability-related tasks. (R2)	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified at least 70% but less than 90% of its System Personnel's capabilities to perform all of their assigned Real-time reliability-related tasks. (R2) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner failed to verify its System Personnel's capabilities to perform each new or modified task within six months of making a modification to its Real-time reliability-related task list. (2.1)	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified less than 70% of its System Personnel's capabilities to perform all of their assigned Real-time reliability-related tasks. (R2)
R3	**Long-term Planning**	**Medium**	**None**	**None**	**None**	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner did not provide its System Personnel with any form of simulation technology training such as a simulator, virtual technology, or other technology that replicates the operational behavior of the Bulk Electric System. (R3) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, or

						Transmission Owner did not verify its System Personnel capabilities to perform each new or modified Real-time reliability-related task within twelve months of gaining operational authority or control over a Facility with an established IROL or establishes operating guides or protection systems to mitigate IROL violations. (R3.1)
R4	**Long-term Planning**	**Medium**	**None**	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner failed to evaluate its training established in Requirement R4 each calendar year. (4.1)	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner failed to use a systematic approach to training to establish training requirements as defined in Requirement R4.	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner failed to develop training for its Operations Support Personnel. (R4) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner failed to implement training for its Operations Support Personnel. (R4)
R5	**Long-term Planning**	**Medium**	**None**	The Generator Operator failed to evaluate its training established in Requirement R5 each calendar year. (5.1)	The Generator Operator failed to use a systematic approach to develop training as defined in Requirement R5.	The GOP failed to deliver the training as defined in Requirement R5.

Guidelines and Technical Basis

Requirement R1:

Any systematic approach to training will determine: 1) the skills and knowledge needed to perform Real-time reliability-related tasks; 2) what training is needed to achieve those skills and knowledge; 3) if the learner can perform the Real-time reliability-related task(s) acceptably in either a training or on-the-job environment; and 4) if the training is effective, and make adjustments as necessary.

Reference #1: Determining Task Performance Requirements

The purpose of this reference is to provide guidance for a performance standard that describes the desired outcome of a task. A standard for acceptable performance should be in either measurable or observable terms. Clear standards of performance are necessary for an individual to know when he or she has completed the task and to ensure agreement between employees and their supervisors on the objective of a task. Performance standards answer the following questions:

How timely must the task be performed?

Or

How accurately must the task be performed?

Or

With what quality must it be performed?

Or

What response from the customer must be accomplished?

When a performance standard is quantifiable, successful performance is more easily demonstrated. For example, in the following task statement, the criteria for successful performance is to return system loading to within normal operating limits, which is a number that can be easily verified.

> Given a System Operating Limit violation on the transmission system, implement the correct procedure for the circumstances to mitigate loading to within normal operating limits.

Even when the outcome of a task cannot be measured as a number, it may still be observable. The next example contains performance criteria that is qualitative in nature, that is, it can be verified as either correct or not, but does not involve a numerical result.

> Given a tag submitted for scheduling, ensure that all transmission rights are assigned to the tag per the company Tariff and in compliance with NERC and NAESB standards.

Reference #2: Systematic Approach to Training References:
The following list of hyperlinks identifies references for the NERC Standard PER-005 to assist with the application of a systematic approach to training:

(1) DOE-HDBK-1078-94, A Systematic Approach to Training

http://www.publicpower.org/files/PDFs/DOEHandbookTrainingProgramSystematicApproach.pdf

(2) DOE-HDBK-1074-95, January 1995, Alternative Systematic Approaches to Training, U.S. Department of Energy, Washington, D.C. 20585 FSC 6910

http://www.catagle.com/112-1/download_php-spec_DOE-HDBK-1074-95_003254_1.htm

(3) ADDIE – 1975, Florida State University

http://www.nwlink.com/~donclark/history_isd/addie.html

(4) DOE Standard - Table-Top Needs Analysis
DOE-HDBK-1103-96

http://www.cms.doe.gov/sites/prod/files/2013/06/f2/hdbk1103.pdf

Reference #3: Normal and Emergency Operations Topics
These topics are identified as meeting the topic criteria for normal and emergency operations training.

A. Recognition and Response to System Emergencies

1. Emergency drills and responses
2. Communication tools, protocols, coordination
3. Operating from backup control centers
4. System operations during unstudied situations
5. System Protection
6. Geomagnetic disturbances weather impacts on system operations
7. System Monitoring – voltage, equipment loading
8. Real-time contingency analysis
9. Offline system analysis tools
10. Monitoring backup plans
11. Sabotage, physical, and cyber threats and responses

B. Operating Policies and Standards Related to Emergency Operations

1. NERC standards that identify emergency operations practices (e.g. EOP Standards)
2. Regional reliability operating policies

3. Sub-regional policies and procedures
4. ISO/RTO policies and procedures

C. Power System Restoration Philosophy and Practices

1. Black start
2. Interconnection of islands – building islands
3. Load shedding – automatic (under-frequency and under-voltage) and manual
4. Load restoration philosophies

D. Interconnected Power System Operations

1. Operations coordination
2. Special protections systems
3. Special operating guides
4. Voltage and reactive control, including responding to eminent voltage collapse
5. Understanding the concepts of Interconnection Reliability Operating Limits versus System Operating Limits
6. DC tie operations and procedures during system emergencies
7. Thermal and dynamic limits
8. Unscheduled flow mitigation − congestion management
9. Local and regional line loading procedures
10. Radial load and generation operations and procedures
11. Tie line operations
12. E-tagging and Interchange Scheduling
13. Generating unit operating characteristics and limits, especially regarding reactive capabilities and the relationship between real and reactive output

E. Technologies and Tools

1. Forecasting tools
2. Power system study tools
3. Interchange Distribution Calculator (IDC)

F. Market Operations as They Relate to Emergency Operations

1. Market rules
2. Locational Marginal Pricing (LMP)
3. Transmission rights
4. OASIS

5. Tariffs
6. Fuel management
7. Real-time, hour-ahead and day-ahead tools

Definitions of Simulation and Simulators

Georgia Institute of Technology

Modeling & Simulation for Systems Engineering

http://www.pe.gatech.edu/conted/servlet/edu.gatech.conted.course.ViewCourseDetails?COURSE_ID=840

Simulation is the process of designing a model of a system and conducting experiments to understand the behavior of the system and/or evaluate various strategies for the operation of the system. The modeling & simulation life cycle refers to steps that take place during the course of a simulation study, which include problem formulation, conceptual model development, and output data analysis. Explore modeling & simulation, by using the M&S life cycle as an outline for exploring systems engineering concepts.

University of Central Florida – Institute for Simulation & Training

http://www.ist.ucf.edu/overview.htm

Just what is "simulation" anyway (or, Simulation 101)**?**
And what about "modeling"? (see below)
But what does IST do with simulations? (answer)

In its broadest sense, simulation is imitation. We've used it for thousands of years to train, explain and entertain. Thanks to the computer age, we're really getting good at using simulation for all three.

Simulations (and models, too) are abstractions of reality. Often they deliberately emphasize one part of reality at the expense of other parts. Sometimes this is necessary due to computer power limitations. Sometimes it's done to focus your attention on an important aspect of the simulation. Whereas models are mathematical, logical, or some other structured representation of reality, simulations are the specific application of models to arrive at some outcome (more about models, below).

Three types of simulations
Simulations generally come in three styles: live, virtual and constructive. A simulation also may be a combination of two or more styles.

Live simulations typically involve humans and/or equipment and activity in a setting where they would operate for real. Think *war games* with soldiers out in the field or manning command posts. Time is continuous, as in the real world. Another example of live simulation is testing a car battery using an electrical tester.

Virtual simulations typically involve humans and/or equipment in a computer-controlled setting. Time is in discrete steps, allowing users to concentrate on the important stuff, so to speak. A flight simulator falls into this category.

Constructive simulations typically do not involve humans or equipment as participants. Rather than by time, they are driven more by the proper sequencing of events. The anticipated path of a hurricane might be "constructed" through application of temperatures, pressures, wind currents and other weather factors.

A simulator is a device that may use any combination of sound, sight, motion and smell to make you feel that you are experiencing an actual situation. Some video games are good examples of low-end simulators. For example, you have probably seen or played race car arcade games.

The booths containing these games have a steering wheel, stick shift, gas and brake pedals and a display monitor. You use these devices to "drive" your "race car" along the track and through changing scenery displayed on the monitor. As you drive, you hear the engine rumble, the brakes squeal and the metal crunch if you crash. Some booths use movement to create sensations of acceleration, deceleration and turning. The sights, sounds and feel of the game booth combine to create, or simulate, the experience of driving a car in a race.

Most people first think of "flight simulators" or "driving simulators" when they hear the term "simulation." But simulation is much more.

Because they can recreate experiences, simulations hold great potential for training people for almost any situation. Education researchers have, in fact, determined that people, especially adults, learn better by experience than through reading or lectures. Simulated experiences can be just as valuable a training tool as the real thing.

Simulations are complex, computer-driven *re*-creations of the real thing. When used for training, they must recreate "reality" accurately, otherwise you may not learn the right way to do a task.

For example, if you try to practice how to fly in a flight simulator game that does not accurately *model* (see definition, below) the flight characteristics of an airplane, you will not learn how a real aircraft responds to your control.

Building simulator games is not easy, but creating simulations that *accurately* answer such questions as *"If I do this, what happens then?"* is even more demanding.

Over the years, government and industry, working independently with new technologies and hardware, developed a wide range of products and related applications to improve simulation science. This independence, however, often led to sporadic or redundant research efforts.

To benefit from each other's latest advances, researchers from across the country needed better communication and, ideally, a common source of supporting academic studies. The State of Florida recognized these needs and in 1982 established the Institute for Simulation and Training at the University of Central Florida.

What we do at IST

IST's mission is to advance the state of the art and science of modeling and simulation by

- performing basic and applied simulation research
- supporting education in modeling and simulation and related fields
- serving public and private simulation communities

We don't produce simulator hardware. That's a job for industry. But we've successfully developed working prototype hardware that provides new uses for simulations. We'll also help develop new applications for existing hardware, and scientifically test the results using human factors and other criteria for effective human-machine interface and learning. Too often overlooked, human factors testing is crucial to ultimate simulation effectiveness. We're fortunate to be closely connected, through joint faculty appointments and working relationships, with one of the top, if not the leading human factors department in the nation—right here at UCF.

We also explore the frontiers of simulation science, expanding our knowledge of ways to stimulate the human senses with advanced optical, audio and haptic technologies.

Still obfuscated? Go here...

Modeling: a model definition

A computer model, as used in modeling and simulation science, is a mathematical representation of something—a person, a building, a vehicle, a tree—any object. A model also can be a representation of a process—a weather pattern, traffic flow, air flowing over a wing.

Models are created from a mass of data, equations and computations that mimic the actions of things represented. Models usually include a graphical display that translates all this number crunching into an animation that you can see on a computer screen or by means of some other visual device.

Models can be simple images of things—the outer shell, so to speak—or they can be complex, carrying all the characteristics of the object or process they represent. A complex model will simulate the actions and reactions of the real thing. To make these models behave the way they would in real life, accurate, real-time simulations require fast computers with lots of number crunching power.

Standard Development Timeline

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

Development Steps Completed

1. SAR and supporting package posted for comment (~~Dates of posting TBD~~July 19, 2013 – September 3, 2013).
2. Draft standard posted for comments and ballot. (August 19, 2013 – September 3, 2013).
3. Draft standard posted for additional comments and ballot (September 25, 2013 – November 9, 2013).

Description of Current Draft

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with ~~Parallel Initial~~ Ballot	July 2013
~~15~~Additional 45-day Formal Comment Period with ~~Parallel~~ Ballot	September 2013
~~Recirculation~~Final ballot	~~October~~November 2013
BOT adoption	~~November~~December 2013

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved.

Glossary Term:

When the standard becomes effective, ~~these~~this defined ~~terms~~term will be removed from the individual standard and added to the Glossary.

Rationale for System Operator: The definition of the existing NERC Glossary Term "System Operator" has been modified to remove Generator Operator (GOP). The term control center was not capitalized as the proposed NERC Glossary Term "Control Center" is not consistent with the applicability of this standard.

System Operator: An individual at a ~~Control Center that~~control center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System in Real-time.

Standard Only Terms:

The following terms are defined for use only within PER-005-2~~,~~ and ~~should remain with the standard~~, upon approval ~~rather than being~~, will not be moved to the NERC Glossary of Terms:

Rationale for System Personnel: The term "System Personnel" has been created to identify specific personnel with applicable entities, and allows the standard to be more concise by preventing repetition of the long description throughout the standard.

System Personnel: System Operators of a Reliability Coordinator, Transmission Operator or Balancing Authority, and the Transmission Owner personnel described in the Applicability Section of this standard.

Rationale for Operations Support Personnel: This definition uses language from the FERC Orders 693 and 742 to define those operations support personnel subject to the standard. The definition clarifies that functional entities (Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), and Transmission Owner (TO)) identify "Operations Support Personnel."

Operations Support Personnel: Individuals, as identified by the Reliability Coordinators, Balancing Authorities, Transmission Operators, or Transmission Owners, who ~~carry out~~perform outage coordination ~~and~~or assessments, or who determine SOLs, IROLs, or operating nomograms~~[1] for~~,[2] in direct support of Real-time ~~operations~~, reliability-related tasks performed by System Operators.

~~[1] Nomograms are used in the WECC region to describe element operating limits.~~

[2] Nomograms are used in the WECC Region to describe element operating limits.

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

A. Introduction

1. **Title:** **Operations Personnel Training**

2. **Number:** PER-005-2

3. **Purpose:** To ensure that personnel performing or supporting Real-time, reliability-related tasks on the Bulk Electric System are ~~competent to perform those tasks.~~trained using a systematic approach to training.

4. **Applicability:**

4.1. Functional Entities:

4.1.1 Reliability Coordinator

4.1.2 Balancing Authority

4.1.3 Transmission Operator

Rationale for ~~Transmission Owner~~TO: Extending the applicability to ~~Transmission Owners~~TOs is necessary to address the FERC directive that the ERO develop formal training requirements for local transmission control center operator personnel. In Order No. 742 at P 62, the Commission clarified its understanding that local control center personnel *"exercise control over a significant portion of the Bulk-Power System under the supervision of the personnel of the registered transmission operator. The supervision may take the form of directive specific step-by-step instructions and at other times may take the form of the implementation of predefined operating procedures. In all cases, the Commission continued, the local transmission control center personnel must understand what they are required to do in the performance of their duties to perform them effectively on a timely basis. Thus, omitting such local transmission control center personnel from the PER-005-1 training requirements creates a reliability gap~~.~~."* See FERC Order 693 at P 1343 and 1347. The word facility was intentionally left lower-case as there may be a facility that is not included in the NERC glossary term "Facility".

4.1.4 Transmission Owner that has:

~~**4.1.4.1** Personnel in a transmission control center who operate a portion of the Bulk Electric System at the direction of its Transmission Operator.~~

~~Rationale for Generator Operator: Extending the applicability to Generator Operators at a centrally located dispatch center is necessary to address the FERC directive that the ERO develop specific requirements addressing the scope, content and duration appropriate for generator operator personnel. The Commission explains in Order No. 693 at P 1359 that *although a generator operator typically receives instructions from a balancing authority, it is essential that generator operator personnel have appropriate training to understand those instructions, particularly in an emergency situation in which instructions may be succinct and require immediate action.* Order No. 742 further clarified that the directive *applies to generator operator personnel at a centrally located dispatch center who receive direction and then develop specific dispatch instructions for plant operators under their control. Plant operators located at the generator plant site are not required to be trained in PER-005-2.*~~

4.1.4.1 Personnel at a facility, excluding field switching personnel, who act independently to carry out tasks that require Real-time operation of the Bulk Electric System, including protecting assets, protecting personnel safety, adhering to regulatory requirements and establishing stable islands during system restoration.

Rationale for GOP: Extending the applicability to GOPs that have dispatch personnel at a centrally located dispatch center is necessary to address the FERC directive that the ERO develop specific requirements addressing the scope, content and duration appropriate for certain GOP personnel. The Commission explains in Order No. 693 at P 1359 that "*although a generator operator typically receives instructions from a balancing authority, it is essential that generator operator personnel have appropriate training to understand those instructions, particularly in an emergency situation in which instructions may be succinct and require immediate action.* Order No. 742 further clarified that the directive *applies to generator operator personnel at a centrally-located dispatch center who receive direction and then develop specific dispatch instructions for plant operators under their control. Plant operators located at the generator plant site are not required to be trained in PER-005-2.*" Based on the FERC order, this applicability section clarifies which GOP personnel are not subject to the standard.

4.1.5 Generator Operator that has:

~~**4.1.5.1**~~ ~~Personnel~~Dispatch personnel at a centrally located dispatch center who receive direction from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control.

~~**4.1.5.2**~~**4.1.5.1** ~~Personnel~~ This personnel does not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions, without making any modifications~~, are excluded~~.

5. Effective Date:

5.1. ~~Requirement R1, Requirement R2, Requirement R3 part 3.1, Requirement R4 and Requirement R5~~This standard shall become effective the first day of the first calendar quarter that is 24 months beyond the date that this standard is approved by ~~applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, Requirement R1, Requirement R2, Requirement R3 part 3.1, Requirement R4 and Requirement R5 become effective the first day of the first calendar quarter that is 24 months beyond the date this standard is approved by the NERC Board of Trustees', or as otherwise made pursuant to the laws applicable to such ERO governmental authorities.~~an applicable governmental authority or is otherwise provided for in a jurisdiction where approval by an applicable authority is required for a standard to go into effect.

~~Requirement R3, with the exclusion of part 3.1,~~ Where approval by an

~~Rationale for changes to requirements in the PER Standard related to Transmission Owners and Calendar Year:~~

- ~~Transmission Owners personnel at local transmission control centers have been added to the PER standard and are subject to all the Requirements of PER-005-2. The reason for adding Transmission Owners is to address Order No. 693 and Order No. 742 FERC directives to include local transmission control center operator personnel.~~
- ~~To address industry input, the term *annual* has been changed to *each calendar year*.~~
- ~~PER-005-2 provides a requirement for training, but does not create a requirement for certification.~~

applicable governmental authority is not required, this standard shall become effective on the first day of the first calendar quarter ~~beyond~~that is 24 months after the date ~~that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, Requirement R3 becomes effective the first day of the first calendar quarter beyond the date this~~ the standard is ~~approved~~adopted by the NERC Board of ~~Trustees',~~Trustees or as otherwise ~~made pursuant to the laws applicable to such ERO governmental authorities.~~provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall use a systematic approach to training ~~(SAT)~~ to develop and implement a training program for its System Personnel[3] as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology.

1.1.1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall review, and update if necessary, its list of Real-time reliability-related tasks identified in part 1.1 each calendar year.

1.2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall design and develop training materials according to its training program, based on the Real-time reliability-related task list created in part ~~1.1 and part 1.~~1.1.

1.3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall deliver ~~the~~ training ~~established in part 1.2~~ to its System Personnel according to its program.

1.4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall implement the changes identified.

M1. Each Reliability Coordinator, Balancing Authority, Transmission Operator~~,~~ and Transmission ~~Owner~~owner shall ~~review~~have available for inspection evidence of using

[3] As used in this standard, the term "System Personnel" is defined as System Operators of a Reliability Coordinator, Transmission Operator or Balancing Authority, and the Transmission Owner personnel described in the Applicability Section of this standard.

a systematic approach to training to establish and ~~update its list of tasks identified~~implement a training program, as specified in ~~part 1.1 each calendar year~~Requirement R1.

M1.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection its methodology and its company-specific Real-time reliability-related task list, with the date of the last ~~update~~review, as specified in Requirement R1 ~~parts 1.1 and 1.~~part 1.1.

M1.2 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training materials, as specified in Requirement R1 part 1.2.

M1.3 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection System Personnel training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R1 part 1.3.

M1.4 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed ~~an annual~~a training program evaluation each calendar year, as specified in Requirement R1 part 1.4.

Rationale for changes to R2: ~~A change from~~ System ~~Operator~~Personnel, as opposed to System ~~Personnel~~Operator, is used to capture specific personnel of a Transmission Owner in addition to the Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ and Transmission ~~Owner~~Operator in one term ~~versus spelling each term out a second time in~~

R2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its System Personnel ~~identified~~assigned to perform each ~~assigned task in~~of the Real-time reliability-related tasks identified under Requirement R1 ~~parts~~part 1.1 ~~and 1.1.1~~. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning ~~-~~]*

2.1. Within six months of a modification or addition of ~~Bulk Electric System~~BES company-specific Real-time reliability-related tasks, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its System Personnel to perform the new or modified Real-time reliability-related tasks identified in Requirement R1 part ~~1.~~1.1.

M2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence to show that it verified the capabilities of each of ~~the~~its System Personnel ~~identified~~assigned to perform each ~~assigned~~ of the Real-time reliability-related task ~~in~~identified under

~~Rationale for changes to R3: The 32 hours of Emergency Operations training has been removed since this training should be covered as part of the systematic approach to training process in Requirement R1. The 32 hours is inherent to the systematic approach to training process and a legacy to the 2003 blackout. The removal of 32 hours is also considered to be a paragraph 81 concept due to it being redundant to the systematic approach to training process. Requirement R3.1 also covers the FERC directive for the creation of an implementation plan for simulation technology.~~

Requirement R1 ~~parts~~part 1.1~~ and 1.1.1~~, as specified in Requirement R2. This evidence ~~can~~may be documents such as ~~training~~ records showing ~~successful completion of~~capability to perform Real-time reliability-related tasks with the employee name and date; supervisor check sheets showing the employee name, date, and Real-time reliability-related task completed; or the results of learning assessments.

Rationale for changes to R3: The requirement mandates the use of specific training technologies. It does not require training on Interconnection Reliability Operating Limits (IROLs). The standard allows entities that gain operational authority or control over a facility a 12 month period to comply with the requirements of Requirement R3 to provide them sufficient time to obtain simulation technology.

The requirement to provide a minimum of 32 hours of Emergency Operations training has been removed since the appropriate time would be identified as part of the systematic approach to training process in Requirement R1 through the analysis phase of a systematic approach to training and outlined in a continuous education section of their training program. Any additional hours may be duplicative or repetitive for the entity in providing training to their personnel. Requirement R3.1 also covers the FERC directive for the creation of an implementation plan for simulation technology.

R3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that has operational authority or control over Facilities with established ~~IROLs~~Interconnection Reliability Operating Limits (IROLs) or has established operating guides or protection systems to mitigate IROL violations shall provide its System Personnel with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the ~~Bulk Electric System.~~BES, according to its training program. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. ~~Each~~When a Reliability Coordinator, Balancing Authority, Transmission Operator, ~~and~~or Transmission Owner that did not have an IROL gains operational authority or control over a Facility with an established IROL or establishes operating guides or protection systems to mitigate IROL violations, it shall comply with Requirement R3 within ~~6~~12 months of gaining that authority~~,~~ or control, or establishing such operating guides or protection systems.

M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that System Personnel completed training that includes the use of simulation technology, as specified in Requirement R3.

M3.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that System Personnel completed training that included the

Rationale for R4: The requirement requires the training of Operations Support Personnel on the impact of their job function to the Real-time reliability-related tasks identified under Requirement R1. It does not require training on the actual Real-time reliability-related tasks conducted by the System Operator.

This is a new requirement applicable to Operations Support Personnel as defined herein. In FERC Order No. 742, the Commission noted that NERC, in developing Reliability Standard PER-005-1, did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include operations planning and operation support staff who carry out outage planning and assessments and those who develop System Operating Limits (SOL), IROLs, or operating nomograms for Real-time operations. This requirement does not require that entities create a new, comprehensive systematic approach to training process for training Operations Support Personnel. Rather, the requirements contemplate that entities will look to the systematic approach to training process already developed for System Operators. The entity may use the list created from requirement R1 part 1.1 and select the reliability-related tasks that Operations Support Personnel support and therefore should be trained on.

use of simulation technology, as specified in Requirement R3, within ~~6~~12 months of gaining that authority~~,~~ or control, or establishing such operating guides or protection systems.

~~Rationale for R4: This is a new requirement applicable to Support Personnel as defined above in the definition section. In FERC Order No. 742, the Commission noted that NERC, in developing Reliability Standard PER-005-1, did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include operations planning and operation support staff who carry out outage planning and assessments and those who develop System Operating Limits (SOL), Interconnection Reliability Operating Limits (IROL), or operating nomograms for Real-time operations. This requirement does not require that entities create a new, comprehensive systematic approach to training (SAT) process for training support personnel. Rather, the requirements contemplate that entities will look to the SAT process already developed for System Operators. The entity can use the list created from requirement R1 and select the reliability-related tasks that support personnel conduct and therefore should be trained on.~~

R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall ~~establish~~use a systematic approach to training to develop and implement training for its Operations Support Personnel~~specific~~[4] on the impact of their job function(s) to those Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1~~and part 1.1.1 that relate to the Support Personnel's job function.~~. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]

4.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall conduct an evaluation each calendar year of the training established in Requirement R4 to identify and implement changes to the training.

M4 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection ~~training materials and training records that provide~~ evidence that Operations Support Personnel completed training~~.~~ in accordance with its systematic approach. This evidence ~~can~~may be documents such as training records showing successful completion of training with the employee name and date.

R5. ~~Each Generator Operator shall use a systematic approach to training to establish and implement training for its personnel described in applicability section 4.1.5. The training shall also include topics identified as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*~~

~~Rationale for R5: This is a new requirement applicable to Generator Operators described in the applicability section. In FERC Order No. 742, the Commission noted that in developing proposed Reliability Standard PER-005-1, NERC did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include generator operators centrally-located at a generation control center with a direct impact on the reliable operation of the Bulk-Power System. The Commission acknowledged that the training for GOPs need not be as extensive as the training for TOPs and BAs. FERC also stated that the systematic approach to training methodology is flexible enough to build on existing training programs by validating and supplementing the existing training content, where necessary, using systematic methods. It is important that the relevant generator operator personnel receive the necessary training. This requirement does not necessitate an SAT process that is as comprehensive as that used for TOPs, RCs and BAs. R5 also acknowledges that in order to provide the necessary training applicable to GOPs, GOPS will need to coordinate with their RC, BA, TOP and TO to understand the training topics that each GOP should be trained on.~~

[4] As used in this standard, the term "Operations Support Personnel" is defined as Indiv Balancing Authorities, Transmission Operators, or Transmission Owners, who perform SOLs, IROLs, or operating nomograms, in direct support of Real-time, reliability-related

~~**5.1.** Each Generator Operator shall coordinate with its Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner to identify training topics that address the impact of the decisions and actions of a Generator Operator's personnel as it pertains to the reliability of the Bulk Electric System during normal and emergency operations.~~

~~**5.1.1.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall provide input as requested by the Generator Operator.~~

~~**M4.** Each Generator Operator shall have available for inspection training materials and training records that provide evidence that its applicable personnel completed training. This evidence can be documents such as training records showing successful completion of training with the employee name and date.~~

~~**M4.1** Each Generator Operator shall have available for inspection evidence, such as an email or attestation that it coordinated with the Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner in establishing the training requirements.~~

M4.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence~~, such as an email or attestation, that it provided input to the Generator Operator.~~ (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed a training program evaluation each calendar year, as specified in Requirement R4 part 4.1.

Rationale for R5: The requirement requires the training of certain GOP dispatch personnel on their job function(s) as it pertains to the reliable operations of the BES. This requirement mandates the use of a systematic approach to training which allows for each entity to tailor its training program to the needs of its organization. This requirement does not necessitate a systematic approach to training process that is as comprehensive as that used for RCs, BAs, and TOPs.

This is a new requirement applicable to certain GOPs as described in the applicability section. In FERC Order No. 742, the Commission noted that in developing proposed Reliability Standard PER-005-1, NERC did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include GOPs centrally-located at a generation dispatch center with a direct impact on the reliable operation of the BES. The Commission acknowledged that the training for GOPs need not be as extensive as the training for TOPs and BAs. FERC also stated that the systematic approach to training methodology is flexible enough to build on existing training programs by validating and supplementing the existing training content, where necessary, using systematic methods.

R6. Each Generator Operator shall use a systematic approach to develop and deliver training to its personnel described in Applicability Section 4.1.5 of this standard on the impact of their job function(s) as it pertains to reliable operations of the BES during normal and emergency operations. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1 Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training.

M5. Each Generator Operator shall have available for inspection evidence that its applicable personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training with the employee name and date.

M5.1 Each Generator Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed a training program evaluation each calendar year, as specified in Requirement R5 part 5.1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

Each Reliability Coordinator, Balancing Authority, Transmission Operator Transmission Owner, and Generator Operator shall keep data or evidence to show compliance for three years or since its last compliance audit, whichever time frame is the greatest, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator, Balancing Authority, Transmission Operator Transmission Owner, or Generator Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

1.3. Compliance Monitoring and Assessment Processes:

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

1.4. Additional Compliance Information

None

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	None	The Reliability Coordinator, Balancing Authority, Transmission Operator, ~~and~~or Transmission Owner, failed to ~~provide evidence that it updated~~review its company-specific Real-time reliability-related task list to identify new or modified Real-time reliability-related tasks each calendar year. (1.1.~~2)~~1.) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, ~~and~~or Transmission Owner, failed to ~~provide evidence of evaluating~~implement the identified changes to the Real-time reliability-related task. (1.1.1.) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner, failed to evaluate its training program each calendar year to identify needed changes to its training program(s). (1.4)	The Reliability Coordinator, Balancing Authority, Transmission Operator, ~~and~~or Transmission Owner failed to design and develop training materials based on the Real-time reliability-related task lists. (1.2)	The Reliability Coordinator, Balancing Authority, Transmission Operator, ~~and~~or Transmission Owner failed to prepare a Real-time reliability-related task list. (1.1 or 1.1.1.) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, ~~and~~or Transmission Owner failed to deliver training based on the Real-time reliability-related task lists. (1.3)

R2	**Long-term Planning**	**High**	**None**	The Reliability Coordinator, Balancing Authority, Transmission Operator, ~~and~~or Transmission Owner verified at least 90% but less than 100% of its System ~~Personnel~~Personnel's capabilities to perform ~~each~~all of their assigned ~~task from its~~Real-time reliability-related tasks ~~list~~. (R2)	The Reliability Coordinator, Balancing Authority, Transmission Operator, ~~and~~or Transmission Owner verified at least 70% but less than 90% of its System ~~Personnel~~Personnel's capabilities to perform ~~each~~all of their assigned ~~task from its task lists~~Real-time reliability-related tasks. (R2) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, ~~and~~or Transmission Owner failed to verify its System ~~Personnel~~Personnel's capabilities to perform each new or modified task within six months of making a modification to its Real-time reliability-related task list ~~of the tasks in Real-time.~~. (2.1)	The Reliability Coordinator, Balancing Authority, Transmission Operator, ~~and~~or Transmission Owner verified less than 70% of its System ~~Personnel~~Personnel's capabilities to perform ~~each~~all of their assigned ~~task from its task lists~~Real-time reliability-related tasks. (R2)
R3	**Long-term Planning**	**Medium**	**None**	**None**	**None**	The Reliability Coordinator, Balancing Authority, Transmission Operator, ~~and~~or Transmission Owner did not provide its System Personnel with any form of simulation technology training ~~(R3)~~such as a simulator, virtual technology, or other technology that replicates the operational behavior of the Bulk Electric System. (R3)

						OR The Reliability Coordinator, Balancing Authority, Transmission Operator, ~~and~~or Transmission Owner did not verify its System Personnel capabilities to perform each new or modified ~~task within six months of making a modification to its task list.~~Real-time reliability-related task within twelve months of gaining operational authority or control over a Facility with an established IROL or establishes operating guides or protection systems to mitigate IROL violations. (R3.1)
R4	**Long-term Planning**	**Medium**	**None**	~~**None**~~The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner failed to evaluate its training established in Requirement R4 each calendar year. (4.1)	~~**None**~~The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner failed to use a systematic approach to training to establish training requirements as defined in Requirement R4.	The Reliability Coordinator, Balancing Authority, Transmission Operator, ~~and~~or Transmission Owner failed to ~~establish~~develop training for its Operations Support Personnel. (R4) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, ~~and~~or Transmission Owner failed to implement training for its Operations Support Personnel. (R4)

R5	**Long-term Planning**	**Medium**	**None**	~~**None**~~The Generator Operator failed to evaluate its training established in Requirement R5 each calendar year. (5.1)	The Generator Operator failed to use a systematic approach to develop training ~~to establish training requirements~~ as defined in Requirement R5.	~~The Generator Operator failed to coordinate with its Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner to identify training topics as defined in Requirement R5 part 5.1~~ ~~OR~~ ~~The Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner failed to provide the requested input as defined in Requirement R5 part 5.1.1.~~ ~~OR~~ The GOP failed to ~~implement~~deliver the training as defined in Requirement R5.

Guidelines and Technical Basis

Requirement R1:

Any systematic approach to training will~~: 1)~~ determine: 1) the skills and knowledge needed to perform Real-time reliability-related tasks~~,~~; 2) ~~determine~~ what training is needed to achieve those skills and knowledge~~,~~; 3) ~~determine how to assess the acquisition of those skills and knowledge by the learner, 4) should determine~~ if the learner can perform the Real-time reliability-related task(s) acceptably in either a training or on-the-job environment~~, 5) determine~~; and 4) if the training is effective, and make adjustments as necessary.

Reference #1: Determining Task Performance Requirements

The purpose of this reference is to provide guidance ~~in writing~~for a performance standard that describes the desired outcome of a task. A standard for acceptable performance should be in either measurable or observable terms. Clear standards of performance are necessary for an individual to know when he or she has completed the task and to ensure agreement between employees and their supervisors on the objective of a task. Performance standards answer the following questions:

How timely must the task be performed?

Or

How accurately must the task be performed?

Or

With what quality must it be performed?

Or

What response from the customer must be accomplished?

When a performance standard is quantifiable, successful performance is more easily demonstrated. For example, in the following task statement, the criteria for successful performance is to return system loading to within normal operating limits, which is a number that can be easily verified.

> Given a System Operating Limit violation on the transmission system, implement the correct procedure for the circumstances to mitigate loading to within normal operating limits.

Even when the outcome of a task cannot be measured as a number, it may still be observable. The next example contains performance criteria that is qualitative in nature, that is, it can be verified as either correct or not, but does not involve a numerical result.

> Given a tag submitted for scheduling, ensure that all transmission rights are assigned to the tag per the company Tariff and in compliance with NERC and NAESB standards.

Reference #2: Systematic Approach to Training References:
The following list of hyperlinks identifies references for the NERC Standard PER-005 to assist with the application of a systematic approach to training:

(1) DOE-HDBK-1078-94, A Systematic Approach to Training

http://www.publicpower.org/files/PDFs/DOEHandbookTrainingProgramSystematicApproach.pdf

(2) DOE-HDBK-1074-95, January 1995, Alternative Systematic Approaches to Training, U.S. Department of Energy, Washington, D.C. 20585 FSC 6910

http://www.catagle.com/112-1/download_php-spec_DOE-HDBK-1074-95_003254_1.htm

(3) ADDIE – 1975, Florida State University
http://www.nwlink.com/~donclark/history_isd/addie.html

(4) DOE Standard - Table-Top Needs Analysis
DOE-HDBK-1103-96

http://www.cms.doe.gov/sites/prod/files/2013/06/f2/hdbk1103.pdf

~~**Requirement R2:**~~

~~**Requirement R3:**~~

~~**Requirement R4:**~~

~~**Requirement R5:**~~

Reference #3: Normal and Emergency Operations Topics
These topics are identified as meeting the topic criteria for normal and emergency operations training.

A. Recognition and Response to System Emergencies

1. Emergency drills and responses
2. Communication tools, protocols, coordination
3. Operating from backup control centers
4. System operations during unstudied situations
5. System Protection
6. Geomagnetic disturbances weather impacts on system operations
7. System Monitoring – voltage, equipment loading

8. Real-time contingency analysis
9. Offline system analysis tools
10. Monitoring backup plans
11. Sabotage, physical, and cyber threats and responses

B. Operating Policies and Standards Related to Emergency Operations

1. NERC standards that identify emergency operations practices (e.g. EOP Standards)
2. Regional reliability operating policies
3. Sub-regional policies and procedures
4. ISO/RTO policies and procedures

C. Power System Restoration Philosophy and Practices

1. Black start
2. Interconnection of islands – building islands
3. Load shedding – automatic (under-frequency and under-voltage) and manual
4. Load restoration philosophies

D. Interconnected Power System Operations

1. Operations coordination
2. Special protections systems
3. Special operating guides
4. Voltage and reactive control, including responding to eminent voltage collapse
5. Understanding the concepts of Interconnection Reliability Operating Limits versus System Operating Limits
6. DC tie operations and procedures during system emergencies
7. Thermal and dynamic limits
8. Unscheduled flow mitigation – congestion management
9. Local and regional line loading procedures
10. Radial load and generation operations and procedures
11. Tie line operations
12. E-tagging and Interchange Scheduling
13. Generating unit operating characteristics and limits, especially regarding reactive capabilities and the relationship between real and reactive output

E. Technologies and Tools

1. Forecasting tools

2. Power system study tools
3. Interchange Distribution Calculator (IDC)

F. Market Operations as They Relate to Emergency Operations

1. Market rules
2. Locational Marginal Pricing (LMP)
3. Transmission rights
4. OASIS
5. Tariffs
6. Fuel management
7. Real-time, hour-ahead and day-ahead tools

Definitions of Simulation and Simulators

Georgia Institute of Technology

Modeling & Simulation for Systems Engineering

http://www.pe.gatech.edu/conted/servlet/edu.gatech.conted.course.ViewCourseDetails?COURSE_ID=840

Simulation is the process of designing a model of a system and conducting experiments to understand the behavior of the system and/or evaluate various strategies for the operation of the system. The modeling & simulation life cycle refers to steps that take place during the course of a simulation study, which include problem formulation, conceptual model development, and output data analysis. Explore modeling & simulation, by using the M&S life cycle as an outline for exploring systems engineering concepts.

University of Central Florida – Institute for Simulation & Training

http://www.ist.ucf.edu/overview.htm

Just what is "simulation" anyway (or, Simulation 101)**?**
And what about "modeling"? (see below)
But what does IST do with simulations? (answer)

In its broadest sense, simulation is imitation. We've used it for thousands of years to train, explain and entertain. Thanks to the computer age, we're really getting good at using simulation for all three.

Simulations (and models, too) are abstractions of reality. Often they deliberately emphasize one part of reality at the expense of other parts. Sometimes this is necessary due to computer power limitations. Sometimes it's done to focus your attention on an important aspect of the simulation. Whereas models are mathematical, logical, or some other structured representation of reality, simulations are the specific application of models to arrive at some outcome (more about models, below).

Three types of simulations
Simulations generally come in three styles: live, virtual and constructive. A

simulation also may be a combination of two or more styles.

Live simulations typically involve humans and/or equipment and activity in a setting where they would operate for real. Think *war games* with soldiers out in the field or manning command posts. Time is continuous, as in the real world. Another example of live simulation is testing a car battery using an electrical tester.

Virtual simulations typically involve humans and/or equipment in a computer-controlled setting. Time is in discrete steps, allowing users to concentrate on the important stuff, so to speak. A flight simulator falls into this category.

Constructive simulations typically do not involve humans or equipment as participants. Rather than by time, they are driven more by the proper sequencing of events. The anticipated path of a hurricane might be "constructed" through application of temperatures, pressures, wind currents and other weather factors.

A simulator is a device that may use any combination of sound, sight, motion and smell to make you feel that you are experiencing an actual situation. Some video games are good examples of low-end simulators. For example, you have probably seen or played race car arcade games.

The booths containing these games have a steering wheel, stick shift, gas and brake pedals and a display monitor. You use these devices to "drive" your "race car" along the track and through changing scenery displayed on the monitor. As you drive, you hear the engine rumble, the brakes squeal and the metal crunch if you crash. Some booths use movement to create sensations of acceleration, deceleration and turning. The sights, sounds and feel of the game booth combine to create, or simulate, the experience of driving a car in a race.

Most people first think of "flight simulators" or "driving simulators" when they hear the term "simulation." But simulation is much more.

Because they can recreate experiences, simulations hold great potential for training people for almost any situation. Education researchers have, in fact, determined that people, especially adults, learn better by experience than through reading or lectures. Simulated experiences can be just as valuable a training tool as the real thing.

Simulations are complex, computer-driven *re*-creations of the real thing. When used for training, they must recreate "reality" accurately, otherwise you may not learn the right way to do a task.

For example, if you try to practice how to fly in a flight simulator game that does not accurately *model* (see definition, below) the flight characteristics of an airplane, you will not learn how a real aircraft responds to your control.

Building simulator games is not easy, but creating simulations that *accurately* answer such questions as *"If I do this, what happens then?"* is even more demanding.

Over the years, government and industry, working independently with new technologies and hardware, developed a wide range of products and related applications to improve simulation science. This independence, however, often led to sporadic or redundant research efforts.

To benefit from each other's latest advances, researchers from across the country needed better communication and, ideally, a common source of supporting academic studies. The State of Florida recognized these needs and in 1982 established the Institute for Simulation and Training at the University of Central Florida.

What we do at IST

IST's mission is to advance the state of the art and science of modeling and simulation by

- performing basic and applied simulation research
- supporting education in modeling and simulation and related fields
- serving public and private simulation communities

We don't produce simulator hardware. That's a job for industry. But we've successfully developed working prototype hardware that provides new uses for simulations. We'll also help develop new applications for existing hardware, and scientifically test the results using human factors and other criteria for effective human-machine interface and learning. Too often overlooked, human factors testing is crucial to ultimate simulation effectiveness. We're fortunate to be closely connected, through joint faculty appointments and working relationships, with one of the top, if not the leading human factors department in the nation—right here at UCF.

We also explore the frontiers of simulation science, expanding our knowledge of ways to stimulate the human senses with advanced optical, audio and haptic technologies.

Still obfuscated? Go here...

Modeling: a model definition

A computer model, as used in modeling and simulation science, is a mathematical representation of something—a person, a building, a vehicle, a tree—any object. A model also can be a representation of a process—a weather pattern, traffic flow, air flowing over a wing.

Models are created from a mass of data, equations and computations that mimic the actions of things represented. Models usually include a graphical display that translates all this number crunching into an animation that you can see on a computer screen or by means of some other visual device.

Models can be simple images of things—the outer shell, so to speak—or they can be complex, carrying all the characteristics of the object or process they represent. A complex model will simulate the actions and reactions of the real thing. To make these models behave the way they would in real life, accurate, real-time simulations require fast computers with lots of number crunching power.

Implementation Plan

Project 2010-01 Operations Personnel Training

Implementation Plan for PER-005-2 – Operations Personnel Training

Approvals Required
PER-005-2 – Operations Personnel Training

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

Revisions to Glossary Terms
When the standard becomes effective, this defined term will be removed from the individual standard and added to the Glossary.

System Operator: An individual at a control center of a Balancing Authority, Transmission Operator, or Reliability Coordinator who operates or directs the operation of the Bulk Electric System in Real-time.

Other Definitions Used within the Standard
The following terms are defined for use only within PER-005-2 and, upon approval of the standard, will not be moved to the NERC Glossary of Terms:

System Personnel: System Operators of a Reliability Coordinator, Transmission Operator or Balancing Authority, and the Transmission Owner personnel described in the Applicability Section of this standard.

Operations Support Personnel: Individuals, as identified by the Reliability Coordinators, Balancing Authorities, Transmission Operators or Transmission Owners, who perform outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms,[1] in direct support of Real-time, reliability related tasks performed by System Operators.

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Operator

[1] Nomograms are used in the WECC Region to describe element operating limits.

- Transmission Owners that have personnel at a facility, excluding field switching personnel, who act independently to carry out tasks that require Real-time operation of the Bulk Electric System, including protecting assets, protecting personnel safety, adhering to regulatory requirements and establishing stable islands during system restoration.
- Generator Operators that have dispatch personnel at a centrally located dispatch center who receive direction from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control. These personnel does not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions, without making any modifications.

Applicable Facilities
None

Conforming Changes to Other Standards
None

Effective Dates
PER-005-2 shall become effective as follows:

This standard shall become effective the first day of the first calendar quarter that is 24 months beyond the date that this standard is approved by an applicable governmental authority or is otherwise provided for in a jurisdiction where approval by an applicable authority is required for a standard to go into effect.

Where approval by an applicable governmental authority is not required, this standard shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Actions to be Completed as of the Effective Date:

This section describes the actions that an entity must complete as of the effective date of PER-005-2. This section does not address evidence of compliance; see measures, compliance input and RSAWs for further information regarding possible evidence.

<u>Requirement R1:</u>

R1: An entity must have developed and implemented a training program that is based on a systematic approach to training.

1.1: An entity must have defined and documented its methodology for creating a list of company specific Real-time reliability related tasks, and must have a list of these tasks.

1.1.1: Entities already subject to PER-005-1 (RC, BA and TOP) must conduct a review once in the calendar year that this standard becomes effective; however this may be conducted either under the existing standard (PER-005-1) prior to the effective date of proposed standard (PER-005-2) or under the proposed standard (PER-005-2) after it becomes effective.

Entities that were not previously subject to PER-005-1 would not be expected to have conducted a review prior to the effective date of the proposed standard, or in the calendar year that the proposed standard becomes effective. The entity's first review would occur in the first calendar year following the effective date of this standard.

1.2: An entity must have completed the design and development of training materials as necessary under its training program. An entity is not obligated to have designed and developed training materials for all future training.

1.3: Entities already subject to PER-005-1 must continue to implement training in accordance with its existing training program.

Entities that were not previously subject to PER-005-1 must begin to implement training in accordance with its training program as of the effective date. Under the standard, such entities are not expected to have delivered training prior to the effective date.

1.4: Entities already subject to PER-005-1 (RC, BA and TOP) must conduct an evaluation once in the calendar year that this standard becomes effective; however this may be conducted either under the existing standard (PER-005-1) prior to the effective date of the proposed standard (PER-005-2) or under the proposed standard after it becomes effective.

Entities that were not previously subject to PER-005-1 would not be expected to have conducted an evaluation prior to the effective date of the proposed standard or in the calendar year that the proposed standard becomes effective. The entity's first required evaluation would occur in the first calendar year following the effective date of the proposed standard.

Requirement R2:

R2: Entities already subject to PER-005-1 (RC, BA and TOP) must have verified their System Personnel's[2] capabilities to perform each of its assigned Real-time reliability-related tasks, at least once.

[2] As used in this standard, the term "System Personnel" is defined as System Operators of a Reliability Coordinator, Transmission Operator or Balancing Authority, and the Transmission Owner personnel described in the Applicability Section of this standard.

Entities that were not previously subject to PER-005-1 must have verified its System Personnel's capabilities to perform each of its assigned Real-time reliability-related tasks, at least once, as identified in Requirement R1 part 1.1, prior to the effective date of the standard.

2.1: Entities already subject to PER-005-1 (RC, BA and TOP) must have, within six months, verified its System Personnel's capabilities to perform a new or modified Real-time reliability-related task identified Requirement R1 part 1.1 pursuant to PER-005-1.

Entities that were not previously subject to PER-005-1 would not be expected to have verified its System Personnel's capabilities to perform a new or modified Real-time reliability-related task identified under Requirement R1 part 1.1 prior to the effective date of the standard. This requirement pertains to reliability-related tasks that are new or modified following the effective date of this standard.

Requirement R3:

R3: Entities already subject to PER-005-1 (RC, BA and TOP) must have completed training using simulation technology according to its training program under the existing standard (PER-005-1) and must continue to provide training using simulation technology according to its training program after the effective date of the proposed standard (PER-005-2).

Entities that were not previously subject to PER-005-1 (TO) must begin to implement training using simulation technology according to its training program as of the effective date. Under the standard, these entities are not expected to have delivered simulation training prior to the effective date.

3.1: Entities already subject to PER-005-1 (RC, BA and TOP) that gained operational authority or control over Facilities with established IROLs or has established operating guides or protection systems to mitigate IROL violations must have provided each System Operator with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES during normal and emergency conditions prior to the effective date.

Entities that were not previously subject to PER-005-1 are not required to have completed this action prior to the effective date of the standard. This requirement pertains to IROLs that are gained following the effective date of this standard.

Requirement R4:

R4: The personnel identified in this requirement were not previously subject to PER-005-1. The entities (RC, BA, TOP and TO) must have established a training program for their Operations Support Personnel[3] and must have begun to implement training in accordance with their

[3] As used in this standard, the term "Operations Support Personnel" is defined as Individuals, as identified by the Reliability Coordinators, Balancing Authorities, Transmission Operators, or Transmission Owners, who perform outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms, in direct support of Real-time, reliability-related tasks performed by System Operators.

training program as of the effective date. Under the standard, entities are not expected to have delivered or developed material for all future training identified in its training program prior to the effective date.

4.1: The personnel identified in this requirement were not previously subject to PER-005-1 and the entities are not required to have conducted a review prior to the effective date. The entity's first review of the training for its Operations Support Personnel would occur in the first calendar year following the effective date of this standard.

Requirement R5:

R5: Generator Operators were not previously subject to PER-005-1. Generator Operators must have established its training program and must have begun to implement training in accordance with its training program as of the effective date. Under the standard, Generator Operators are not expected to have delivered or developed material for all future training identified in its training program prior to the effective date.

5.1: Generator Operators were not previously subject to PER-005-1 and they are not required to have conducted a review prior to the effective date. The Generator Operators' first review would occur in the first calendar year following the effective date of this standard.

Justification

The 24-month period for implementation of PER-005-2 will provide sufficient time for the applicable entities to make necessary modifications to their systematic approach to training and, for entities not yet subject to the standard, time to develop a systematic approach to training that is compliant with the proposed standard. This time frame is consistent with the 24-month implementation period FERC approved for PER-005-1 to allow for Reliability Coordinators, Balancing Authorities, and Transmission Operators to develop a systematic approach to training. The standard drafting team concluded that the same timeframe (24-months) should be provided to the new applicable entities and for the entities currently subject to PER-001-1 to development training for their Operations Support Personnel.

Retirements

PER-005-1 – System Personnel Training should be retired at 11:59:59 of the day immediately prior to the effective date of PER-005-2 in the particular jurisdiction in which the new standard is becoming effective.

Attachment 1
Approved Standards Incorporating the Term "System Operator"

EOP-005-2 — System Restoration from Blackstart Resources

EOP-006-2 — System Restoration Coordination

EOP-008-1 — Loss of Control Center Functionality

IRO-002-3 — Reliability Coordination – Analysis Tools

IRO-014-1 — Procedures, Processes, or Plans to Support Coordination between Reliability Coordinators

MOD-008-1 — TRM Calculation Methodology

MOD-020-0 — Providing Interruptible Demands and DCLM Data

PER-003-1 — Operation Personnel Credentials

PRC-004-WECC-1 – Protection System and Remedial Action Scheme Maintenance and Testing

PRC-023 -2 — Transmission Relay Loadability

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Implementation Plan

Project 2010-01 Operations Personnel Training

Implementation Plan for PER-005-2 – Operations Personnel Training

Approvals Required

PER-005-2 – Operations Personnel Training

Prerequisite Approvals

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

Revisions to Glossary Terms

~~The following definitions shall become effective when PER-005-2~~ *When the standard* becomes *effective*~~:~~*, this defined term will be removed from the individual standard and added to the Glossary.*

> **System Operator:** An individual at a ~~Control Center that~~control center of a Balancing Authority, Transmission Operator, or Reliability Coordinator who operates or directs the operation of the Bulk Electric System in ~~real~~Real-time.

Other Definitions Used within the Standard

The following terms are defined for use only within PER-005-2~~,~~ and ~~should remain with the standard,~~ upon approval ~~rather than being~~of the standard, will not be moved to the NERC Glossary of Terms:

> **System Personnel**: System Operators of a Reliability Coordinator, Transmission Operator or Balancing Authority, and the Transmission Owner personnel described in the Applicability Section of this standard.

> **Operations Support Personnel:** Individuals, as identified by the Reliability Coordinators, Balancing Authorities, Transmission Operators or Transmission Owners, who ~~carry out~~perform outage coordination ~~and~~or assessments, or who determine SOLs, IROLs, or operating nomograms ~~for~~,[1] in direct support of Real-time ~~operations~~, reliability related tasks performed by System Operators.

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Operator

[1] Nomograms are used in the WECC Region to describe element operating limits.

- Transmission ~~Owner~~Owners that ~~has~~have personnel ~~in~~at a ~~Transmission control center~~facility, excluding field switching personnel, who ~~operate a portion~~act independently to carry out tasks that require Real-time operation of the Bulk Electric System~~ at the direction of its Transmission Operator~~, including protecting assets, protecting personnel safety, adhering to regulatory requirements and establishing stable islands during system restoration.
- Generator ~~Operator~~Operators that ~~has~~have dispatch personnel at a centrally located dispatch center who receive direction from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control.~~-~~ These personnel does not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions, without making any modifications.

Applicable Facilities
None

Conforming Changes to Other Standards
None

Effective Dates
PER-005-2 shall become effective as follows:

~~Requirement R1, Requirement R2, Requirement R3 part 3.1, Requirement R4 and Requirement R5~~This standard shall become effective the first day of the first calendar quarter that is 24 months beyond the date that this standard is approved by ~~applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, Requirement R1, Requirement R2, Requirement R3 part 3.1, Requirement R4 and Requirement R5 become effective the first day of the first calendar quarter that is 24 months beyond the date this standard is approved by the NERC Board of Trustees', or as otherwise made pursuant to the laws applicable to such ERO governmental authorities.~~an applicable governmental authority or is otherwise provided for in a jurisdiction where approval by an applicable authority is required for a standard to go into effect.

~~Requirement R3, with the exclusion of part 3.1,~~Where approval by an applicable governmental authority is not required, this standard shall become effective on the first day of the first calendar quarter ~~beyond~~that is 24 months after the date ~~that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, Requirement R3 becomes effective the first day of the first calendar quarter beyond the date this standard~~ the standard is ~~approved~~adopted by the NERC Board of ~~Trustees',~~Trustees or as otherwise ~~made~~provided for in that jurisdiction.

Actions to be Completed as of the Effective Date:

NERC

This section describes the actions that an entity must complete as of the effective date of PER-005-2. This section does not address evidence of compliance; see measures, compliance input and RSAWs for further information regarding possible evidence.

Requirement R1:

R1: An entity must have developed and implemented a training program that is based on a systematic approach to training.

- 1.1: An entity must have defined and documented its methodology for creating a list of company specific Real-time reliability related tasks, and must have a list of these tasks.
  - 1.1.1: Entities already subject to PER-005-1 (RC, BA and TOP) must conduct a review once in the calendar year that this standard becomes effective; however this may be conducted either under the existing standard (PER-005-1) prior to the effective date of proposed standard (PER-005-2) or under the proposed standard (PER-005-2) after it becomes effective.

    Entities that were not previously subject to PER-005-1 would not be expected to have conducted a review prior to the effective date of the proposed standard, or in the calendar year that the proposed standard becomes effective. The entity's first review would occur in the first calendar year following the effective date of this standard.
- 1.2: An entity must have completed the design and development of training materials as necessary under its training program. An entity is not obligated to have designed and developed training materials for all future training.
- 1.3: Entities already subject to PER-005-1 must continue to implement training in accordance with its existing training program.

  Entities that were not previously subject to PER-005-1 must begin to implement training in accordance with its training program as of the effective date. Under the standard, such entities are not expected to have delivered training prior to the effective date.
- 1.4: Entities already subject to PER-005-1 (RC, BA and TOP) must conduct an evaluation once in the calendar year that this standard becomes effective; however this may be conducted either under the existing standard (PER-005-1) prior to the effective date of the proposed standard (PER-005-2) or under the proposed standard after it becomes effective.

  Entities that were not previously subject to PER-005-1 would not be expected to have conducted an evaluation prior to the effective date of the proposed standard or in the calendar year that the proposed standard becomes effective. The entity's first required evaluation would occur in the first calendar year following the effective date of the proposed standard.

Requirement R2:

R2: Entities already subject to PER-005-1 (RC, BA and TOP) must have verified their System Personnel's[2] capabilities to perform each of its assigned Real-time reliability-related tasks, at least once~~, pursuant to ***the laws applicable to such ERO governmental authorities.***~~PER-005-1.

~~Rationale for changes to requirements in the PER Standard related to Transmission Owners and Calendar Year:~~

- ~~Transmission Owners personnel at local transmission control centers have been added to the PER standard and are subject to all the Requirements of PER-005-2. The reason for adding Transmission Owners is to address Order No. 693 and Order No. 742 FERC directives to include local transmission control center operator personnel.~~
- ~~To address industry input, the term *annual* has been changed to *each calendar year*.~~
- ~~PER-005-2 provides a requirement for training, but does not create a requirement for certification.~~

Entities that were not previously subject to PER-005-1 must have verified its System Personnel's capabilities to perform each of its assigned Real-time reliability-related tasks, at least once, as identified in Requirement R1 part 1.1, prior to the effective date of the standard.

2.1: Entities already subject to PER-005-1 (RC, BA and TOP) must have, within six months, verified its System Personnel's capabilities to perform a new or modified Real-time reliability-related task identified Requirement R1 part 1.1 pursuant to PER-005-1.

Entities that were not previously subject to PER-005-1 would not be expected to have verified its System Personnel's capabilities to perform a new or modified Real-time reliability-related task identified under Requirement R1 part 1.1 prior to the effective date of the standard. This requirement pertains to reliability-related tasks that are new or modified following the effective date of this standard.

Requirement R3:

R3: Entities already subject to PER-005-1 (RC, BA and TOP) must have completed training using simulation technology according to its training program under the existing standard (PER-005-1) and must continue to provide training using simulation technology according to its training program after the effective date of the proposed standard (PER-005-2).

Entities that were not previously subject to PER-005-1 (TO) must begin to implement training using simulation technology according to its training program as of the effective date. Under the standard, these entities are not expected to have delivered simulation training prior to the effective date.

3.1: Entities already subject to PER-005-1 (RC, BA and TOP) that gained operational authority or control over Facilities with established IROLs or has established operating guides or protection systems to mitigate IROL violations must have provided each System

[2] As used in this standard, the term "System Personnel" is defined as System Operators of a Reliability Coordinator, Transmission Operator or Balancing Authority, and the Transmission Owner personnel described in the Applicability Section of this standard.

Operator with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES during normal and emergency conditions prior to the effective date.

Entities that were not previously subject to PER-005-1 are not required to have completed this action prior to the effective date of the standard. This requirement pertains to IROLs that are gained following the effective date of this standard.

Requirement R4:

R4: The personnel identified in this requirement were not previously subject to PER-005-1. The entities (RC, BA, TOP and TO) must have established a training program for their Operations Support Personnel[3] and must have begun to implement training in accordance with their training program as of the effective date. Under the standard, entities are not expected to have delivered or developed material for all future training identified in its training program prior to the effective date.

4.1: The personnel identified in this requirement were not previously subject to PER-005-1 and the entities are not required to have conducted a review prior to the effective date. The entity's first review of the training for its Operations Support Personnel would occur in the first calendar year following the effective date of this standard.

Requirement R5:

R5: Generator Operators were not previously subject to PER-005-1. Generator Operators must have established its training program and must have begun to implement training in accordance with its training program as of the effective date. Under the standard, Generator Operators are not expected to have delivered or developed material for all future training identified in its training program prior to the effective date.

5.1: Generator Operators were not previously subject to PER-005-1 and they are not required to have conducted a review prior to the effective date. The Generator Operators' first review would occur in the first calendar year following the effective date of this standard.

Justification

The 24-month period for implementation of PER-005-2 will provide ~~ample~~sufficient time for the applicable entities to make necessary modifications to ~~existing or creation of new~~ their systematic approach to training ~~programs~~and, for ~~compliance.~~entities not yet subject to the standard, time to develop a systematic approach to training that is compliant with the proposed standard. This time

[3] As used in this standard, the term "Operations Support Personnel" is defined as Individuals, as identified by the Reliability Coordinators, Balancing Authorities, Transmission Operators, or Transmission Owners, who perform outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms, in direct support of Real-time, reliability-related tasks performed by System Operators.

frame is consistent with the 24-month implementation period FERC approved for PER-005-1 to allow for Reliability Coordinators, Balancing Authorities, and Transmission Operators to develop a systematic approach to training. The standard drafting team concluded that the same timeframe (24-months) should be provided to the new applicable entities and for the entities currently subject to PER-001-1 to development training for their Operations Support Personnel.

Retirements

PER-005-1 – System Personnel Training should be retired at ~~midnight~~11:59:59 of the day immediately prior to the effective date of PER-005-2 in the particular jurisdiction in which the new standard is becoming effective.

Attachment 1
Approved Standards Incorporating the Term "System Operator"

EOP-005-2 — System Restoration from Blackstart Resources

EOP-006-2 — System Restoration Coordination

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IRO-002-3 — Reliability Coordination – Analysis Tools

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MOD-020-0 — Providing Interruptible Demands and DCLM Data

PER-003-1 — Operation Personnel Credentials

~~PER-005-1 — System Personnel Training~~
PRC-004-WECC-1 – Protection System and Remedial Action Scheme Maintenance and Testing

PRC-023 -2 — Transmission Relay Loadability

Unofficial Comment Form

Project 2010-01 Training
PER-005-1 (Operations Personnel Training)

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard. The electronic comment form must be completed by 8:00 p.m. ET **Monday, November 11, 2013**.

If you have questions please contact Jordan Mallory or by telephone at 404-446-9733.

The project page may be accessed by clicking here.

Background Information

The Project 2010-01 Training Standard Drafting Team posted an initial draft of the Standard PER-005-2 (Operations Personnel Training) for comment from July 19 to September 3, 2013. The drafting team has revised the standard based on stakeholder recommendations that the drafting team considered appropriate. Changes made to the PER-005-2 standard are redlined and can be accessed by clicking here.

This posting solicits comment on the revised PER-005-2 standard. The standard responds to FERC Order No. 693 and No. 742.

Questions on PER-005-2

1. The drafting team has revised PER-005-2 in response to stakeholder comments. Do you agree with the revised Support Personnel and System Operator definitions? If you do not agree or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes
☐ No
Comments:

2. The drafting team has revised PER-005-2 in response to stakeholder comments. Do you agree with the revised standard? If you do not agree or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes
☐ No
Comments:

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Item 2d-Att 2

Standards Authorization Request Form

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

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

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Operations Personnel Training		
Date Submitted:	Revised: September 25, 2013 Original: July 18, 2013		
SAR Requester Information			
Name:	Jordan Mallory		
Organization:	NERC		
Telephone:	404-446-9733	E-mail:	Jordan.mallory@nerc.net
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
Address outstanding FERC directives, modify System Operator definition (project 2010-16), and incorporate ERO initiatives, including drafting results-based or performance-based standards that are consistent with Paragraph 81 criteria.

SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):
• Modify System Operator Definition (Project 2010-16). • Define applicable entities to address outstanding FERC Directives from Order No. 693 and Order No. 742. • Modify existing PER-005-1 requirements for additional applicable entities and personnel. • Remove the requirement to provide at least 32 hours of emergency operations training from Requirement R3 of PER-005-1 as it no longer meets criteria set forth in the standard for utilizing a systematic approach to training. The appropriate amount of such training should be determined by the applicable entities through the analysis phase of a systematic approach to training and outlined in a continuous education section of their training program. Any additional hours may be duplicative or repetitive for the entity in providing training to their personnel.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
This project will address the following FERC directives. In addition, the project will review the present standard to eliminate ambiguity within the standard. 1. This SAR is needed to address outstanding FERC Directives from Order No. 693 and Order No. 742. The following is a summary of the FERC Directives to the ERO: ▪ "Develop specific Requirements addressing the scope, content and duration appropriate for generator operator personnel." Order No. 693 at P 1363. A new requirement has been suggested to address Generator Operator personnel at a centrally located dispatch center who receive direction from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control. Personnel at a centrally located dispatch center who relay dispatch instructions, without making any modifications, are excluded. ▪ "Include [operations support personnel] who carry out outage coordination and assessments in accordance with IRO-004-1 and TOP-002-2 and determine SOLs and IROLs or operating nomograms in accordance with IRO-005-1 and TOP-004-0." Order No. 693 at P 1372. A new requirement has been suggested to address operation support and support staff personnel for training. The term Operations Support Personnel has been defined solely for the revised PER-005-1 standard. ▪ Consider whether personnel responsible for ensuring that critical reliability applications

SAR Information
of the EMS, such as state estimator, contingency analysis and alarm processing packages are available, up-to-date in terms of system data and produce useable results should be included in a mandatory training standard. Order No. 693 at P 1373. The team considered whether there is technical justification for including EMS personnel in the standard. ▪ Consider the necessity of developing a similar implementation plan with respect to PER-005-1, Requirement R3.1 addressing simulation technology. Order No. 693 at P 1390-1391 and Order No. 742 at P 55. ▪ Expand the applicability of PER-005 to include training requirements for local transmission control center" operator personnel and define the term "local transmission control center." Order No. 693 at P 1343; Order No. 742 at P 64. The team thought it would be a better path to define local transmission control center through extending the applicability to Transmission Owners versus creating a new term for the NERC Glossary. Transmission Owner in the PER standard is defined as "Personnel at a facility, excluding field switching personnel, who act independently to carry out tasks that require Real-time operation of the Bulk Electric System including protecting assets, protecting personnel safety, adhering to regulatory requirements and establishing stable islands during system restoration ." Transmission Owner has been added to all the requirements of the suggested revised PER-005-1 standard. 2. Revise definition of System Operator in glossary of terms to address industry concerns for clarity based on Project 2010-16. 3. Implement Paragraph 81 criteria by identifying Reliability Standards requirements that either: (a) provide little protection to the BES; (b) are unnecessary or (c) are redundant.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Detailed description of this project can be found in the Technical White Paper included with the initial SAR posting.

Reliability Functions

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

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

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

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

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

Related Standards	
Standard No.	Explanation

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	None
FRCC	None
MRO	None
NPCC	None
RFC	None
SERC	None

Regional Variances	
SPP	None
WECC	None

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Item 2d-Att 1

Standards Authorization Request Form

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

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

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Operations Personnel Training		
Date Submitted:	Revised: September 25, 2013 Original: July 18, 2013		
SAR Requester Information			
Name:	Jordan Mallory		
Organization:	NERC		
Telephone:	404-446-9733	E-mail:	Jordan.mallory@nerc.net
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
~~Resolve~~Address outstanding FERC directives, modify System Operator definition (project 2010-16), and ~~to~~ incorporate ERO initiatives ~~such as~~, including drafting results-based~~,~~ or performance-based~~,~~ standards that are consistent with Paragraph 81~~, etc~~ criteria.

SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):
• Modify System Operator Definition (Project 2010-16). • Define applicable entities to address outstanding FERC Directives from Order No. 693 and Order No. 742. • Modify existing PER-005-1 requirements for additional applicable entities and personnel. • ~~Remove existing PER-005-1 R3 prescriptive 32 hours of emergency operations as it is covered under the Systematic Approach to Training and thus is repetitive. In Paragraph 81 of the March 15, 2012 Order (link), FERC provided an opportunity for the ERO to remove requirements that did little to protect to the BPS pursuant to specific criteria. The requirement for 32 hours of training meets the Paragraph 81 criteria for redundancy. It further is not a results-based requirement, as it is unnecessarily prescriptive.~~Remove the requirement to provide at least 32 hours of emergency operations training from Requirement R3 of PER-005-1 as it no longer meets criteria set forth in the standard for utilizing a systematic approach to training. The appropriate amount of such training should be determined by the applicable entities through the analysis phase of a systematic approach to training and outlined in a continuous education section of their training program. Any additional hours may be duplicative or repetitive for the entity in providing training to their personnel.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
This project will ~~be addressing~~address the following FERC directives. In addition, the project will ~~be reviewing~~review the present standard to eliminate ~~in~~ ambiguity within the standard. 1. This SAR is needed to address outstanding FERC Directives from Order No. 693 and Order No. 742. The following is a summary of the FERC Directives to the ERO: ▪ "Develop specific Requirements addressing the scope, content and duration appropriate for generator operator personnel~~.~~." Order No. 693 at P 1363. A new requirement ~~R5~~ has been suggested ~~as an addition~~ to ~~a revised PER-005-1 capturing~~address Generator ~~Operators Personnel~~Operator personnel at a centrally located dispatch center who receive direction from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control. Personnel at a centrally located dispatch center who relay dispatch instructions, without making any modifications, are excluded. ▪ "Include [operations support personnel] who carry out outage coordination and assessments in accordance with IRO-004-1 and TOP-002-2 and determine SOLs and IROLs or operating nomograms in accordance with IRO-005-1 and TOP-004-0~~.~~." Order No. 693

SAR Information
at P 1372. A new requirement ~~R4~~ has been suggested ~~as an addition~~ to ~~a revised PER-005-1~~ ~~capturing~~address operation support and support staff personnel for training. The term Operations Support Personnel has been ~~created with a definition~~defined solely for the revised PER-005-1 standard. ▪ Consider whether personnel responsible for ensuring that critical reliability applications of the EMS, such as state estimator, contingency analysis and alarm processing packages are available, up-to-date in terms of system data and produce useable results should be included in a mandatory training standard. ~~(Technical Justification)~~ Order No. 693 at P 1373. The team considered whether there is technical justification for including EMS personnel in the standard. ▪ Consider the necessity of developing a similar implementation plan with respect to PER-005-1, Requirement R3.1~~. (~~ addressing simulation technology~~)~~. Order No. 693 at P 1390-1391 and Order No. 742 at P 55. ▪ ~~Develop a definition~~Expand the applicability of ~~"local transmission control center" for developing the~~PER-005 to include training requirements for local transmission control center" operator personnel~~.~~ and define the term "local transmission control center." Order No. 693 at P 1343; Order No. 742 at P 64. The ~~group~~team thought it would be a better path to define local transmission control center through extending the applicability to Transmission Owners versus creating a new term for the NERC Glossary. Transmission Owner in the PER standard is defined as "Personnel ~~in a transmission control center who operate a portion of the Bulk Electric System at the direction of its Transmission Operator."~~at a facility, excluding field switching personnel, who act independently to carry out tasks that require Real-time operation of the Bulk Electric System including protecting assets, protecting personnel safety, adhering to regulatory requirements and establishing stable islands during system restoration ." Transmission Owner has been added to all the requirements of the suggested revised PER-005-1 standard. 2. Revise definition of System Operator in glossary of terms to address industry concerns for clarity based on Project 2010-16. 3. Implement Paragraph 81 criteria by identifying Reliability Standards requirements that either: (a) provide little protection to the ~~BPS~~BES; (b) are unnecessary or (c) are redundant.

SAR Information
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Detailed description of this project can be found in the Technical White Paper~~, of this~~ included with the initial SAR ~~submittal package~~posting.

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

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

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

Reliability and Market Interface Principles	
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

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

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	None
FRCC	None
MRO	None
NPCC	None
RFC	None
SERC	None
SPP	None
WECC	None

Project 2010-01 Operations Personnel Training
PER-005-2 Mapping Document

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
R1. Reliability Coordinator, Balancing Authority and Transmission Operator shall use a systematic approach to training to establish a training program for the BES company-specific reliability-related tasks performed by its System Operators and shall implement the program. **1.1.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall create a list of BES company-specific reliability-related tasks performed by its System Operators. **1.1.1.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall update its list of BES	Requirement R1 parts 1.1.1., 1.1., 1.2., 1.3., and 1.4.	**R1.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall use a systematic approach to training to develop and implement a training program for its System Personnel[1] as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **1.1** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology. **1.1.1.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall review, and update if

[1] As used in this standard, the term "System Personnel" is defined as System Operators of a Reliability Coordinator, Transmission Operator or Balancing Authority, and the Transmission Owner personnel described in the Applicability Section of this standard.

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
company-specific reliability-related tasks performed by its System Operators each calendar year to identify new or modified tasks for inclusion in training. **1.2.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall design and develop learning objectives and training materials based on the task list created in R1.1. **1.3.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall deliver the training established in R1.2. **1.4**. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall conduct an annual evaluation of the training program established in R1, to identify any needed changes to the training program and shall implement the changes identified.		necessary, its list of Real-time reliability-related tasks identified in part 1.1 each calendar year. **1.2.**Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall design and develop training materials according to its training program, based on the Real-time reliability-related task list created in part 1.1. **1.3.**Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall deliver training to its System Personnel according to its program. **1.4.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall implement the changes identified.
R2. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator's capabilities to perform each assigned task	Requirement R2 and 2.1.	**R2.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its System Personnel assigned to perform each of the Real-time

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
identified in R1.1 at least one time. **2.1.** Within six months of a modification of the BES company-specific reliability-related tasks, each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator's capabilities to perform the new or modified tasks.		reliability-related tasks identified under Requirement R1 part 1.1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]* **2.1** Within six months of a modification or addition of BES company-specific Real-time reliability-related tasks, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its System Personnel to perform the new or modified Real-time reliability-related tasks identified in Requirement R1 part 1.1.
R3. At least every 12 months each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each of its System Operators with at least 32 hours of emergency operations training applicable to its organization that reflects emergency operations topics, which includes system restoration using drills, exercises or other training required to maintain qualified personnel. **3.1.** Each Reliability Coordinator, Balancing	This Requirement has been updated with deleting R3 and moving 3.1 from the approved standard to be the new R3. Part 3.1 in the proposed standard it addresses the implementation of simulation technology.	**R3.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs) or has established operating guides or protection systems to mitigate IROL violations shall provide its System Personnel with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES, according to its training program. *[Violation Risk Factor: Medium] [Time Horizon:*

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
Authority and Transmission Operator that has operational authority or control over Facilities with established IROLs or has established operating guides or protection systems to mitigate IROL violations shall provide each System Operator with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES during normal and emergency conditions.		*Long-term Planning]* **3.1** When a Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not have an IROL gains operational authority or control over a Facility with an established IROL or establishes operating guides or protection systems to mitigate IROL violations, it shall comply with Requirement R3 within 12 months of gaining that authority or control, or establishing such operating guides or protection systems.
	This requirement is new to PER-005-2.	**R4.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall use a systematic approach to training to develop and implement training for its Operations Support Personnel[2] on the impact of their job function(s) to those Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. [Violation Risk Factor:

[2] As used in this standard, the term "Operations Support Personnel" is defined as Individuals, as identified by the Reliability Coordinators, Balancing Authorities, Transmission Operators, or Transmission Owners, who perform outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms, in direct support of Real-time, reliability-related tasks performed by System Operators.

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
		Medium] [Time Horizon: Long-term Planning] **4.1** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall conduct an evaluation each calendar year of the training established in Requirement R4 to identify and implement changes to the training.
	This requirement is new to PER-005-2.	**R5.** Each Generator Operator shall use a systematic approach to develop and deliver training to its personnel described in Applicability Section 4.1.5 of this standard on the impact of their job function(s) as it pertains to reliable operations of the BES during normal and emergency operations. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **5.1** Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training.

Project 2010-01 Operations Personnel Training PER-005-2 Mapping Document

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
R1. Reliability Coordinator, Balancing Authority and Transmission Operator shall use a systematic approach to training to establish a training program for the BES company-specific reliability-related tasks performed by its System Operators and shall implement the program. **1.1.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall create a list of BES company-specific reliability-related tasks performed by its System Operators. **1.1.1.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall update its list of BES	Requirement R1 parts 1.1.1., 1.1., 1.2., 1.3., and 1.4.	**R1.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall ~~review and update its list of tasks identified in part 1.1 each calendar year.~~use a systematic approach to training to develop and implement a training program for its System Personnel[1] as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **1.1** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall ~~review and update its list of tasks identified in part 1.1 each calendar year.~~create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology.

[1] As used in this standard, the term "System Personnel" is defined as System Operators of a Reliability Coordinator, Transmission Operator or Balancing Authority, and the Transmission Owner personnel described in the Applicability Section of this standard.

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
company-specific reliability-related tasks performed by its System Operators each calendar year to identify new or modified tasks for inclusion in training. **1.2.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall design and develop learning objectives and training materials based on the task list created in R1.1. **1.3.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall deliver the training established in R1.2. **1.4**. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall conduct an annual evaluation of the training program established in R1, to identify any needed changes to the training program and shall implement the changes identified.		**1.1.1.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall review, and update if necessary, its list of Real-time reliability-related tasks identified in part 1.1 each calendar year. ~~1.1.~~1.2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall design and develop training materials according to its training program, based on the Real-time reliability-related task list created in part 1.1~~ and part 1.1.1~~. ~~1.2.~~1.3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall deliver ~~the~~ training ~~established in part 1.2~~ to its System Personnel according to its program. ~~1.3.~~ Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement R1~~,~~ to identify any needed changes to the training program and shall implement the changes identified.

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 **NERC Board Approved**	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
		~~1.3.~~1.4.
R2. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator's capabilities to perform each assigned task identified in R1.1 at least one time. **2.1.** Within six months of a modification of the BES company-specific reliability-related tasks, each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator's capabilities to perform the new or modified tasks.	Requirement R2 and 2.1.	**R2~~:~~.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its System Personnel ~~identified~~assigned to perform each ~~assigned task in~~of the Real-time reliability-related tasks identified under Requirement R1 ~~parts~~part 1.1~~ and 1.1.1. ~~. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]* ~~2.1.~~ Within six months of a modification or addition of ~~Bulk Electric System~~BES company-specific Real-time reliability-related tasks, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its System Personnel to perform the new or modified Real-time reliability-related tasks identified in Requirement R1 part 1.1.~~1.~~ **2.1**
R3. At least every 12 months each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each of	This Requirement has been updated with deleting R3 and moving	**R3.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that has operational authority or control over Facilities with

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
its System Operators with at least 32 hours of emergency operations training applicable to its organization that reflects emergency operations topics, which includes system restoration using drills, exercises or other training required to maintain qualified personnel. **3.1.** Each Reliability Coordinator, Balancing Authority and Transmission Operator that has operational authority or control over Facilities with established IROLs or has established operating guides or protection systems to mitigate IROL violations shall provide each System Operator with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES during normal and emergency conditions.	3.1 from the approved standard to be the new R3. Part 3.1 in the proposed standard it addresses the implementation of simulation technology.	established ~~IROLs~~Interconnection Reliability Operating Limits (IROLs) or has established operating guides or protection systems to mitigate IROL violations shall provide its System Personnel with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the ~~Bulk Electric System.~~BES, according to its training program. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **3.1** ~~3.1. Each~~When a Reliability Coordinator, Balancing Authority, Transmission Operator, ~~and~~or Transmission Owner that did not have an IROL gains operational authority or control over a Facility with an established IROL or establishes operating guides or protection systems to mitigate IROL violations, it shall comply with Requirement R3 within ~~6~~12 months of gaining that authority~~,~~ or control, or establishing such operating guides or protection systems.
	This requirement is ~~a~~ new to PER-005-2.	**R4.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
		~~establish~~use a systematic approach to training to develop and implement training for its Operations Support Personnel ~~specific~~[2] on the impact of their job function(s) to those Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1 ~~and part 1.1.1 that relate to the Support Personnel's job function.~~ . [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] **4.1** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall conduct an evaluation each calendar year of the training established in Requirement R4 to identify and implement changes to the training.

[2] As used in this standard, the term "Operations Support Personnel" is defined as Individuals, as identified by the Reliability Coordinators, Balancing Authorities, Transmission Operators, or Transmission Owners, who perform outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms, in direct support of Real-time, reliability-related tasks performed by System Operators.

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
	This requirement is ~~a~~ new to PER-005-2.	**R5.** Each Generator Operator shall use a systematic approach to develop and deliver training to ~~establish and implement training for~~ its personnel described in ~~applicability section~~Applicability Section 4.1.5 of this standard on the impact of their job function(s) as ~~follows:~~it pertains to reliable operations of the BES during normal and emergency operations. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* ~~**5.1** Each Generator Operator shall coordinate with its Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner to identify training topics that address the impact of the decisions and actions of a Generator Operator's personnel as it pertains to the reliability of the Bulk Electric System during normal and emergency operations.~~ ~~**5.1.1.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall provide input as requested by the Generator Operator.~~ **5.1** Each Generator Operator shall conduct an evaluation

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	Transitions to the below Requirement in New Standard or Other Action	Proposed Standard PER-005-2
		each calendar year of the training established in Requirement R5 to identify and implement changes to the training.

Compliance Operations

Draft Reliability Standard Compliance Guidance for PER-005-2
October 1, 2013

Introduction
The NERC Compliance department (Compliance) worked with the PER-005 standard drafting team (SDT) to review the proposed standard PER-005-2. The purpose of the review was to discuss the requirements of the proposed standard to obtain an understanding of its intended purpose and the evidence necessary to support compliance. The purpose of this document is to address specific questions posed by the PER SDT in order to aid in the drafting of the requirements and provide a level of understanding regarding evidentiary support necessary to demonstrate compliance.

While all compliance evaluations require levels of auditor judgment, participating in these reviews allows Compliance to develop training and approaches to support a high level of consistency in audits conducted by the Regional Entities. The following questions and answers are intended to assist the SDT in further refining the standard and to serve as a resource in the development of training for auditors.

PER-005-2 Questions

Question 1
For Requirement R1, what criteria would an auditor use to determine if a registered entity uses a systematic approach to training for developing its training program?

Compliance Response to Question 1
A systematic approach to training is a concept or methodology. This version of the standard retains flexibility for the entity to determine how it will apply the principles of this concept to develop and implement its training program. There are different models of systematic approaches to training, and the standard does not specify a certain model that should be used.

Consistent with FERC orders[1] and current Electric Reliability Organization's practices, to determine whether the entity used a systematic approach to training, an auditor will evaluate whether the entity's training program follows the principles below:

- Assess training needs (analysis)
- Conduct the training activity (design, develop and implement)
- Evaluate the training activity (evaluate the effectiveness of the training)

[1] See FERC Order No. 742 at P 25 and Order No. 693 at P 1380, 1382.

Further, as provided in the Application Guidelines attached to the standard, an auditor will assess whether the entity's training program, using a systematic approach to training:

1. determined the skills and knowledge needed to perform Real-time reliability-related tasks;
2. determined what training is needed to achieve those skills and knowledge;
3. determined if the trainee can perform the Real-time reliability-related task(s) acceptably in either a training or on-the-job environment; and
4. determined if the training is effective, and makes adjustments as necessary.

Question 2
In Requirement R3, does an entity that has one or more IROLs have 12 months to conduct simulation technology training when it obtains another IROL?

Compliance Response to Question 2
No, if an entity currently has one or more IROLs, it has the ability to conduct simulation technology. The 12 months applies only to an entity that did not have any IROLs but obtains an IROL for the first time.

Question 3
Is an auditor to assess a registered entity based on a systematic approach to training for the Operations Support Personnel referenced in Requirement R4?

Compliance Response to Question 3
Yes. An auditor will evaluate the entity's systematic approach to training with regard to the impact of the Operations Support Personnel's job function on the Real-time reliability-related tasks, NOT on the Operations Support Personnel's ability to conduct these tasks.

Operations Support Personnel are required to receive training only on how their job functions impact the Real-time reliability-related tasks. Therefore, modifying the assessment outlined above in Question #1, rather than:

- determined the skills and knowledge needed to perform Real-time reliability-related tasks;

the auditor will determine if the entity's systematic approach to training:

- determined the skills and knowledge needed to understand the impact of the job function(s) on the Real-time reliability-related tasks.

Question 4
Since Requirement R5 does not include the same parts as Requirement R1 to define a systematic approach to training, do entities have to adhere to the Requirement R1 parts for Requirement R5?

Compliance Response to Question 4

No. However, an auditor would verify that an entity followed a systematic approach to training. An auditor will evaluate this systematic approach to training with regard to the impact of the Generator Operator's (GOP's) job function(s) on the reliable operations of the BES during normal and emergency operations.

Consistent with FERC orders[2] and current Electric Reliability Organization's practices, to determine whether the entity used a systematic approach to training, an auditor will evaluate whether the entity's training program follows the principles below:

- Assess training needs (analysis)
- Conduct the training activity (design, develop and implement)
- Evaluate the training activity (evaluate the effectiveness of the training)

Further, as provided in the Application Guidelines attached to the standard, an auditor will assess whether the entity's training program, using a systematic approach to training:

1. determined the skills and knowledge needed to understand the impact of the Generator Operator's job function(s) on the reliable operations of the BES during normal and emergency operations.
2. determined what training is needed to achieve those skills and knowledge;
3. determined if the trainee can support the reliable operation of the BES during normal and emergency operations acceptably in either a training or on-the-job environment; and
4. determined if the training is effective, and makes adjustments as necessary.

Conclusion

Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training. Attachment A represents the version of the proposed standard requirements referenced in this document.

[2] See FERC Order No. 742 at P 25 and Order No. 693 at P 1380, 1382.

Compliance Operations

Draft Reliability Standard Compliance Guidance for PER-005-2
October 1, 2013

Introduction
The NERC Compliance department (Compliance) worked with the PER-005 standard drafting team (SDT) to review the proposed standard PER-005-2. The purpose of the review was to discuss the requirements of the proposed standard to obtain an understanding of its intended purpose and the evidence necessary to support compliance. The purpose of this document is to address specific questions posed by the PER SDT in order to aid in the drafting of the requirements and provide a level of understanding regarding evidentiary support necessary to demonstrate compliance.

While all compliance evaluations require levels of auditor judgment, participating in these reviews allows Compliance to develop training and approaches to support a high level of consistency in audits conducted by the Regional Entities. The following questions and answers are intended to assist the SDT in further refining the standard and to serve as a resource in the development of training for auditors.

PER-005-2 Questions

Question 1
For Requirement R1, what criteria would an auditor use to determine if a registered entity uses a systematic approach to training for developing its training program?

Compliance Response to Question 1
A systematic approach to training is a concept or methodology. This version of the standard retains flexibility for the entity to determine how it will apply the principles of this concept to develop and implement its training program. There are different models of systematic approaches to training, and the standard does not specify a certain model that should be used.

Consistent with FERC orders[1] and current Electric Reliability Organization's practices, to determine whether the entity used a systematic approach to training, an auditor will evaluate whether the entity's training program follows the principles below:

- Assess training needs (analysis)
- Conduct the training activity (design, develop and implement)
- Evaluate the training activity (evaluate the effectiveness of the training)

[1] See FERC Order No. 742 at P 25 and Order No. 693 at P 1380, 1382.

Further, as provided in the Application Guidelines attached to the standard, an auditor will assess whether the entity's training program, using a systematic approach to training:

1. determined the skills and knowledge needed to perform ~~or support~~ Real-time reliability-related tasks;
2. determined what training is needed to achieve those skills and knowledge;
3. determined if the trainee can perform ~~or support~~ the Real-time reliability-related task(s) acceptably in either a training or on-the-job environment; and
4. determined if the training is effective, and makes adjustments as necessary.

Question 2
In Requirement R3, does an entity that has one or more IROLs have 12 months to conduct simulation technology training when it obtains another IROL?

Compliance Response to Question 2
No, if an entity currently has one or more IROLs, it has the ability to conduct simulation technology. The 12 months applies only to an entity that did not have any IROLs but obtains an IROL for the first time.

Question 3
Is an auditor to assess a registered entity based on a systematic approach to training for the Operations Support Personnel referenced in Requirement R4?

Compliance Response to Question 3
Yes. An auditor will evaluate the entity's systematic approach to training with regard to the impact of the Operations Support Personnel's job function on the Real-time reliability-related tasks, NOT on the Operations Support Personnel's ability to conduct these tasks.

Operations Support Personnel are required to receive training only on how their job functions impact the Real-time reliability-related tasks~~reliable operations of the Bulk Electric System (BES)~~. Therefore, modifying the assessment outlined above in Question #1, rather than:

- determined the skills and knowledge needed to perform Real-time reliability-related tasks;

the auditor will determine if the entity's systematic approach to training:

- determined the skills and knowledge needed to understand the impact of the job function(s) on the Real-time reliability-related tasks.

Question 4
Since Requirement R5 does not include the same parts as Requirement R1 to define a systematic approach to training, do entities have to adhere to the Requirement R1 parts for Requirement R5?

Compliance Response to Question 4

No. However, an auditor would verify that an entity followed a systematic approach to training. An auditor will evaluate this systematic approach to training with regard to the impact of the Generator Operator's (GOP's) job function(s) on the reliable operations of the BES during normal and emergency operations.

Consistent with FERC orders[2] and current Electric Reliability Organization's practices, to determine whether the entity used a systematic approach to training, an auditor will evaluate whether the entity's training program follows the principles below:

- Assess training needs (analysis)
- Conduct the training activity (design, develop and implement)
- Evaluate the training activity (evaluate the effectiveness of the training)

Further, as provided in the Application Guidelines attached to the standard, an auditor will assess whether the entity's training program, using a systematic approach to training:

1. determined the skills and knowledge needed to understand the impact of the Generator Operator's job function(s) on the reliable operations of the BES during normal and emergency operations.
2. determined what training is needed to achieve those skills and knowledge;
3. determined if the trainee can support the reliable operation of the BES during normal and emergency operations acceptably in either a training or on-the-job environment; and
4. determined if the training is effective, and makes adjustments as necessary.

Conclusion

Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training. Attachment A represents the version of the proposed standard requirements referenced in this document.

[2] See FERC Order No. 742 at P 25 and Order No. 693 at P 1380, 1382.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

PER-005 Standards White Paper

July 18, 2013

RELIABILITY | ACCOUNTABILITY




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Executive Summary

A Personnel, Performance, Training, and Qualifications (PER) ad hoc group was formed to work with industry stakeholders to address five outstanding Federal Energy Regulatory Commission (FERC) directives.

The five outstanding FERC directives are as follows:

1. The Commission directs the Electric Reliability Organization (ERO) to develop specific requirements addressing the scope, content, and duration appropriate for Generator Operator (GOP) personnel (Order No. 693, P. 1363).
2. The Commission directs the ERO to develop a modification to PER-002-0 to require training of operations planning and operations support staff of Transmission Operators (TOPs) and Balancing Authorities (BAs) who have a direct impact on the reliable operation of the Bulk-Power System (BPS) (Order No. 693, P. 1372).
3. The Commission directs the ERO to consider personnel responsible for ensuring that critical reliability applications of the EMS, such as state estimator, contingency analysis and alarm processing packages, are available, up to date in terms of system data and produce useable results that can also have an impact on the reliable operation of the BPS (Order No. 693, P. 1373).
4. The Commission directs the ERO to consider the necessity of developing a similar implementation plan with respect to PER-005-1, Requirement R3.1 (Order No. 742, P. 24).
5. The Commission directs the ERO to develop through a separate reliability standards development project formal training requirements for local transmission control center operator personnel, and to develop a definition of "local transmission control center" in the standards development project (Order No. 742, P. 64).

The ERO is required to comply with FERC directives unless there is an equally effective and efficient method of addressing the reliability concern, or if there is evidence that the directive has been overcome by events or is no longer needed. These five directives were challenging due to the variance of industry opinion.

The PER informal development project reviewed the FERC directives, conducted outreach to industry stakeholders, and developed the pro forma standard. There were differing opinions from industry; some stated that the directives should be complied with while others stated there was sufficient justification as to why the directives were no longer needed. Although persuasive, the majority of the arguments as to why the directives were no longer needed had been addressed by FERC in prior orders as outlined in Appendix A. The discussion for each of the above directives are summarized as follows.

First, discussions were held regarding GOP dispatchers at a local control center. Through industry feedback, it became apparent that stakeholders needed a better understanding of the types of GOPs FERC was including in the directive. Initially it appeared that the directive would apply only to those GOPs that make independent decisions; however, FERC had addressed that narrow reading in FERC Order 693 P. 1359. The group's final determination was that even though GOPs at a local control center receive direction from their BA or TOP, those that take direction and then develop dispatch instructions for their plant operators are the specific GOPs the FERC Orders are attempting to capture. Therefore, the pro forma standard expanded the applicability in PER-005 to include these specific types of GOPs.

Second, the ad hoc group received strong feedback from industry that operations planning and operations support staff should not be included in the PER standard. Some of the reasons presented were: the System Operator is the one who impacts the Bulk Electric System (BES) and not the support personnel; support personnel do not make any Real-time decisions on BES operations; mandating training would distract training staff from the more critical functions of training System Operators; and this would create an administrative burden and would be too costly of a task on industry for the reliability protection it offers. Through further research it was determined that these were the same arguments previously presented and responded to by FERC in Orders 693 and 742 (see Appendix A). Therefore, as the informal development effort was not able to provide an argument that had not previously been rejected by FERC, the ad hoc group continued with the inclusion of support personnel in PER-005.

The third major discussion was in regard to the directive for the ERO to consider including personnel responsible for ensuring that critical reliability applications of the EMS, such as state estimator, contingency analysus and alarm processing packages, are available, up-to-date in terms of system data and produce useable results can also have an impact on the reliable operation of the BPS. Similar to the previously described discussions, many of the arguments had been addressed by FERC, but there was new evidence in this area. The argument for not including EMS personnel in the training standard at this time is based on a report provided by the Event Analysis Subcommittee (EAS). The EAS worked with the NERC Event Analysis (EA) staff to review the events that have been cause-coded since October 2010. The database has over 263 events; 208 of them were cause-coded to allow for trending and cluster analysis. The EAS and NERC EA staff queried the 208 events and looked in particular for cause codes that pertain to human errors and training that were less than adequate. The query produced 44 events that had the possibility for human errors or training being a contributing factor in the event. An analysis of those 44 events indicated that only 10 had human error or training as a contributing factor. Six of those 10 events were related to the loss of EMS or SCADA. Out of the six events, only two were deemed to be a training issue. Therefore, based on the information, the EAS and PER ad hoc group do not believe it is necessary at this time to require EMS support personnel to receive the level of training required of a BA, Reliability Coordinator (RC), and TOP by NERC standard PER-005.

Fourth, the ad hoc group and industry stakeholders agreed with the Commission on developing an implementation plan with respect to the simulation technology requirement. The ad hoc group determined that six months would suffice for an entity to become compliant with the simulation technology requirement in PER-005. No feedback has been received thus far from industry regarding this suggested change.

Last, the group addressed the local transmission control center directive by expanding the PER-005 applicability section to Transmission Owners (TO) and creating a standard-only definition. The group defined “local transmission control center” in the standard as *personnel in a transmission control center who operate a portion of the Bulk Electric System at the direction of its Transmission Operator.* This term will not become a part of the NERC Glossary of Terms used in NERC Reliability Standards at this time.

In summary, the PER ad hoc group created a pro forma standard (PER-005-2) extending the applicability to certain GOPs, support personnel, and TOs, excluding EMS support personnel. The 32-hour requirement has been removed as it is inherent to the systematic approach to training that training hours should be left up to each entity. The requirement for 32 hours of training meets the Paragraph 81 criteria for redundancy and was further not a results-based requirement and considered unnecessarily prescriptive. A new requirement R3.1 was created to develop the implementation of the simulation technology requirement.

The pro forma standard was drafted to provide maximum flexibility to industry while addressing the reliability concerns in the FERC directives. Under the pro forma standard, each entity has the ability to identify its reliability-related tasks, determine which of its personnel conduct those tasks, and determine the appropriate training and level of training for each employee. The ad hoc group understood the concerns from industry regarding the systematic approach to training, and each requirement has been left up to the entity to decide which approach should be used.

Purpose

The purpose of the PER-005 white paper is to provide the issues, rationale, and support for the revisions to the PER-005 standard. This white paper provides an explanation of how each of the FERC directives was addressed, including the issues that were raised during informal development and the rationale for proceeding or not proceeding with each. This paper will also provide technical justification and support for the revisions to the standard. The contents in this paper will provide the standard drafting team with the basis for the pro forma standard so they can begin the formal standard development process.

History of the PER-005 Informal Development

In February 2012, the North American Electric Reliability Corporation (NERC) Board of Trustees (Board) formed the Standards Process Input Group (SPIG) to address the widespread frustration with the duration of the standards development process.[1] In May 2012, SPIG submitted a report to the NERC Board recommending improving both the timeliness and quality of the standards. The process manual changes were approved by the Board in February 2013.[2] Since then, the Board issued a resolution requesting SPIG, the Members Representative Committee (MRC), NERC staff, and industry stakeholders to reform their standards development paradigm. Changes were integrated into the 2013–15 Reliability Standards Development Plan (RSDP) and Standards Committee (SC) Strategic Plan.[3]

The evolving standards process includes an informal development period in which NERC Standards developers work with an ad hoc group to gather information up front from industry regarding the FERC directives or other standards development project. There are three approaches to consider when addressing FERC directives: comply with the FERC directive, present an equally and effective alternative, or provide technical justification as to why the directive is no longer needed.

A PER ad hoc group was formed in January of 2013 to work with industry stakeholders to address five outstanding FERC directives. The ad hoc group addressed each directive through informal development, with the goal of filing a revised standard with FERC by December 31, 2013.

The PER ad hoc group held its first informal development meeting February 25–27, 2013, in Atlanta, Georgia. A small ad hoc group of industry subject matter experts (SMEs) representing RCs', BAs', GOPs', TOPs', and TOs' participated in discussions about the FERC directives and possible resolutions to address them. The ad hoc group created the first draft of a pro forma standard to address each directive. The ad hoc group conducted conference calls, workshops, and, to reach additional industry participants, two webinars: a March 15 informational webinar and an April 4 industry feedback webinar requesting feedback from industry regarding the PER ad hoc group suggestions. Multiple conference calls were held with the ad hoc group to keep all members aware of feedback received.

A second informal meeting was held April 22–23, 2013, at NERC's Atlanta office. The meeting was a continuation of the efforts of the first meeting with the addition of discussion on the information received through the outreach efforts. The ad hoc group discussed issues raised by industry and revised the pro forma standard based on that information. The group presented the revised pro forma standard to industry at the May 31 industry feedback webinar and other conference calls. During the webinar, polling questions were presented to participants, and 147 out of 323 people participated in the polling. The purpose of this polling was to gauge industry's support of the suggested PER-005 standard.

The last informal development meeting was held June 20–21, 2013 to develop the materials necessary to move into the formal process. This will entail submitting a Standard Authorization Request (SAR), the pro forma standard, input to a reliability standards audit worksheet (RSAW), an implementation plan, a mapping document, and a technical white paper to the NERC Standards Committee (SC).

A complete list of entities that participated during the informal development can be located in Appendix B.

[1] May 9, 2012 NERC Board minutes: http://www.nerc.com/gov/bot/Agenda%20Minutes%20and%20Highlights%20DL/2012/BOT_050912m_complete.pdf
[2] August 16, 2012 NERC Board minutes: http://www.nerc.com/gov/bot/Agenda%20Minutes%20and%20Highlights%20DL/2012/0-BOT08-12a-complete.pdf
[3] 2013–15 Reliability Standards Development Plan: http://www.nerc.com/pa/Stand/Standards%20Development%20Plan%20Library/2013-2015_RSDP_BOT_Approved_12-19-12.pdf

Outstanding FERC Directives and Technical Discussions

There are five outstanding FERC directives from Order 693[4] and Order 742.[5] Each directive was discussed in detail during the informal development stage, and below are the summaries of the discussions.

Applicability of the PER Standard to GOP Dispatchers

FERC Order 693 ¶ 1360-1361, 1363

P. 1360. We agree with FirstEnergy and others that some clarification is required regarding which generator operator personnel should be subject to formal training under the Reliability Standard. As noted above, a generator operator typically receives instructions from a balancing authority. Some generator operators are structured in such a way that they have a centrally-located dispatch center that receives direction and then develops specific dispatch instructions for plant operators under their control. For example, a balancing authority may direct a centrally-located dispatch center to deliver 300 MW to the grid, and the dispatch center would determine the best way to deliver that generation from its portfolio of units. In this type of structure, it is the personnel of the centrally located dispatch center that must receive formal training in accordance with the Reliability Standard. Plant operators located at the generator plant site also need to be trained but the responsibility for this training is outside the scope of the Reliability Standard.

P. 1361. Other generator operators may be structured in such a way that the dispatch center and the single generation plant are at the same site. In this structure as well, some personnel will perform dispatch activities while others are designated as plant operators. Again, it is the dispatch personnel that must receive formal training in accordance with the Reliability Standard. Plant operators also need to be trained but the responsibility for this training is outside the scope of the Reliability Standard.

P. 1363. Further, the Commission agrees with MidAmerican, SDG&E and others that the experience and knowledge required by transmission operators about Bulk-Power System operations goes well beyond what is needed by generation operators; therefore, training for generator operators need not be as extensive as that required for transmission operators. Accordingly, the training requirements developed by the ERO should be tailored in their scope, content and duration so as to be appropriate to generation operations personnel and the objective of promoting system reliability. Thus, in addition to modifying the Reliability Standard to identify generator operators as applicable entities, we direct the ERO to develop specific Requirements addressing the scope, content and duration appropriate for generator operator personnel.

FERC Order 742 ¶ 83-84

P. 83. EPSA requests clarification of several statements in the NOPR regarding the Order No. 693 directive related to expanding the applicability of the system operator training Reliability Standard to include certain generator operators. First, EPSA expresses concern that the NOPR discussion broadly addresses generator operator personnel in a way that could be construed as subjecting all generator operator personnel, regardless of the disposition of the generating unit and how it fits into the grid and the topology of the grid, to the system operator training requirements. Therefore EPSA seeks clarification that the Commission did not intend for the NOPR to expand the Order No. 693 directives. We confirm that we have not modified the scope of applicability of the Order No. 693 directive regarding generator operator training. As described in Order No. 693, the directive applies to generator operator personnel at a centrally-located dispatch center who receive direction and then develop specific dispatch instructions for plant operators under their control. Those generator operator personnel must receive formal training of the nature provided to system operators under PER-005-1. As clarified in Order No. 693, this group of personnel would include a generator operator’s dispatch personnel where a single generator and dispatch center are located at the same site.

P. 84. EPSA also seeks clarification regarding the statement in the NOPR that: “[I]n the event communication is lost, the generator operator personnel must have had sufficient training to take appropriate action to ensure reliability of the Bulk-Power System.” EPSA expresses concern that this statement suggests that if communication is lost with the grid operator, the generator operator must take unilateral action for which it requires training. EPSA notes that generator operators do not take such unilateral action nor do they have access to information to make such decisions. Therefore, EPSA asks the Id. Commission to make clear that while communication should be addressed in training requirements for centrally located generator operator dispatch employees, the Commission is not extending related responsibilities or training requirements to generator operator employees. We grant the requested clarification, and affirm that we are not modifying the Order No.

[4] *Mandatory Reliability Standards for the Bulk-Power System*, 118 FERC ¶ 61,218, FERC Stats. & Regs. ¶ 31,242 (Order No. 693), *order on reh’g, Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 (Order No. 693-A) (2007).

[5] FERC Order 742 PP 83-84

693 directive regarding training for certain generator operator dispatch personnel, nor are we expanding a generator operator's responsibilities.

Consideration of Directive

The PER ad hoc group considered all options (such as complying with the FERC directive, presenting an equally and effective alternative, or providing technical justification as to why the directive is no longer needed) when addressing GOPs at a centrally located dispatcher center who receive direction and then develop specific dispatch instructions for plant operators under their control.[6] The ad hoc group suggested a revised PER-005-1 standard that expands the applicability section to these specific GOPs, leaving it up to the entity to identify the reliability-related tasks its GOP personnel should be trained on. The group attempted to draw a bright line of GOPs that make independent decisions. Through subsequent discussions with FERC's OER staff, the group learned that this bright line, per the FERC orders, would not address the FERC directive. It appears that the intent of the FERC order is for GOPs at a control center who receive direction from their BAs or TOPs to develop specific dispatch instructions (not just that make an independent decision) for their plant operator. These are the people who should be captured under the standard. The group considered and suggested a revised PER-005 that extends applicability to these specific GOPs. The standard language allows the entity to decide which systematic approach to training should be used when training GOPs and includes coordination on training topics with the entity's RC, BA, TOP, and TO.

Technical Discussions

Many technical discussions were held regarding increasing the applicability of the PER standard to GOP dispatchers. The feedback provided in the list below are the reasons provided by industry as to why this directive was no longer needed for GOP dispatchers.

- All decisions that GOPs make that impact the reliability of the BES must be approved by the BA, TOP, or RC. Even in the case of an emergency situation, the GOP will not make any decisions until approved by the BA, TOP, or RC. It was further explained that there are GOPs that do not develop dispatch instruction and simply take the information received from the BA, TOP, or RC and relayed information directly to the plant operator.
- FERC limited emergency shutdowns of generation to occur at the plant level, not the dispatch level; at this time, the FERC order does not require plant operators to be trained.
- The NERC Functional Model was stated many times as a reason to show that GOP dispatchers follow the direction of the BA or TOP. The NERC Functional Model for GOPs states that GOPs in Real time:
    - Provide Real-time operating information to the Transmission Operators and the required Balancing Authority.
    - Adjust real and reactive power as directed by the Balancing Authority and Transmission Operators.[7]
- When a GOP would be making decisions that impact reliability, they are also registered as the BA or TOP.

Entities that agreed with GOPs being added to the standard made the following comments:

- Consider including some criteria regarding various sizes of generation like in CIP Version 5.
- Consider creating a new standard addressing GOP dispatchers.
- PPL Electric Utilities Corp., Louisville Gas and Electric Co., and PPL Generation LLC stated that the TOP or BA should prepare the GOP training modules since the goal is to ensure that dispatchers do what the TOP or BA wants in emergency situations.

The arguments provided above constitutes the same arguments that FERC rejected in Order Nos 693 and 742 (see Appendix A).

[6] FERC Order 742 P 83.
[7] NERC functional model: http://www.nerc.com/pa/Stand/Resources/Documents/FunctionalModelTechnicalDocumentV5Clean2009Dec1.pdf

FERC Order 693 P. 1393 clearly states that GOP dispatchers need to be trained using the systematic approach to training methodology.

> 1393. Accordingly, the Commission approves Reliability Standard PER-002-0. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to PER-002-0 through the Reliability Standards development process that: (1) identifies the expectations of the training for each job function; (2) develops training programs tailored to each job function with consideration of the individual training needs of the personnel; (3) expands the Applicability section to include (a) reliability coordinators, (b) local transmission control center operator personnel (as specified in the above discussion), **(c) generator operators centrally-located at a generation control center with a direct impact on the reliable operation of the Bulk-Power System and** (d) operations planning and operations support staff who carry out outage planning and assessments and those who develop SOLs, IROLs or operating nomograms for Real-time operations; **(4) uses the Systematic Approach to Training (SAT) methodology in its development of new training programs** and (5) includes the use of simulators by reliability coordinators, transmission operators and balancing authorities that have operational control over a significant portion of load and generation.[8]

The pro forma standard is written to require the use of a Systematic Approach to Training, but provides the entity the ability to determine the reliability-related tasks GOP dispatchers need to be trained on and the method of how the GOP dispatchers are trained.

There were discussions regarding whether training for GOPs should be in a separate standard, however the current PER-005 is a systematic approach to training based standard and thus it is logical to include the GOP dispatchers within the current standard.

Because the ad hoc group received the same feedback that was provided in FERC Order Nos. 693 and 742; the ad hoc group suggested expanding the applicability section in PER-005 to capture these certain GOP dispatchers using the systematic approach to training, which is left up to the entity.

Applicability of the PER Standard to Operations Planning and Operations Support Staff

FERC Order 693 ¶ 1366

P. 1366. As mentioned above, the Commission proposed in the NOPR to direct the ERO to develop a modification to PER-002-0 to require training of operations planning and operations support staff of transmission operators and balancing authorities who have a direct impact on the reliable operation of the Bulk-Power System.[9]

FERC Order 742 ¶ 82

P. 82. Associated Electric expressed concern that the NOPR definition of the “operations planning and operations support staff” who should receive training pursuant to the Order No. 693 directive is “broad and will encompass operations planning and operation support staff who engage in tasks that do not directly affect the reliable operation of the bulk electric system.” The Commission clarifies that the scope of the Reliability Standard or modification to a Reliability Standard to address training for “operations planning and operations support staff” is limited by the qualifications stated in Order No. 693. Specifically, in Order No. 693, the Commission directed the ERO to develop a modification to PER-002-0 that extends applicability of the training requirements to the operations planning and operations support staff of transmission operators and balancing authorities. The Commission further clarified that such directive applies only to operations planning and operations support personnel who: “carry out outage coordination and assessments in accordance with Reliability Standards IRO-004-1 and TOP-002-2, and those who determine SOLs and IROLs or operating nomograms in accordance with Reliability Standards IRO-005-1 and TOP-004-0.” The NOPR did not expand or alter the scope of this directive as set forth in Order No. 693.[10]

[8] FERC Order 693 P 1363.
[9] FERC Order 693 P 1366.
[10] FERC Order 742 P 82.

Consideration of Directive

The PER ad hoc group held multiple discussions regarding the impact that operations planning and operations support staff have on the BES. The feedback received from industry regarding this topic was deemed to be the same arguments provided in the NOPR and rejected in FERC Orders 693 and 742 (see Appendix A). Therefore, the ad hoc group group revised PER-005-1 to incorporate operations planning and support personnel in the standard.

Technical Discussions

Industry provided the following information regarding operations planning and operations support staff about why training is not needed for support personnel:

- Training will provide no reliability benefit because of the administrative burden on entities and costly burden on industry with uncertain benefits.
- Training will provide no reliability impact because System Operators make the final decision, and support personnel do not make Real-time decisions.
- Operations planning and planning support staff is ambiguous and should be clarified.
- Entities appear to already train their support personnel; therefore, it should not be a mandatory requirement.

Again, the feedback received was deemed to be the same arguments provided on FERC Orders 693 and 742; therefore, the ad hoc group revised PER-005-1 to incorporate operations planning and support personnel in the standard.

Applicability of the PER Standard to EMS Personnel FERC Order 693 ¶ 1373

1373. In addition, the Commission is aware that the personnel responsible for ensuring that critical reliability applications of the EMS, such as state estimator, contingency analysis and alarm processing packages, are available, up-to-date in terms of system data and produce useable results can also have an impact on the Reliable Operation of the Bulk-Power System. Because these employees' impact on Reliable Operation is not as clear, we direct the ERO to consider, through the Reliability Standards development process, whether personnel that perform these additional functions should be included in mandatory training pursuant to PER-002-0.[11]

Consideration of Directive

Through discussion with industry, the ad hoc group determined that the report provided by the Event Analysis Subcommittee (EAS) serves as rationale for why EMS personnel should not be included in the PER standard at this time. The technical discussion section below provides more in-depth information regarding this determination.

Technical Discussions

As background, in Orders 693 and 742, the Commission directed NERC to consider whether there is a need to include EMS personnel in the training standard. In contrast to the directive for GOPs and operations support personnel, FERC did not conclude that it was necessary to include EMS personnel in the standard; rather, it directed the ERO to consider EMS personnel inclusion. The ad hoc group discussed the issue with industry stakeholders and concluded that the data does not support a need to include EMS personnel in the standard at this time.

Based on the information in the EMS report on cause-coded events, the EAS and PER ad hoc group do not believe it is necessary at this time to require EMS support personnel to receive the level of training required of a BA, Reliability Coordinator (RC), and TOP by NERC Reliability Standard PER-005.

Lastly, the EMS events will continue to be monitored, and if EMS events begin to indicate that training is a root or contributing cause, NERC will readdress inclusion of EMS personnel to PER-005. A request will be submitted to the Operating Committee (OC) to produce an EMS guideline for training EMS personnel.

[11] FERC Order 693 P 1373.

New Simulation Technology Implementation Plan
FERC Order 742 ¶ 24

With respect to EEI's comment regarding the effective date for entities that may become subject to the simulator training requirement in PER-005-1 R3.1, the Commission believes that this issue should be considered by the ERO. We note that, with respect to the Critical Infrastructure Protection (CIP) Reliability Standards, NERC has developed a separate implementation plan that essentially gives responsible entities some lead time before newly acquired assets must be in compliance with the effective CIP Reliability Standards. **We direct NERC to consider the necessity of developing a similar implementation plan with respect to PER-005-1, Requirement R3.1.**[12]

Consideration of Directive

The PER ad hoc group was in agreement that a new subrequirement 3.1 should be developed in the PER-005 standard to address entities that may become subject to simulator training in the future. Further discussion was held regarding the best time frame for entities to become compliant, and the general consensus was that six months is a reasonable timeframe. This information was presented at webinars, conferences, and face-to-face meetings, and no feedback was received regarding the implementation plan of simulator training for entities.

Technical Discussions

The ad hoc group did not receive feedback regarding the implementation plan for simulation technology.

Applicability of the PER Standard to Local Transmission Control Center
FERC Order 742 ¶ 64

Accordingly, we adopt our NOPR proposal and direct the ERO to develop through a separate Reliability Standards development project formal training requirements for local transmission control center operator personnel. Finally, given the numerous comments stating that term "local transmission control center" should be defined, we direct NERC to develop a definition of "local transmission control center" in the standards development project for developing the training requirements for local transmission control center operator personnel. We will not evaluate Associated Electric's proposed definition but, rather, leave it to the ERO to develop an appropriate definition that reflects the scope of local transmission control centers. The Commission will not opine on the appropriate definition of local transmission control center, as this definition can be addressed first using NERC's Reliability Standards Development Procedures.

Consideration of Directive

The ad hoc group considered whether to define local transmission control center in the NERC Glossary of Terms or create a standard-only definition. The group defined "local transmission control center" by extending the PER standard applicability to TOs and developing a definition that only applies to the PER standard. The suggested TO standard-only definition is *personnel in a transmission control center who operate a portion of the BES at the direction of its Transmission Operator*.

Technical Discussions

The group did not receive many comments regarding expanding formal training for local transmission control center operator personnel and defining local transmission control center. The group suggested a revision to PER-005-1 and created a standard-only definition of "local transmission control center."

Other Issues

Inconsistent usage of "each calendar year," "annual," and "at least every twelve months"

The PER ad hoc group changed all terms (such as "annual" and "at least every twelve months") to "each calendar year" due to "each calendar year" being better defined than the other two terms.

Definitions

System Operator

A SAR was submitted for GOPs to be removed from the System Operator definition. The ad hoc group removed the term and suggested a revised definition. The suggested definition is as follows: *An individual at a ~~c~~Control ~~c~~Center ~~(Balancing~~*

[12] FERC Order 742 P 64

~~*Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control*~~ *who operates or directs the operation of the Bulk ~~e~~Electric ~~s~~System in Real time.*

System Personnel

The term "System Personnel" was created as a standard-only definition for PER-005. The purpose of this definition is to capture certain applicable entities within the requirement instead of having to type each one out individually, multiple times, in a requirement. The suggested definition is as follows: *System Operators of a Reliability Coordinator, Transmission Operator, or Balancing Authority, and the Transmission Owner personnel described in the Applicability Section of this standard.*

Support Personnel

The term "System Personnel" was created as a standard-only definition for PER-005. The purpose of this definition is to capture certain applicable personnel within the requirement as a group for clarity. The suggested definition is as follows: *Individuals who carry out outage coordination and assessments, or determine SOLs, IROLs, or operating nomograms for Real-time operations.*

Conclusion

The informal development initiative provided key discussions regarding the outstanding PER FERC directives. This white paper encapsulates all of the components of what is needed for the Standards Committee to act on, discuss, and ultimately authorize the PER Standard Authorization Request.

Appendix A: Industry Arguments and FERC Responses

The below table shows initial arguments received from industry regarding FERC Orders 693 and 742. Also shown below are the arguments received from industry to-date that are deemed to be the same arguments found in both orders.

EXTENDING APPLICABILITY TO GOPS				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comment**
<u>Clarification of Applicable GOPs</u> Many commenters requested clarification as to which GOPs needed to be trained: 1) FirstEnergy supported GOP training but noted there was some confusion over the GOP classification, which is sometimes used to refer to dispatch personnel (or fleet operators at a control center) and other times used to refer to a plant or unit operator. FirstEnergy requested that the Commission direct NERC to recognize this distinction. 2) California PUC, Nevada Companies, Reliant, Dynegy, MISO, and Wisconsin Electric all presented various arguments as to why training should not be extended to plant operators. These entities did not argue against application of the training standard to dispatch personnel.	Order No. 693 at PP. 1350, 1352-54	FERC clarified that the directive to train GOPs only applies to GOPs located at a dispatch center that receives direction and then develops specific dispatch instructions for plant operators under their control. FERC clarified that plant operators need not be trained under the standard.	Order No. 693 at PP. 1360-61 See also Order No. 742 at P. 83.	

EXTENDING APPLICABILITY TO GOPS				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comment**
Decision-Making Arguments A number of commenters, including Xcel, argued that GOPs need not be trained because they do not make independent decision. They argued that GOPs simply take their direction from Transmission Operators, Balancing Authorities, and Reliability Coordinators, which limits their ability to exercise independent action impacting the reliability of the Bulk-Power System.	Order No. 693 at PP. 1351; 1354	FERC rejected this argument, stating: "Xcel and others oppose extending the applicability of PER-002-0 to generator operators, because they take directions from balancing authorities and others, which limits their ability to impact reliability. Although a generator may be given direction from the balancing authority, it is essential that generator operator personnel have appropriate training to understand those instructions, particularly in an emergency situation in which instructions may be succinct and require immediate action. Further, if communication is lost, the generator operator personnel should have had sufficient training to take appropriate action to ensure reliability of the Bulk-Power System. Thus, we direct the ERO to develop a modification to make PER-002-0 applicable to generator operators.	Order No. 693 at P. 1359	Decision-Making Arguments A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that all decisions that GOPs make that impact the BES must be approved by BA, TOP, or RC have the final say in the decisions being made.

EXTENDING APPLICABILITY TO GOPS				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comment**
<u>No Reliability Benefit Argument</u> Entergy, Xcel and Nevada companies further argued that generator operator training will provide limited benefit. Entergy further stated that that expanding the applicability to generator operators would provide little benefit to those personnel in the performance of their own functions, and could distract them from those functions.	Order No. 693 at P. 1351; 1357	FERC disagreed, stating that with the limitation of training to dispatch personnel, "the benefits to the Bulk-Power System will be maximized and the cost of formal training limited."	Order No. 693 at P. 1362	<u>No Reliability Benefit Argument</u> Creating training for GOPs will be costly and provide no benefit.
<u>Scarcity of Resources and Cost Argument</u> Entergy argued that training would be extremely costly and would divert necessary resources from more important reliability objectives. TAPS also opposed the expanded applicability, especially in the case of small systems, because it believes that the requirement would be costly with no benefits to reliability.	Order No. 693 at P. 1351; 1357	See above. FERC rejected these arguments, stating that the limitation to dispatch personnel would limit the cost of training.	Order No. 693 at P. 1362	<u>Scarcity of Resources and Cost Argument</u> A number of commenters, through verbal conversations and the chat feature during PER webinars stated that it will be costly to train GOPs. Smaller entities state it will be a costly to provide training to their GOPs and no major benefits will appear.
<u>Scope of Training Arguments</u> Many commenters discussed the scope of training for GOPs, arguing that the scope, content, and duration needs to be limited and tailored to their functions.	Order No. 693 at P. 1356	FERC agreed, stating that training for Generator Operators need not be as extensive as that required for Transmission Operators, and the training requirements developed by the ERO should be tailored in their scope, content, and duration so as to be appropriate to Generation Operations personnel and the objective of promoting system reliability.	Order No. 693 at P. 1363	<u>Scope of Training Arguments</u> Concerns about GOPs that do not develop dispatch instructions will be captured regardless.

EXTENDING APPLICABILITY TO GOPS				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comment**
Size Limitation Arguments APPA, TAPS, and the Process Electricity Committee requested a size limitation, arguing that while a generator plays an important role in the reliable operations of the Bulk Electric System, the Generator Operator takes commands from the Rransmission Operator, Balancing Authority, or Reliability Coordinator. Without a size limitation, the standard would require many small generators to enroll in a training program.	Order No. 693 at P. 1357	FERC responded that concerns regarding the need for a size limitation on Generator Operators should be satisfied by FERC's determination that the applicability of particular entities should be determined based on the ERO compliance registry criteria.	Order No. 693 at P. 1357	Size Limitation Arguments Comments received stated that a size limitation needs to be captured like CIP V5.
In response to the Order No. 742 NOPR, a number of commenters challenged the need for the directive.	Order No. 742 at P. 79	FERC rejected these arguments as beyond the scope of Order No. 742 and as collateral attacks on the ruling in Order No. 693 and refused to address the arguments again.	Order No. 742 at PP. 79, 81	

EXTENDING APPLICABILITY TO GOPS				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comment**
EPSA Clarification EPSA sought clarification regarding the statement in the NOPR, "[I]n the event communication is lost, the generator operator personnel must have had sufficient training to take appropriate action to ensure reliability of the Bulk-Power System." EPSA expressed concern that this statement suggests that if communication is lost with the grid operator, the Generator Operator must take unilateral action for which it requires training. EPSA notes that Generator Operators do not take such unilateral action, nor do they have access to information to make such decisions. EPSA asks the Commission to make clear that while communication should be addressed in training requirements for centrally located Generator Operator dispatch employees, the Commission is not extending related responsibilities or training requirements to Generator Operator employees.	Order No. 742 at P. 84	FERC granted the requested clarification and affirmed that it did not modify the Order No. 693 directive regarding training for certain Generator Operator dispatch personnel, nor expand a Generator Operator's responsibilities.	Order No. 742 at P. 84	

EXTENDING APPLICABILITY TO SUPPORT PERSONNEL				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comments**
<u>No Reliability Benefit</u> EEI states that the extension of the applicability to "operations support personnel" could result in a dramatic expansion of industry training requirements with uncertain benefits to system reliability.	Order No. 693 at P. 1368	FERC stated that because it is limiting training of support personnel to those who carry out outage coordination and assessments and those who determine SOLs and IROLs or operating nomograms, the directive is limited to those with a direct impact on reliability.	Order No. 693 at P. 1374	<u>No Reliability Benefit</u> A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that expanding PER-005 applicability to support personnel will capture a variety of people who do not impact the BES.
<u>TOP makes decision</u> Entergy argued that it is unnecessary to require all staff supporting the Transmission Operator to be trained in the Transmission Operator's Reliability Standards responsibilities, because as long as the supporting personnel work under the direction of a NERC-certified Transmission Operator, there is no need for duplicative training for supporting personnel.	Order No. 693 at P. 1370	FERC stated that because it is limiting training of support personnel to those who carry out outage coordination and assessments and those who determine SOLs and IROLs or operating nomograms, the directive is limited to those with a direct impact on reliability.	Order No. 693 at P. 1374	<u>TOP makes decision</u> A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that decisions are made by the NERC-Certified System Operators.
<u>Administrative Burden</u> APPA expressed concern about expanding the applicability to operations planning and operations support staff, especially if the Commission adopts its proposed interpretation of the Bulk Electric System, because this would become quite onerous for small utilities.	Order No. 693 at P. 1368	FERC limited the scope of what support personnel must be trained and clarified that training for support personnel should be tailored to the functions they perform and need not be trained to the same extent as Transmission Operators.	Order No. 693 at P 1375	<u>Administrative Burden</u> A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that this would be a huge administrative burden regarding the SAT process.

EXTENDING APPLICABILITY TO SUPPORT PERSONNEL				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comments**
Directive is Ambiguous Wisconsin Electric argued that the Commission's proposal does not address how to identify the operations planning and operations support personnel who would be subject to the Reliability Standard and how to develop compliance measures for them. It contended that the proposed modification is ambiguous and should not be implemented. Northern Indiana also argued that the terms "operations planning" and "operations support staff" should be clarified.	Order No. 693 at P. 1368	FERC clarified that the support personnel who need to be trained are those who carry out outage coordination and assessments in accordance with Reliability Standards IRO-004-1 and TOP-002-2, and those who determine SOLs and IROLs or operating nomograms in accordance with Reliability Standards IRO-005-1 and TOP-004-0. FERC said that because the reliability impact of EMS personnel are unclear, it directed NERC to consider whether such personnel need to be trained.	Order No. 693 at P. 1372	Directive is Ambiguous A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that "operations planning" and "operations support" are too broad.
Scope of Training Entergy commented that if training is required, it should focus on the functions operations planning and operations support staff must perform, not on the functions that others perform.	Order No. 693 at P. 1370	FERC clarified that training for support personnel should be tailored to the functions they perform and need not be trained to the same extent as transmission operators.		Scope of Training

EXTENDING APPLICABILITY TO SUPPORT PERSONNEL				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comments**
No Reliability Benefit In response to the Order No. 742 NOPR, a number of commenters challenged the need for the directive. For example, Associated Electric urged the Commission to direct NERC to adopt a definition of "operations planning" and "operations support staff" that more narrowly identifies those personnel who will be subject to the training standard. Associated Electric stated that the directive in Order No. 693 is broad and will encompass operations planning and operation support staff who engage in tasks that do not directly affect the reliable operation of the Bulk Electric System. GSOC and GTC do not support expanding the applicability of the PER-005-1 training requirements to any other personnel and argue that time spent expanding training requirements to other personnel will take away from their job of supporting their operating personnel—a use of time and resources that could actually decrease reliability.	Order No. 742 at P. 80	FERC rejected these arguments as beyond the scope of Order No. 742 and as collateral attacks on the ruling in Order No. 693 and refused to address the arguments again.	Order No. 742 at PP. 79, 81	No Reliability Benefit A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that tasks performed by support personnel do not directly affect the BES. Support personnel may guide, but do not operate.

Appendix B: Entity Participants

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

Table 2: Entity Participation in PER Informal Development

ACES Power	CPS Energy	IESO	NV Energy	Southern Co.
AECI	CSU	IMPA	OGE	STEC
AEP	CWLP	Integry Group	OMU	Sunflower
AES	DC PUD	IREA	ORU	Sycamore
ALCOA	Detroit Renewable	ISO-NE	OUC	TID
Alliant Energy	Direct Energy	ITC	OXY	Tri-State G&T
Ameren	Dominion	KCPL	PacifiCorp	TVA
AMP Partners	DTE Energy	KUA	PEPCO	
APS	Duke Energy	LCEC	PGE	
ATC	Dynegy	LCRA	PGN	**Regional Entities**
Austin Energy	Energy GRP	LES	PJM	FRCC
Blackhills Corp	Entergy	LGE-KU	PNM	MRO
BPA	EP Electric	Luminant	PNM Resources	NPCC
Brazos Electric	ERCOT	MGE	PPL	RFC
Brownsville PUD	Essential Power LLC	MidAmerican	Seattle Power & Light	SERC
CAISO	Exelon Corp	Minnkota Power	Sempra Utilities	SPP
CB Power	FMTN	MISO Energy	Sharyland	TRE
Center Point Energy	FPL	NaturEner	SMEPA	WECC
Chelan PUD	GASOC	NIPSCO	SMMPA	
City of Tacoma	GC Pud	Northwestern	SMUD	
City Utilities	Hydro Manitoba	NRECA	Snohomish PUD	
Cleco Corporation	Hydro-Quebec	NU	South Westgen	

Table 3: Presentations and Events

NERC Operating Committee	FRCC Compliance Workshop
NERC EAS	WECC Operations Training Subcommittee
NERC Standards and Compliance Workshop	WECC Standing Committees
NERC News	TRE Standards Discussion Forum

Proposed Timeline for the Project 2010-01 Standard Drafting Team (SDT)

Anticipated Date	Location	Event
July 2013	-	SC Authorizes SAR and Pro Forma Standard for Posting
July 2013		Conduct Nominations for Project 2012-05 SDT
July 2013	-	Post SAR and Pro Forma standard for 45-Day Comment Period
August 2013	-	Conduct Ballot
September 2013	-	45-Day Comment Period and Ballot Closes
September 2013	San Francisco	PER Standard Drafting Team Face to Face Meeting to Respond to Initial Comments and Make Possible Revisions
October 7, 2013	Webinar	PER Industry Webinar
Mid-November 2013	Atlanta, GA	PER Standard Drafting Team Face to Face Meeting to Respond to Initial Comments and Make Possible Revisions
November 2013	-	Conduct Final Ballot
December 2013	-	NERC Board of Trustees Adoption
December 31, 2013 (Targeted)	-	NERC Files Petition with the Applicable Governmental Authorities

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

DRAFT Reliability Standard Audit Worksheet[1]

PER-005-2 – Operations Personnel Training

This section to be completed by the Compliance Enforcement Authority.

Audit ID: Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity: Registered name of entity being audited
NCR Number: NCRnnnnn
Compliance Enforcement Authority: Region or NERC performing audit
Compliance Assessment Date(s)[2]: Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method: Audit
Names of Auditors: Supplied by CEA

Applicability of Requirements *[RSAW developer to insert correct applicability]*

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1	X								X			X[3]	X		
R2	X								X			X[3]	X		
R3	X								X			X[3]	X		
R4	X								X			X[3]	X		
R5				X[4]											

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.
[3] Applicable to Transmission Owner that has personnel at a facility, excluding field switching personnel, who act independently to carry out tasks that require Real-time operation of the Bulk Electric System, including protecting assets, protecting personnel safety, adhering to regulatory requirements and establishing stable islands during system restoration.
[4] Applicable to Generator Operator that has dispatch personnel at a centrally located dispatch center who receive directions from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control. This personnel does not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions, without making any modifications.

Subject Matter Experts

Identify Subject Matter Expert(s) responsible for this Reliability Standard. (Insert additional rows if necessary)

Registered Entity Response (Required):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

R1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall use a systematic approach to training to develop and implement a training program for its System Personnel as follows:

1.1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology.

1.1.1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall review, and update if necessary, its list of Real-time reliability-related tasks identified in part 1.1 each calendar year.

1.2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall design and develop training materials according to its training program, based on the Real-time reliability-related task list created in part 1.1.

1.3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall deliver training to its System Personnel according to its program.

1.4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall implement the changes identified.

M1. Each Reliability Coordinator, Balancing Authority, Transmission Operator and Transmission owner shall have available for inspection evidence of using a systematic approach to training to establish and implement a training program, as specified in Requirement R1.

M1.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection its methodology and its company-specific Real-time reliability-related task list, with the date of the last review, as specified in Requirement R1 part 1.1.

M1.2 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training materials, as specified in Requirement R1 part 1.2.

M1.3 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection System Personnel training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R1 part 1.3.

M1.4 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed a training program evaluation each calendar year, as specified in Requirement R1 part 1.4.

Definition of System Operator
An individual at a control center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System in Real-Time.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[5]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
(part 1.1) List of BES company-specific Real-time reliability-related tasks and documented methodology for developing task list.
(part 1.1.1) Evidence, such as a memo, meeting minutes, or dated task list, of review of the task list each calendar year.
(part 1.2) Samples of training materials as requested by the auditor.
(part 1.3) An organization chart or other list identifying all System Personnel and the Real-time reliability-related tasks they perform. List of training delivered and attendance logs for a sample of training sessions requested by the auditor.
(part 1.4) Evidence, such as a memo, meeting minutes, or other information as specified in M1.4 demonstrating that the review of the training program occurred every calendar year and a list of needed changes to the training program based on the review.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

[5] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Compliance Assessment Approach Specific to PER-005-2, R1

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process.
	(part 1.1) and (part 1.1.1) Verify entity's list of Real-time reliability-related tasks, related methodology, and evidence of review each calendar year. Ensure list of Real-time reliability-related tasks was created pursuant to their methodology.
	(part 1.2) Review sample of training materials provided to determine if they support the Real-time reliability-related task list.
	(part 1.3) Agree specific System Personnel, as selected by the auditor from the organization chart, back to attendance logs for training that was delivered related to the Real-time reliability-related tasks they perform pursuant to its program.
	(part 1.4) Review evidence that the review of the training program occurred every calendar year. Review list of changes to the training program based on the review and examine training materials, or other documents, to gain reasonable assurance that changes identified were implemented into the training program.

Note to Auditor: The training staff does not have to be internal staff of the entity.

While the sub-requirements for Requirement R1 address the elements of a systematic approach to training consistent with FERC orders No.742 at P25 and No. 693 at P1380 and P1382, an auditor will evaluate whether the entity's overall training program follows the principles below:

- Assess training needs (analysis)
- Conduct the training activity (design, develop and implement)
- Evaluate the training activity (evaluate the effectiveness of the training)

Auditors are to interpret a calendar year as January 1 to December 31.

Changes such as simply rewording for clarification that do not affect the task performance or knowledge requirements, are not considered a modified task.

It is acceptable to group tasks under a job position, and then identify the System Operators that perform that job position, in lieu of assigning tasks to each individual System Operator.

The nature and extent of audit procedures applied related to this requirement will vary depending on certain risk factors to the Bulk Electric System and the auditor's assessment of management practices specific to this requirement. In general, more extensive audit procedures will be applied where risks to the Bulk Electric System are higher and management practices are determined to be less effective.

Based on the assessment of risk and internal controls, as described above, specific audit procedures applied for this requirement may range from exclusion of this requirement from audit scope to the auditor reviewing training records for an entity's entire population of System Personnel.

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its System Personnel assigned to perform each of the Real-time reliability-related tasks identified under Requirement R1 part 1.1.

2.1. Within six months of a modification or addition of BES company-specific Real-time reliability-related tasks, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its System Personnel to perform the new or modified Real-time reliability-related tasks identified in Requirement R1 part 1.1.

M2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence to show that it verified the capabilities of each of its System Personnel assigned to perform each of the Real-time reliability-related task identified under Requirement R1 part 1.1, as specified in Requirement R2. This evidence may be documents such as records showing capability to perform Real-time reliability-related tasks with the employee name and date; supervisor check sheets showing the employee name, date, and Real-time reliability-related task completed; or the results of learning assessments.

Registered Entity Response (Required):
Question: Has entity modified or added a Real-time reliability-related task, since the Requirement R1 part 1.1 task list was initially developed? ☐ Yes ☐ No

If so, when was task added, or what task was modified and when?

Include additional information regarding the Question in gray area below, including the type of response and format of the response requested, as appropriate.
Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[6]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
(R2) Documentation, such as provided in M2, evidencing selected System Personnel's capabilities to perform the Real-time reliability-related tasks selected by the auditor based on tasks identified under Requirement R1 part 1.1.
(part 2.1) A list of modifications or additions to company-specific Real-time reliability-related tasks. Entity's previous list of company-specific Real-time reliability-related tasks. Documentation, such as provided in M2, evidencing selected System Personnel to perform modified or new tasks, as selected by the auditor.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PER-005-2, R2
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R2) For a sample of System Personnel and Real-time reliability-related tasks, review documentation verifying the personnel's capabilities to perform the task at least one time.
	(part 2.1) Determine if entity added any Real-time reliability-related tasks, which can be gleaned from auditor's knowledge of the entity's history and operations based on experience and specific facts discovered during the audit scoping process as confirmed with the entity, the entity's own assertions, a comparison of the current task list with a previous task list (also see part 1.4), or any combination thereof. For a sample of additions, examine dated documentation to verify each of its System Personnel's capabilities occurred within six months of the modification or addition.

[6] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Note to Auditor: Note entity's response to above Questions.

The nature and extent of audit procedures applied related to this requirement will vary depending on certain risk factors to the Bulk Electric System and the auditor's assessment of management practices specific to this requirement. In general, more extensive audit procedures will be applied where risks to the Bulk Electric System are higher and management practices are determined to be less effective.

Based on the assessment of risk and internal controls, as described above, specific audit procedures applied for this requirement may range from exclusion of this requirement from audit scope to the auditor reviewing training records for an entity's entire population of System Personnel.

Auditor Notes:

R3 Supporting Evidence and Documentation

R3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs) or has established operating guides or protection systems to mitigate IROL violations shall provide its System Personnel with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES, according to its training program.

3.1. When a Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not have an IROL gains operational authority or control over a Facility with an established IROL or establishes operating guides or protection systems to mitigate IROL violations, it shall comply with Requirement R3 within 12 months of gaining that authority or control, or establishing such operating guides or protection systems.

M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that System Personnel completed training that includes the use of simulation technology, as specified in Requirement R3.

M3.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that System Personnel completed training that included the use of simulation technology, as specified in Requirement R3, within 12 months of gaining that authority or control, or establishing such operating guides or protection systems.

Registered Entity Response (Required):
Question: Has entity gone from a situation of not having an IROL to either gaining operational authority or control over a Facility with an established IROL or establishing operating guides or protection systems to mitigate IROL violations? ☐ Yes ☐ No

Include additional information regarding the Question in gray area below, including the type of response and format of the response requested, as appropriate.
Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[7]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
(R3) Documentation such as training materials and attendance logs, evidencing emergency operations training pursuant to its training program using simulation technology replicating the operational behavior of the BES, for a sample of System Personnel selected by the auditor.
(part 3.1) A dated list of IROLs acquired in accordance with Requirement R3 part 3.1.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PER-005-2, R3
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the

[7] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

	RSAW Developer's Guide for more information.
	(R3) Review training materials and interview entity personnel to verify that the entity trained System Personnel using simulation technology that replicated the operational behavior of the BES pursuant to its training program. Agree specific System Personnel, as selected by the auditor from the organization chart (evidence for part 1.3), back to attendance logs for training using simulation technology.
	(part 3.1) Determine if entity obtained an IROL as outlined in Requirement R3 part 3.1, which can be gleaned from auditor's knowledge of the entity's history and operations based on experience and specific facts discovered during the audit scoping process as confirmed with the entity, the entity's own operating records and assertions, or any combination thereof. For a sample of System Personnel, examine dated training materials and attendance records to verify training occurred within 12 months.

Note to Auditor: Note entity's response to above Questions.

Only applicable to entities that have operational authority or control over Facilities with IROLs, or operating guides or protection systems to mitigate IROL violations.

12 month window to execute simulation training only applies to entities newly acquiring IROLs (per above), since entities with existing IROLs should already have access to simulation technology.

The nature and extent of audit procedures applied related to this requirement will vary depending on certain risk factors to the Bulk Electric System and the auditor's assessment of management practices specific to this requirement. In general, more extensive audit procedures will be applied where risks to the Bulk Electric System are higher and management practices are determined to be less effective.

Based on the assessment of risk and internal controls, as described above, specific audit procedures applied for this requirement may range from exclusion of this requirement from audit scope to the auditor reviewing training records for an entity's entire population of System Personnel.

Auditor Notes:

<u>**R4 Supporting Evidence and Documentation**</u>

R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall use a systematic approach to training to develop and implement training for its Operations Support Personnel on the impact of their job function(s) to those Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1.

4.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall conduct an evaluation each calendar year of the training established in Requirement R4 to identify and implement changes to the training.

M4 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence that Operations Support Personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training with the employee name and date.

M4.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed a training program evaluation each calendar year, as specified in Requirement R4 part 4.1.

Definition of Operations Support Personnel

Individuals, as identified by the Reliability Coordinators, Balancing Authorities, Transmission Operators, or Transmission Owners, who perform outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms, in direct support of Real-time, reliability-related tasks performed by System Operators.

Registered Entity Response to General Compliance with this Requirement (Required):

Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[8]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
(R4) A list of the entity's Operations Support Personnel with a description of each role within the organization along with the Real-time reliability-related tasks they impact. Evidence that that training was developed using a systematic approach, and a list of training that has been delivered for Operations Support Personnel along with attendance logs for a sample of training sessions requested by the auditor.
(part 4.1) Evidence, such as a memo, meeting minutes, or other information as specified in M4 demonstrating the review of the training occurred every calendar year and a list of needed changes to the training program based on the review.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

[8] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PER-005-2, R4
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R4) Interview entity to understand their process for determining training requirements for Operations Support Personnel. Select a sample of Operations Support Personnel and training materials for training specific to Operations Support Personnel. Vouch a sample of personnel back to attendance logs and review the sample of training materials.
	(part 4.1) Review evidence that the review of the training occurred every calendar year. Review list of changes to the training based on the review and examine training materials, or other documents, to gain reasonable assurance that changes identified were implemented into the training.

Note to Auditor: An auditor will evaluate the entity's systematic approach to training with regard to the impact of the Operations Support Personnel's job function on the Real-time reliability-related tasks.

Operations Support Personnel are required to receive training only on how their job functions impact the Real-time reliability-related tasks, not on the Operations Support Personnel's ability to conduct these tasks. Therefore, the auditor will only determine if the entity's systematic approach to training determined the skills and knowledge needed to understand the impact of the job function(s) on the Real-time reliability-related tasks.

Consistent with FERC orders No.742 at P25 and No. 693 at P1380 and P1382 and current Electric Reliability Organization's practices, to determine whether the entity used a systematic approach to training, an auditor will evaluate whether the entity's training program follows the principles below:

- Assess training needs (analysis)
- Conduct the training activity (design, develop and implement)
- Evaluate the training activity (evaluate the effectiveness of the training)

The nature and extent of audit procedures applied related to this requirement will vary depending on certain risk factors to the Bulk Electric System and the auditor's assessment of management practices specific to this requirement. In general, more extensive audit procedures will be applied where risks to the Bulk Electric System are higher and management practices are determined to be less effective.

Based on the assessment of risk and internal controls, as described above, specific audit procedures applied for this requirement may range from exclusion of this requirement from audit scope to the auditor reviewing training records for an entity's entire population of Operations Support Personnel.

Auditor Notes:

<u>R5 Supporting Evidence and Documentation</u>

R5. Each Generator Operator shall use a systematic approach to develop and deliver training to its personnel described in Applicability Section 4.1.5 of this standard on the impact of their job function(s) as it pertains to reliable operations of the BES during normal and emergency operations.

5.1 Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training.

M5. Each Generator Operator shall have available for inspection evidence that its applicable personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training with the employee name and date.

M5.1 Each Generator Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed a training program evaluation each calendar year, as specified in Requirement R5 part 5.1.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[9]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
(R5) A list of personnel in accordance with Applicability Section 4.1.5 and 4.1.5.1 of this Reliability Standard with a description of their role and position within the organization. Evidence that that training was developed using a systematic approach, and a list of training delivered for such personnel along with attendance logs for a sample of training sessions requested by the auditor.
(part 5.1) Evidence, such as a memo, meeting minutes, or other information as specified in M5.1 demonstrating the review of the training occurred every calendar year and a list of needed changes to the training program based on the review.

[9] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PER-005-2, R5
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R5) Interview entity to understand their process for determining training requirements for applicable personnel. Select a sample of personnel and training materials for training specific to their impact on the reliable operations of the BES during normal and emergency operations. Agree a sample of personnel back to attendance logs and review the sample of training materials.
	(part 5.1) Review evidence that the review of the training occurred every calendar year. Review list of changes to the training based on the review and examine training materials, or other documents, to gain reasonable assurance that changes identified were implemented into the training.

Note to Auditor: An auditor will evaluate the systematic approach with regard to the impact of the GOP's job function(s) on the reliable operations of the BES during normal and emergency operations.

Consistent with FERC orders No.742 at P25 and No. 693 at P1380 and P1382 and current Electric Reliability Organization's practices, to determine whether the entity used a systematic approach, an auditor will evaluate whether the entity's training program follows the principles below:

- Assess training needs (analysis)
- Conduct the training activity (design, develop and implement)
- Evaluate the training activity (evaluate the effectiveness of the training)

A calendar year is January 1 through December 31.

The nature and extent of audit procedures applied related to this requirement will vary depending on certain risk factors to the Bulk Electric System and the auditor's assessment of management practices specific to this requirement. In general, more extensive audit procedures will be applied where risks to the Bulk Electric

System are higher and management practices are determined to be less effective.

Based on the assessment of risk and internal controls, as described above, specific audit procedures applied for this requirement may range from exclusion of this requirement from audit scope to the auditor reviewing training records for an entity's entire population of Generator Operators.

Auditor Notes:

Revision History

Version	Date	Reviewers	Revision Description
1	10/24/2013	NERC Compliance, Standards	New Document

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement Reminder

Project 2010-01 Training (PER-005-2)

An Additional Ballot and Non-Binding Poll is now open through November 12, 2013

Now Available

An additional ballot for **PER-005-2** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels is now open through **8 p.m. Eastern on Tuesday, November 12, 2013.**

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

Instructions for Balloting

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

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

Next Steps

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

Standards Development Process

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

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

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Standards Announcement Update

Project 2010-01 Training
PER-005-2

Comment Period: September 27, 2013 – November 12, 2013

Upcoming:
Additional Ballot and Non-Binding Poll: November 1-12, 2013

The comment and ballot periods will be extended one day due to the Veterans Day Holiday.

Now Available

A 45-day formal comment period for **PER-005-2** is now open through **8 p.m. Eastern on Tuesday, November 12, 2013.**

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

Instructions for Commenting
A formal comment period is open through **8 p.m. Eastern on Tuesday, November 12, 2013.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps
An additional ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted as outlined above.

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

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

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Standards Announcement Update

Project 2010-01 Training
PER-005-2

Comment Period: September 27, 2013 – November 12, 2013

Upcoming:
Additional Ballot and Non-Binding Poll: November 1-12, 2013

The comment and ballot periods will be extended one day due to the Veterans Day Holiday.

Now Available

A 45-day formal comment period for **PER-005-2** is now open through **8 p.m. Eastern on Tuesday, November 12, 2013**.

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

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Tuesday, November 12, 2013.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted as outlined above.

Standards Development Process

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

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

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Standards Announcement

Project 2010-01 Training (PER-005-2)

Additional Ballot and Non-Binding Poll Results

Now Available

An additional ballot for **PER-005-2** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Tuesday, November 12, 2013 and Wednesday, November 13, 2013 respectively.**

This standard achieved a quorum but did not receive sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Approval	Non-binding Poll Results
Quorum: 76.23% Approval: 56.48%	Quorum: 76.00% Supportive Opinions: 51.66%

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

Next Steps

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

Standards Development Process

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

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

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Ballot Results	
Ballot Name:	Project 2010-01 Training PER-005-2
Ballot Period:	11/1/2013 - 11/12/2013
Ballot Type:	Additional Ballot
Total # Votes:	295
Total Ballot Pool:	387
Quorum:	**76.23 % The Quorum has been reached**
Weighted Segment Vote:	56.48 %
Ballot Results:	**There were not sufficient affirmative votes for approval.**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	105	1	46	0.575	34	0.425	0	3	22
2 - Segment 2	9	0.8	5	0.5	3	0.3	0	1	0
3 - Segment 3	86	1	38	0.585	27	0.415	0	3	18
4 - Segment 4	31	1	9	0.409	13	0.591	0	1	8
5 - Segment 5	88	1	30	0.508	29	0.492	0	2	27
6 - Segment 6	52	1	22	0.564	17	0.436	0	0	13
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	5	0.2	1	0.1	1	0.1	0	0	3
9 - Segment 9	2	0.1	1	0.1	0	0	0	0	1
10 - Segment 10	9	0.7	5	0.5	2	0.2	0	2	0
Totals	**387**	**6.8**	**157**	**3.841**	**126**	**2.959**	**0**	**12**	**92**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Negative	COMMENT RECEIVED
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton	Affirmative	
1	Austin Energy	James Armke		
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Negative	COMMENT RECEIVED
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morisette)
1	City of Tallahassee	Daniel S Langston	Abstain	
1	Clark Public Utilities	Jack Stamper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Austin Energy)
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	CPS Energy	Richard Castrejana	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Negative	SUPPORTS THIRD PARTY COMMENTS - (See Dominion's submitted comments)
1	Duke Energy Carolina	Douglas E. Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	El Paso Electric Company	Pablo Onate		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	

1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
1	JEA	Ted Hobson	Negative	COMMENT RECEIVED
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agengcy (FMPA))
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett		
1	Lower Colorado River Authority	Martyn Turner	Negative	COMMENT RECEIVED
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	COMMENT RECEIVED
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Negative	SUPPORTS THIRD PARTY COMMENTS - ISO-NE Comments
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Huston Ferguson)
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	COMMENT RECEIVED
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Oncor Electric Delivery	Jen Fiegel		
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Negative	SUPPORTS THIRD PARTY COMMENTS - (Consolidated Edison Co. of NY Inc.)
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		

1	Platte River Power Authority	John C. Collins		
1	Portland General Electric Co.	John T Walker	Negative	SUPPORTS THIRD PARTY COMMENTS - (Angela Gaines, PGE, comment related to R4.)
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Negative	COMMENT RECEIVED
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	SUPPORTS THIRD PARTY COMMENTS - (LCRA Transmission Services Corporation)
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO Comments)
1	Seattle City Light	Pawel Krupa	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comment)
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tampa Electric Co.	Beth Young	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ron Donahey)
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Texas Municipal Power Agency	Brent J Hebert		
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State G & T Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum		
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	

2	ISO New England, Inc.	Kathleen Goodman	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC SRC)
2	Midwest ISO, Inc.	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	SUPPORTS THIRD PARTY COMMENTS - (src)
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Negative	COMMENT RECEIVED
3	American Public Power Association	Nathan Mitchell		
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blue Ridge Electric	James L Layton	Negative	COMMENT RECEIVED
3	Bonneville Power Administration	Rebecca Berdahl	Negative	COMMENT RECEIVED
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	COMMENT RECEIVED
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson		
3	City of Garland	Ronnie C Hoeinghaus		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Abstain	
3	City Water, Light & Power of Springfield	Roger Powers		
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	COMMENT RECEIVED
3	Consumers Energy Company	Gerald G Farringer	Negative	COMMENT RECEIVED
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala		
3	Dominion Resources, Inc.	Connie B Lowe	Negative	SUPPORTS THIRD PARTY COMMENTS - (See Dominion's Submitted comments)
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Negative	COMMENT RECEIVED
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
				SUPPORTS THIRD PARTY

3	Great River Energy	Brian Glover	Negative	COMMENTS - (ACES Power Marketing)
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	Ayesha Sabouba voting for Segment 3
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (JEA)
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent		
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Negative	COMMENT RECEIVED
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (See NPCC Comments)
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (NIPSCO) Huston Ferguson - (NIPSCO)
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Electric Utility	David Anderson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municial Power Agency)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Consoidated Edison Co. of NY, Inc.)
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward		
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Abstain	
3	Rutherford EMC	Thomas M Haire	Abstain	

3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (LCRA Transmission Services Corporation)
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comment)
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morisette)
3	Tampa Electric Co.	Ronald L. Donahey	Negative	COMMENT RECEIVED
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Matthew Beilfuss)
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Abstain	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jerry Farringer)
4	Detroit Edison Company	Daniel Herring		
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Fort Pierce Utilities Authority	Cairo Vanegas	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen		
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal

				Power Agency)
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	North Carolina Electric Membership Corp.	John Lemire	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seattle City Light Paul Haase's comment)
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative)
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	COMMENT RECEIVED
4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	COMMENT RECEIVED
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Matt Beilfuss We Energies)
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren has submitted comments.)
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Arkansas Electric Cooperative Corporation	Brent R Carr		
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Negative	COMMENT RECEIVED
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty		
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	

5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jerry Farringer)
5	CPS Energy	Robert Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (LCRA and City of Austin)
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dominion)
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	JEA	John J Babik	Negative	COMMENT RECEIVED
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Luminant Energy - Brenda Hampton)
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC comments)
5	NextEra Energy	Allen D Schriver		

5	NiSource	Huston Ferguson	Negative	COMMENT RECEIVED
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Orlando Utilities Commission	Richard K Kinas		
5	PacifiCorp	Ryan Millard	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PowerSouth Energy Cooperative	Tim Hattaway		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Negative	COMMENT RECEIVED
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (LCRA Transmission Services Corporation)
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes		
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith on behalf of Seminole Electric Cooperative Inc)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Feather Power Project	Kathryn Zancanella		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morisette)
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ron Donahey)
5	Tenaska, Inc.	Scott M. Helyer		
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS - (Matthew Beilfuss)

5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Alabama Electric Coop. Inc.	Ron Graham		
6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	COMMENT RECEIVED
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Negative	COMMENT RECEIVED
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	SUPPORTS THIRD PARTY COMMENTS - (See Dominion's submitted comments.)
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Negative	COMMENT RECEIVED
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton	Negative	COMMENT RECEIVED
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS - (H Ferguson - NIPSCO)
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	John Volz		
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
				SUPPORTS

6	Salt River Project	Steven J Hulet	Negative	THIRD PARTY COMMENTS - (LCRA Transmission Services Corporation)
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet		
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith has submitted comments on behalf of Seminole Electric Cooperative, Inc.)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kieth Morisette)
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (support comments made by Ron Donahey)
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Edward C Stein		
8		Merle Ashton		
8		Roger C Zaklukiewicz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Northeast Utilities)
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Abstain	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Account Log-In/Register

Non-binding Poll Results

Project 2010-01 PER-005-2

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2010-01 Training PER-005-2 Non-binding Poll
Poll Period:	11/1/2013 - 11/13/2013
Total # Opinions:	266
Total Ballot Pool:	350
Summary Results:	76.00% of those who registered to participate provided an opinion or an abstention; 51.66% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

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

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

NERC

1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	COMMENT RECEIVED
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Negative	SUPPORTS THIRD PARTY COMMENTS ISO-NE Comments
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Huston Ferguson)
1	NorthWestern Energy	John Canavan		
1	Ohio Valley Electric Corp.	Robert Mattey	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	COMMENT RECEIVED
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
1	Oncor Electric Delivery	Jen Fiegel		
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Negative	SUPPORTS THIRD PARTY COMMENTS - (Consolidated Edison Co. of NY, Inc.)
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Negative	SUPPORTS THIRD PARTY COMMENTS - (Angela Gaines, PGE, comment on R4.)
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	

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

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

3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (JEA)
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent		
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to National Grid comments submitted by M. Jones)
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (See NPCC Comments)
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (NIPSCO)
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Consolidated Edison Co. of NY, Inc.)

3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons		
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Abstain	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (LCRA Transmission Services Corporation)
3	Santee Cooper	James M Poston	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morisette)
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Abstain	
4	City of Clewiston	Kevin McCarthy		
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jerry Farringer)
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED

4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen		
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	North Carolina Electric Membership Corp.	John Lemire	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative)
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	COMMENT RECEIVED
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Matt Beilfuss We Energies)
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko	Abstain	
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Arkansas Electric Cooperative Corporation	Brent R Carr		
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		

5	Bonneville Power Administration	Francis J. Halpin	Negative	COMMENT RECEIVED
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty		
5	City of Tallahassee	Karen Webb	Abstain	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Jerry Farringer)
5	CPS Energy	Robert Stevens	Negative	SUPPORTS THIRD PARTY COMMENTS - (LCRA and City of Austin)
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown		
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy)
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	JEA	John J Babik	Negative	COMMENT RECEIVED

5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Karin Schweitzer		
5	Luminant Generation Company LLC	Rick Terrill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Luminant Energy- Brenda Hampton)
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC comments)
5	NextEra Energy	Allen D Schriver	Affirmative	
5	NiSource	Huston Ferguson	Negative	COMMENT RECEIVED
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (Interchange Standard)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (MRO NSRF)
5	Orlando Utilities Commission	Richard K Kinas		
5	PacifiCorp	Bonnie Marino-Blair		
5	Pattern Gulf Wind LLC	Grit Schmieder-		

		Copeland		
5	Portland General Electric Co.	Matt E. Jastram		
5	PowerSouth Energy Cooperative	Tim Hattaway		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Negative	COMMENT RECEIVED
5	Puget Sound Energy, Inc.	Lynda Kupfer	Abstain	
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (LCRA Transmission Services Corporation)
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes		
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith on behalf of Seminole Electric Cooperative Inc)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Feather Power Project	Kathryn Zancanella		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Keith Morisette)
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ron Donahey)
5	Tenaska, Inc.	Scott M. Helyer		
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Mark Stein	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman		
5	Wisconsin Electric Power Co.	Linda Horn		
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Abstain	

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6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	COMMENT RECEIVED
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Andrew Gallo)
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Negative	COMMENT RECEIVED
6	Duke Energy	Greg Cecil		
6	FirstEnergy Solutions	Kevin Querry	Negative	COMMENT RECEIVED
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson		
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
6	Northern California Power Agency	Steve C Hill		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS - (H. Ferguson, NIPSCO)
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Oklahoma Gas & Electric)
6	Omaha Public Power District	Douglas Collins		

6	PacifiCorp	Kelly Cumiskey		
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Negative	SUPPORTS THIRD PARTY COMMENTS - (LCRA Transmission Services Corporation)
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet		
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bret Galbraith has submitted comments on behalf of Seminole Electric Cooperative, Inc.)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Kieth Morisette)
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (support comments made by Ron Donahey)
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
8		Edward C Stein		
8		Roger C Zaklukiewicz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Northeast Utilities)
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	

10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Abstain	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Negative	COMMENT RECEIVED
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (63 Responses)
Name (35 Responses)
Organization (35 Responses)
Group Name (28 Responses)
Lead Contact (28 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (10 Responses)
Comments (63 Responses)
Question 1 (43 Responses)
Question 1 Comments (53 Responses)
Question 2 (52 Responses)
Question 2 Comments (53 Responses)

Individual
dd
ddd
Agree
sdaDd
Individual
Martyn Turner
LCRA Transmission Services Corporation
No
The definition of “Operations Support Personnel” is too vague. Specifically, the portion of the definition containing “in direct support” is critical to the determination of exactly what positions fall under this new definition. Especially critical is the context in which term “direct” is to be employed. Nowhere in the standard is this critical terminology defined. From dictionary.com the definition of direct is: 1) to manage or guide by advice, helpful information, instruction, etc. 2) to regulate the course of ; control 3) to administer; manage; supervise 4) to give authoritative instructions to; command; order or ordain 5) to serve as a director in the production or performance of (a musical work, play, motion picture, etc.). Obviously the intent of the Standard is not address musical or theatre productions so #5 is easily dismissed. But what of the other four possibilities? Does someone who orders an operator to perform an action included under this new requirement? What about an individual that provides advice? What about someone that writes a procedure pertaining to load shedding? Are procedure writers and all possible contributors and/or reviewers to be

included under the umbrella of “Operations Support Personnel”? If an individual not in a real-time position volunteers to write a procedure or provides input on one that affects real-time operations, do they instantly fall under the auspices of this standard? Do managers of System Operators fall under this standard? These are but a tiny fraction of the possibilities created by not succinctly and clearly defining the phrase “in direct support”. Vague or interpretive guidance creates a situation where Transmission Operators and auditors alike are left to apply subjective metrics in order to determine compliance. Unfortunately, those metrics may not be the same leading to confusion and possible noncompliance or even failure to recognize noncompliance. Consider changing the language to read: Operations Support Personnel: Individuals, as identified by the Reliability Coordinators, Balancing Authorities, Transmission Operators, or Transmission Owners, who perform outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms, in direct support of Real-time, reliability-related tasks performed by System Operators. Individuals that directly support Real-Time, reliability-related tasks performed by System Operators shall be defined with respect to this standard, as those individuals that provide information, data, assessments, or outage coordination that are impactful at the point of execution by operating personnel. Support functions that do no more that to review proposed changes to procedures, provide advice on processes, or are tangentially involved in outage coordination do not fall under the definition of Operations Support Personnel with respect to this standard. For outage coordination, only those positions that serve to create finished schedules that direct the removal of equipment from service and coordinate those schedules with a Reliability Coordinator shall be considered as applicable to this definition. Individuals that serve as the point-of-contact between a Reliability Coordinator and real-time operations shall be considered as Operations Support Personnel. Persons in administrative roles or that serve to coordinate activates between work groups and the personnel that complete and submit outage schedules shall not be considerd as Operations Support Personnel.
No
The negative response is due to several factors: 1) The 24 month time frame required in 5.1 is insufficient. Training personnel in the organizations affected by this proposed standard typically have multiple duties. Speaking from personal experience much can happen in 24 months that affect the amount of time and effort that can be applied towards meeting this standard: retirements and terminations require new operators to be hired and trained, existing continual training, administrative duties, personal/family constraints, etc. In addition, most training personnel were very familiar with the tasks performed by system operators and already had training programs and content in place that addressed them when PER-005-1 was introduced. That information facilitated the transition to PER-005-1 simplifying it to a great extent. The new positions that would fall under this standard are largely outside existing

training programs requiring a great deal more research, content production, and training delivery. Limiting the time to implement all of that to 24 months threatens quality as trainers potentially would cut corners in order to ensure completion. A 24 month time limit in no way assures that all 24 months would be available to implement this standard. Expand the time limit to 36 months at a minimum. 2) R4 is ill-defined and vague. The requirement dictates the use of a Systematic Approach to Training (SAT) with respect to Operations Support Personnel within the limits of the R-R tasks they impact previously identified for system personnel. But to limit the scope of an SAT to just those connections defies the very definition of "systematic" and the use of an SAT itself for that matter since that process is used to find ALL tasks associated with a given position not those predetermined by a very limited scope of some sort. For example, job analysis surveys are often used to determine which tasks operating personnel themselves consider to be important by employing simple ratings scales. But limiting such surveys, and thus the SAT itself, to tasks only associated with tasks performed by others predetermines the outcome to a significant extent. The resulting job task analysis (essential to the successful implementation of an SAT) would be incomplete. Furthermore, requiring an SAT for Operations Support Personnel goes far beyond what is really necessary-training support personnel on how they impact R-R tasks, especially how the information they use, data they provide, or coordination impacts real-time operating personnel R-R tasks. An application of SAT would require identification of ALL tasks that a given individual performs that could impact an R-R task. Not how they impact tasks. That is a substantive difference with respect to content development. Potentially, the results would be voluminous. Proposed change: Do away with the requirement of the SAT in R4 and require the organization to identify the tasks impacted and train Support Personnel on how their role impacts those tasks. That would make R4 straight forward and easy to manage.
Individual
Chris Scanlon
Exelon
Yes
Exelon supports the proposed defintions and is voting Affirmative. We do however remain concerned that "coordination" could be construed to include work done by a wide range of personnel not invloved in direct support of Real-time, reliability-related tasks performed by System Operators.
Yes
Group
MRO NERC Standards Review Forum
Russel Mountjoy-Secretary

No
The NSRF does agree with the definition of System Operator that the SDT is proposing. The NSRF does not agree with having definitions that are only applicable to a single Standard; System Personnel and Operations Support Personnel. Upon review, we have found the Drafting Team Guidelines, dated April 2009. It does give guidance as stated below: The SDT should avoid developing new definitions unless absolutely necessary. There is a glossary of terms that has been approved for use in reliability standards. Before a drafting team adds a new term, the team should check the latest version of the Glossary of Terms for Reliability Standards to determine if the same term, or a term with the same meaning, has already been defined. If a term is used in a standard and the term is defined in a collegiate dictionary, then there is no need to also include the term in the NERC Glossary of Reliability Terms. The addition of an adjective or a prefix to an already defined term should not result in a new defined term. It is very difficult to reach consensus on new terms. If a simple phrase can be used in a standard to replace a new term, then the drafting team should consider using the phrase rather than trying to obtain stakeholder consensus on the new term. Each drafting team is charged with developing a Standard that provides clarity by being properly written for the the applicable entity to understand without added guidance, in this case, Standard applicable definitions. Recommend that the SDT either propose to add System Personnel and Operations Support Personnel to the Glossary of Terms or rewrite the Requirements so that Standard applicable definitions are not needed within PER-005-2.
Yes
NSRF does not believe Requirement 4 is appropriate for all listed Applicable Entities all of the time. Requirement 4 implies that ALL Applicable Entities shall develop and implement training for their Operations Support Personnel that is based on the company-specific, real-time reliability-related tasks performed by the System Operators found in Requirement 1.1. However, outage planning functions for BES Facilities for smaller, vertically-integrated utilities would be performed in the long-term horizon and would need the approval of the Reliability Coordinator. The smaller BA's, TO's, and TOP's don't perform the actual outage planning. They rely on the Reliability Coordinator to perform the outage planning because these smaller entites may not have the tools required for this kind of planning Furthermore, the smaller vertically-integrated utilities are not likely to own or operate any BES Facilities that carry IROL. There seems to be some added confusion with the clean and red-line versions of the Draft Standard. The red-line version has a Requirement 6 for the GOP to use the SAT to develop and deliver training. This corresponds to Requirement 5 in the clean version. The inclusion of the Transmission Owner local transmission control center operator personnel in the Applicability Section 4.1.4.1 needs to be further addressed. On page 21 in the NERC Functional Model, the Transmission Owner owns its transmission facilities and provides for the maintenance of

those facilities. This section on Transmission Owners goes on to state that “the organization serving as Transmission Owner may operate its transmission facilities or arrange for another organization (which may or may not be a Transmission Owner) to operate and/or maintain its transmission facilities. “ Adjacent to this statement in the NERC Functional Model is a reference to see “Transmission Operator,” Section “Bundling with the Reliability Coordinator or Transmission Owner.” On page 17 of the NERC Functional Model, a description is provided of instances when the Transmission Owner and Transmission Operator are “bundled” in an RTO situation. It states that the RTO members would be responsible for complying with all Reliability Standards associated with the Transmission Operator, and would be NERC-certified as such. Therefore, the issue of having Transmission Owner local transmission control center operator personnel included in Applicability Section 4.1.4.1 is unnecessary. These local transmission control center operator personnel are actually un-registered Transmission Operators and should be addressed through the registration process. If they “exercise control over a significant portion of the Bulk-Power System, and implement predefined operating procedures in a timely basis” this is no different than what the NERC Functional Model says about Transmission Operators: “The Transmission Operator operates or directs the operation of transmission facilities, and maintains local-area reliability, that is, the reliability of the system and area for which the Transmission Operator has responsibility.” Operating transmission facilities to maintain reliability is a real-time function of the Transmission Operator. In Order No. 742 at P 62, we agree with the Commission that “omitting the local transmission control center personnel from the PER-005-1 training requirements creates a reliability gap.” However, this reliability gap should be corrected through the proper registration of the personnel performing Transmission Operator functions, not through the undefined “local transmission control center operator personnel” classification. In section 4.1.5.1, under Applicabilitry: Suggest that the word “any” should be struck and replace with the word “independent” or words “independent and specific” to better tie in with the FERC intent from Order 693 and 742 which seemed to be focused on individuals who would receive a general direction and would then have to “understand” those instructions and develop specific dispatch instructions for their plants to maintain system reliability. This seems different than normal internal plant adjustments that might be required to meet a requested MISO dispatch, especially when there are multiple generators at one plant complex.
Individual
William H. Chambliss
Virginia State Corporation Commission
Yes
Yes

Individual
Scott Bos
Muscatine Power and Water
Yes
MP&W does not agree with having definitions that are only applicable to a single Standard: System Personnel, System Operator and Operations Support Personnel. In SDT guidelines from April of 2009, it states that "the SDT should avoid developing new definitions unless absolutely necessary. There is a glossary of terms that has been approved for use in reliability standards. Before a drafting team adds a new term, the team should check the latest version of the Glossary of Terms for Reliability Standards to determine if the same term, or a term with the same meaning, has already been defined. If a term is used in a standard and the term is defined in a collegiate dictionary, then there is no need to also include the term in the NERC Glossary of Reliability Terms. The addition of an adjective or a prefix to an already defined term should not result in a new defined term. It is very difficult to reach consensus on new terms. If a simple phrase can be used in a standard to replace a new term, then the drafting team should consider using the phrase rather than trying to obtain stakeholder consensus on the new term."
No
MP&W does not believe Requirement 4 is appropriate for all listed Applicable Entities all of the time. Requirement 4 implies that ALL Applicable Entities shall develop and implement training for their Operations Support Personnel that is based on the company-specific, real-time reliability-related tasks performed by the System Operators found in Requirement 1.1. However, outage planning functions for BES Facilities for smaller, vertically-integrated utilities would be performed in the long-term horizon and would need the approval of the Reliability Coordinator. The smaller BA's, TO's, and TOP's don't perform the actual outage planning. They rely on the Reliability Coordinator to perform the outage planning because these smaller entites may not have the tools required for this kind of planning. And likewise, the smaller, vertically-integrated utilities may not possess the tools or have the staff required to perform their own assessments but participate in assessments performed by their Planning Authority. Furthermore, the smaller vertically-integrated utilities are not likely to own or operate any BES Facilities that carry IROL. The inclusion of the Transmission Owner local transmission control center operator personnel in the Applicability Section 4.1.4.1 needs to be further addressed. On page 21 in the NERC Functional Model, the Transmission Owner owns its transmission facilities and provides for the maintenance of those facilities. This section on Transmission Owners goes on to state that "the organization serving as Transmission Owner may operate its transmission facilities or arrange for another organization (which may or may not be a Transmission Owner) to operate and/or maintain its transmission facilities." Adjacent

to this statement in the NERC Functional Model is a reference to see "Transmission Operator," Section "Bundling with the Reliability Coordinator or Transmission Owner." On page 17 of the NERC Functional Model, a description is provided of instances when the Transmission Owner and Transmission Operator are "bundled" in an RTO situation. It states that the RTO members would be responsible for complying with all Reliability Standards associated with the Transmission Operator, and would be NERC-certified as such. Therefore, the issue of having Transmission Owner local transmission control center operator personnel included in Applicability Section 4.1.4.1 is unnecessary. These local transmission control center operator personnel are actually un-registered Transmission Operators and should be addressed through the registration process. If they "exercise control over a significant portion of the Bulk-Power System, and implement predefined operating procedures in a timely basis" this is no different than what the NERC Functional Model says about Transmission Operators: "The Transmission Operator operates or directs the operation of transmission facilities, and maintains local-area reliability, that is, the reliability of the system and area for which the Transmission Operator has responsibility." Operating transmission facilities to maintain reliability is a real-time function of the Transmission Operator. In Order No. 742 at P 62, we agree with the Commission that "omitting the local transmission control center personnel from the PER-005-1 training requirements creates a reliability gap." However, this reliability gap should be corrected through the proper registration of the personnel performing Transmission Operator functions, not through the undefined "local transmission control center operator personnel" classification.
Group
SERC OC Review Group
Stuart Goza
Yes
We support the SDT's clarifications included in these two definitions. The specificity of the wording narrows the applicability of the requirements to only certain, clearly-defined individuals.
Yes
The Standard Drafting Team is to be commended for an excellent job incorporating the diverse and often conflicting comments collected from the first posting. We generally agree with the revised purpose statement and the tightened language of the requirements to mandate a systematic approach to training for all applicable personnel. In the Applicability Section (4.1.4.1) the identification of TO personnel to whom the standard applies still seems ambiguous. "Protecting safety, assets and adhering to regulations" are crucial responsibilities which are not unique to control center operators. And the TO control center personnel may

or may not act independently. To better identify TO personnel who must be trained using systematic approach, we suggest language more consistent with FERC Order 742. Suggested re-write for 4.1.4.1: “Transmission Owner (TO) that has personnel at a facility, excluding field switching personnel, who exercise control over a significant portion of the Bulk Electric System. Such personnel may carry out tasks that require Real-time operation of the BES under the direct supervision of the registered Transmission Operator. This TO personnel may also act independently to implement pre-defined operating procedures.” As written R5 states: “Each Generator Operator shall use a systematic approach to develop and deliver training to its personnel described in Applicability Section 4.1.5 of this standard on the impact of their job function(s) as it pertains to reliable operations of the BES during normal and emergency operations. Suggested re-write for R5: Each Generator Operator shall use a systematic approach to develop and deliver training to its personnel described in Applicability Section 4.1.5 of this standard on the impact of their job function(s) as it pertains to reliable operations of the BES. (delete: during normal and emergency operations.) The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
Yes
Yes
Individual
Angela P. Gaines for Tracy North
Portland General Electric Company
No
R.4 is no longer viable as written. The Systematic Approach to Training (SAT) is primarily a PERFORMANCE BASED ISD model. This means that the training developed using this model is intended to ensure that personnel perform their required job tasks correctly. One should not use this system to simply inform personnel of “the impact of their job function”. It might be determined through job & task analysis that “knowledge of the impact on Reliability-Related Tasks” is indeed an important element of proper operations support task performance. However, the SAT process is not designed to stop at that point and focus solely on one single knowledge item. This is because the focus of SAT is CORRECT TASK PERFORMANCE. If we feel that “knowledge of the impact” was important enough for us to write a requirement

specifically for it, then we must assume that lack of this knowledge could lead to incorrect performance. But, if we don't expect the performance of the tasks to be negatively impacted, then we mustn't waste our time writing a requirement for it. Neither should we waste our time implementing the SAT process around one single knowledge item. Ultimately we have to ask ourselves what we are trying to accomplish. Does FERC expect that we will train support personnel to properly perform reliability related job functions or to just ensure they are properly informed about their impact. If it's simply to have them understand the impact, then SAT is not the proper tool. If we know that improper performance of support tasks such as SOL and IROL determinations impact reliability, then those personnel should be trained in the same manner as system operators. My suggestion is that R4 wording be returned to the prior version.
Group
Northeast Power Coordinating Counci
Guy Zito
No
Suggest revising the proposed definition of System Operator to: System Operator: An individual at a control center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who monitors and controls and directs the operation of the Bulk Electric System in Real-time. Without more explicit wording, personnel at locations other than an "individual at a control center" who are not system operators may be included under that definition. Distribution related field, substation and satellite location personnel should not be classified as System Operators by an overly broad definition. A System Operator performs two critical functions: monitoring and control (of the status of Bulk Electric System assets). Anyone who does not perform these functions must rely on a System Operator to perform them, and is not operating independently. They are not System Operators.
No
The Applicability section of the standard related to Transmission Owners and Generator Operators requires clarification. In the Applicability section, for the Transmission Owner the list of tasks in 4.1.4.1 do not "define" the applicable Transmission Owner personnel. The protection of Transmission Owner assets and personnel safety should be outside the reach of NERC standards. Propose the following revision to the wording in the Applicability Section 4.1.4: 4.1.4 Transmission Owner that has: 4.1.4.1. Personnel at a facility that acts as a centralized Control Center for the Transmission Owner who interact with their Reliability Coordinator, Balancing Authority or Transmission Operator. Field switching personnel or other personnel who do not act independently of this centralized Transmission Owner Control Center are exempt. The definitions should not be specific to this standard. They should be

included in the NERC Glossary of Terms Used in Reliability Standards. The rigid definitions create confusion as to their application within each entity. It is very difficult to identify which position a requirement would apply to within a specific organization. Suggest that each entity define the applicability of PER-005-2 within its own organization; for example, any position that has a task that has an impact on the operations of the main transmission system. Pertaining to Section 4.1.5 Generator Operator, suggest changing “may” to “has the authority”. It is possible that the GOP may receive specific dispatch instructions in some instances, but in other instances be allowed the flexibility to develop dispatch instructions based on RC, BA or TOP guidance. Additionally, “plant operators” needs to clarify that it only applies to dispatch instructions for BES generators, and does not include dispatch instructions for non-BES generation plant operators. From Section 4.1.5, “Dispatch personnel at a centrally located dispatch center who receive direction from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and has the authority to develop specific dispatch instructions for BES generator plant operators under their control.” This use of “personnel” does not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions, without making any modifications. Remove footnotes 2 and 3 as they are unnecessary. Repetition of Standard Only Glossary Terms in the footnotes in not necessary. In Part 1.1, the additional phrase “based on a defined and documented methodology” is of concern. The training program for the responsible entity needs to be based on “the list of Bulk Electric System (BES) company specific Real-time reliability-related tasks”. Part 1.1 thus should end at the word “tasks”. Adding the phrase “based on defined and documented methodology” does not add any value to the requirement, but creates an uncertainty as to “who defines the methodology” and with what criteria is the methodology defined. In the SDT’s Summary Consideration report, there is no mention of any comment made to this part in the previous posting, thus providing no basis for this addition. We suggest removing this phrase from Part 1.1. Requirement R2 requires that each RC, BA, TOP, and TO shall verify, at least once, the capabilities of its System Personnel. The Implementation Plan states that entities that were not previously subject to PER-005-1 must have verified its System Personnel’s capabilities to perform each of its assigned Real-time reliability-related tasks, at least once, as identified in Requirement R1 part 1.1, prior to the effective date of the standard. Requiring entities to perform certain activities prior to the effective date of the standard means in practice advancing its effective date, which is not possible in certain jurisdictions where requirements cannot be legally enforceable prior to the standard's effective date. An entity meeting the requirement before the effective date may constitute good practice but an entity cannot be held non-compliant for not doing it. Suggest changing to: Entities that were not previously subject to PER-005-1 must have verified its System Personnel’s capabilities to perform each of its assigned

Real-time reliability-related tasks, at least once, as identified in Requirement R1 part 1.1, within one year of the standard becoming in force within their respective jurisdiction. The suggested 1 year could be reduced to 6 months if felt appropriate. Regarding R5, these personnel do not need to be trained on the “impact of their job function(s) as it pertains to reliable operations of the BES during normal and emergency operations.” The intent is to train these personnel “on their job function(s) as it (they) pertain(s) to…”. Also regarding Requirement R5, the words “to training” are missing after “systematic approach”. The training in R5 is required regardless of the personnel’s capability since there is no requirement to assess the capabilities of the personnel for the identified tasks. Suggest adding language to allow for a demonstration of capabilities on the required tasks similar to R2. Additionally, a grace period similar to R2.1 should be added to R5 to allow time between a change in the training program to the time training is required to be completed. Requirement R4 should be deleted in its entirety. From page 4 of the White Paper: “The argument for not including EMS personnel in the training standard at this time is based on a report provided by the Event Analysis Subcommittee (EAS). The EAS worked with the NERC Event Analysis (EA) staff to review the events that have been cause-coded since October 2010. The database has over 263 events; … [and] only two were deemed to be a training issue. Therefore, based on the information, the EAS and PER ad hoc group do not believe it is necessary at this time to require EMS support personnel to receive the level of training required of a BA, Reliability Coordinator (RC), and TOP by NERC standard PER-005.” Requirements R1, R4 and R5 stipulate the use of systematic approach to training to develop and implement training or training program (note the inconsistent wording among them) for their respective group of personnel. While R4 and R5 contain a HIGH VSL for failing to use systematic approach to training to develop and implement the training program, R1 does not have a similar VSL. Suggest adding a HIGH VSL to R1 to address this. From the Compliance Input document: “Question 2: In Requirement R3, does an entity that has one or more IROLs have 12 months to conduct simulation technology training when it obtains another IROL? Compliance Response to Question 2: No, if an entity currently has one or more IROLs, it has the ability to conduct simulation technology. The 12 months applies only to an Entity that did not have any IROLs but obtains an IROL for the first time.” Please clarify that the training is in general response to IROLs and not specific to each individual IROL. Also from the Compliance Input document: “Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training. Attachment A represents the version of the proposed standard requirements referenced in this document.” This is inconsistent with both the SPM From Section 3.6 of the SPM: “Collectively, each drafting team: • Drafts proposed language for the Reliability Standards, definitions, Variances, and/or Interpretations and associated implementation plans. • Develops and refines technical

documents that aid in the understanding of Reliability Standards. • Works collaboratively with NERC Compliance Monitoring and Enforcement Staff to develop Reliability Standard Audit Worksheets ("RSAWs") at the same time Reliability Standards are developed. • etc…"
Group
Quality Training Systems
Stefanie Pressl
No
Comment 1: M1.2 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training materials, as specified in Requirement R1 part 1.2. From the Implementation Plan, we understand that training materials are required only for training that has been delivered. That is, entities need not have training materials developed as of the effective date of the standard if they have no personnel being trained at that time. We suggest adding clarifying verbiage to M1.2 as follows: M1.2 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training materials, as specified in Requirement R1 part 1.2, for all training that has been delivered. Comment 2: R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall use a systematic approach to training to develop and implement training for its Operations Support Personnel on the impact of their job function(s) to those Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. Suggested Revision: Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall use a systematic approach to training to develop and implement training for its Operations Support Personnel on the tasks they perform that may impact the performance of the Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. Educating someone on the impact of their job function is quite different from teaching them how to do their jobs. The former can be satisfied by some form of "awareness training" but the latter refers to performance-based training (i.e., SAT). While it may be reasonable to limit this requirement to job tasks that support real-time reliability-related tasks of the system operators, FERC Order 693 states that the training should be on tasks that impact real-time reliability related tasks of the system operators, not simply be about the impact of their job function. FERC Order 693 Paragraph 1375: 1375. Several commenters express concern that the operations planning and operations support staffs will be required to be trained on the transmission operators' responsibilities. The Commission clarifies that this is not the case. Training programs for operations planning and operations support staff must be tailored to the needs of the function, the tasks performed and personnel involved. The "Rationale for R4" states "It does not require training on the actual Real-time reliability-related tasks conducted by the System Operator." It later states

“The entity may use the [task] list created from requirement R1 part 1.1 and select the reliability-related tasks that Operations Support Personnel support and therefore should be trained on.” We think this language is contradictory and will cause confusion to the industry. We do not believe NERC is suggesting that the support personnel should be trained on selected tasks from the task list created pursuant to R1.1. Rather, we believe NERC is trying to say (or should be saying) that support personnel should be trained on tasks that they perform that support reliability-related tasks of System Personnel. Comment 3 R5. Each Generator Operator shall use a systematic approach to develop and implement training for its personnel described in Applicability Section 4.1.5 of this standard on the impact of their job function(s) as it pertains to reliable operations of the BES during normal and emergency operations. Suggested Revision: Each Generator Operator shall use a systematic approach to develop and implement training for its personnel described in Applicability Section 4.1.5 of this standard on the tasks they perform that may impact reliable operations of the BES during normal and emergency operations. As explained for R4 above, educating someone on the impact of their job function is quite different from teaching them how to do their jobs. The former can be satisfied by some form of “awareness training” but the latter refers to performance-based training (i.e., SAT). In contrast to our reaction to R4, we do not believe that limiting Generator Operator training to job tasks that support real-time reliability-related tasks of the system operators is sufficient. There may be real-time tasks performed by GOP dispatch personnel that are independent of any system operator tasks but have an impact on the reliability of the bulk electric system nevertheless. In the “Rationale for R5” it states, “This requirement does not necessitate a systematic approach to training process that is as comprehensive as that used for RCs, BAs, and TOPs.” We are rather concerned about this statement. What is a systematic approach to training that is less comprehensive than that required for RCs, BAs, and TOPs? What is okay to leave out of the process? We would argue that the systematic approach should not be less comprehensive, but by applying that approach correctly the results will likely be narrower in scope. FERC Order 693, Paragraph 1363 “…the experience and knowledge required by transmission operators about bulk power system operations goes well beyond what is needed by generator operators; therefore training for generator operators need not be as extensive as that required for transmission operators.” The above passage says nothing about the SAT process not being as comprehensive as what is used for transmission operators; it just suggests that the resulting training will be less comprehensive, with which we agree. Comment 4 Task Qualifications (Re: R4 and R5) There is no explicit requirement that the support personnel or generator operators be qualified on the tasks they perform. However, in the Application Guidelines, it states “Any systematic approach to training will determine…. if the learner can perform the real-time reliability-related tasks acceptably in either a training or on-the-job environment.” So, neither R4 nor R5 (nor any

subpart thereof) mentions task qualifications, but the Application Guidelines state that task qualifications are a required part of any SAT process. With this information alone, we would be inclined to say that task qualifications are required, but when one considers that R1 specifically mentions task qualifications but R4 and R5 do not, it will likely lead people to believe that task qualifications are not required for R4 and R5. This lack of parallelism within the standard is likely to cause confusion. It is our professional opinion that task qualifications must be required; otherwise, we will have training with no proof of mastery. Therefore we suggest adding, at a minimum, the equivalent of R2 and R2.1 to both R4 and R5. Ideally, the standard should have greater parallelism across functional entities by also including the equivalent of R1.1 through R1.4 to both R4 and R5.
Individual
Thomas Foltz
American Electric Power
No
AEP does not recommend using terms defined only within a standard and not including them in the NERC Glossary of Terms. This is especially troubling given that the “local term” references “global terms” which *are* specified in the NERC glossary. Terms should only be capitalized when they are included in the NERC Glossary. It might be possible to document this well enough in the applicability section without having to create locally defined terms. In addition, if local terms are indeed used, those terms should be referenced within the Applicability section. For the definition of Operations Support Personnel, we recommend removing the word “or” from “outage coordination or assessments” so that it reads “who perform outage coordination assessments…”.
No
R 4.1: The most recently proposed changes appear to be a step back in terms of clarity. The description provided to identify the personnel actually states more clearly who is *not* included rather than exactly who *is*. 4.1.5.1: GOP personnel at a centrally located dispatch center would not normally make modifications to directions issued by the RC, BA, TO or TOP unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the GOP operator should immediately inform the issuer of the directive/instruction of the inability to perform the directive so that the issuer may implement alternate remedial actions. The exception to this would be instructions, not directives, issued by the market operator where the GOP operator has the authority to follow or not follow instructions based on the GOP operators determination of financial impacts associated with market instructions. Normally instructions from the RC, TOP or TO are reliability issues and the GOP operator would not modify those instructions unless absolutely

necessary due safety or regulatory concerns, and notification would be made to the RC, TOP or TO. This would also be the case with the BA unless market instructions are also issued by the BA operator. In that case, modifications might be necessary and acceptable. Perhaps clarifications on the type of instruction whether reliability or market or both should be considered.
Group
ACES Standards Collaborators
Brian Van Gheem
No
(1) We appreciate the Standard Drafting Team’s efforts in attempting to address the applicability issues identified in NERC Standard PER-005-1. However, we disagree with its approach to define Standard-specific terms instead of pursuing the creation of new terms within the NERC Glossary of Terms. As instructed within the NERC Drafting Team Guidelines that were revised in April 2009 and endorsed by the NERC Standards Committee, the Standard Drafting Team should avoid developing new definitions for Standard revisions. We feel that introducing the terms “System Personnel” and “Operations Support Personnel” were not absolutely necessary, but rather done to address a localized variance with “local transmission control centers.” Consequentially, this expanded the applicability of this Standard to include Transmission Owners. A better approach to resolving this variance would be to remain in-bounds within the NERC Reliability Functional Model and use the NERC Rules of Procedure to assign the proper NERC Functional Entity and applicable compliance delegation, respectively. This is a registration issue that could be better handled by compliance staff when facts and circumstances arise. This alternative is equally effective and these proposed definitions do not need to be added to the standard. (2) If the Standard Drafting Team had a concern regarding entities that act independently of Reliability Coordinators and Transmission Operators based on specific system conditions, then the error lies within the NERC Reliability Functional Model and should be addressed there accordingly. Our recommendation is to remove all Standard-specific definitions altogether.
No
(1) We appreciate the Standard Drafting Team in attempting to align outstanding FERC Directives and NERC Projects with this revision to NERC Standard PER-005. We also welcome the Standard Drafting Team’s reference to the systematic approach to training process by removing the 32 hour requirement for emergency operations training. Likewise, we appreciate the Standard Drafting Team’s consideration of expanding the response time for entities that identify or inherit Interconnection Reliability Operating Limits to 12 months. (2) However, we have several concerns with the direction taken in this revision. The title of the

Standard should simply state that this is a “Personnel Training” standard and avoid references to “System” or “Operations” altogether. It should be up to each registered entity to determine which personnel is applicable and should receive required training based on the job function. (3) The use of systematic approach to training is unclear and industry needs additional guidance on what is expected for compliance purposes. The drafting team should provide additional guidance in the technical justification section of the Standard or provide examples in the PER-005 white paper. (4) The applicability criteria identified for Transmission Owners and Generator Operators in Section A should be identified by the individual entity, as in-line with a systematic approach to training. The current approach of applicable personnel creates confusion and opportunities for inconsistent compliance approaches by regional auditors. (5) The measures identified in this Standard create unnecessary burdens for entities to achieve compliance. The RSAW states that an entity should maintain an organizational chart that identifies which employees are considered “System Personnel” to meet compliance with the standard. This is a zero-defect approach to compliance. We are concerned that auditors would argue that certain personnel should have been included as applicable employees that must receive training and find a possible violation for each instance. The Standard should focus on internal controls and management practices consistent with NERC’s Reliability Assurance Initiative (RAI). This is a subjective measure and the auditor is given too much discretion to determine which personnel are applicable to the Standard. Instead, it should be up to the registered entity to determine the applicable personnel. The Standard Drafting Team should revise the Standard to allow the entity to determine appropriate personnel and clarify what evidence is permissible, by providing examples in the measures and the RSAW that are consistent with the RAI. (6) For Requirements R1 and R4, we recommend modifying the scope of these requirements and their subparts. We believe R1 and R4 are proposing unnecessary requirements for an entity to review its training program each calendar year. This is an administrative task that meets Paragraph 81 criteria. (7) The training standard should focus on certified operators, which are required to take CEH training. The industry already trains its critical personnel through the use of CEH Providers. These Providers are already subject to annual reviews based on NERC’s training and continuing education policies. This does not need to be reinforced in a reliability standard that is subject to enforcement actions. Requiring a separate review of an entity’s training plan, which is subject to compliance, is redundant and unnecessary. We recommend that the SDT consider equally efficient alternatives to this requirement, such as NERC’s policies that are already in place. (8) For Requirement R3, we recommend including “table top” simulated exercises as a method of simulation for applicable personnel. We do not agree that simulation technology is the only way to train for operating the Bulk Electric System. Simulated exercises, such as the NERC-approved GridEx, provide industry with valuable training to adapt and respond to

disturbances. Rather than addressing the issue with the definition of "simulation technology" within Requirement R3, the SDT should add a section for "Definitions of Simulation and Simulators" under the Application Guidelines in this Standard. These guidelines identify specific academic definitions and do not include the industry-adopted definition of "table top" simulated exercises. An entity should be allowed to identify its own combination of "table top" simulated exercises and exercises using simulation technology that adheres to the systematic approach to training process. (9) We do not find the technical support for simulations as relevant or appropriate to be included in a reliability standard. It is out of scope to include who IST is, their mission, or any of the graphics that show outdated technology of simulations. This appears to be a copy-and-paste directly from a web site. We recommend the SDT revise the Applications Guidelines section to only reference appropriate SAT resources. (10) The Violations Severity Levels for Requirement R3 are binary in nature and should be modified to a graduated severity level. The Standard Drafting Team should follow a similar structure of the Requirement R2's Violations Severity Levels by including percentages of System Personnel that have received simulation technology training. (11) We do not believe the Time Horizons are appropriate for this Standard. Training should not be considered as Long-term planning because training does not occur six to nine months out. Training should be either "Same-day Operations"or "Operations Planning". In addition, the Violation Risk Factors are rather excessive at Medium for impacts to the BES. We are not convinced that missing a training session has a direct correlation to impacting the BES in a way that would result in cascading, instability, or separation. (12) The Application Guidelines Reference #3 is not clear. These bulleted lists do not provide any rationale or justification for why these topics should be trained upon. Registered entities serve different functions for reliability and are in the best position to determine which tasks should be included in their training program. For example, what do Market Rules and LMPs have to do with an emergency? This section needs to be revised. (13) Thank you for the opportunity to comment.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
No
1. Part 1.1: We do not agree with the additional phrase "based on defined and documented methodology". The training program for the responsible entity needs to be based on "the list of Bulk Electric System (BES) company specific Real-time reliability-related tasks". Part 1.1 thus should end at the word "tasks". Adding the phrase "based on defined and documented methodology" does not add any value to the requirement, but creates an uncertainty as to

“who defines the methodology” and with what criteria is the methodology deinfed. In the SDT’s Cummary Consideration report, there isno mentikn of any comment made to this part in the previous posting, and hence we have no idea on the basis for this addition. We suggest removing this phrase from Part 1.1. 2. We appreciate the SDT’s effort to revise Requirement R4 to address concerns raised in the last posting regarding the lack of clarity in this requirement. The revised R4 is much improved in terms of providing clarity as to who need to be trained and on which set of tasks. However, the language as presented is still a bit confusing despite we understand the intent. R4 stipulates that: R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall use a systematic approach to training to develop and implement training for its Operations Support Personnel on the impact of their job function(s) to those Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. We do not agree that these personnel need to be trained on the “impact of their job functions to those Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1”. Rather, we believe the intent is to train these personnel “on their job functions that have an impact on those Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1.” We suggest R4 be revised accordingly. 3. The above comment and suggestion apply to R5. 4. Requirements R5: The words “to training” are missing after “systematic approach”. 5. Requirements R1, R4 and R5 stipulate the use of systematic approach to training to develop and implement training or training program (note the inconsistent wording among them) for their respective group of personnel. While R4 and R5 contain a HIGH VSL for failing to use systematic approach to training to develop and implement the training program, R1 does not have a simiar VSL. Suggest to add a HIGH VSL to R1 to address this.
Individual
Russ Schneider
Flathead Electric Cooperative, Inc.
No
I do not like the concept of having definitions just within the standard that entities can hope auditors won't apply to other situations that were not intended. I do not support any changes to the Control Center definition either. The fact that the draft is not consistent with the current definition of Control Center is indicative of the inappropriately expanded scope of the new definitions.
No
The scope should be limited to operations personnel that fall under the existing definition of Control Center or System Operator in the current NERC Glossary.

Group
Iberdrola USA
John Allen
No
There are two terms in the definition of System Operator that could cause issues. (1) Using the lower case "control center", i.e., not the NERC Glossary definition, could lead to future confusion. Either the NERC Glossary definition should be used, or another term should be used. In general, we feel that if a term is defined in the NERC Glossary, that same term should not be used in its common or undefined form. (2) The word "operates" in the definition of System Operator is not clear and could cause more personnel to be included as "System Operators" than is intended. We suggest replacing the word "operates" with the term "makes operational decisions" to eliminate those that may only implement System Operator decisions and directions from being classified as a System Operator.
Yes
Individual
Matthew Beilfuss
Wisconsin Electric
Yes
No
Expanding the scope of GOP training to encompass a systematic approach to training (SAT) will likely identify tasks and training that is already identified within existing standards. Requirements for GOP personnel to complete training or be familiar with tasks is explicitly required in the current versions of EOP-005, CIP-004, and PRC-001. Also, the content and rigor of the VAR standards create explicit procedural requirements that address GOP impact on reliable operations of the BES during normal and emergency operations. Given that no individual Generator has a reliability impact on the BES, training requirements to address specific instances where BES reliability is potentially impacted by a GOP has been appropriately addressed within the standards. Additionally, a requirement for a GOP systematic approach to training within PER-005-2 is an odd fit given that the balance of the standard is written to address System Personnel and Real-time reliability-related tasks. If it is viewed as necessary to require a SAT program for GOPs, this can better be addressed by a standalone standard. As PER-005-2 is written, the compliance framework and requirements applicable to managing the System Operator SAT are different than the GOP SAT.
Individual
Brian Reich

Idaho Power Company
Yes
Yes
Group
DTE Electric
Kathleen Black
Yes
We support the definitions in general, but we have some concerns on the support personnel. Our main concern is that we have employees who perform outage coordination or assessments that are economically based and have no impact on reliability. To provide clarification, we suggest the following definition: Individuals, as identified by the Reliability Coordinators, Balancing Authorities, Transmission Operators, or Transmission Owners, who perform reliability-related outage coordination or assessments, or determine SOLs, IROLS, or operating nomograms,in direct support of Real-time, reliability-related tasks performed by System Operators.
Yes
We agree in general, but we have some concerns as noted below: R4 requires "training" to be developed and implemented. R4.1 requires we conduct an evaluation of the "training". Neither R4 or 4.1 requires a training program, however, M4.1 requires the training "program" is evaluated each calendar year. It seems that R4 and R5 should specify that there be a training program as in R1. This same concern is true for R5, 5.1 and M5.1.
Group
PacifiCorp
Ryan Millard
Yes
Yes
Group
Tennessee Valley Authority
Brandy Spraker
Agree
SERC Operating Committee
Individual
Shirley Mayadewi
Manitoba Hydro

Yes
Yes
Although Manitoba Hydro is in general agreement with the standard, we have the following comments: (1) M1 - capitalize the word ”Owner” for consistency with other measures in the standard. (2) M1.4 - for consistency with other measures, suggest inserting the words, “this evidence may be documents” prior to “such as”. (3) M2 - for clarity, change the word “task” to “tasks”. (4) Definition of Terms – it appears as though the definition of System Operator will purposely use a lower case ‘control centre’ even though there is a defined term Control Centre in the Glossary of Terms. While it is good to differentiate if the defined term in the Glossary is not applicable in this instance, this is prone to confusion as people may well assume the lack of capitalization was inadvertent. (5)4. Applicability (and R3) – same concern as above. We notice that the word ‘facility’ has been purposely left lower case in order to differentiate from the already defined term ‘Facility’ in the Glossary of Terms. (6) R1 – unclear what the term ‘systematic approach to training’ includes, and no explanation or description is given (7) R1 – not sure why footnote 3 (and similarly footnote 4 in R4) are necessary. No other defined term in the standard has an explanation of the definition attached to it. (8) R1, 1.1 – the list of Real-time reliability related tasks are described inconsistently throughout the standard, sometimes described as ‘company specific’, sometimes also ‘BES’. What is the term BES meant to add to the description? - Does it mean BES companies? BES reliability risks? (9) R1, 1.4 and R4, 4.1 – the reference to each calendar year ‘of the training program’ is unclear. Is it supposed to mean each calendar year that the training program is in effect? It may not be delivered each year. Or each calendar year after the training program is first developed? The Measure just refers to each calendar year. (10) The requirements and measures seem to alternate between the words ‘establish’ and ‘develop’ and the words ‘implement’ and ‘deliver’ when referring to the same obligation. Consistency would be preferable. Likewise, program should be training program throughout to be consistent. (11) R3 – the words ‘according to its training program’ would be more appropriate moved to follow the words ‘emergency operations training’ (12) R4, R5 and M4, M5 – the language of these requirements and measures should more closely track the language of R1 and M1 since the requirements R1 and R4 and R5 are so similar. (13) R6 (which should be R5) – the words ‘described in Applicability Section 4.1.5 of this standard’ is unnecessary. This type of language is not included for any other group of applicable entities/personnel. The Applicability section covers applicability, it doesn’t seem necessary to repeat in the requirement. (14) Compliance 1.3 - The language refers specifically to a process found in the NERC Rules of Procedure. We have not previously seen this reference (generally in draft standards, there is a list of processes that may be used). The reference included in this draft standard is concerning because Manitoba has its own Compliance and Monitoring program and has only adopted

select aspects of the NERC Rules of Procedure. (15) VSLs – R1 – Moderate VSL – the language that references 1.1.1 does not really match up with what 1.1.1 says. 1.1.1 requires the entity to update the list of tasks 'if necessary'. The Measure makes no reference to updating, and then the VSL refers to making identified changes. (16) VSLs – R1 – Severe VSL – the wording that references 1.3 is slightly different than what 1.3 actually says. 1.2 requires that the training be delivered according to its training program. The VSLs require the training be delivered according to its task list. (17) VSLs – R2 – the way the language is now is confusing. Needs to be clarified whether the percentage refers to the percentage of the System Personnel or the percentage of the capabilities. In other words, is it that 90% of the System Personnel had their capabilities verified, or is it that 90% of the capabilities were verified.
Individual
Kayleigh Wilkerson
Lincoln Electric System
Yes
Yes
Although supportive of the latest version of PER-005-2, LES is concerned with the amount of detail and information provided within the "Definitions of Simulation and Simulators" section of the Application Guidelines. As currently drafted, this section appears to be a copied and pasted document with portions resembling a third party sales pitch. While appreciative of the information, LES recommends consolidating the definitions of simulation, and other relevant information, to provide industry members a clear and concise reference.
Group
Oklahoma Gas and Electric
Terri Pyle
No
Initially, we believe that the existing language is sufficient, however, during the NERC webinar on Oct 7, there were several questions asked about the people that fall under the proposed definition of Support Personnel (e.g. managers, senior managers or VPs), and the answer provided by members of the SDT was that those people should be trained. If that is correct, a whole company's employee roster could be implicated by this language. We ask that the SDT provide further clarification to the audit approach and guidance on the definition to avoid the definition from becoming a moving target.
No
The definition of Transmission Owner presents possible concerns: 4.1.4.1 Personnel at a facility, excluding field switching personnel, who act independently to carry out tasks that

require Real-time operation of the Bulk Electric System, including protecting assets, protecting personnel safety, adhering to regulatory requirements and establishing stable islands during system restoration. It was asked during the webinar on Oct 7 that if outage coordinator is listed as one of the operations support personnel and field switching personnel is excluded from definition of Transmission Owner, then, this presents a contradicting position. In addition, questions were asked about security since the definition of TO includes protecting assets and personnel safety. The SDT was not able to answers questions related to security and how they fit into training. We ask the drafting team to provide additional clarification on the definition of Transmission Owner.
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
No
Modify the current definition of System Operator to read as follows: System Operator: An individual at a control center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who monitors and controls the operation of the Bulk Electric System in Real-time. Rationale: Without tight wording, personnel at locations other than an "individual at a control center" who are not system operators may be swept into the definition. Distribution-related field, substation and satellite location personnel, such as District Operators, should not be classified as System Operators by an overly broad definition. A System Operator performs two critical functions: monitoring and control (of the status of bulk electric system assets). Anyone who does not perform these functions must rely on a System Operator, and is not operating independently. Therefore, they are not System Operators.
No
Delete Requirement R4 in its entirety. On page 4, the white paper notes: The argument for not including EMS personnel in the training standard at this time is based on a report provided by the Event Analysis Subcommittee (EAS). The EAS worked with the NERC Event Analysis (EA) staff to review the events that have been cause-coded since October 2010. The database has over 263 events; … [and] only two were deemed to be a training issue. Therefore, based on the information, the EAS and PER ad hoc group do not believe it is necessary at this time to require EMS support personnel to receive the level of training required of a BA, Reliability Coordinator (RC), and TOP by NERC standard PER-005. Using the same rational employed in the white paper to defer consideration of requirements related to EMS support personnel, the drafting team should defer consideration of applicability of R4 to Operations Support Personnel until such time as a substantial, documented reliability gap is identified by further study. We do not believe that Operations Support Personnel should be

required “to receive the level of training required of a BA, Reliability Coordinator (RC), and TOP by NERC standard PER-005.” We, therefore, propose to revised the Applicability wording in 4.1.4.1. as follows: 4.1.4 Transmission Owner that has: 4.1.4.1 Personnel at a facility, excluding field switching personnel, who act independently to carry out tasks that require real-time reliable operation of the Bulk Electric System. The NERC glossary clearly defines the terms real-time and reliable operation.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
SERC SOS
Individual
Ronald L Donahey
Tampa Electric Company
No
The section “Rational for R4” states: “This requirement does not require that entities create a new, comprehensive systematic approach to training process for training Operations Support Personnel.” However R4.1 states: “Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall conduct an evaluation each calendar year of the training established in Requirement R4 to identify and implement changes to the training.” M4 states: “Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed a training program evaluation each calendar year, as specified in Requirement R4 part 4.1. This would led one to believe that there is a need for a new training program/process for Operations Support Personnel.
Individual
David Kiguel
David Kiguel
No
1. The proposed draft continues to use the vague "Systematic Approach" term, which, as used, is not measurable. The Compliance Operations document tries to clarify its meaning by listing criteria that auditors would use to determine if a registered entity uses a systematic approach to training for developing its program. In doing so, it repeats the content of the Applications Guidelines in the draft standard, which only gives high level principles. As

written, auditors could potentially use their assessment in a subjective and inconsistent manner. I suggest modifying requirement R1 so it clearly establishes the minimim areas that the assessment must address. 2. R2 requires that each RC, BA, TOP, and TO shall verify, at least once, the capabilities of its System Personnel. The Implementation Plan states that entities that were not previously subject to PER-005-1 must have verified its System Personnel's capabilities to perform each of its assigned Real-time reliability-related tasks, at least once, as identified in Requirement R1 part 1.1, prior to the effective date of the standard. Requiring entities to perform certain activities prior to the effective date of the standard means in practice advancing its effective date, which is not feasible in certain jurisdictions. Requirements cannot be enforced prior to the standard's effective date. Doing it before the effective date may constitute good practice and being proactive, but an entity cannot be held non-compliant for not doing it at a time when the standard is not yet enforceable. I suggest changing to: Entities that were not previously subject to PER-005-1 must have verified its System Personnel's capabilities to perform each of its assigned Real-time reliability-related tasks, at least once, as identified in Requirement R1 part 1.1, within one year of the standard becoming in force within their respective jurisdiction. Note: The suggested 1 year could be reduced to 6 months at the SDT's option.
Group
Southwest Power Pool Regional Entity
Emily Pennel
Yes
Regarding R3 – the simulator training needs to be on the IROL, if that is the point of the requirement. M1 should be "Transmission Owner" not "Transmission owner."
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
No
"The proposed definition of "Operations Support Personnel" includes individuals who "perform … assessments … or … determine SOLs". These phrases can easily be misunderstood and further clarity is needed. On the webinar on Oct. 28th, the SDT noted that the definition is not intended to include personnel performing seasonal assessments. However, this may not be the natural reading of the definition in light of the TOP standards such as TOP-002-2.1b R11 and TOP-005-2a R2. If the personnel performing seasonal assessments are not to be included into the definition of "Operations Support Personnel", the definition should be revised to state what type of assessments are in view. In regard to determining SOLs, many parts of the interconnected system are not limited by stability-related SOLs, which might be

established on a day to day basis. Rather, these areas are limited by the thermal capability of system equipment and the established SOLs are determined based on these thermal ratings. Since the basis for these ratings (and, hence, the SOL) is the facility rating methodology required under FAC-008-3, this definition could pull in the engineering functions performing the work to determine the correct ratings. We don't believe this is the intention of the standard nor the FERC orders. If the intention is to incorporate the personnel who perform assessments that identify new SOLs for real-time operations but not those who perform seasonal assessments nor the engineering staff who determine the facility ratings, the definition should be revised to ensure the correct personnel are identified. Given the comments above, a proposed revision might be: "Operations Support Personnel: Individuals, as identified by the Reliability Coordinators, Balancing Authorities, Transmission Operators, or Transmission Owners, who perform current-day outage coordination or assessments, or who determine current-day SOLs, IROLs, or operating nomograms,2 in direct support of Real-time, reliability-related tasks performed by System Operators."
No
Please see comments in response to Question #1.
Individual
Bret Galbraith
Seminole Electric
No
(1) The proposed definition for Operations Support Personnel appears to be too broad in that it does not give due process notification to the regulated community of which particular personnel this Standard will apply. This Standard will apply to those personnel who "perform outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms in direct support of Real-time, reliability-related tasks performed by System Operators." For example, one of Seminole's concerns is that personnel involved in developing Facility Ratings, such as under FAC-008, will be covered under this definition as their Facility Ratings methodology/inventories may directly affect the SOL/IROL development, and thus support System Operators. The same concern applies to relay protection engineers who design relay protections schemes, in that under a broad reading of this definition, their actions support System Operators. Seminole requests that the SDT attempt to clarify this proposed definition in a subsequent ballot action in order to provide clearer guidance to the regulated industry.
No
(1) The applicability section for Transmission Owners states the following: Personnel at a facility, excluding field switching personnel, who act independently to carry out tasks that require Real-time operation of the Bulk Electric System, including protecting assets,

protecting personnel safety, adhering to regulatory requirements and establishing stable islands during system restoration. (emphasis added). This applicability section is also broad in that it appears to cover multiple departmental personnel, ranging from environmental affairs staff, to relay system protection engineers, to possibly safety personnel. For example, if the need to fire fuel oil on a turbine arises due to an emergency, environmental staff may proceed independently to receive a waiver to a permit limit that limits hours on fuel oil. It is unclear whether these personnel are covered under this section. In addition, the reference to personnel involved in "protecting assets," appears to be very broad, and Seminole requests that the SDT elaborate on those particular individuals the SDT wishes to be covered by this Standard. (2) In the posted redline version of the proposed Standard in section M-1, "Transmission Owner" was revised to "Transmission owner," i.e., lower case "o." Can the SDT explain the reason for the change as Seminole believes "Owner" should remain capitalized? (3) Ambiguity exists in Requirement R4 where it states "[Each Applicable Entity shall] …develop and implement training for its Operations Support Personnel on the impact of their job function(s) to those Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1" The statement appears to refer to the tasks of the system operators, however, Seminole cannot conclude whether the SDT has considered that the tasks of a support person and the tasks of an operator are different. The issue for Seminole is whether this statement mandates the creation and training of an entirely different set of tasks, one based on the overall tasks of support personnel, or are the support personnel to be trained on the tasks of the operators in which they support? Seminole requests that the SDT clarify this requirement. (4) Seminole has concerns with Reference #3 in the Application Guidelines, specifically, whether the topic criteria listed are mandatory criteria to be evaluated in developing training material. If the criteria listed are mandatory, or even suggested criteria, does the NERC SDT reason that personnel who support operations concerning the listed topics are all Support Personnel, such as personnel who assist in the development of tariffs (see Section F within Reference #3)? Seminole requests clarification on the References in the Application Guidelines.
Individual
John Idzior
ReliabilityFirst Corporation
Yes
No
ReliabilityFirst votes in the negative because this standard has a number of issues surrounding 1) the lack of periodicity in Requirement R1 and Requirement R2 and the lack of understanding of the intent of meaning of systematic approach to training from a compliance

standpoint. ReliabilityFirst offers the following comments for consideration: 1. Requirement R1, Part 1.2 a. ReliabilityFirst believes there should be a time period associated with Requirement R1, Part 1.2. As written, if an entity adds a new Real-time reliability-related task to their list, it would be left to the discretion of the entity on when they want to include the new training in their program. ReliabilityFirst recommends the following for consideration: “Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall design and develop training materials according to its training program, based on the Real-time reliability-related task list created in part 1.1. [Newly updated Real-time reliability-related tasks identified in part 1.1.1 shall be included in the training program within 45 calendar days of identification. 2. Requirement R1, Part 1.3 a. If an entity verified the capability of their System Operators to perform the company-specific reliability related tasks, are they required to deliver any other training unless needed? Can the SDT clarify if this is the intent SDT or is this more required in Requirement R2? 3. Requirement R2 a. ReliabilityFirst questions the intent of the phrase “at least once” within Requirement R2. Is it the intent that the capabilities of its System Personnel only need to be verified once before they are able to go on shift? ReliabilityFirst believes System Personnel should be trained prior being able to go on shift and then annually thereafter. ReliabilityFirst recommends the following for consideration: “Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once [prior to going on shift and annually thereafter], the capabilities of its System Personnel assigned to perform each of the Real-time reliability-related tasks identified under Requirement R1 part 1.1. 4. Requirement R3, Part 3.1 a. ReliabilityFirst believes the 12 month period in which an entity has to comply with Requirement R3 (if they gain operational authority or control over a Facility with an established IROL) is excessive. IROLs can have a large reliability impact on the BES and training using simulation technology should be provided as soon as practical. ReliabilityFirst recommends modifying the timeframe to six months. 5. ReliabilityFirst requests the SDT further elaborate what is meant by the term “systematic approach to training”. It is unclear how an auditor would assess whether an entity applied a systematic approach to training when assessing compliance with the requirements. 6. VSL for Requirement R1 a. The second Moderate VSL states the entity failed to “…implement the identified changes to the Real-time reliability-related task” though Part 1.1.1 does not require implementation. To be consistent with the language of the requirement, ReliabilityFirst recommends the following for consideration: “The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner, failed to [update] the identified changes to the Real-time reliability-related task. (1.1.1.)
Individual
Kathleen Goodman

ISO New England Inc.
Agree
IRC SRC
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Pamela Hunter
Yes
Yes
Group
IRC/Standards Review Committee
Gregory Campoli
No
Defintion of System Operator Because it could impact the intent of other standards where the definition is used, the definition of system operator shouldn't be changed. If the PER standard is not intended to apply to control center operators of generator fleets or is to apply to Transmission Owners, we prefer it being addressed in the applicability of the standard. Definition of Operations Support Personnel If kept, the definition of Operations Support Personnel should be revised to: "Individuals, as identified by the Reliability Coordinators, Balancing Authorities, Transmission Operators, or Transmission Owners, who perform next-day or same-day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms,1 in direct support of Real-time, reliability-related tasks performed by System Operators."
No
Definitions of Terms Used in Standard During the Industry Webinar (Question and Answer section at 39:00 minute mark), SDT made a distinction between the term "training" vs. "training program". SDT explained that the "training" term used in R4 and R5 does not have to follow all the steps involved in SAT in addition, the drafting team intention was to have less onerous documentation requirements for Compliance purposes. Because there is a meaningful difference meant by the SDT for each of the above terms, they should be defined under the section "Definitions of Terms Used in Standard". Introduction Section 4.1.4.1. While we don't disagree that Transmission Owners should protect personnel safety, the EPAct specifically precluded NERC from developing safety-related standards. The standard should be silent on safety issues. As such we recommend the section be modified such that the

paragraph ends at “Bulk Electric System” as shown below: 4.1.4.1 Personnel at a facility, excluding field switching personnel, who act independently to carry out tasks that require Real-time operation of the Bulk Electric System. Requirements and Measures R1 Part 1.1 We do not agree with the additional phrase “based on defined and documented methodology”. The training program for the responsible entity needs to be based on “the list of Bulk Electric System (BES) company specific Real-time reliability-related tasks”. Part 1.1 thus should end at the word “tasks”. Adding the phrase “based on defined and documented methodology” does not add any value to the requirement, but creates an uncertainty as to “who defines the methodology” and with what criteria is the methodology defined. In the SDT’s Summary Consideration report, there is no mention of any comment made to this part in the previous posting, and hence we have no idea on the basis for this addition. We suggest removing this phrase from Part 1.1. R3 R3 ties simulation training for Emergency Operations (EO) directly to an entity’s operational authority or control over facilities with established IROLs. NERC’s Glossary of Terms defines Emergency as “Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System”. EO clearly goes beyond operating guidelines and/or protection systems to mitigate IROLs and includes loss of generation resources, operating and contingency reserves, load shedding, loss of EMS, loss of primary control center, power system restoration … SRC believes that simulation training for EO should be a requirement for RC, BA, and TOP and agrees with the applicability of R3 to TO if TO has operational authority or control over IROL facilties or established operating guides or protection systems to mitigate IROLs. Furthermore, the standard should clarify that the training should not be on individual IROL’s, but the established guidelines and protection systems to mitigate IROLs. R3 Part 3.1 can create confusion . R2 requires the verification of the capabilities of each System Personnel to perform new or modified Real-time reliability-related tasks within six months. Addition of new IROL will, in most cases, modify or create new Real-time reliability-related tasks. As such, applicable entities are required to train on the addition or change of Real-time reliability-related tasks associated with the new IROL within six months. The language for R3 Part 3.1 needs to clarify that applicable entities still have to comply with R2. R4 We appreciate the SDT’s effort to revise Requirement R4 to address concerns raised in the last posting regarding the lack of clarity in this requirement. The revised R4 is much improved in terms of providing clarity as to who need to be trained and on which set of tasks. However, the language as presented is still a bit confusing despite our understanding of the intent. R4 stipulates that: R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall use a systematic approach to training to develop and implement training for its Operations Support Personnel on the impact of their job function(s) to those

Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. We do not agree that these personnel need to be trained on the “impact of their job functions to those Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1”. Rather, we believe the intent is to train these personnel “on their job functions that have an impact on those Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1.” We suggest R4 be revised accordingly. R5 Requirements R5: The words “to training” are missing after “systematic approach”. Table of Compliance Elements Requirements R1, R4 and R5 stipulate the use of systematic approach to training to develop and implement training or training program for their respective group of personnel. While R4 and R5 contain a HIGH VSL for failing to use systematic approach to training to develop and implement the training program, R1 does not have a simiar VSL. Suggest to add a HIGH VSL to R1 to address this.
Individual
Alice Ireland
Xcel Energy
No
Xcel Energy believes it is inappropriate to have the same term defined one way in the NERC glossary, and another way in a standard. Either the term System Operator should be modified and implemented to all relevant standards, or the team should find another way to clarify applicability within PER-005.
Yes
Other than the comment on the definition of System Operator, Xcel Energy is in support of the current draft. However, affirmation/clarification is requested on the following items: 1) Is continuing training required? 2) Are job performance measures (JPMs) required? 3) If JPM is successfully completed, then does that negate the need for initial training – in otherwords do we need both JPMs and Training? 4) Confirmation of a “narrow JTA” – only tasks that directly affect real time system operations, not a full JTA.
Group
Dominion
Mike Garton
No
Suggest the definition of Operations Support Personnel be modified by replacing "System Operators" with "System Personnel" as indicated below: Operations Support Personnel: Individuals, as identified by the Reliability Coordinators, Balancing Authorities, Transmission Operators, or Transmission Owners, who perform outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms,1 in direct support of Real-time,

reliability-related tasks performed by System Personnel.
No
1. Requirement R1, subpart 1.1 – Dominion does not believe the added language “based on a defined and documented methodology” adds clarity and in fact, may add ambiguity. Suggest striking this language from R1, subpart 1.1 as well as Measure M1, subpart M1.1. 2. M1 – Dominion suggests that “Transmission owner” needs to be capitalized consistent with R1. 3. R5 – this is the only requirement in the standards that includes …”during normal and emergency operations.” Therefore, Dominion suggests striking this language in R5 to be consistent. 4. General comment – The requirement sub-parts (e.g. 1.1, 1.2, etc.) are not preceded with an “R” while the measure subparts (e.g. M1.1, M1.2) are preceded with an “M.” Dominion suggests applying the same convention to both requirements and measures. 5. For clarity of applicability, Dominion suggests removing the sentence “This personnel does not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions, without making any modifications” from section 4.1.5.1 and instead making it a footnote to that section. 6. Implementation Plan Actions to be Completed as of the Effective Date – Requirement R1, subpart 1.3 states in part that entities that were not previously subject to PER-005-1 are not expected to have delivered training prior to the effective date; however, Requirement 2, suggests that these same entities must have verified the capability of their System Personnel to perform Real-time reliability-related tasks prior to the effective date of the standard. PER-005-1 does not apply to System Personnel therefore there should be no assumption that the capabilities of such personnel has been previously verified regardless of whether PER-005-1 applied to the Applicable Entity. Dominion suggests that the SDT review and modify the Implementation Plan accordingly. 7. Suggest Revising Section 4.1.5.1 as follows: “This personnel does not include . . . “ should be “These personnel do not include . . . “
Individual
Scott Berry
Indiana Municipal Power Agency
No
IMPA is concerned about the wording used for applicability of the Generator Operator. What happens when a Generator Operator as part of normal operations relays dispatch instructions, but has the one time when an emergency occurs and they have to follow emergency instructions to prevent damage to the generating unit. An Audit may view this emergency action as not relaying dispatch instructions and say the standard is applicable to the Generator Operator who has not used a systematic approach to develop and deliver training to its personnel. The auditor could find the Generator Operator in violation of the

applicable requirements of the standard. IMPA would recommend allowing Generator Operators to take emergency action to prevent damage to their generating units and not let this go against the action of “relay dispatch actions”. IMPA also agrees with the comments submitted by Carol Chinn with Floriday Municipal Power Agency (FMPA).
Group
Duke Energy
Michael Lowman
No
We commend the drafting team on its continued effort and appreciate the opportunity to provide the following comments. Duke Energy suggests rewording Section 4.1.4.1 of the Applicability Section as follows: “4.1.4 Transmission Owner (TO) that has: 4.1.4.1 Personnel at a facility, excluding field switching personnel, who exercise control over a significant portion of the Bulk Electric System. Such personnel may carry out tasks that require Real-time operation of the BES under the direct supervision of the registered Transmission Operator. This TO personnel may also act independently to implement pre-defined operating procedures.” Duke Energy believes that definitions used in NERC standards should be added to the NERC Glossary of Terms instead of having “standard only” definitions. Having definitions only applicable and imbedded in the standard could lead to confusion for an auditor and others if multiple definitions are created. By keeping these definitions in the NERC Glossary of Terms, it eliminates this confusion and provides clarity to the industry by having one universal definition for each term instead of having multiple definitions. Having “standard only” definitions appears to be in disagreement with the first paragraph of the Introduction to the NERC Glossary of Terms which states, “This Glossary lists each term that was defined for use in one or more of NERC’s continent-wide or Regional Reliability Standards and adopted by the NERC Board of Trustees from February 8, 2005 through October 30, 2013.”
No
Requirement 3 – While Duke Energy can support this requirement as written, we strongly believe that the 32 hours of Emergency Operations Training is necessary for the industry. While we understand that NERC is moving towards a more risk based approach, our concern is the lack of a tangible amount of training hours that would be deemed appropriate by an auditor. In theory, Duke Energy agrees with the concept of allowing the registered entities to determine an acceptable time/level of training. However, we feel in this instance that based on the impact that Emergency Operations has on the reliability of the BES, and the open-ended nature of interpretation available to an auditor, an industry-wide number of training hours is more suitable. Requirement 4 - Duke Energy believes that the time horizon in Requirement 4 should be set to the Operations Planning Time Horizon instead on the Long-

Term Planning Horizon. Outage coordination and assessments, determination of SOLs, IROLs, and development of operating nomograms are performed in the Operations Planning Time Horizon and not in the Long Term Planning Horizon as indicated in Requirement 4. Duke Energy is concerned that an auditor could come the conclusion that Transmission Planners would fall under the compliance umbrella of Operations Support Personel based on the current time horizon as written in this requirement. Requirements 4 & 5- Duke Energy believes clarification is needed regarding the timeframes for administering initial training for TOP and GOP support staff and the frequency of training thereafter in Requirements 4 & 5. This clarification will enable the industry to shape their training programs for new employees, transfers, and existing employees. Duke Energy is concerned that without specifying timeframes and frequency of training in this requirement, entities could be found non-compliant if an auditor disagreed with the way their training programs are established. These timing requirements are clearly identified for System Personnel in R1-R3, but are not included for the GOP or Operations Support Personel in Requirements 4&5 as currently written. Requirement 5 – Duke Energy believes that coordination between the GOP and those who define the reliability-related tasks is essential for ensuring that the GOP receives meaningful training on the impacts that their job functions have on the BES. FERC order 693 P.1356 states, “stating that training for Generator Operators need not be as extensive as that required for Transmission Operators, and the training requirements developed by the ERO should be tailored in their scope, content, and duration so as to be appropriate to Generation Operations personnel and the objective of promoting system reliability. “ Duke Energy is concerned that the removal of this coordination would not satisfy the FERC Order and would not be tailored in scope, content, and duration so as to be appropriate to Generation Operations personnel and the objective of promoting system reliability. Duke Energy recommends reinserting the language for coordination as used in the previous draft of this standard. Based on our belief on the importance of coordination between the GOP and those who define the reliability-related tasks , Duke Energy is unable to support this standard as written.
Individual
Gerald G Farringer
Comsumers Energy
No
: The term “System Personnel” is still redundant and seems to provide no useful distinction. It refers to the “System Operator”s of the applicable entities and should be removed from the standard. The definition for “Operations Support Personnel” can still pull individuals that simply administer outage scheduling programs into the rquirements of PER-005. We believe this is an over-reach for the standard and causes more administrative overhead without a

reliability gain. We applaud the clarity added in the definition for “Generator Operator” in 4.1.5.1.
No
The addition of the term “methodology” in M1.1 is not required and only serves to add subjectivity to the process. If the right tasks are identified the methodology of how they were determined does not matter.
Group
US Bureau of Reclamation
Erika Doot
Yes
The Bureau of Reclamation (Reclamation) believes that the definitions of Support Personnel and System Operator have improved since the first posting. Reclamation agrees with the drafting team’s decision to define System Operators as Balancing Authority, Transmission Operator, and Reliability Coordinator personnel only. Reclamation also agrees with the drafting team’s decision to specify that Operations Support Personnel perform assesments “in direct support of Real-time reliability-related tasks” performed by System Operators.
No
Reclamation is unable to determine which Transmission Owner and Generator Operator personnel would be subject to the standard because of unclear language in the Applicability Section. In Transmission Owner applicability statement 4.1.4.1, Reclamation does not understand how or when Transmission Owners “act independently to carry out tasks that require Real-Time operation of the Bulk Electric System.” Reclamation believes that Transmission Owners who are not Transmission Operators do not “act independently,” when protecting assets, protecting personnel safety, adhering to regulatory requirements, and establishing stable islands. Instead, Transmission Owners operate in coordination with Transmission Operators when altering the state of Bulk Electric System facilities. Reclamation struggles to understand which Transmission Owner personnel could be subject to the standard under the proposed Transmission Owner applicability section. Reclamation belives that Transmission Owners who act independently should be registered as Transmission Operators. In addition, the proposed Transmission Owner applicability language does not appear to be consistent with the recommendataion in FERC Order 742 paragraph 62, which is directed at “local control center personnel” who act “under the supervision of the personnel of the registered Transmission Operator.” Reclamation recommends that NERC and the drafting team engage FERC in conversations to better understand the intent of the order. Reclamation is also unclear on which Generator Operator personnel would fall within the scope of the proposed standard. Reclamation requests clarification on the term “centrally

located dispatch centers," and whether a "centrally located dispatch center" may control a single generation site. Reclamation does not consider Generator Operator control room personnel to be dispatchers. Instead, Reclamation considers dispatchers to be the System Operators of Balancing Authorities, Transmission Operators, and Reliability Coordinators. The proposed Applicability Section appears to exempt "plant operators located at a generator plant site," however generation control room personnel often "receive direction from" their Transmission Operators and Balancing Authorities. Reclamation recommends that the drafting team redraft the Generator Operator applicability statements to remove mention of dispatch centers or define the term.
Individual
David Jendras
Ameren
Yes
The NERC Glossary of Terms defines that System Operator is at TOP, BA or RC, so leave that out of definition for System Personnel.
No
We are concerned that the language for this Standard might be interpreted by some to cover all training. We believe that this Standard only applies to training on Real-time Reliability Related tasks. There is nothing in this Standard that addresses initial training on theory and operation of the electrical system or training on Real-time Non-Reliability Related tasks. The term "Training Program" as it relates to PER-005 only applies to training developed and delivered on Real-time Reliability Related tasks that are company specific. We are concerned that ther drafting team is moving away from industries general understanding of the SAT process. The SAT process is used to analyze, design, develop, implement and evaluate training materials based on Job Tasks and Job Tasks Analysis. Yes the SAT it is used to develop a total training program, but this is not addressed in this Standard. Rational for changes to R3 - The 32 hours of Emergency Operations Training needs to be left in R3 as it applies only to System Operators. There is nothing in R1 that addresses 32 hours of annual training. There is also nothing in this Standard that says you have to have a Continuous Education section in the training. This Standards says that I have to develop training on Real-time Reliability Related Tasks that are company specific, deliver the training, verify at least once that the task can be performed, and verify that any new or modified task can be performed. Once this has been done there is nothing in this Standard that says we have to do any other kind of additional training ever! That is why the 32 hours needs to remain as part of this Standard. We request the following changes and clarifications to the drafting team: (a) Purpose - Don't re-write it - just insert "System Personnel". (b) System Personnel definition needs to include Generator

Operator. (c) R1 - Don't re-write it, just insert "Transmisison Owner" and "System Personnel". (d) R1.1 - Add "performed by its System Personnel" (e) R1.2 - Delete "according to its training program" (f) R1.3 - Don't re-write it, just add "Transmission Owner". (g) R3 - Leave this the way it is as it currently as it only applies to System Operators. (h) R3.1 - Leave it the way it is currently just add "Transmission Owner". Never did like this section about using simulation technology as it only applies to entities with IROLs. You could be a very large company with no defined IROLs and would not be required to use emergency operations training using simulation. Don't think this is what FERC was getting at! (i) R3.2 - Make the new R3.1 into R3.2. (j) R4 - Doesn't address training on new or modified tasks.
Individual
Brian Evans-Mongeon
Utility Services
No
The applicability section of the standard related to Transmission Owners and Generator Operators requires some clarity. Suggest more restrictive language for 4.1.4.1: “Operations Personnel at a BES transmission facility, excluding field switching personnel, who have the authority and responsibility to act independent of dispatch instruction from a RC, BA or TOP to carry out tasks that require Real-time operation of the Bulk Electric System, including protecting assets, protecting personnel safety, adhering to regulatory requirements and establishing stable islands during system restoration.” Suggest changing “may” to “has the authority”. It is possible that the GOP may receive specific dispatch instructions in some instances, but in other instances be allowed the flexibility to develop dispatch instructions based on RC, BA or TOP guidance. Additionally, “plant operators” needs to clarify that it only applies to dispatch instructions for BES generators, and does not include dispatch instructions for non-BES generation plant operators. “Dispatch personnel at a centrally located dispatch center who receive direction from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and has the authority to develop specific dispatch instructions for BES generator plant operators under their control. This personnel does not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions, without making any modifications.” Remove footnotes 2 and 3 as unnecessary. R5: Training in R5 is required regardless of the personnel’s capability since there is no requirement to assess the capabilities of the personnel, for the identified tasks. Suggest adding language to allow for a demonstration of capabilities on the required tasks similar to R2. Additionally, a grace period similar to R2.1 should be added to R5 to allow time between a change in the training program to the time training is required to be completed.

Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
Yes
These comments are submitted on behalf of the following PPL NERC Registered Affiliates (PPL): Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. The PPL NERC Registered Affiliates believe that the Applicability section should be changed so that, in parallel with the industry approved criteria in CIP V5, section 4.1.5 reads: 4.1.5 Generator Operator that has: 4.1.5.1 Dispatch personnel at a centrally located dispatch center, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection, who receive direction from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control.
Individual
Texas Reliability Entity
Texas Reliability Entity
No
(1) The Generator Operator applicability statement (4.1.5) is too narrow and somewhat ambiguous. GOP operating personnel at a dispatch center need to understand the dispatch instructions and related communications that they relay, even if they are not intended to make modifications. If they do not understand the instructions they are much more likely to pass them along incorrectly or to take improper actions. Furthermore, these dispatch personnel often need to consider personnel safety, equipment limitations and other issues in connection with instructions they receive and pass along. (1A) Texas RE has several examples of operator voice recordings in which generation dispatch personnel did not understand basic information and instructions that they received from BA and TOP operators. These occurrences demonstrate that it is critical for GOP operators to receive a reasonable amount of training, so that operating instructions do not sound like a foreign language to them, even if they are not personally responsible for taking action. Failure to require this training will result in a reliability gap. (1B) The standard as drafted does not satisfy the cited FERC directive. In Order 693 (P 1359) FERC stated “Although a generator may be given direction

from the balancing authority, ***it is essential that generator operator personnel have appropriate training to understand those instructions***, particularly in an emergency situation in which instructions may be succinct and require immediate action. Further, if communication is lost, the generator operator personnel should have had sufficient training to take appropriate action to ensure reliability of the Bulk-Power System." Applicable instructions include MW dispatch, voltage support, emergency readiness, emergency steps, weather issues, status conditions, and similar instructions. (1C) Proposed standard COM-002-4 introduces the defined term "Operating Instruction." GOP personnel who deal with Operating Instructions should be trained under this PER standard to ensure the reliability of the Bulk Power System. We suggest changing the GOP applicability provision to "4.1.5 Generator Operator that has dispatch personnel at a centrally located dispatch center who receive Operating Instructions from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner. This does not include plant operators located at a generator plant." (2) Requirement R5 presently calls for applicable GOP personnel to be trained only "on the impact of their job function," similar to the training required in R4 for Operations Support Personnel. We feel that this is insufficient, and that the standard should require GOP personnel to be trained to perform their reliability-related job functions. Unlike Operations Support Personnel, these GOP personnel are directly involved in real-time operations and communications. (3) Applicability section 4.1.4, Transmission Owner, is unclear and ambiguous. We have been told that this language was intended to address a situation in a different part of the country (perhaps a registration irregularity), but it is not clear who this is intended to apply to in the ERCOT region. Many TO personnel are involved with protecting assets and personnel safety, so this description would appear to include all TOs who have "personnel at a facility." (4) VSLs for R2: First, it is not clear whether the percentages in the VSL refer to the number of individuals whose capabilities are to be verified, or to the number of individuals multiplied by the number of identified tasks. Second, is this intended to be a zero-defect requirement? The way it is written, failure to verify one task for one individual constitutes a violation. Third, if an individual fails to successfully demonstrate a capability, does that count as a failure to verify, resulting in a violation? In other words, is the intent to ensure that the verification process occurrs, or to ensure that every individual is proficient in every task? (5) The VSLs for R5 should mirror those for R4. The requirements are almost identical, and we don't understand why the VSLs are different.
Group
Florida Municipal Power Agency
Frank Gaffney
No
1. THE APPLICABILITY TO TRANSMISSION OWNERS IS TOO BROAD AND NOT NECESSARY TO

ADDRESS THE FERC DIRECTIVE Original Applicability language from last posting: Transmission Owner that has: 4.1.4.1 Personnel in a transmission control center who operate a portion of the Bulk Electric System at the direction of its Transmission Operator. Proposed Standard language was revised to the following applicability: Transmission Owner that has: 4.1.4.1 Personnel at a facility, excluding field switching personnel, who act independently to carry out tasks that require Real-time operation of the Bulk Electric System, including protecting assets, protecting personnel safety, adhering to regulatory requirements and establishing stable islands during system restoration. This applicability language will still apply to all Transmission Owners to comply with this standard regardless of whether they have a thousand breakers or one breaker. Even if the Transmission Owner does not meet these qualifications, the Transmission Owner will still have to “prove the negative” on a routine basis creating an unnecessary administrative burden. The FERC simply directed NERC to define “local transmission control center” and that has not been done. The following FMPA comments from last posting are still of concern and apply to this version of the standard. It is clear by the language in the order at P62, that FERC was concerned with large entities with significant control and impact on the BES. Order 742 at P62. The Commission understands that local transmission control center personnel exercise control over a significant portion of the Bulk-Power System under the supervision of the personnel of the registered transmission operator. This supervision may take the form of directing specific step-by-step instructions and at other times may take the form of the implementation of predefined operating procedures. For example, ISO New England, Inc., PJM Interconnection, L.L.C., and New York Independent System Operator, Inc., are registered transmission operators who issue operating instructions that are carried out by local transmission control centers such as PSE&G, PPL Electric Utilities Corp., PECO Energy Company, Baltimore Gas and Electric Co., Consolidated Edison of New York, Inc., National Grid USA, and Long Island Power Authority, which are not registered transmission operators. The combined peak load of these three RTOs is in excess of 200 gigawatts. In all cases, the local transmission control center personnel must understand what they are required to do in the performance of their duties to perform them effectively on a timely basis. Thus, omitting such local transmission control center personnel from the PER-005-1 training requirements creates a reliability gap. The Commission believes that identifying these entities would be a valuable step in delineating the magnitude of that gap. (emphasis added) The directive in the order 742 did not direct that all Transmission Owners be included in the training requirements, but only directed that local transmission control center operator personnel have training requirements and to define “local transmission control center”. 64. Accordingly, we adopt our NOPR proposal and direct the ERO to develop through a separate Reliability Standards development project formal training requirements for local transmission control center operator personnel. Finally, given the numerous comments stating that term “local transmission control center” should be defined, we direct NERC to develop a definition of “local transmission control center” in the standards development project for developing the training requirements for local transmission control center operator personnel. (emphasis added) The SDT should abandon the approach of adding the broad Transmission Owners applicability that will include any Transmission Owner regardless of size or impact to the BES and/or to prove they are excluded. Instead, the SDT should establish some boundaries and criteria around a “local transmission control center” definition as directed by FERC. Possibly MW’s controlled by the control center or other criteria, such as those within the CIP v5 bright lines, may be appropriate. 2. THE DRAFT RSAW WAS POSTED WITH THE PROPOSED STANDARD, BUT THERE ARE CONFLICTING STATEMENTS IN THE CONSIDERATION OF COMMENTS SUMMARY DATED SEPT 27, 2013 On Page 7 of the Consideration of Comments from last posting, the following is stated: Compliance Input The SDT received comments regarding a Reliability Standards Audit Worksheet (RSAW). The Compliance department will not provide the RSAW until six months before the standard is implemented. In the meantime, a document titled “Compliance Input” is provided, along with the posted standard, to explain the contents of the RSAW. It’s not clear whether this applies to the Draft RSAW that was posted and whether it may be revised without Stakeholder knowledge after the Standard is approved. The Standard Process Input Group RSAW recommendation that was approved by the BOT in 2012 stated that the “Changes to RSAWs after the ballot body develops measure/standard require Board approval”. 3. THE DRAFT RSAW “NOTES TO AUDITOR” INCLUDE RELIABILITY ASSURANCE INITIATIVE (RAI) LANGUAGE THAT ALLOWS FOR AUDITOR DISCRETION WITHOUT ESTABLISHED GUIDELINES, PLUS A ZERO TOLERANCE APPROACH. The draft RSAW was developed and posted during this ballot period, which is appreciated. But the RSAW includes vague language that does not provide regulatory certainty for registered entities. The references to “risk factors” and “auditor’s assessment of management practices” are similar to what is being proposed in the RAI program that is still under development and not ready for implementation. Additionally, there are references to risk and internal controls that provides the auditor the latitude to either exclude a requirement or review an entity’s entire population of training records, which is zero tolerance approach to auditing. This is problematic. The following language is included in the NOTES TO AUDITOR for all Requirements (R1-R5) in the Standard. The nature and extent of audit procedures applied related to this requirement will vary depending on certain risk factors to the Bulk Electric System and the auditor’s assessment of management practices specific to this requirement. In general, more extensive audit procedures will be applied where risks to the Bulk Electric System are higher and management practices are determined to be less effective. Based on the assessment of risk and internal controls, as described above, specific audit procedures applied for this requirement may range from exclusion of this requirement from audit scope

to the auditor reviewing training records for an entity’s entire population of System Personnel. (emphasis added)
Group
MEAG Power
Scott Miller
Agree
Lower Colorado River Authority
Individual
Michelle R. D'Antuono
Occidental Chemical Corporation
Agree
City of Austin dba Austin Energy (AE)
Individual
Andrew Gallo
City of Austin dba Austin Energy
Yes
No
City of Austin dba Austin Energy (AE) respectfully requests consideration of the following comments/suggestions: (1) The applicability language for Transmission Owners (TO) in Section 4.1.4.1 has been incrementally modified to address various industry comments and has recently ballooned to a point where it has lost clarity. For example, use of the term “facility” instead of “control center” and phrases like “protecting personnel safety” and “adhering to regulatory requirements” could lead to interpretations of including personnel working for an entity registered as a TO but having nothing to do with the local control center. As AE understands it, the SDT is trying to bring in only TOs who have a local control center for BES facilities who are not registered as TOPs, and we believe this can be conveyed in a simple manner by leveraging the proposed revised definition of System Operator. That is, 4.1.4 should read “Transmission Owner that has personnel at a control center who operate or direct the operation of the Bulk Electric System in Real-time.” Note “control center” is intentionally lower case. The consistency in this definition puts the focus on the job function of the personnel while addressing the fact that there are variations in registration. (2) As an alternative to comment (1), if the SDT can specify the target TOs by including references to specific regions or addressing AE’s concerns in some other way, AE could support that approach, as well. (3) AE suggests the SDT revise the applicability language for Generator Operators (GOPs) in Section 4.1.5.1 to exclude specific regions, such as the ERCOT Region,

which operate a centralized nodal market. In those regions, an ISO (or similar entity) issues dispatch instructions and GOPs do not have independent decision-making authority regarding dispatch as described in FERC Order 693 paragraph 1360 (see page 7 of the PER-005 Standards White Paper.) (4) AE suggests the following revision to Requirement R2 part 2.1: "Within six months of a modification or addition to its BES company-specific Real-time reliability-related task list, each … identified in Requirement R1 part 1.1.1." This slight change clarifies that the timeframe is based on a change to the task list not the task, which matches the language in the associated VSL. Additionally, the change to reference part 1.1.1 instead of part 1.1 more accurately points to the act of modifying or adding to the list instead of writing the original list. In this way, R2 goes with R1 part 1.1 and R2 part 2.1 goes with R1 part 1.1.1. (5) AE requests the SDT revise the similar but not identical language in R4 and R5. R4 says "… shall use a systematic approach to training to develop and implement training …" whereas R5 says "… shall use a systematic approach to develop and deliver training …" Using different language seems to indicate different intent. AE believes the intent of the terms "implement" and "deliver" is the same and identical language would be appropriate. The VSLs would also need revision. (6) The VSL for R1 includes a moderate level to address the failure "to implement the identified changes to the Real-time reliability-related task (1.1.1.)" and a severe level to address the failure "to prepare a Real-time reliability-related task list (1.1 or 1.1.1.)" AE believes the act of implementing the identified changes to the task is accomplished by updating the task list as required by R1 part 1.1.1. As such, two VSLs cover the same failure. AE recommends resolving this discrepancy by striking "or 1.1.1" from the severe VSL. (7) AE recommends striking the phrase "to establish training requirements" from the VSL for R4 since R4 does not require the establishment of training requirements. (8) The VSLs for R1 and R4 both address the failure to develop training. However, the VSL is high in R1 and severe in R4. AE requests the "develop" VSL for R4 be changed from severe to high. Failure to develop training for Operations Support Personnel (R4) should not be higher than the failure to develop training for System Personnel (R1).
Individual
Keith Morisette
Tacoma Power
Yes
No
The use of the phrase "systematic approach to training" (SAT) in R4 is problematic since the same phrase is used in R1 to mean something different. The term SAT is well defined by FERC and understood as it relates to R1. The use of the term "systematic approach to training" in R4 is not consistent with this definition of "systematic approach to training" as written in

FERC Order No. 742 para 25, which indicates that "[the training] …is directly related to the needs of the position in question". The training in R4 requires the training of Operations Support Personnel on the impact of their job function to the Real-time reliability-related tasks and not on the needs of their own position. Additionally the Rationale for R4 in the latest redline states: "This requirement does not require that entities create a new, comprehensive systematic approach to training process for training Operations Support Personnel." We agree that this should not be required and therefore the phrase "systematic approach to training" should not be used in the requirement.
Group
National Grid
Michael Jones
No
Recommendation to modify the current definition of System Operator to read as follows: System Operator: An individual at a control center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who monitors and directs the operation of the Bulk Electric System in Real-time. Without more explicit wording, personnel at locations other than an "individual at a control center" who are not system operators may be encompassed by the definition. Distribution-related field, substation and satellite location personnel should not be classified as System Operators by an overly broad definition. A System Operator performs two critical functions: monitoring and directs the control (of the status of Bulk Electric System assets). Anyone who does not perform these functions must rely on a System Operator to perform them, and is not operating independently. They are not System Operators.
No
The Applicability section of the standard related to Transmission Owners and Generator Operators requires clarification. In the Applicability section, for the Transmission Owner the list of tasks in 4.1.4.1 does not adequately clarify applicable Transmission Owner personnel. The protection of Transmission Owner assets and personnel safety should be outside the reach of NERC standards. Section 4.1.4.1 rewording: Personnel at a facility that acts as a centralized Control Center for the Transmission Owner whose role is to interact with their Reliability Coordinator, Balancing Authority or Transmission Operator. Field switching personnel or other personnel who do not act independently of this centralized Transmission Owner Control Center are exempt. Requirement R2: Requires that each RC, BA, TOP, and TO shall verify, at least once, the capabilities of its System Personnel. The Implementation Plan states that entities that were not previously subject to PER-005-1 must have verified its System Personnel's capabilities to perform each of its assigned real-time reliability-related tasks, at least once, as identified in Requirement R1 part 1.1, prior to the effective date of the

standard. This potentially results in requiring entities to perform compliance activities prior to the effective date of the standard which could present problems in certain jurisdictions. Suggest changing to: Entities that were not previously subject to PER-005-1 must have verified its System Personnel's capabilities to perform each of its assigned Real-time reliability-related tasks, at least once, as identified in Requirement R1 part 1.1, within one year (or six months), of the standard becoming in force within their respective jurisdiction.
Group
JEA
Tom McElhinney
No
The term Support Personnel is still to vague and could encompass all back office workers and perhaps planning groups therefore requiring them to take all the training that system operators are required to take.
Individual
Brett Holland
Kansas City Power & Light
Agree
SPP - Robert Rhodes
Group
Luminant
Brenda Hampton
Yes
No
Since this standard is not intended to apply to GOPs that receive unit specific dispatch instructions and then relay them to plants, Applicability Section 4.1.5.1 should be modified to explicitly state that GOPs in certain regions are not included in this standard; i.e. this standard does not apply to GOPs within ISOs/RTOs that normally issue unit specific dispatch instructions (e.g. ERCOT). This way there is no misunderstanding about whether the Requirement is applicable. The rational for R5 states that the requirement mandates a systematic approach to training be used to tailor the training program to the needs of the organization and that the systematic approach to training does not need to be as comprehensive as the ones used for RCs, BAs and TOPs. While we agree with the rational, it is not clear based on the requirement what specifically a systematic approach to training would be or what could constitute compliance. Also the measure (M5) requires evidence of completed training but the RSAW ask for evidence that training was developed using a

systematic approach. The measure or the evidence requirement in the RSAW needs to be changed so they are in sync.
Individual
Jack Stamper
Clark Public Utilities
Agree
Austin Energy
Individual
Catherine Wesley
PJM Interconnection
No
PJM still finds the definition for Support Personnel confusing. Further clarification is needed to better define what direct support is provided by the Support Personnel. PJM recommends the addition of the phrase, 'and next day analysis' after Real-time in the definition.
No
PJM continues to feel there are concerns with this approach to the FERC directives and "issues" that "should be vetted" in conjunction with other "equally effective and efficient" solutions, even as Order 742 allows. PJM offers that reliability would be better served if the standard included an option or path for applicable entities to participate in a training program that has been granted accreditation. This would be more in line with how other industries implement a systematic approach to training and seem more in line with the stated goals of the NERC Reliability Assurance Initiative (RAI). Instead of incenting a minimalistic, siloed approach to training that potentially focuses on finding administrative errors in training records and learning objectives, accreditation could promote excellence by putting focus on the program and its processes. A more holistic approach to training would provide the industry more flexibility in responding to trends and changes, including identifying and requiring appropriate training for new types of participants as their potential to effect the reliability of the BES increases.
Individual
John Brockhan
CenterPoint Energy Houston Electric LLC.
Yes
CenterPoint Energy agrees with the SDTs revisions to the definitions of Support Personnel and System Operator. CenterPoint Energy would like the SDT to consider the following additions to the definitions to assist in delineating those specific personnel intended for System

Operator. “System Operator: An individual at a control center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, granted with the responsibility and authority to operate or direct the operation of the Bulk Electric System in Real-time.”
No
CenterPoint Energy appreciates the SDT for their time and effort dedicated to facilitating the industry in its understanding and input into the Operations Personnel Training Standard. CenterPoint Energy is concerned that many years from approval of this standard as written, the intent and the scope of the Transmission Owner applicability would be lost. An auditor, auditing to the written language and not being a part of the development and the history of this standard could interpret the applicability section and expect to see personnel that were not originally a part of the FERC directive. “Protecting personnel safety,” for example could be interpreted as safety personnel, working for a TO registered entity that has no relevance to a control center or a facility that has personnel that are operating or directing the operation of the BES. CenterPoint suggest removing the following language “including protecting assets, protecting personnel safety, adhering to regulatory requirements and establishing stable islands during system restoration”, and suggest the following for consideration. “4.1.4.1 Personnel at a control center, excluding field switching personnel that have been granted independent authority or responsibility to perform Real-time reliability related operation of the Bulk Electric System.”
Group
Western Area Power Administration
Lloyd A. Linke
Agree
US Bureau of Reclamation
Individual
Michiko Sell
Public Utility District No. 2 of Grant County, Washington
No
GCPD feels the definition of "Operations Support Personnel" is too vague and fears that the measure of Operations Support Personnel cannot be consistently applied without further interpretation. Individuals who serve in roles that directly support real-time, reliability-related tasks performed by System Operators that are merely administrative in nature, should not be subject to this training requirement.
No
GCPD agrees with comments (1-8) as submitted by City of Austin dba Austin Energy.

Group
Bonneville Power Administration
Jamison Dye
Yes
No
BPA recommends that the standard drafting team create a definition for “Bulk Electric System company specific reliability related task.” Although BPA understands the benefit of having the flexibility to create a company-specific definition and to create a task list based on that definition, BPA maintains this would allow auditors the ability to make different and inconsistent interpretations of definitions. BPA understands the drafting team does not have control over the auditors, and this is why we are recommending the definition in order to create more clarity in the standard. BPA believes that R3.1 should also address when a new IROL is discovered within its TOP or BA. BPA believes that each reference material should refer back to a specific requirement in the standard. For example, Reference #3. The only reference to “normal and emergency operations” is in R6. BPA recommends the drafting team either revise each reference to refer to a specific requirement or eliminate the reference from the standard. BPA also believes that R4.1 and M4.1 have become too prescriptive; the requirement of both an annual evaluation of the training and the number of elements listed to show that it was evaluated, is unnecessary for meeting the training requirements of support personnel. BPA requests that “internal audit results” in M4.1 be defined.
Group
seattle city light
paul haase
Agree
Lower Colorado River Authority (LCRA)
Group
FirstEnergy
Doug Hohlbaugh
No
FirstEnergy disagrees with each definitions based on 1) the revised applicability statement for the Transmission Owner and 2) the use of the "as identified" within the Operating Support Personnel definition. FirstEnergy does not agree with the revised Transmission Owner applicability statement that now indicates personnel "who act independently". FirstEnergy recommends the team revert to the prior Transmission Owner statement since the Transmission Owners within PJM operate BES facilities under the direction of the PJM

Transmission Operator. Since each definition in question refers to the Transmission Owner, by extension we disagree with each on this basis. Additionally, the Operating Support Personnel definition raises questions as to which entity is responsible for the tasks described and clear expectations are needed for a compliance audit. It should not be up to each functional entity to simply "self identify" which tasks they support. The task expectations need to come from clearly identified standard requirement, agreements, assignments, etc. For example, in the operations time horizon the determination of SOLs, IROLs is a functional responsibility of the Transmission Operator and Reliability Coordinator as described in NERC reliability standard FAC-014-2. A Transmission Owner's role in the determination of SOLs/IROLs should not come into question unless the responsible Transmission Operator/Reliability Coordinator has established a clear reliance on the Transmission Owner through clear documented agreements or protocols. Lastly, we believe the general reference to "assessments" in the phrase "outage coordination or assessments" as stated in the Operating Support Personnel may inadvertently extend the training to some Transmission Owner support staff beyond what is intended. The definition should clarify that the assessments are current-day, day-ahead or week ahead to avoid potential inclusion of corporate personnel who may have a longer term seasonal assessment view.
No
FirstEnergy's concerns/comments raised regarding Draft 1 of the proposed standard remain. In the last comment period we suggested that that collaborative effort already completed by separately registered TOP and TO organizations, such as an IOU and RTO/ISO organizations, should be permitted without the need for a Transmission Owner to independently perform expectations under requirement R1. For example, PJM (TOP) and its member TO companies have already invested a significant amount of time and resources to jointly and consistently implement a systematic approach to training (SAT) for applicable transmission operations personnel. As part of the implemented SAT, a detailed job task analysis was performed collaboratively, resulting in a common approach for the established set of reliability-related tasks. The Requirement R1 should be clarified to recognize and maintain these coordinated efforts. Based on the above comments, FE recommends that text "jointly or independently" after the word "shall" in requirement R1. As revised the text would read "R1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall independently or jointly use a systematic approach to training (SAT) …" FirstEnergy would appreciate a response from the drafting team as to why the "jointly or independently" was not incorporated, to the extent the next draft remains unchanged in this regard.
Group
SPP Standards Review Group
Robert Rhodes

Yes
The definition of Operations Support Personnel is fine as long as the audit approach and guidance adhere to the definition. If it varies any, then the definition becomes a moving target and the compliance focus isn't directed toward the definition.
No
In the Applicability Section under Transmisssion Owner in 4.1.4.1 'field switching personnel' have been excluded from the training requirements of PER-005-2. This is somewhat confusing and we ask the drafting team to provide additional clarification as to how they arrived at this decision. In the first sentence in the 4th line of M2, 'task' should be plural.

Additional Comments Submitted:

NIPSCO
Huston E. Ferguson

Comments for NIPSCO to justify Negative votes:

- Aspects of this revision don't adhere to the NERC Functional Model
- This revision contains definitions unique to just this standard and not applicable across all standards
- Unsure of how or if the unique definitions used in just this standard, just this revision, will apply or interact with the other standards

Apprehensive about how auditors will interpret this standard and it's unique stand-alone definitions and their interaction with the other standards and the NERC model definition

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Blue Ridge Electric
Lee Layton

My negative vote on 2010-1, PER-005 is as follows,

"This revision of the standard is including TO's without a strong justification for the need and no tangible information on how the need for a TO to comply will be determined."

Tri-State Generation and Transmission
Sergio Banuelos

1. The drafting team has revised PER-005-2 in response to stakeholder comments. Do you agree with the revised Support Personnel and System Operator definitions? If you do not agree

or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes

☒ No

Comments: **We do not believe the new defined term “System Personnel” is needed. Maintaining the System Operator definition is adequate.**

When the term “System Operator” is used within PER-005-2, it is used in the “System Personnel” definition that is defined for use only within PER-005-2 which is not intended to be a NERC Glossary definition. Within the “System Personnel” definition, “System Operators” are limited to those from entities that are RCs, TOPs, BAs, and TOs. GOPs are not listed, and therfore are excluded as it is written. The PER team did not make it clear whether GOPs are going to be included in the proposed “System Personnel” definition.

Support Personnel needs to be defined more clearly and in more detail.

We question the need to extend the applicability of the standard to Transmission Owners. Local transmission control centers that operate portions of the BES meet the definition of a System Operator, therefore meeting the conditions required to register as a Transmission Operator.

2. The drafting team has revised PER-005-2 in response to stakeholder comments. Do you agree with the revised standard? If you do not agree or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes

☒ No

Comments: **Requirement 1.3 states training shall be delivered to System Personnel. We believe System Operator should be added, and prefer it be used in place of the new term System Personnel.**

Currently the ad-hoc group has some useful rationale for Generator Operator under 4.1.5. However, once the standard gets approved the rationale box will be removed and the applicability to plant operators will not be clear. Therefore Tri-State requests that the last sentence from the “Rationale for Generator Operator” box stating "*Plant operators located at the generator plant site are not required to be trained in PER-005-2*" should be added as the last sentence in the Applicability Section 4.1.5.1.

Standard Development Timeline

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

Development Steps Completed

1. SAR and supporting package posted for comment (July 19, 2013 – September 3, 2013).
2. Draft standard posted for comments and ballot (July 19, 2013 – September 3, 2013).
3. Draft standard posted for additional comments and ballot (September 25, 2013 – November 9, 2013).
4. Draft standard posted for additional comments and ballot (December 4, 2013 – January 17, 2013).

Description of Current Draft

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Ballot	July 2013
Additional 45-day Formal Comment Period with Ballot	September 2013
Additional 45-day Formal Comment Period with Ballot	December 2013
Final ballot	January 2014
BOT adoption	February 2014

Definitions of Terms Used in Standard

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

Rationale for System Operator: The definition of the existing NERC Glossary Term "System Operator" has been modified to remove Generator Operator (GOP) in response to Project 2010-16.

The term "System Operator" contains another NERC Glossary term "Control Center", which was approved by FERC on November 22, 2013. The inclusion of GOPs within the approved definition of Control Center does not bring GOPs into the System Operator definition. The System Operator definition specifies that it only applies to Balancing Authority (BA), Transmission Operator (TOP) or Reliability Coordinator (RC) personnel.

The modifications to the definition of "System Operator" do not affect other standards; see the PER-005-2 White Paper, which cross checks System Operator with other NERC Standards.

System Operator: An individual at a Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System in Real-time.

Rationale for Operations Support Personnel: The term Operations Support Personnel is used to identify those support personnel of Reliability Coordinators (RC), Balancing Authorities (BA), or Transmission Operators (TOP) that FERC identified in Order No. 693.

Operations Support Personnel: Individuals who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms,[1] in direct support of Real-time operations of the Bulk Electric System.

[1] Nomograms are used in the WECC Region to describe element operating limits.

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

A. Introduction

1. **Title:** **Operations Personnel Training**
2. **Number:** PER-005-2
3. **Purpose:** To ensure that personnel performing or supporting Real-time operations on the Bulk Electric System are trained using a systematic approach.
4. **Applicability:**

4.1. Functional Entities:

4.1.1 Reliability Coordinator

4.1.2 Balancing Authority

4.1.3 Transmission Operator

Rationale for TO: Extending the applicability to TOs is necessary to address the FERC directive that the ERO develop formal training requirements for local transmission control center operator personnel. In Order No. 742 at P 62, the Commission clarified its understanding that local control center personnel *"exercise control over a significant portion of the Bulk-Power System under the supervision of the personnel of the registered transmission operator. The supervision may take the form of directive specific step-by-step instructions and at other times may take the form of the implementation of predefined operating procedures. In all cases, the Commission continued, the local transmission control center personnel must understand what they are required to do in the performance of their duties to perform them effectively on a timely basis. Thus, omitting such local transmission control center personnel from the PER-005-1 training requirements creates a reliability gap."* See FERC Order 693 at P 1343 and 1347.

The word facilities was intentionally left lower-case as there may be a facility that is not included in the NERC glossary term "Facility".

4.1.4 Transmission Owner that has:

4.1.4.1 Personnel, excluding field switching personnel, who can act independently to operate or direct the operation of the Transmission Owner's Bulk Electric System transmission facilities in Real-time.

Rationale for GOP: Extending the applicability to Generator Operators (GOPs) that have dispatch personnel at a centrally located dispatch center is necessary to address the FERC directive that the ERO develop specific requirements addressing the scope, content and duration appropriate for certain GOP personnel. The Commission explains in Order No. 693 at P 1359 that "*although a generator operator typically receives instructions from a balancing authority, it is essential that generator operator personnel have appropriate training to understand those instructions, particularly in an emergency situation in which instructions may be succinct and require immediate action."* Order No. 742 further clarified that the directive "*applies to generator operator personnel at a centrally-located dispatch center who receive direction and then develop specific dispatch instructions for plant operators under their control. Plant operators located at the generator plant site are not required to be trained in PER-005-2."* Based on the FERC order, this applicability section clarifies which GOP personnel are subject to the standard.

4.1.5 Generator Operator that has:

4.1.5.1 Dispatch personnel at a centrally located dispatch center who receive direction from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner, and may develop specific dispatch instructions for plant operators under their control. These personnel do not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions without making any modifications.

5. Effective Date:

5.1. This standard shall become effective the first day of the first calendar quarter that is 24 months beyond the date that this standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable authority is required for a standard to go into effect.

Where approval by an applicable governmental authority is not required, this standard shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement a training program for its System Operators as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology.

1.1.1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 1.1 each calendar year.

1.2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 1.1.

1.3. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall deliver training to its System Operators according to its training program.

1.4. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall implement the changes identified.

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence of using a systematic approach to develop and implement a training program for its System Operators, as specified in Requirement R1.

M1.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection its methodology and its BES company-specific Real-time reliability-related task list, with the date of the last review, as specified in Requirement R1 part 1.1 and part 1.1.1.

M1.2 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection training materials, as specified in Requirement R1 part 1.2.

M1.3 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection System Operator training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R1 part 1.3.

M1.4 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation of its training program each calendar year, as specified in Requirement R1 part 1.4.

Rationale for changes to R2: Transmission Owners personnel at local transmission control centers have been added to the PER standard and are subject to Requirements R2, R3 and R4 of PER-005-2. The reason for adding Transmission Owners is to address Order No. 693 and Order No. 742 FERC directives to include local transmission control center operator personnel.

R2. Each Transmission Owner shall use a systematic approach to develop and implement a training program for its personnel identified in Applicability Section 4.1.4.1 of this standard as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall create a list of BES company-specific Real-time reliability-related tasks based on a defined and documented methodology.

2.1.1. Each Transmission Owner shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 2.1 each calendar year.

2.2. Each Transmission Owner shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 2.1.

2.3. Each Transmission Owner shall deliver training to its personnel identified in Applicability Section 4.1.4.1 of this standard according to its training program.

2.4. Each Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement R2 to identify any needed changes to the training program and shall implement the changes identified.

M2. Each Transmission Owner shall have available for inspection evidence of using a systematic approach to training to develop and implement a training program for its applicable personnel, as specified in Requirement R2.

M2.1 Each Transmission Owner shall have available for inspection its methodology and its BES company-specific Real-time reliability-related task list, with the date of the last review, as specified in Requirement R2 part 2.1.

M2.2 Each Transmission Owner shall have available for inspection training materials, as specified in Requirement R2 part 2.2.

M2.3 Each Transmission Owner shall have available for inspection training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R2 part 2.3.

M2.4 Each Transmission Owner shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation of its training program each calendar year, as specified in Requirement R2 part 2.4.

Rationale for R3: This Requirement was brought forward from the previous version with the addition of Transmission Owners. It provides an entity with an opportunity to create a baseline from which to assess training needs as it develops a systematic approach.

R3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1 or Requirement R2 part 2.1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

3.1. Within six months of a modification or addition of a BES company-specific Real-time reliability-related task, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its personnel identified in Requirement R1 or Requirement R2 to perform

the new or modified BES company-specific Real-time reliability-related tasks identified in Requirement R1 part 1.1 or Requirement R2 part 2.1.

M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence to show that it verified the capabilities of each of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1 or Requirement R2 part 2.1. This evidence may be documents such as records showing capability to perform BES company-specific Real-time reliability-related tasks with the employee name and date; supervisor check sheets showing the employee name, date, and BES company-specific Real-time reliability-related task completed; or the results of learning assessments.

M3.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner shall present evidence that it verified the capabilities of applicable personnel to perform new or modified BES company-specific Real-time reliability-related tasks within 6 months of a modification or addition of a BES company-specific Real-time reliability-related task.

Rationale for changes to R4: The requirement mandates the use of specific training technologies. It does not require training on Interconnection Reliability Operating Limits (IROLs). The standard allows entities that gain operational authority or control over a Facility with IROLs or established protection systems or operating guides to mitigate IROL violations 12 months to comply with Requirement R4 to provide them sufficient time to obtain simulation technology.

The requirement to provide a minimum of 32 hours of Emergency Operations training has been removed since the appropriate number of hours would be identified as part of the systematic approach in Requirement R1 and Requirement R2 through the analysis phase and outlined in a continuous education section of their training program. Any additional hours may be duplicative or repetitive for the entity in providing training to its personnel. Requirement R4.1 covers the FERC directive for the creation of an implementation plan for simulation technology.

R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. A Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not previously meet the criteria of Requirement R4, shall comply with Requirement R4 within 12 months of meeting the criteria.

M4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that personnel identified in Requirement R1 or Requirement R2 completed

training that includes the use of simulation technology, as specified in Requirement R4.

M4.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that personnel identified in Requirement R1 or Requirement R2 completed training that included the use of simulation technology, as specified in Requirement R4, within 12 months of meeting the criteria of Requirement R4.

Rationale for R5: This is a new requirement applicable to Operations Support Personnel. In FERC Order No. 742, the Commission noted that NERC, in developing Reliability Standard PER-005-1, did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include operations planning and operation support staff who carry out outage planning and assessments and those who develop System Operating Limits (SOL), Interconnection Reliability Operating Limits (IROL), or operating nomograms for Real-time operations. This requirement contemplates that entities will look to the systematic approach already developed under Requirement R1. The entity can use the list created from Requirement R1 and select the BES company-specific Real-time reliability-related tasks with which Operations Support Personnel are involved.

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence that Operations Support Personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training. Documentation of training shall include employee name and date of training.

M5.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation each calendar year, as specified in Requirement R5 part 5.1.

Rationale for R6: This requirement requires the training of certain GOP dispatch personnel on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. This requirement mandates the use of a systematic approach which allows for each entity to tailor its training to the needs of its organization.

This is a new requirement applicable to certain GOPs as described in the applicability section. In FERC Order No. 742, the Commission noted that in developing proposed Reliability Standard PER-005-1, NERC did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include GOPs centrally-located at a generation dispatch center with a direct impact on the reliable operation of the BES. The Commission acknowledged that the training for GOPs need not be as extensive as the training for TOPs and BAs. FERC also stated that the systematic approach to training methodology is flexible enough to build on existing training programs by validating and supplementing the existing training content, where necessary, using systematic methods.

R6. Each Generator Operator shall use a systematic approach to develop and implement training to its personnel identified in Applicability Section 4.1.5 of this standard, on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R6 to identify and implement changes to the training.

M6. Each Generator Operator shall have available for inspection evidence that its applicable personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training. Documentation of training shall include employee name and date of training.

M6.1 Each Generator Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation each calendar year, as specified in Requirement R6 part 6.1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the compliance enforcement authority may ask an entity to

provide other evidence to show that it was compliant for the full-time period since the last audit.

Each Reliability Coordinator, Balancing Authority, Transmission Operator Transmission Owner, and Generator Operator shall keep data or evidence to show compliance for three years or since its last compliance audit, whichever time frame is greater, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator, Balancing Authority, Transmission Operator Transmission Owner, or Generator Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**Medium**	**None**	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to review or update, if necessary, its BES company-specific Real-time reliability-related task list each calendar year. (1.1.1.) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator, failed to evaluate its training program each calendar year to identify needed changes to its training program(s). (1.4) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator, failed to implement the identified changes to the training program(s). (1.4.)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to use a systematic approach to develop and implement a training program. (R1) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to design and develop training materials based on the BES company-specific Real-time reliability-related task lists. (1.2)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to create a BES company-specific Real-time reliability-related task list. (1.1.) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to deliver training based on the BES company-specific Real-time reliability-related task lists. (1.3)
R2	**Long-term Planning**	**Medium**	**None**	The Transmission Owner failed to review or update, if necessary, its company-specific Real-time reliability-	The Transmission Owner failed to use a systematic approach to develop and implement a training program. (R2)	The Transmission Owner failed to create a BES company-specific Real-time reliability-related task list. (2.1.) OR

				related task list each calendar year. (2.1.1.) OR The Transmission Owner failed to evaluate its training program each calendar year to identify needed changes to its training program(s). (2.4) OR The Transmission Owner failed to implement the identified changes to the training program(s). (2.4.)	OR The Transmission Owner failed to design and develop training materials based on the BES company-specific Real-time reliability-related task lists. (2.2)	The Transmission Owner failed to deliver training based on the BES company-specific Real-time reliability-related task lists. (2.3)
R3	**Long-term Planning**	**High**	**None**	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of at least 90% but less than 100% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3)	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of at least 70% but less than 90% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner failed to verify the capabilities of its personnel identified in Requirements R1 or Requirement	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of less than 70% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3)

					R2 to perform each new or modified task within six months of making a modification to its BES company-specific Real-time reliability-related task list. (3.1)	
R4	**Long-term Planning**	**Medium**	**None**	**None**	**None**	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that meet the criteria of Requirement R4 did not provide its personnel identified in Requirement R1 or Requirement R2 with any form of simulation technology training such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. (R4) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner did not provide its personnel identified in Requirement R1 or Requirement R2 with any form of simulation technology training such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES within twelve months of meeting the criteria of Requirement R4. (R4.1)

R5	**Long-term Planning**	**Medium**	**None**	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to evaluate its training established in Requirement R5 each calendar year. (5.1)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to develop training for its Operations Support Personnel. (R5) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator developed training but failed to use a systematic approach. (R5)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to implement training for its Operations Support Personnel. (R5)
R6	**Long-term Planning**	**Medium**	**None**	The Generator Operator failed to evaluate its training established in Requirement R6 each calendar year. (6.1)	The Generator Operator failed to develop training for its personnel. (R6) OR The Generator Operator developed training but failed to use a systematic approach. (R6)	The Generator Operator failed to implement the training for its personnel identified in Requirement R6. (R6)

Guidelines and Technical Basis

Requirement R1:

Any systematic approach to training will determine: 1) the skills and knowledge needed to perform BES company-specific Real-time reliability-related tasks; 2) what training is needed to achieve those skills and knowledge; 3) if the learner can perform the BES company-specific Real-time reliability-related task(s) acceptably in either a training or on-the-job environment; and 4) if the training is effective, and make adjustments as necessary.

Reference #1: Determining Task Performance Requirements

The purpose of this reference is to provide guidance for a performance standard that describes the desired outcome of a task. A standard for acceptable performance should be in either measurable or observable terms. Clear standards of performance are necessary for an individual to know when he or she has completed the task and to ensure agreement between employees and their supervisors on the objective of a task. Performance standards answer the following questions:

How timely must the task be performed?

Or

How accurately must the task be performed?

Or

With what quality must it be performed?

Or

What response from the customer must be accomplished?

When a performance standard is quantifiable, successful performance is more easily demonstrated. For example, in the following task statement, the criteria for successful performance is to return system loading to within normal operating limits, which is a number that can be easily verified.

> Given a System Operating Limit violation on the transmission system, implement the correct procedure for the circumstances to mitigate loading to within normal operating limits.

Even when the outcome of a task cannot be measured as a number, it may still be observable. The next example contains performance criteria that is qualitative in nature, that is, it can be verified as either correct or not, but does not involve a numerical result.

> Given a tag submitted for scheduling, ensure that all transmission rights are assigned to the tag per the company Tariff and in compliance with NERC and NAESB standards.

Reference #2: Systematic Approach to Training References:
The following list of hyperlinks identifies references for the NERC Standard PER-005 to assist with the application of a systematic approach to training:

(1) DOE-HDBK-1078-94, A Systematic Approach to Training

http://www.publicpower.org/files/PDFs/DOEHandbookTrainingProgramSystematicApproach.pdf

(2) DOE-HDBK-1074-95, January 1995, Alternative Systematic Approaches to Training, U.S. Department of Energy, Washington, D.C. 20585 FSC 6910

http://www.catagle.com/112-1/download_php-spec_DOE-HDBK-1074-95_003254_1.htm

(3) ADDIE – 1975, Florida State University

http://www.nwlink.com/~donclark/history_isd/addie.html

(4) DOE Standard - Table-Top Needs Analysis
DOE-HDBK-1103-96

http://www.cms.doe.gov/sites/prod/files/2013/06/f2/hdbk1103.pdf

Reference #3: Recognized Operator Training Topics
See Appendix A – Recognized Operator Training Topics within the NERC System Operator Certification Program Manual.
http://www.nerc.com/pa/Train/SysOpCert/Documents/SOC_Program_Manual_February_2012_Final.pdf

Reference #4: Definitions of Simulation and Simulators

Georgia Institute of Technology – Modeling & Simulation for Systems Engineering
http://www.pe.gatech.edu/conted/servlet/edu.gatech.conted.course.ViewCourseDetails?COURSE_ID=840

University of Central Florida – Institute for Simulation & Training
Just what is "simulation" anyway (or, Simulation 101)?
And what about "modeling"?
But what does IST do with simulations?
http://www.ist.ucf.edu/overview.htm

NERC
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RELIABILITY CORPORATION

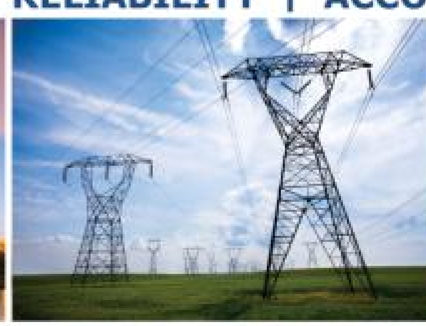
Consideration of Comments Summary

Project 2010-01 Training (PER)

Revised December 23, 2013

RELIABILITY | ACCOUNTABILITY



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Introduction

The Project 2010-01 drafting team thanks everyone who submitted comments on the draft PER-005-2 standard. This standard was posted for a 45-day public comment period from August 23, 2013, through September 3, 2013. An additional 45-day public comment period was conducted from September 27, 2013, through November 12, 2013. NERC asked stakeholders to provide feedback on the standard and associated documents using a special electronic comment form. There were 63 sets of responses, including comments from 35 companies, which represented nine of the 10 industry segments.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, please contact Vice President and Director of Standards Mark Lauby at (404) 446-2560 or mark.lauby@nerc.net. There is also a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is found in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Consideration of Comments

Purpose

The PER standard drafting team (SDT) appreciates industry comments on the proposed PER-005-2 standard. The SDT reviewed all comments carefully and made changes to the standard accordingly; however, the new Standard Processes Manual (SPM) does not require the SDT to respond to each comment if a successive ballot is needed. The following pages are a summary of the comments received and how the PER SDT addressed them.

Administrative

A few commenters questioned why there is an "M" before the sub-part in the measures, but no longer an "R" in front of the sub-requirements. There is no longer an "R" because the sub-requirements are now considered parts of the main requirement. The "M" in front of the sub-parts of the measure are included for clarity.

Implementation Plan

Several commenters expressed concern that the implementation plan indicated they could be subject to enforcement prior to the effective date. However, the implementation plan provides information regarding what actions and entities must be compliant with beginning on the effective date. The requirements cannot be enforced prior to the effective date.

NERC Glossary of Terms

System Operator

There were comments received regarding the definition of the term "System Operator" and why it should be changed back to the original "monitors and controls" instead of the new "operates or directs." The phrase "monitor and control" was ambiguous, while simultaneously having a narrow focus. The SDT used the "operates or directs" language to more accurately reflect the duties performed by the System Operator.

The System Operator constantly monitors the Bulk Electric System (BES) and reacts to varying system conditions; therefore, the word "operates" was chosen because it incorporates the "monitor and control" phrase. The System Operator is reacting to varying system conditions by modifying system configurations, generator outputs, and transmission loadings and guiding field personnel in the performance of their duties regarding the BES. As such, "directs," incorporates the term "control."

There were additional comments as to why "control center" was not capitalized. This term has been capitalized within the System Operator Definition. Originally, there was concern that capitalizing the term "Control Center" would include GOPs in the definition of System Operators. However, even though the NERC Glossary term "Control Center" includes GOPs, the definition of the System Operator clearly restricts applicability to RCs, BAs, and TOPs. The updated System Operator definition is stated below:

> ***System Operator:*** *An individual at a Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System in Real-time.*

Operations Support Personnel

There were several comments requesting the standard-only term "Operations Support Personnel" be moved to the NERC Glossary. In response to these comments, the SDT modified the definition so that it could be moved to the NERC Glossary. In the draft of proposed PER-005-2, which was posted September 27, 2013, the term included a reference to entity-determined "BES company-specific, Real-time reliability-related tasks." Because this reference was specific to PER-005-2 and not appropriate for a universal definition in the NERC Glossary, it was removed and replaced with the phrase "Real-time operations of the Bulk Electric System."

Although the definition includes the words “direct support,” the drafting team added “current day or next day” to provide clarity regarding the scope of the Operations Support Personnel definition. Note that “current day or next day” modifies “outage coordination or assessments,” describing the type of outage coordination or assessments. It does not describe a time horizon for activities. Supporting activities needed to carry out “current day or next day outage coordination or assessments” may be conducted ahead of time. The language was added to clarify that seasonal assessments are not included.

Definition of Terms Used in the Standard

A number of comments received stated that the use of “System Personnel” was redundant and unnecessary. The term “System Personnel” has been removed.[2]

There are no longer any standard-only definitions or terms within PER-005-2.

Applicability Section

Transmission Owner (TO)

There were several comments regarding the list of examples in the applicable TO personnel description posted with the prior PER-005-2 draft. The SDT removed this list of examples and modified this applicability to clearly define which TOs are subject to PER-005-2. The updated applicability states: “Personnel, excluding field switching personnel, who can act independently to operate or direct the operation of its Bulk Electric System transmission facilities in Real-time.”

Generator Operator (GOP)

Comments were received requesting further clarification on the term “centrally located dispatch centers” of the PER-005-2 Generator Operator applicability. FERC provides an example of which Generator Operators should receive training in FERC Order No. 693 P. 1360. It states:

> *“We agree with FirstEnergy and others that some clarification is required regarding which generator operator personnel should be subject to formal training under the Reliability Standard. As noted above, a generator operator typically receives instructions from a balancing authority. Some generator operators are structured in such a way that they have a centrally-located dispatch center that receives direction and then develops specific dispatch instructions for plant operators under their control. For example, a balancing authority may direct a centrally-located dispatch center to deliver 300 MW to the grid, and the dispatch center would determine the best way to deliver that generation from its portfolio of units. In this type of structure, it is the personnel of the centrally located dispatch center that must receive formal training in accordance with the Reliability Standard. Plant operators located at the generator plant site also need to be trained but the responsibility for this training is outside the scope of the Reliability Standard.”*[3]

Furthermore, there are some GOP’s located at dispatch centers who develops dispatch instructions. These GOPs would be applicable to PER-005-2. However, plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions without making any modifications, would not be subject to PER-005-2.

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[2] See comments under Requirement R2 for further discussion.

[3] *Mandatory Reliability Standards for the Bulk-Power System*, 118 FERC ¶ 61,218, FERC Stats. & Regs. ¶ 31,242 (Order No. 693), *order on reh’g, Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 (Order No. 693-A) (2007) http://www.ferc.gov/whats-new/comm-meet/2007/031507/e-13.pdf

Systematic Approach

Several comments were received pointing out the discrepancy between the use of "systematic approach to training" in Requirement R1 and "systematic approach" in Requirements R4 and R5. The commenters were concerned about whether this was intentional or there was an implied difference.

In Requirements R1 and now R2, the intent is for applicable entities to use a systematic approach to develop and implement a training program. In Requirements R5 and R6, the intent is for applicable entities to use a systematic approach to develop and implement training. This difference reflects FERC's statement in Order No. 693, which stated that training for Operations Support Personnel and a GOP's dispatch personnel need not be as extensive as the training for System Operators. The focus of Requirements R5 and R6 is not on developing an extensive training program but on training the applicable personnel on the manner in which their job functions impact reliable operations of the BES. The requirements allow entities to develop training practices that are tailored to the needs of each organization. Should an entity decide to develop an extensive training program for applicable Operations Support Personnel and GOP dispatch personnel, they may do so. However, it is not necessarily required by the standard.

Requirement R1

Based on concerns for standard-only definitions, the term "System Personnel" was removed and a new requirement (new Requirement R2) was developed to address local transmission control center personnel. Other than removing TO applicability, this requirement reflects the previous draft of PER-005-2.

The SDT made editorial changes throughout to ensure a consistent term for tasks: "Bulk Electric System (BES) company-specific, Real-time reliability-related tasks."

Requirement R2 (Now Requirement R3)

There were some comments about changes to task lists and the six-month verification time frame. The SDT clarified that under Requirement R3 entities must verify applicable personnel's capabilities to perform new or modified tasks within six months of the change and cannot wait to do so during their annual review. This requirement provides entities the opportunity to create a baseline from which to assess training needs while developing a systematic approach to training. The SDT also included the new consistent term for tasks: "Bulk Electric System (BES) company-specific, Real-time reliability-related tasks" in this requirement.

Requirement R3 (Now Requirement R4)

Some commenters stated that the SDT should keep the 32-hour Emergency Operations Training requirement. Other commenters raised applicability issues. The SDT determined that it was not necessary to keep the 32-hour Emergency Operations Training requirement because the periodicity of such training should be addressed in an entity's training program and tailored to the needs of that organization. With respect to the applicability issue, the requirement was reworded to clarify that it is applicable to those entities with authority or control over Interconnection Reliability Operating Limits (IROLs) or those with operating guides or protections systems used to mitigate IROL violations. The requirement does not contain specific training requirements for IROLs, but rather that simulation technology must be used in emergency operations training for applicable entities.

Requirement R4 (Now Requirement R5)

There were concerns raised that the definition of Operations Support Personnel is only limited to personnel that support System Operators, but the requirement includes TOs, which do not have System Operators. The SDT clarified that Operations Support Personnel are intended to directly support System Operators. Accordingly, TOs are no longer included in this requirement.

Several commenters believed that the training should focus on the Operations Support Personnel's job functions, rather than how their job functions impact the BES company-specific, Real-time reliability-related tasks. Further, the commenters felt that if the intent of the requirement was to train on the knowledge (i.e., the impact of their jobs) rather than their job functions (i.e., performance), then a systematic approach—specifically the ADDIE method—was not an appropriate tool. The SDT acknowledged that the ADDIE method does focus on performance training; however, the SDT used systematic approach in a generic sense looking to entities to utilize the three major principles of a systematic approach, which are provided below.

- Assess training needs (analysis)
- Conduct the training activity (design, develop, and implement)
- Evaluate the training activity (evaluate the effectiveness of the training)

These principles can be used for developing training for knowledge as well as performance. Accordingly, the SDT did not modify the standard consistent with these comments.

Requirement R5 (Now Requirement R6)

Several commenters believed that the training should focus on the GOP personnel job functions, rather than how these job functions impact the reliable operations of the BES during normal and emergency operations. Further, the commenters felt that if the intent of the requirement was to train on the knowledge (i.e., the impact of their jobs) rather than their job functions (i.e., performance) than a systematic approach, specifically the ADDIE method, was not an appropriate tool. The drafting team acknowledged that the ADDIE method does focus on performance training; however, the team used systematic approach in a generic sense looking to entities to utilize the three major principles of a systematic approach, which are provided below.

- Assess training needs (analysis)
- Conduct the training activity (design, develop and implement)
- Evaluate the training activity (evaluate the effectiveness of the training)

These principles can be used for developing training for knowledge as well as performance. Accordingly, the SDT did not modify the standard consistent with these comments.

Violation Severity Levels (VSLs)

Several comments were received stating that the VSLs were inconsistent between Requirements R1, R4, and R5 in regard to the use of a systematic approach. The drafting team modified the VSLs to be consistent.

Time Horizon

The SDT received several comments regarding how the time horizon should be Operations Planning or Operations Assessment instead of long-term planning for the PER-005-2 standard. Training is a continuous, long-term activity. As such, even though the topic addresses Real-time activities, there is sufficient time for an entity to mitigate the violation over a longer period. Therefore, the time horizon should not be changed to Operations Planning or Operations Assessment.[4] Additionally, the use of the long-term time horizon is FERC-approved under PER-005-1.[5]

[4] See Time Horizon document in the Standard Resources section of the NERC website.
http://www.nerc.com/pa/Stand/Resource%20Documents/Time_Horizons.pdf

[5] See PER-005-1 FERC approved standard. http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PER-005-1&title=System Personnel Training&jurisdiction=United States

Attachment A – SDT Members Contact Information

Table 1: Standard Drafting Team Member Contact Information			
	Participant	**Entity**	**Phone Number**
Chair	Patti Metro	NRECA	(571) 334-8890
Vice Chair	Lauri Jones	PG&E	(415) 973-0918
Member	Charles Abell	Ameren	(314) 554-3817
Member	Sam Austin	TVA	(423) 751-2935
Member	Jim Bowles	ERCOT	(512) 248-3942
Member	Jeff Gooding	FP&L	(305) 442-5804
Member	Mark Grear	Constellation	(410) 470-4380
Member	Venona Greaff	OXY	(713) 552-8575
Member	John Rymer	MISO	(317) 249-5698
NERC Staff	Stanley Winbush	American Electric Power	(614) 413-2489
NERC Staff	Jordan Mallory	NERC	(404) 446-9733
NERC Staff	Darrel Richardson	NERC	(609) 613-1848

Standard Development Timeline

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

Development Steps Completed

1. SAR and supporting package posted for comment (July 19, 2013 – September 3, 2013).
2. Draft standard posted for comments and ballot~~. (August~~ (July 19, 2013 – September 3, 2013).
3. Draft standard posted for additional comments and ballot (September 25, 2013 – November 9, 2013).
4. Draft standard posted for additional comments and ballot (December 4, 2013 – January 17, 2013).

Description of Current Draft

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Ballot	July 2013
Additional 45-day Formal Comment Period with Ballot	September 2013
Additional 45-day Formal Comment Period with Ballot	December 2013
Final ballot	~~November 2013~~January 2014
BOT adoption	~~December 2013~~February 2014

Definitions of Terms Used in Standard

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

~~**Glossary Term:**~~

~~*When the standard becomes effective, this defined term will be removed from the individual standard and added to the Glossary.*~~

Rationale for System Operator: The definition of the existing NERC Glossary Term "System Operator" has been modified to remove Generator Operator (GOP) in response to Project 2010-16.

The term "System Operator" contains another NERC Glossary term "Control Center", which was approved by FERC on November 22, 2013. The inclusion of GOPs within the approved definition of Control Center does not bring GOPs into the System Operator definition. The System Operator definition specifies that it only applies to Balancing Authority (BA), Transmission Operator (TOP), or Reliability Coordinator (RC) personnel. ~~control center was not capitalized as the proposed NERC Glossary Term "Control Center" is not consistent with the applicability of this standard.~~

The modifications to the definition of "System Operator" do not affect other standards; see the PER-005-2 White Paper, which cross checks System Operator with other NERC Standards.

System Operator: An individual at a ~~control center~~Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System in Real-time.

~~**Standard Only Terms:**~~

~~*The following terms are defined for use only within PER-005-2 and, upon approval, will not be moved to the NERC Glossary of Terms:*~~

~~**Rationale for System Personnel:** The term "System Personnel" has been created to identify specific personnel with applicable entities, and allows the standard to be more concise by preventing repetition of the long description throughout the standard.~~

~~**System Personnel**: System Operators of a Reliability Coordinator, Transmission Operator or Balancing Authority, and the Transmission Owner personnel described in the Applicability Section of this standard.~~

Rationale for Operations Support Personnel: Th~~is~~e term Operations Support personnel is used to identify those support personnel of ~~definition uses language from the FERC Orders 693 and 742 to define those operations support personnel subject to the standard. The definition clarifies that functional entities (~~Reliability Coordinators (RC), Balancing Authori~~ty~~ties (BA), Transmission Operators (TOP) that FERC identified in Order No. 693.~~, and Transmission Owner (TO)) identify "Operations Support Personnel."~~

Operations Support Personnel: Individuals~~, as identified by the Reliability Coordinators, Balancing Authorities, Transmission Operators, or Transmission Owners,~~ who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms,[1] in direct support of Real-time~~, reliability-related tasks performed by System Operators.~~ operations of the Bulk Electric System.

[1] Nomograms are used in the WECC Region to describe element operating limits.

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

A. Introduction

1. **Title:** **Operations Personnel Training**
2. **Number:** PER-005-2
3. **Purpose:** To ensure that personnel performing or supporting Real-time~~, reliability-related tasks on the Bulk Electric System are trained using a systematic approach to training.~~ operations on the Bulk Electric System are trained using a systematic approach.
4. **Applicability:**

4.1. Functional Entities:

4.1.1 Reliability Coordinator

4.1.2 Balancing Authority

4.1.3 Transmission Operator

Rationale for TO: Extending the applicability to TOs is necessary to address the FERC directive that the ERO develop formal training requirements for local transmission control center operator personnel. In Order No. 742 at P 62, the Commission clarified its understanding that local control center personnel *"exercise control over a significant portion of the Bulk-Power System under the supervision of the personnel of the registered transmission operator. The supervision may take the form of directive specific step-by-step instructions and at other times may take the form of the implementation of predefined operating procedures. In all cases, the Commission continued, the local transmission control center personnel must understand what they are required to do in the performance of their duties to perform them effectively on a timely basis. Thus, omitting such local transmission control center personnel from the PER-005-1 training requirements creates a reliability gap."* See FERC Order 693 at P 1343 and 1347.

The word faciliti~~y~~es was intentionally left lower-case as there may be a facility that is not included in the NERC glossary term "Facility".

4.1.4 Transmission Owner that has:

4.1.4.1 Personnel~~ at a facility~~, excluding field switching personnel, who can act independently to ~~carry out tasks that require Real-time~~ operate or direct the operation of the Transmission Owner's Bulk Electric System~~, including protecting assets, protecting personnel safety, adhering to regulatory requirements and establishing stable islands during system restoration.~~ transmission facilities in Real-time.

Rationale for GOP: Extending the applicability to Generator Operators (GOPs) that have dispatch personnel at a centrally located dispatch center is necessary to address the FERC directive that the ERO develop specific requirements addressing the scope, content and duration appropriate for certain GOP personnel. The Commission explains in Order No. 693 at P 1359 that "*although a generator operator typically receives instructions from a balancing authority, it is essential that generator operator personnel have appropriate training to understand those instructions, particularly in an emergency situation in which instructions may be succinct and require immediate action.*" Order No. 742 further clarified that the directive "*applies to generator operator personnel at a centrally-located dispatch center who receive direction and then develop specific dispatch instructions for plant operators under their control. Plant operators located at the generator plant site are not required to be trained in PER-005-2.*" Based on the FERC order, this applicability section clarifies which GOP personnel are not subject to the standard.

4.1.5 Generator Operator that has:

4.1.5.1 Dispatch personnel at a centrally located dispatch center who receive direction from ~~their~~the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner, and may develop specific dispatch instructions for plant operators under their control. ~~This~~These personnel ~~does~~do not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions~~,~~ without making any modifications.

5. Effective Date:

5.1. This standard shall become effective the first day of the first calendar quarter that is 24 months beyond the date that this standard is approved by an applicable governmental authority or ~~is~~as otherwise provided for in a jurisdiction where approval by an applicable authority is required for a standard to go into effect.

Where approval by an applicable governmental authority is not required, this standard shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ and Transmission ~~Owner~~Operator shall use a systematic approach to ~~training to~~ develop and implement a training program for its System ~~Personnel~~[2]Operators as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

~~[2] As used in this standard, the term "System Personnel" is defined as System Operators of a Reliability Coordinator, Transmission Operator or Balancing Authority, and the Transmission Owner personnel described in the Applicability Section of this standard.~~

1.1. Each Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ and Transmission ~~Owner~~Operator shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology.

1.1.1. Each Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ and Transmission ~~Owner~~Operator shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 1.1 each calendar year.

1.2. Each Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ and Transmission ~~Owner~~Operator shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 1.1.

1.3. Each Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ and Transmission ~~Owner~~Operator shall deliver training to its System ~~Personnel~~Operators according to its training program.

1.4. Each Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ and Transmission ~~Owner~~Operator shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall implement the changes identified.

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator ~~and Transmission owner~~ shall have available for inspection evidence of using a systematic approach to ~~training to establish~~develop and implement a training program for its System Operators, as specified in Requirement R1.

M1.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator~~, and Transmission Owner~~ shall have available for inspection its methodology and its BES company-specific Real-time reliability-related task list, with the date of the last review, as specified in Requirement R1 part 1.1~~.~~ and part 1.1.1.

M1.2 Each Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ and Transmission ~~Owner~~Operator shall have available for inspection training materials, as specified in Requirement R1 part 1.2.

M1.3 Each Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ and Transmission ~~Owner~~Operator shall have available for inspection System ~~Personnel~~Operator training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R1 part 1.3.

M1.4 Each Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ and Transmission ~~Owner~~Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed ~~a~~an evaluation of its training program~~ evaluation~~ each calendar year, as specified in Requirement R1 part 1.4.

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Rationale for changes to R2: Transmission Owners ~~System P~~personnel~~,~~ at local transmission control centers have been added to the PER standard and are subject to Requirements R2, R3, and R4 of PER-005-2. The reason for adding Transmission Owners is to address Order No. 693 and Order No. 742 FERC directives to include local transmission control center operator personnel. ~~as opposed to System Operator, is used to capture specific personnel of a Transmission Owner in addition to the Reliability Coordinator, Balancing Authority, and Transmission Operator in one term.~~

R2. Each Transmission Owner shall use a systematic approach to develop and implement a training program for its personnel identified in Applicability Section 4.1.4.1 of this standard as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall create a list of BES company-specific Real-time reliability-related tasks based on a defined and documented methodology.

2.1.1. Each Transmission Owner shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 2.1 each calendar year.

2.2. Each Transmission Owner shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 2.1.

2.3. Each Transmission Owner shall deliver training to its personnel identified in Applicability Section 4.1.4.1 of this standard according to its training program.

2.4. Each Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement R2 to identify any needed changes to the training program and shall implement the changes identified.

M2. Each Transmission Owner shall have available for inspection evidence of using a systematic approach to training to develop and implement a training program for its applicable personnel, as specified in Requirement R2.

M2.1 Each Transmission Owner shall have available for inspection its methodology and its BES company-specific Real-time reliability-related task list, with the date of the last review, as specified in Requirement R2 part 2.1.

M2.2 Each Transmission Owner shall have available for inspection training materials, as specified in Requirement R2 part 2.2.

M2.3 Each Transmission Owner shall have available for inspection training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R2 part 2.3.

M2.4 Each Transmission Owner shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation of its training program each calendar year, as specified in Requirement R2 part 2.4.

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Rationale for changes to R3: The requirement was brought forward from the previous version with the addition of Transmission Owners. It provides an entity with an opportunity to create a baseline from which to assess training needs as it develops a systematic approach. ~~mandates the use of specific training technologies. It does not require training on Interconnection Reliability Operating Limits (IROLs). The standard allows entities that gain operational authority or control over a facility a 12 month period to comply with the requirements of Requirement R3 to provide them sufficient time to obtain simulation technology.~~

~~The requirement to provide a minimum of 32 hours of Emergency Operations training has been removed since the appropriate time would be identified as part of the systematic approach to training process in Requirement R1 through the analysis phase of a systematic approach to training and outlined in a continuous education section of their training program. Any additional hours may be duplicative or repetitive for the entity in providing training to their personnel. Requirement R3.1 also covers the FERC directive for the creation of an implementation plan for simulation technology.~~

~~R2.~~R3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its ~~System Personnel~~personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1~~.~~ or Requirement R2 part 2.1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

~~2.1.~~3.1. Within six months of a modification or addition of a BES company-specific Real-time reliability-related ~~tasks~~task, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its ~~System Personnel~~personnel identified in Requirement R1 or Requirement R2 to perform the new or modified BES company-specific Real-time reliability-related tasks identified in Requirement R1 part 1.1 or Requirement R2 part 2.1.

~~M2.~~M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence to show that it verified the capabilities of each of its ~~System Personnel~~personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related ~~task~~tasks identified under Requirement R1 part 1.1~~, as specified in~~ or Requirement R2 part 2.1. This evidence may be documents such as records showing capability to perform BES company-specific Real-time reliability-related tasks with the employee name and date; supervisor check sheets showing the employee name, date, and BES company-specific Real-time reliability-related task completed; or the results of learning assessments.

M3.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner shall present evidence that it verified the capabilities of applicable personnel to perform new or modified BES company-specific Real-time reliability-related tasks within 6 months of a modification or addition of a BES company-specific Real-time reliability-related task.

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Rationale for R4: The requirement mandates the use of specific training technologies. It does not require training on Interconnection Reliability Operating Limits (IROLs). The standard allows entities that gain operational authority or control over a Facility with IROLs or established protection systems or operating guides to mitigate IROL violations 12 months to comply with Requirement R4 to provide them sufficient time to obtain simulation technology.~~requires the training of Operations Support Personnel on the impact of their job function to the Real-time reliability-related tasks identified under Requirement R1. It does not require training on the actual Real-time reliability-related tasks conducted by the System Operator.~~

Th~~is~~e ~~is a new~~ requirement to provide a minimum of 32 hours of Emergency Operations training has been removed since the appropriate number of hours would be identified as part of the systematic approach in Requirement R1 and Requirement R2 through the analysis phase and outlined in a continuous education section of their training program. Any additional hours may be duplicative or repetitive for the entity in providing training to its personnel. Requirement R4.1 covers the FERC directive for the creation of an implementation plan for simulation technology.

~~applicable to Operations Support Personnel as defined herein. In FERC Order No. 742, the Commission noted that NERC, in developing Reliability Standard PER-005-1, did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include operations planning and operation support staff who carry out outage planning and assessments and those who develop System Operating Limits (SOL), IROLs, or operating nomograms for Real-time operations. This requirement does not require that entities create a new, comprehensive systematic approach to training process for training Operations Support Personnel. Rather, the requirements contemplate that entities will look to the systematic approach to training process already developed for System Operators. The entity may use the list created from requirement R1 part 1.1 and select the reliability-related tasks that Operations Support Personnel support and therefore should be trained on.~~

~~R3.~~**R4.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs~~)~~), or (2) has established ~~operating guides or~~ protection systems or operating guides to mitigate IROL violations, shall provide its ~~System Personnel~~personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES~~, according to its training program.~~. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

~~3.1.~~**4.1.** ~~When a~~A Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not ~~have an IROL gains operational authority or control over a Facility with an established IROL or establishes operating guides or protection systems to mitigate IROL violations, it~~previously meet the criteria of Requirement R4, shall comply with Requirement ~~R3~~R4 within

12 months of ~~gaining that authority or control, or establishing such operating guides or protection systems.~~meeting the criteria.

~~M3.~~M4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that ~~System Personnel~~personnel identified in Requirement R1 or Requirement R2 completed training that includes the use of simulation technology, as specified in Requirement ~~R3~~R4.

~~M3.1~~M4.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that ~~System Personnel~~personnel identified in Requirement R1 or Requirement R2 completed training that included the use of simulation technology, as specified in Requirement ~~R3~~R4, within 12 months of ~~gaining that authority or control, or establishing such operating guides or protection systems.~~meeting the criteria of Requirement R4.

Rationale for R5: Th~~is~~e is a new applicable to Operations Support Personnel. In FERC Order No. 742, the Commission noted that NERC, in developing Reliability Standard PER-005-1, did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include operations planning and operation support staff who carry out outage planning and assessments and those who develop System Operating Limits (SOL), Interconnection Reliability Operating Limits (IROL), or operating nomograms for Real-time operations. This requirement contemplates that entities will look to the systematic approach already developed under Requirement R1. The entity can use the list created from Requirement R1 and select the BES company-specific Real-time reliability-related tasks with which Operations Support Personnel are involved. ~~requirement requires the training of certain GOP dispatch personnel on their job function(s) as it pertains to the reliable operations of the BES. This requirement mandates the use of a systematic approach to training which allows for each entity to tailor its training program to the needs of its organization. This requirement does not necessitate a systematic approach to training process that is as comprehensive as that used for RCs, BAs, and TOPs.~~

~~This is a new requirement applicable to certain GOPs as described in the applicability section. In FERC Order No. 742, the Commission noted that in developing proposed Reliability Standard PER-005-1, NERC did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include GOPs centrally located at a generation dispatch center with a direct impact on the reliable operation of the BES. The Commission acknowledged that the training for GOPs need not be as extensive as the training for TOPs and BAs. FERC also stated that the systematic approach to training methodology is flexible enough to build on existing training programs by validating and supplementing the existing training content, where necessary, using systematic methods.~~

~~R4.~~R5. Each Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ and Transmission ~~Owner~~Operator shall use a systematic approach to ~~training to~~ develop and implement training for its identified Operations Support Personnel~~[3]~~ on ~~the impact of~~how their job function(s) ~~to~~impact those BES company-specific Real-time reliability-

~~[3] As used in this standard, the term "Operations Support Personnel" is defined as Individuals, as identified by the Reliability Coordinators, Balancing Authorities, Transmission Operators, or Transmission Owners, who perform outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms, in direct support of Real-time, reliability-related tasks performed by System Operators.~~

related tasks identified by the entity pursuant to Requirement R1 part 1.1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4~~5~~.1 Each Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ and Transmission ~~Owner~~Operator shall conduct an evaluation each calendar year of the training established in Requirement ~~R4~~R5 to identify and implement changes to the training.

~~M4~~M5. Each Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ and Transmission ~~Owner~~Operator shall have available for inspection evidence that Operations Support Personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training~~ with the~~. Documentation of training shall include employee name and date of training.

~~M4~~M5.1 Each Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ and Transmission ~~Owner~~Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed ~~a training program~~an evaluation each calendar year, as specified in Requirement ~~R4~~R5 part ~~4~~5.1.

Rationale for R6: This requirement requires the training of certain GOP dispatch personnel on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. This requirement mandates the use of a systematic approach which allows for each entity to tailor its training to the needs of its organization.

This is a new requirement applicable to certain GOPs as described in the applicability section. In FERC Order No. 742, the Commission noted that in developing proposed Reliability Standard PER-005-1, NERC did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include GOPs centrally-located at a generation dispatch center with a direct impact on the reliable operation of the BES. The Commission acknowledged that the training for GOPs need not be as extensive as the training for TOPs and BAs. FERC also stated that the systematic approach to training methodology is flexible enough to build on existing training programs by validating and supplementing the existing training content, where necessary, using systematic methods.

~~R5.~~R6. Each Generator Operator shall use a systematic approach to develop and ~~deliver~~implement training to its personnel ~~described~~identified in Applicability Section 4.1.5 of this standard, on ~~the impact of~~how their job function(s) ~~as it pertains to~~impact the reliable operations of the BES during normal and emergency operations. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

~~5.1.~~6.1. Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement ~~R5~~R6 to identify and implement changes to the training.

~~M5~~M6. Each Generator Operator shall have available for inspection evidence that its applicable personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training~~ with the~~. Documentation of training shall include employee name and date of training.

~~M5~~M6.1 Each Generator Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed ~~a training program~~an evaluation each calendar year, as specified in Requirement ~~R5~~R6 part ~~5~~6.1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

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

Each Reliability Coordinator, Balancing Authority, Transmission Operator Transmission Owner, and Generator Operator shall keep data or evidence to show compliance for three years or since its last compliance audit, whichever time frame is ~~the greatest~~greater, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator, Balancing Authority, Transmission Operator Transmission Owner, or Generator Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

1.3. Compliance Monitoring and Assessment Processes:

~~As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.~~Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	None	The Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ or Transmission ~~Owner,~~Operator failed to review ~~its~~or update, if necessary, its BES company-specific Real-time reliability-related task list ~~to identify new or modified Real-time reliability-related tasks~~ each calendar year. (1.1.1.) OR The Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ or Transmission ~~Owner, failed to implement the identified changes to the Real-time reliability-related task. (1.1.1.)~~ ~~OR~~ ~~The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner~~Operator, failed to evaluate its training program each calendar year to identify needed changes to its training program(s). (1.4)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to use a systematic approach to develop and implement a training program. (R1) OR The Reliability Coordinator, Balancing Authority, or Transmission ~~Owner~~Operator failed to design and develop training materials based on the BES company-specific Real-time reliability-related task lists. (1.2)	The Reliability Coordinator, Balancing Authority, or Transmission Operator~~, or Transmission Owner~~ failed to ~~prepare a~~create a BES company-specific Real-time reliability-related task list. (1.1~~ or 1.1.1~~.) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator~~, or Transmission Owner~~ failed to deliver training based on the BES company-specific Real-time reliability-related task lists. (1.3)

				OR The Reliability Coordinator, Balancing Authority, or Transmission Operator, failed to implement the identified changes to the training program(s). (1.4.)		
R2	**Long-term Planning**	**Medium**	**None**	The Transmission Owner failed to review or update, if necessary, its company-specific Real-time reliability-related task list each calendar year. (2.1.1.) OR The Transmission Owner failed to evaluate its training program each calendar year to identify needed changes to its training program(s). (2.4) OR The Transmission Owner failed to implement the identified changes to the training program(s). (2.4.)	The Transmission Owner failed to use a systematic approach to develop and implement a training program. (R2) OR The Transmission Owner failed to design and develop training materials based on the BES company-specific Real-time reliability-related task lists. (2.2)	The Transmission Owner failed to create a BES company-specific Real-time reliability-related task list. (2.1.) OR The Transmission Owner failed to deliver training based on the BES company-specific Real-time reliability-related task lists. (2.3)
~~R2~~R3	**Long-term Planning**	**High**	**None**	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of at least 90% but less than 100% of its ~~System Personnel's~~	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of at least 70% but less than 90% of its ~~System Personnel's capabilities~~	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of less than 70% of its ~~System Personnel's capabilities~~ personnel identified in

				~~capabilities~~ personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (~~R2~~R3)	personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (~~R2~~R3) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner failed to verify ~~its System Personnel's~~the capabilities of its personnel identified in Requirements R1 or Requirement R2 to perform each new or modified task within six months of making a modification to its BES company-specific Real-time reliability-related task list. (~~2~~3.1)	Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (~~R2~~R3)
~~R3~~R4	**Long-term Planning**	**Medium**	**None**	**None**	**None**	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that meet the criteria of Requirement R4 did not provide its ~~System Personnel~~personnel identified in Requirement R1 or Requirement R2 with any form of simulation technology training such as a simulator, virtual technology, or other technology that replicates the operational behavior of the ~~Bulk Electric System. (R3~~BES. (R4)

						OR The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner did not ~~verify its System Personnel capabilities to perform each new or modified Real-time reliability-related task within twelve months of gaining operational authority or control over a Facility with an established IROL or establishes operating guides or protection systems to mitigate IROL violations. (R3~~provide its personnel identified in Requirement R1 or Requirement R2 with any form of simulation technology training such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES within twelve months of meeting the criteria of Requirement R4. (R4.1)

~~R4~~R5	**Long-term Planning**	**Medium**	**None**	The Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ or Transmission ~~Owner~~Operator failed to evaluate its training established in Requirement ~~R4~~R5 each calendar year. (~~4~~5.1)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to develop training for its Operations Support Personnel. (R5) OR The Reliability Coordinator, Balancing Authority, or Transmission ~~Owner~~Operator developed training but failed to use a systematic approach ~~to training to establish training requirements as defined in Requirement R4.~~. (R5)	The Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ or Transmission ~~Owner failed to develop training for its Operations Support Personnel. (R4~~Operator~~)~~ ~~OR~~ ~~The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner~~ failed to implement training for its Operations Support Personnel. (~~R4~~R5)
~~R5~~R6	**Long-term Planning**	**Medium**	**None**	The Generator Operator failed to evaluate its training established in Requirement ~~R5~~R6 each calendar year. (~~5~~6.1)	The Generator Operator failed to develop training for its personnel. (R6) OR The Generator Operator developed training but failed to use a systematic approach ~~to develop training as defined in Requirement R5.~~. (R6)	The ~~GOP~~Generator Operator failed to ~~deliver~~implement the training ~~as defined~~for its personnel identified in Requirement ~~R5.~~R6. (R6)

Application Guidelines

Guidelines and Technical Basis

Requirement R1:

Any systematic approach to training will determine: 1) the skills and knowledge needed to perform BES company-specific Real-time reliability-related tasks; 2) what training is needed to achieve those skills and knowledge; 3) if the learner can perform the BES company-specific Real-time reliability-related task(s) acceptably in either a training or on-the-job environment; and 4) if the training is effective, and make adjustments as necessary.

Reference #1: Determining Task Performance Requirements

The purpose of this reference is to provide guidance for a performance standard that describes the desired outcome of a task. A standard for acceptable performance should be in either measurable or observable terms. Clear standards of performance are necessary for an individual to know when he or she has completed the task and to ensure agreement between employees and their supervisors on the objective of a task. Performance standards answer the following questions:

How timely must the task be performed?

Or

How accurately must the task be performed?

Or

With what quality must it be performed?

Or

What response from the customer must be accomplished?

When a performance standard is quantifiable, successful performance is more easily demonstrated. For example, in the following task statement, the criteria for successful performance is to return system loading to within normal operating limits, which is a number that can be easily verified.

> Given a System Operating Limit violation on the transmission system, implement the correct procedure for the circumstances to mitigate loading to within normal operating limits.

Even when the outcome of a task cannot be measured as a number, it may still be observable. The next example contains performance criteria that is qualitative in nature, that is, it can be verified as either correct or not, but does not involve a numerical result.

> Given a tag submitted for scheduling, ensure that all transmission rights are assigned to the tag per the company Tariff and in compliance with NERC and NAESB standards.

Reference #2: Systematic Approach to Training References:
The following list of hyperlinks identifies references for the NERC Standard PER-005 to assist with the application of a systematic approach to training:

(1) DOE-HDBK-1078-94, A Systematic Approach to Training

http://www.publicpower.org/files/PDFs/DOEHandbookTrainingProgramSystematicApproach.pdf

(2) DOE-HDBK-1074-95, January 1995, Alternative Systematic Approaches to Training, U.S. Department of Energy, Washington, D.C. 20585 FSC 6910

http://www.catagle.com/112-1/download_php-spec_DOE-HDBK-1074-95_003254_1.htm

(3) ADDIE – 1975, Florida State University

http://www.nwlink.com/~donclark/history_isd/addie.html

(4) DOE Standard - Table-Top Needs Analysis
DOE-HDBK-1103-96

http://www.cms.doe.gov/sites/prod/files/2013/06/f2/hdbk1103.pdf

Reference #3: ~~Normal and Emergency Operations~~Recognized Operator Training Topics

~~These topics are identified as meeting the topic criteria for normal and emergency operations training.~~

~~A. Recognition and Response to System Emergencies~~

~~1. Emergency drills and responses~~

~~2. Communication tools, protocols, coordination~~

~~3. Operating from backup control centers~~

~~4. System operations during unstudied situations~~

~~5. System Protection~~

~~6. Geomagnetic disturbances weather impacts on system operations~~

~~7. System Monitoring – voltage, equipment loading~~

~~8. Real-time contingency analysis~~

~~9. Offline system analysis tools~~

~~10. Monitoring backup plans~~

~~11. Sabotage, physical, and cyber threats and responses~~

~~B. Operating Policies and Standards Related to Emergency Operations~~

~~1. NERC standards that identify emergency operations practices (e.g. EOP Standards)~~

2. ~~Regional reliability operating policies~~
3. ~~Sub-regional policies and procedures~~
4. ~~ISO/RTO policies and procedures~~

~~C. Power System Restoration Philosophy and Practices~~

1. ~~Black start~~
2. ~~Interconnection of islands – building islands~~
3. ~~Load shedding – automatic (under-frequency and under-voltage) and manual~~
4. ~~Load restoration philosophies~~

~~D. Interconnected Power System Operations~~

1. ~~Operations coordination~~
2. ~~Special protections systems~~
3. ~~Special operating guides~~
4. ~~Voltage and reactive control, including responding to eminent voltage collapse~~
5. ~~Understanding the concepts of Interconnection Reliability Operating Limits versus System Operating Limits~~
6. ~~DC tie operations and procedures during system emergencies~~
7. ~~Thermal and dynamic limits~~
8. ~~Unscheduled flow mitigation – congestion management~~
9. ~~Local and regional line loading procedures~~
10. ~~Radial load and generation operations and procedures~~
11. ~~Tie line operations~~
12. ~~E-tagging and Interchange Scheduling~~
13. ~~Generating unit operating characteristics and limits, especially regarding reactive capabilities and the relationship between real and reactive output~~

~~E. Technologies and Tools~~

1. ~~Forecasting tools~~
2. ~~Power system study tools~~
3. ~~Interchange Distribution Calculator (IDC)~~

~~F. Market Operations as They Relate to Emergency Operations~~

1. ~~Market rules~~
2. ~~Locational Marginal Pricing (LMP)~~
3. ~~Transmission rights~~

~~4. OASIS~~

~~5. Tariffs~~

~~6. Fuel management~~

~~7. Real-time, hour-ahead and day-ahead tools~~

See Appendix A – Recognized Operator Training Topics within the NERC System Operator Certification Program Manual.
http://www.nerc.com/pa/Train/SysOpCert/Documents/SOC_Program_Manual_February_2012_Final.pdf

Reference #4: Definitions of Simulation and Simulators

Georgia Institute of Technology

– Modeling & Simulation for Systems Engineering
http://www.pe.gatech.edu/conted/servlet/edu.gatech.conted.course.ViewCourseDetails?COURSE_ID=840

~~Simulation is the process of designing a model of a system and conducting experiments to understand the behavior of the system and/or evaluate various strategies for the operation of the system. The modeling & simulation life cycle refers to steps that take place during the course of a simulation study, which include problem formulation, conceptual model development, and output data analysis. Explore modeling & simulation, by using the M&S life cycle as an outline for exploring systems engineering concepts.~~

University of Central Florida – Institute for Simulation & Training
Just what is "simulation" anyway (or, Simulation 101)?
And what about "modeling"?
But what does IST do with simulations?
http://www.ist.ucf.edu/overview.htm

~~**Just what is "simulation" anyway** (or, Simulation 101)**?**~~
~~**And what about "modeling"?** (see below)~~
~~**But what does IST do with simulations?** (answer)~~

~~In its broadest sense, simulation is imitation. We've used it for thousands of years to train, explain and entertain. Thanks to the computer age, we're really getting good at using simulation for all three.~~

~~Simulations (and models, too) are abstractions of reality. Often they deliberately emphasize one part of reality at the expense of other parts. Sometimes this is necessary due to computer power limitations. Sometimes it's done to focus your attention on an important aspect of the simulation. Whereas models are mathematical, logical, or some other structured representation of reality, simulations are the specific application of models to arrive at some outcome (more about models, below).~~

~~**Three types of simulations**~~

~~Simulations generally come in three styles: live, virtual and constructive. A simulation also may be a combination of two or more styles.~~

~~***Live simulations*** typically involve humans and/or equipment and activity in a setting where they would operate for real. Think *war games* with soldiers out in the field or manning command posts. Time is continuous, as in the real world. Another example of live simulation is testing a car battery using an electrical tester.~~

~~***Virtual simulations*** typically involve humans and/or equipment in a computer-controlled setting. Time is in discrete steps, allowing users to concentrate on the important stuff, so to speak. A flight simulator falls into this category.~~

~~***Constructive simulations*** typically do not involve humans or equipment as participants. Rather than by time, they are driven more by the proper sequencing of events. The anticipated path of a hurricane might be "constructed" through application of temperatures, pressures, wind currents and other weather factors.~~

~~A simulator is a device that may use any combination of sound, sight, motion and smell to make you feel that you are experiencing an actual situation. Some video games are good examples of low-end simulators. For example, you have probably seen or played race car arcade games.~~

~~The booths containing these games have a steering wheel, stick shift, gas and brake pedals and a display monitor. You use these devices to "drive" your "race car" along the track and through changing scenery displayed on the monitor. As you drive, you hear the engine rumble, the brakes squeal and the metal crunch if you crash. Some booths use movement to create sensations of acceleration, deceleration and turning. The sights, sounds and feel of the game booth combine to create, or simulate, the experience of driving a car in a race.~~

~~Most people first think of "flight simulators" or "driving simulators" when they hear the term "simulation." But simulation is much more.~~

~~Because they can recreate experiences, simulations hold great potential for training people for almost any situation. Education researchers have, in fact, determined that people, especially adults, learn better by experience than through reading or lectures. Simulated experiences can be just as valuable a training tool as the real thing.~~

~~Simulations are complex, computer-driven *re*-creations of the real thing. When used for training, they must recreate "reality" accurately, otherwise you may not learn the right way to do a task.~~

~~For example, if you try to practice how to fly in a flight simulator game that does not accurately *model* (see definition, below) the flight characteristics of an airplane, you will not learn how a real aircraft responds to your control.~~

~~Building simulator games is not easy, but creating simulations that *accurately* answer such questions as *"If I do this, what happens then?"* is even more demanding.~~

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~~Over the years, government and industry, working independently with new technologies and hardware, developed a wide range of products and related applications to improve simulation science. This independence, however, often led to sporadic or redundant research efforts.~~

~~To benefit from each other's latest advances, researchers from across the country needed better communication and, ideally, a common source of supporting academic studies. The State of Florida recognized these needs and in 1982 established the Institute for Simulation and Training at the University of Central Florida.~~

~~What we do at IST~~

~~IST's mission is to advance the state of the art and science of modeling and simulation by~~

- ~~performing basic and applied simulation research~~
- ~~supporting education in modeling and simulation and related fields~~
- ~~serving public and private simulation communities~~

~~We don't produce simulator hardware. That's a job for industry. But we've successfully developed working prototype hardware that provides new uses for simulations. We'll also help develop new applications for existing hardware, and scientifically test the results using human factors and other criteria for effective human-machine interface and learning. Too often overlooked, human factors testing is crucial to ultimate simulation effectiveness. We're fortunate to be closely connected, through joint faculty appointments and working relationships, with one of the top, if not the leading human factors department in the nation—right here at UCF.~~

~~We also explore the frontiers of simulation science, expanding our knowledge of ways to stimulate the human senses with advanced optical, audio and haptic technologies.~~

~~*Still* obfuscated? Go here...~~

~~Modeling: a model definition~~

~~A computer model, as used in modeling and simulation science, is a mathematical representation of something—a person, a building, a vehicle, a tree—any object. A model also can be a representation of a process—a weather pattern, traffic flow, air flowing over a wing.~~

~~Models are created from a mass of data, equations and computations that mimic the actions of things represented. Models usually include a graphical display that translates all this number crunching into an animation that you can see on a computer screen or by means of some other visual device.~~

~~Models can be simple images of things—the outer shell, so to speak—or they can be complex, carrying all the characteristics of the object or process they represent. A complex model will simulate the actions and reactions of the real thing. To make these models behave the way they would in real life, accurate, real-time simulations require fast computers with lots of number crunching power.~~

Implementation Plan

Project 2010-01 Operations Personnel Training

Implementation Plan for PER-005-2 – Operations Personnel Training

Approvals Required
PER-005-2 – Operations Personnel Training

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

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

System Operator: An individual at a Control Center of a Reliability Coordinator, Balancing Authority, or Transmission Operator who operates or directs the operation of the Bulk Electric System in Real-time.

Operations Support Personnel: Individuals who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms,[1] in direct support of Real-time operations of the Bulk Electric System.

Other Definitions Used within the Standard
None

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Operator

[1] Nomograms are used in the WECC Region to describe element operating limits.

- Transmission Owners that has personnel, excluding field switching personnel, who can act independently to operate or direct the operation of the Transmission Owner's Bulk Electric System transmission facilities in Real-time
- Generator Operators that have dispatch personnel at a centrally located dispatch center who receive direction from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control. These personnel do not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions without making any modifications.

Applicable Facilities
None

Conforming Changes to Other Standards
None

Effective Dates
PER-005-2 shall become effective as follows:

> This standard shall become effective the first day of the first calendar quarter that is 24 months beyond the date that this standard is approved by an applicable governmental authority or is otherwise provided for in a jurisdiction where approval by an applicable authority is required for a standard to go into effect.
>
> Where approval by an applicable governmental authority is not required, this standard shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Actions to be Completed as of the Effective Date:
An implementation period provides time for an entity to become compliant with the standard prior to the standard becoming enforceable. This section describes the requirements that an entity must be compliant with as of the enforceable date of PER-005-2. This section does not address evidence of compliance; see measures, compliance input and RSAWs for further information regarding possible evidence.

<u>Requirement R1:</u>
Reliability Coordinators, Balancing Authorities, and Transmission Operators must have completed the requirements for PER-005-2 Requirement R1 as of the enforceable date of the standard as provided below. Note that these entities are subject to PER-005-1.

R1: Entities must have developed and implemented a training program for its System Operators using a systematic approach.

1.1: Entities must have defined and documented its methodology for creating a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks, and must have a list of these tasks.

1.1.1: Entities must have conducted a review of its tasks list once in the calendar year that this standard becomes enforceable.

Note: this review may be conducted either under the existing standard PER-005-1 or under PER-005-2 after it becomes enforceable, as long as the entity conducts one review during the calendar year.

1.2: An entity must have completed the design and development of training materials as necessary under its training program as of the enforceable date of PER-005-2. An entity is not obligated to have designed and developed training materials for all future training.

1.3: Entities must have delivered training in accordance with their training program as of the enforceable date of PER-005-2.

1.4: Entities must have conducted an evaluation once in the calendar year that PER-005-2 becomes enforceable.

Note: this may be conducted either under PER-005-1 or under PER-005-2 after it becomes enforceable, as long as the entity conducts one evaluation during the calendar year.

<u>Requirement R2:</u>

R2: Applicable Transmission Owners must have developed and implemented a training program for its applicable personnel using a systematic approach.

2.1: An applicable Transmission Owner must have defined and documented its methodology for creating a list of BES company-specific Real-time reliability-related tasks, and must have a list of these tasks as of the enforceable date of PER-005-2.

2.1.1: As applicable Transmission Owners were not previously subject to PER-005-1, they would not be required to have conducted a review prior to the enforceable date of the proposed standard or in the calendar year that the proposed standard becomes enforceable. The entity's first required evaluation would occur within the first calendar year following the enforceable date of PER-005-2.

2.2: An applicable Transmission Owner must have completed the design and development of training materials according to its training program as of the enforceable date of PER-005-2. An entity is not obligated to have designed and developed training materials for all future training.

2.3: As applicable Transmission Owners were not previously subject to PER-005-1, they must begin to implement training in accordance with its training program as of the enforceable date. Under the standard, these entities are not required to have delivered training prior to the enforceable date.

2.4: As applicable Transmission Owners were not previously subject to PER-005-1, they would not be required to have conducted an evaluation prior to the enforceable date of the proposed standard or in the calendar year that the proposed standard becomes enforceable. The entity's first required evaluation would occur within the first calendar year following the enforceable date of PER-005-2.

Requirement R3:

R3: Reliability Coordinators, Balancing Authorities, Transmission Operators and Transmission Owners must have verified the capabilities of its personnel identified in Requirements R1 and R2 to perform each of its assigned BES company-specific Real-time reliability-related tasks, at least once, as of the enforceable date of PER-005-2.

3.1: Reliability Coordinators, Balancing Authorities, and Transmission Operators that are already subject to PER-005-1 are required to, within six months of a change to its task list, have verified the capabilities of its personnel identified in Requirement R1 to perform each new or modified BES company-specific Real-time reliability-related tasks identified in Requirement R1 part 1.1. These entities will continue to have the time allotted to complete the verification under PER-005-1 after the enforceable date of PER-005-2.

Because Transmission Owners were not previously subject to PER-005-1, they are not expected to have verified the capabilities of its personnel identified in Requirement R2 to perform a new or modified BES company-specific Real-time reliability-related tasks identified under Requirement R2 part 2.1 prior to the enforceable date of the standard. This requirement pertains to BES company-specific reliability-related tasks that are newly identified or modified after the enforceable date of PER-005-2.

Requirement R4:

R4: Reliability Coordinators, Balancing Authorities, Transmission Operators and Transmission Owners must be providing training using the simulation technologies described in Requirement R4 according to its training program as of the date PER-005-2 becomes enforceable.

4.1: Entities that do not meet the criteria set forth in Requirement R4 prior to the enforceable date of the standard are required to comply with Requirement R4 within 12 months of meeting the criteria.

Requirement R5:

R5: Reliability Coordinators, Balancing Authorities, and Transmission Operators must have developed training, using a systematic approach, for their Operations Support Personnel on the impact of their job function(s) to those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1 and must have implemented that training according to its systematic approach as of the enforceable date of PER-005-2.

5.1: As Operations Support Personnel were not previously subject to PER-005-1, they would not be required to have conducted an evaluation prior to the enforceable date of the proposed standard or in the calendar year that the proposed standard becomes enforceable. The entity's first required evaluation would occur within the first calendar year following the enforceable date of PER-005-2.

Requirement R6:

R6: Generator Operators must have developed training, using a systematic approach, for their applicable personnel on the impact of their job function(s) to the reliable operations of the BES during normal and emergency operations and must have implemented that training according to its systematic approach as of the enforceable date of PER-005-2.

6.1: As Generator Operators were not previously subject to PER-005-1, they would not be required to have conducted an evaluation prior to the enforceable date of the proposed standard or in the calendar year that the proposed standard becomes enforceable. The entity's first required evaluation would occur within the first calendar year following the enforceable date of PER-005-2.

Justification

The 24-month period for implementation of PER-005-2 will provide sufficient time for the applicable entities to make necessary modifications to their systematic approach to training and, for entities not yet subject to the standard, time to develop a systematic approach to training that is compliant with the proposed standard. This time frame is consistent with the 24-month implementation period FERC approved for PER-005-1 to allow for Reliability Coordinators, Balancing Authorities, and Transmission

Operators to develop a systematic approach to training. The standard drafting team concluded that the same timeframe (24-months) should be provided to the new applicable entities and for the entities currently subject to PER-001-1 to development training for their Operations Support Personnel.

Retirements

PER-005-1 – System Personnel Training should be retired at 11:59:59 pm of the day immediately prior to the enforceable date of PER-005-2 in the particular jurisdiction in which the new standard is becoming enforceable. For entities that are completing actions under Requirement R3.1 of PER-005-1, this requirement will remain in effect until the time allotted under the requirement has expired.

Attachment 1
Approved Standards Incorporating the Term “System Operator”

EOP-005-2 — System Restoration from Blackstart Resources

EOP-006-2 — System Restoration Coordination

EOP-008-1 — Loss of Control Center Functionality

IRO-002-3 — Reliability Coordination – Analysis Tools

IRO-014-1 — Procedures, Processes, or Plans to Support Coordination between Reliability Coordinators

MOD-008-1 — TRM Calculation Methodology

MOD-020-0 — Providing Interruptible Demands and DCLM Data

PER-003-1 — Operation Personnel Credentials

PRC-004-WECC-1 – Protection System and Remedial Action Scheme Maintenance and Testing

PRC-023 -2 — Transmission Relay Loadability

Implementation Plan

Project 2010-01 Operations Personnel Training

Implementation Plan for PER-005-2 – Operations Personnel Training

Approvals Required
PER-005-2 – Operations Personnel Training

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

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

System Operator: An individual at a ~~control center~~Control Center of a Reliability Coordinator, Balancing Authority, or Transmission Operator~~, or Reliability Coordinator~~ who operates or directs the operation of the Bulk Electric System in Real-time.

~~***Other Definitions Used within the Standard***~~
~~The following terms are defined for use only within PER-005-2 and, upon approval of the standard, will not be moved to the NERC Glossary of Terms:~~

~~**System Personnel**: System Operators of a Reliability Coordinator, Transmission Operator or Balancing Authority, and the Transmission Owner personnel described in the Applicability Section of this standard.~~

Operations Support Personnel: Individuals~~, as identified by the Reliability Coordinators, Balancing Authorities, Transmission Operators or Transmission Owners,~~ who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms,[1] in direct support of Real-time~~, reliability related tasks performed by System Operators.~~ operations of the Bulk Electric System.

[1] Nomograms are used in the WECC Region to describe element operating limits.

Other Definitions Used within the Standard
None

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Operator
- Transmission Owners that ~~have~~has personnel~~ at a facility~~, excluding field switching personnel, who can act independently to ~~carry out tasks that require Real-time ~~operate or direct the operation of the Transmission Owner's Bulk Electric System~~, including protecting assets, protecting personnel safety, adhering to regulatory requirements and establishing stable islands during system restoration. ~~ transmission facilities in Real-time
- Generator Operators that have dispatch personnel at a centrally located dispatch center who receive direction from ~~their~~the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control. These personnel ~~does~~do not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions~~,~~ without making any modifications.

Applicable Facilities
None

Conforming Changes to Other Standards
None

Effective Dates
PER-005-2 shall become effective as follows:

This standard shall become effective the first day of the first calendar quarter that is 24 months beyond the date that this standard is approved by an applicable governmental authority or is otherwise provided for in a jurisdiction where approval by an applicable authority is required for a standard to go into effect.

Where approval by an applicable governmental authority is not required, this standard shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Actions to be Completed as of the Effective Date:

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An implementation period provides time for an entity to become compliant with the standard prior to the standard becoming enforceable. This section describes the ~~actions~~requirements that an entity must ~~complete~~be compliant with as of the ~~effective~~enforceable date of PER-005-2. This section does not address evidence of compliance; see measures, compliance input and RSAWs for further information regarding possible evidence.

Requirement R1:

~~R1: An entity~~ Reliability Coordinators, Balancing Authorities, and Transmission Operators must have completed the requirements for PER-005-2 Requirement R1 as of the enforceable date of the standard as provided below. Note that these entities are subject to PER-005-1.

R1: Entities must have developed and implemented a training program ~~that is based on~~for its System Operators using a systematic approach ~~to training~~.

~~1.~~

1~~: An entity~~ .1: Entities must have defined and documented its methodology for creating a list of Bulk Electric System (BES) company~~-~~-specific Real-time reliability~~-~~-related tasks, and must have a list of these tasks.

~~1.~~1.1~~:~~.1: Entities ~~already subject to PER-005-1 (RC, BA and TOP)~~ must ~~conduct~~have conducted a review of its tasks list once in the calendar year that this standard becomes ~~effective; however~~enforceable.

Note: this review may be conducted either under the existing standard ~~(~~PER-005-1~~) prior to the effective date of proposed standard (PER-005-2)~~ or under ~~the proposed standard (~~PER-005-2~~)~~ after it becomes ~~effective~~enforceable, as long as the entity conducts one review during the calendar year.

~~Entities that were not previously subject to PER-005-1 would not be expected to have conducted a review prior to the effective date of the proposed standard, or in the calendar year that the proposed standard becomes effective. The entity's first review would occur in the first calendar year following the effective date of this standard.~~

1.2: An entity must have completed the design and development of training materials as necessary under its training program as of the enforceable date of PER-005-2. An entity is not obligated to have designed and developed training materials for all future training.

1.3: Entities must have delivered training in accordance with their training program as of the enforceable date of PER-005-2.

1.4: Entities must have conducted an evaluation once in the calendar year that PER-005-2 becomes enforceable.

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Note: this may be conducted either under PER-005-1 or under PER-005-2 after it becomes enforceable, as long as the entity conducts one evaluation during the calendar year.

Requirement R2:

~~.~~R2: Applicable Transmission Owners must have developed and implemented a training program for its applicable personnel using a systematic approach.

2.1: An applicable Transmission Owner must have defined and documented its methodology for creating a list of BES company-specific Real-time reliability-related tasks, and must have a list of these tasks as of the enforceable date of PER-005-2.

2.1.1: As applicable Transmission Owners were not previously subject to PER-005-1, they would not be required to have conducted a review prior to the enforceable date of the proposed standard or in the calendar year that the proposed standard becomes enforceable. The entity's first required evaluation would occur within the first calendar year following the enforceable date of PER-005-2.

2.2: An applicable Transmission Owner must have completed the design and development of training materials according to its training program as of the enforceable date of PER-005-2. An entity is not obligated to have designed and developed training materials for all future training.

~~1~~2.3: ~~Entities already subject to PER-005-1 must continue to implement training in accordance with its existing training program.~~

~~Entities that~~As applicable Transmission Owners were not previously subject to PER-005-1, they must begin to implement training in accordance with its training program as of the ~~effective~~enforceable date. Under the standard, ~~such~~these entities are not ~~expected~~required to have delivered training prior to the ~~effective~~enforceable date.

~~1~~2.4: ~~Entities already subject to PER-005-1 (RC, BA and TOP) must conduct an evaluation once in the calendar year that this standard becomes effective; however this may be conducted either under the existing standard (PER-005-1) prior to the effective date of the proposed standard (PER-005-2) or under the proposed standard after it becomes effective.~~

~~Entities that~~As applicable Transmission Owners were not previously subject to PER-005-1, they would not be ~~expected~~required to have conducted an evaluation prior to the ~~effective~~enforceable date of the proposed standard or in the calendar year that the proposed standard becomes ~~effective~~enforceable. The entity's first required evaluation would occur ~~in~~within the first calendar year following the ~~effective~~enforceable date of ~~the proposed standard~~PER-005-2.

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~~Requirement R2:~~

~~R2: Entities already subject to PER-005-1 (RC, BA and TOP) must have verified their System Personnel's[2] capabilities to perform each of its assigned Real-time reliability-related tasks, at least once.~~

~~Entities that were not previously subject to PER-005-1 must have verified its System Personnel's capabilities to perform each of its assigned Real-time reliability-related tasks, at least once, as identified in Requirement R1 part 1.1, prior to the effective date of the standard.~~

~~2.1: Entities already subject to PER-005-1 (RC, BA and TOP) must have, within six months, verified its System Personnel's capabilities to perform a new or modified Real-time reliability-related task identified Requirement R1 part 1.1 pursuant to PER-005-1.~~

~~Entities that were not previously subject to PER-005-1 would not be expected to have verified its System Personnel's capabilities to perform a new or modified Real-time reliability-related task identified under Requirement R1 part 1.1 prior to the effective date of the standard. This requirement pertains to reliability-related tasks that are new or modified following the effective date of this standard.~~

Requirement R3:

R3: ~~Entities~~ Reliability Coordinators, Balancing Authorities, Transmission Operators and Transmission Owners must have verified the capabilities of its personnel identified in Requirements R1 and R2 to perform each of its assigned BES company-specific Real-time reliability-related tasks, at least once, as of the enforceable date of PER-005-2.

3.1: Reliability Coordinators, Balancing Authorities, and Transmission Operators that are already subject to PER-005-1 ~~(RC, BA and TOP) must have completed training using simulation technology according to its training program under the existing standard (PER-005-1) and must~~are required to, within six months of a change to its task list, have verified the capabilities of its personnel identified in Requirement R1 to perform each new or modified BES company-specific Real-time reliability-related tasks identified in Requirement R1 part 1.1. These entities will continue to ~~provide training using simulation technology according to its training program~~ have the time allotted to complete the verification under PER-005-1 after the ~~effective~~enforceable date of ~~the proposed standard (~~PER-005-2~~)~~.

~~Entities that~~ Because Transmission Owners were not previously subject to PER-005-1 ~~(TO) must begin to implement training using simulation technology according to its training program as of the effective date. Under the standard, these entities~~, they are not expected to have ~~delivered~~

~~[2] As used in this standard, the term "System Personnel" is defined as System Operators of a Reliability Coordinator, Transmission Operator or Balancing Authority, and the Transmission Owner personnel described in the Applicability Section of this standard.~~

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~~simulation training~~verified the capabilities of its personnel identified in Requirement R2 to perform a new or modified BES company-specific Real-time reliability-related tasks identified under Requirement R2 part 2.1 prior to the ~~effective~~enforceable date~~.~~

~~3.1: Entities already subject to PER-005-1 (RC, BA and TOP) that gained operational authority or control over Facilities with established IROLs or has established operating guides or protection systems to mitigate IROL violations must have provided each System Operator with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior~~ of the ~~BES during normal and emergency conditions prior to the effective date.~~

~~***Entities that were not previously subject to PER-005-1 are not required to have completed this action prior to the effective date of the standard.***~~standard. This requirement pertains to ~~***IROLs***~~BES company-specific reliability-related tasks that are ~~***gained following***~~newly identified or modified after the ~~***effective***~~enforceable date of ~~***this standard.***~~ PER-005-2.

Requirement R4:

~~R4: The personnel identified in this requirement were not previously subject to PER-005-1. The entities (RC, BA, TOP and TO) must have established a training program for their Operations Support Personnel[3] and must have begun to implement training in accordance with their training program as of the effective date. Under the standard, entities are not expected to have delivered or developed material for all future training identified in its training program prior to the effective date.~~

~~4.1: The personnel identified in this requirement were not previously subject to PER-005-1 and the entities are not required to have conducted a review prior to the effective date. The entity's first review of the training for its Operations Support Personnel would occur in the first calendar year following the effective date of this standard.~~

~~[3] As used in this standard, the term "Operations Support Personnel" is defined as Individuals, as identified by the Reliability Coordinators, Balancing Authorities, Transmission Operators, or Transmission Owners, who perform outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms, in direct support of Real-time, reliability-related tasks performed by System Operators.~~

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R4: Reliability Coordinators, Balancing Authorities, Transmission Operators and Transmission Owners must be providing training using the simulation technologies described in Requirement R4 according to its training program as of the date PER-005-2 becomes enforceable.

4.1: Entities that do not meet the criteria set forth in Requirement R4 prior to the enforceable date of the standard are required to comply with Requirement R4 within 12 months of meeting the criteria.

Requirement R5:

R5: ~~Generator Operators were not previously subject to PER-005-1. Generator~~Reliability Coordinators, Balancing Authorities, and Transmission Operators must have ~~established its~~ developed training ~~program~~, using a systematic approach, for their Operations Support Personnel on the impact of their job function(s) to those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1 and must have ~~begun to implement~~implemented that training ~~in accordance with~~according to its ~~training program~~systematic approach as of the ~~effective date. Under the standard, Generator Operators are not expected to have delivered or developed material for all future training identified in its training program prior to the effective date.~~enforceable date of PER-005-2.

5.1: ~~Generator Operators~~As Operations Support Personnel were not previously subject to PER-005-1 ~~and~~, they ~~are~~would not be required to have conducted ~~a review~~an evaluation prior to the ~~effective date. The Generator Operators' first review~~enforceable date of the proposed standard or in the calendar year that the proposed standard becomes enforceable. The entity's first required evaluation would occur ~~in~~within the first calendar year following the ~~effective~~enforceable date of PER-005-2.

Requirement R6:

R6: Generator Operators must have developed training, using a systematic approach, for their applicable personnel on the impact of their job function(s) to the reliable operations of the BES during normal and emergency operations and must have implemented that training according to its systematic approach as of the enforceable date of ~~this standard.~~ PER-005-2.

6.1: As Generator Operators were not previously subject to PER-005-1, they would not be required to have conducted an evaluation prior to the enforceable date of the proposed standard or in the calendar year that the proposed standard becomes enforceable. The entity's first required evaluation would occur within the first calendar year following the enforceable date of PER-005-2.

Justification

The 24-month period for implementation of PER-005-2 will provide sufficient time for the applicable entities to make necessary modifications to their systematic approach to training and, for entities not

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yet subject to the standard, time to develop a systematic approach to training that is compliant with the proposed standard. This time frame is consistent with the 24-month implementation period FERC approved for PER-005-1 to allow for Reliability Coordinators, Balancing Authorities, and Transmission Operators to develop a systematic approach to training. The standard drafting team concluded that the same timeframe (24-months) should be provided to the new applicable entities and for the entities currently subject to PER-001-1 to development training for their Operations Support Personnel.

Retirements

PER-005-1 – System Personnel Training should be retired at 11:59:59 pm of the day immediately prior to the ~~effective~~enforceable date of PER-005-2 in the particular jurisdiction in which the new standard is becoming ~~effective~~enforceable. For entities that are completing actions under Requirement R3.1 of PER-005-1, this requirement will remain in effect until the time allotted under the requirement has expired.

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Attachment 1
Approved Standards Incorporating the Term "System Operator"

EOP-005-2 — System Restoration from Blackstart Resources

EOP-006-2 — System Restoration Coordination

EOP-008-1 — Loss of Control Center Functionality

IRO-002-3 — Reliability Coordination – Analysis Tools

IRO-014-1 — Procedures, Processes, or Plans to Support Coordination between Reliability Coordinators

MOD-008-1 — TRM Calculation Methodology

MOD-020-0 — Providing Interruptible Demands and DCLM Data

PER-003-1 — Operation Personnel Credentials

PRC-004-WECC-1 – Protection System and Remedial Action Scheme Maintenance and Testing

PRC-023 -2 — Transmission Relay Loadability

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NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Project 2010-01 Training (PER) Revisions

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the draft PER-005-2 standard. The electronic comment form must be completed by 8:00 p.m. ET on **Friday, January 17, 2014**.

If you have questions please contact Jordan Mallory via email or by telephone at 404-446-9733.

The project page may be accessed by clicking here.

Background Information

On March 16, 2007 the Federal Energy Regulatory Commission (FERC) issued Order No. 693, *Mandatory Reliability Standards for the Bulk-Power System* and on November 18, 2010 FERC issued Order No. 742, *System Personnel Training Reliability Standards.* Five outstanding directives remain from those two orders (3 from Order No. 693 and 2 from Order No. 742), which are explained in detail in the PER White Paper contained in the SAR package.

The informal consensus building for PER began in February 2013. Specifically, the ad hoc group engaged stakeholders on how best to address the FERC directives, paragraph 81 candidates and results-based approaches (see page 4 of the PER White Paper regarding the paragraph 81 candidate). A discussion of the ad hoc group's consensus building and collaborative activities are included in the PER White Paper (see SAR package).

Based on stakeholder outreach, the PER ad hoc group has developed one revised proposed reliability standards (PER-005-2) that address the FERC directives and recommendations for improving PER-005-1, which included creating results-based requirements and considering paragraph 81 criteria to ensure that the standards proposals did not include requirements that meet those criteria. A discussion of the ad hoc group's consensus building and collaborative activities are included in the technical white paper.

This posting is soliciting comment on a pro forma standard and a Standard Authorization Request (SAR).

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

Question

1. The drafting team has revised PER-005-2 in response to stakeholder comments. Do you agree with the revised Operations Support Personnel and System Operator definitions? If you do not agree or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes
☐ No

Comments:

2. The drafting team has revised PER-005-2 in response to stakeholder comments. Do you agree with the revised standard? If you do not agree or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes
☐ No

Comments:

Standards Authorization Request Form

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

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

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Operations Personnel Training		
Date Submitted:	Revised: September 25, 2013 Original: July 18, 2013		
SAR Requester Information			
Name:	Jordan Mallory		
Organization:	NERC		
Telephone:	404-446-9733	E-mail:	Jordan.mallory@nerc.net
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
Address outstanding FERC directives, modify System Operator definition (project 2010-16), and incorporate ERO initiatives, including drafting results-based or performance-based standards that are consistent with Paragraph 81 criteria.

SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):
• Modify System Operator Definition (Project 2010-16). • Define applicable entities to address outstanding FERC Directives from Order No. 693 and Order No. 742. • Modify existing PER-005-1 requirements for additional applicable entities and personnel. • Remove the requirement to provide at least 32 hours of emergency operations training from Requirement R3 of PER-005-1 as it no longer meets criteria set forth in the standard for utilizing a systematic approach to training. The appropriate amount of such training should be determined by the applicable entities through the analysis phase of a systematic approach to training and outlined in a continuous education section of their training program. Any additional hours may be duplicative or repetitive for the entity in providing training to their personnel.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
This project will address the following FERC directives. In addition, the project will review the present standard to eliminate ambiguity within the standard. 1. This SAR is needed to address outstanding FERC Directives from Order No. 693 and Order No. 742. The following is a summary of the FERC Directives to the ERO: ▪ "Develop specific Requirements addressing the scope, content and duration appropriate for generator operator personnel." Order No. 693 at P 1363. A new requirement has been suggested to address Generator Operator personnel at a centrally located dispatch center who receive direction from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control. Personnel at a centrally located dispatch center who relay dispatch instructions, without making any modifications, are excluded. ▪ "Include [operations support personnel] who carry out outage coordination and assessments in accordance with IRO-004-1 and TOP-002-2 and determine SOLs and IROLs or operating nomograms in accordance with IRO-005-1 and TOP-004-0." Order No. 693 at P 1372. A new requirement has been suggested to address operation support and support staff personnel for training. The term Operations Support Personnel has been defined solely for the revised PER-005-1 standard. ▪ Consider whether personnel responsible for ensuring that critical reliability applications

SAR Information
of the EMS, such as state estimator, contingency analysis and alarm processing packages are available, up-to-date in terms of system data and produce useable results should be included in a mandatory training standard. Order No. 693 at P 1373. The team considered whether there is technical justification for including EMS personnel in the standard. ▪ Consider the necessity of developing a similar implementation plan with respect to PER-005-1, Requirement R3.1 addressing simulation technology. Order No. 693 at P 1390-1391 and Order No. 742 at P 55. ▪ Expand the applicability of PER-005 to include training requirements for local transmission control center" operator personnel and define the term "local transmission control center." Order No. 693 at P 1343; Order No. 742 at P 64. The team thought it would be a better path to define local transmission control center through extending the applicability to Transmission Owners versus creating a new term for the NERC Glossary. Transmission Owner in the PER standard is defined as "Personnel at a facility, excluding field switching personnel, who act independently to carry out tasks that require Real-time operation of the Bulk Electric System including protecting assets, protecting personnel safety, adhering to regulatory requirements and establishing stable islands during system restoration ." Transmission Owner has been added to all the requirements of the suggested revised PER-005-1 standard. 2. Revise definition of System Operator in glossary of terms to address industry concerns for clarity based on Project 2010-16. 3. Implement Paragraph 81 criteria by identifying Reliability Standards requirements that either: (a) provide little protection to the BES; (b) are unnecessary or (c) are redundant.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Detailed description of this project can be found in the Technical White Paper included with the initial SAR posting.

Reliability Functions

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

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

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

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

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

Related Standards	
Standard No.	Explanation

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	None
FRCC	None
MRO	None
NPCC	None
RFC	None
SERC	None

Regional Variances	
SPP	None
WECC	None

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Item 2d-Att 1

Standards Authorization Request Form

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

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

Request to propose a new or a revision to a Reliability Standard	
Title of Proposed Standard:	Operations Personnel Training
Date Submitted:	Revised: September 25, 2013 Original: July 18, 2013

SAR Requester Information			
Name:	Jordan Mallory		
Organization:	NERC		
Telephone:	404-446-9733	E-mail:	Jordan.mallory@nerc.net

SAR Type (Check as many as applicable)	
☐ New Standard	☐ Withdrawal of existing Standard
☒ Revision to existing Standard	☐ Urgent Action

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
~~Resolve~~Address outstanding FERC directives, modify System Operator definition (project 2010-16), and ~~to~~ incorporate ERO initiatives ~~such as~~, including drafting results-based~~,~~ or performance-based~~,~~ standards that are consistent with Paragraph 81~~, etc~~ criteria.

SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):

- Modify System Operator Definition (Project 2010-16).
- Define applicable entities to address outstanding FERC Directives from Order No. 693 and Order No. 742.
- Modify existing PER-005-1 requirements for additional applicable entities and personnel.
- ~~Remove existing PER-005-1 R3 prescriptive 32 hours of emergency operations as it is covered under the Systematic Approach to Training and thus is repetitive. In Paragraph 81 of the March 15, 2012 Order (link), FERC provided an opportunity for the ERO to remove requirements that did little to protect to the BPS pursuant to specific criteria. The requirement for 32 hours of training meets the Paragraph 81 criteria for redundancy. It further is not a results-based requirement, as it is unnecessarily prescriptive.~~Remove the requirement to provide at least 32 hours of emergency operations training from Requirement R3 of PER-005-1 as it no longer meets criteria set forth in the standard for utilizing a systematic approach to training. The appropriate amount of such training should be determined by the applicable entities through the analysis phase of a systematic approach to training and outlined in a continuous education section of their training program. Any additional hours may be duplicative or repetitive for the entity in providing training to their personnel.

Brief Description (Provide a paragraph that describes the scope of this standard action.)

This project will ~~be addressing~~address the following FERC directives. In addition, the project will ~~be reviewing~~review the present standard to eliminate ~~in~~ ambiguity within the standard.

1. This SAR is needed to address outstanding FERC Directives from Order No. 693 and Order No. 742. The following is a summary of the FERC Directives to the ERO:
   - "Develop specific Requirements addressing the scope, content and duration appropriate for generator operator personnel~~.~~." Order No. 693 at P 1363.

     A new requirement ~~R5~~ has been suggested ~~as an addition~~ to ~~a revised PER-005-1 capturing~~address Generator ~~Operators Personnel~~Operator personnel at a centrally located dispatch center who receive direction from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control. Personnel at a centrally located dispatch center who relay dispatch instructions, without making any modifications, are excluded.
   - "Include [operations support personnel] who carry out outage coordination and assessments in accordance with IRO-004-1 and TOP-002-2 and determine SOLs and IROLs or operating nomograms in accordance with IRO-005-1 and TOP-004-0~~.~~." Order No. 693

SAR Information

at P 1372.

A new requirement ~~R4~~ has been suggested ~~as an addition~~ to ~~a revised PER-005-1 capturing~~address operation support and support staff personnel for training. The term Operations Support Personnel has been ~~created with a definition~~defined solely for the revised PER-005-1 standard.

- Consider whether personnel responsible for ensuring that critical reliability applications of the EMS, such as state estimator, contingency analysis and alarm processing packages are available, up-to-date in terms of system data and produce useable results should be included in a mandatory training standard. ~~(Technical Justification)~~ Order No. 693 at P 1373.

  The team considered whether there is technical justification for including EMS personnel in the standard.

- Consider the necessity of developing a similar implementation plan with respect to PER-005-1, Requirement R3.1~~. (~~ addressing simulation technology~~)~~. Order No. 693 at P 1390-1391 and Order No. 742 at P 55.

- ~~Develop a definition~~Expand the applicability of ~~"local transmission control center" for developing the~~PER-005 to include training requirements for local transmission control center" operator personnel~~.~~ and define the term "local transmission control center." Order No. 693 at P 1343; Order No. 742 at P 64.

  The ~~group~~team thought it would be a better path to define local transmission control center through extending the applicability to Transmission Owners versus creating a new term for the NERC Glossary. Transmission Owner in the PER standard is defined as "Personnel ~~in a transmission control center who operate a portion of the Bulk Electric System at the direction of its Transmission Operator."~~at a facility, excluding field switching personnel, who act independently to carry out tasks that require Real-time operation of the Bulk Electric System including protecting assets, protecting personnel safety, adhering to regulatory requirements and establishing stable islands during system restoration ." Transmission Owner has been added to all the requirements of the suggested revised PER-005-1 standard.

2. Revise definition of System Operator in glossary of terms to address industry concerns for clarity based on Project 2010-16.

3. Implement Paragraph 81 criteria by identifying Reliability Standards requirements that either: (a) provide little protection to the ~~BPS~~BES; (b) are unnecessary or (c) are redundant.

SAR Information
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Detailed description of this project can be found in the Technical White Paper~~, of this~~ included with the initial SAR ~~submittal package~~posting.

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

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

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

Reliability and Market Interface Principles	
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

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

Related Standards

Standard No.	Explanation

Related SARs

SAR ID	Explanation

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	None
FRCC	None
MRO	None
NPCC	None
RFC	None
SERC	None
SPP	None
WECC	None

Project 2010-01 Operations Personnel Training
PER-005-2 Mapping Document

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
R1. Reliability Coordinator, Balancing Authority and Transmission Operator shall use a systematic approach to training to establish a training program for the BES company-specific reliability-related tasks performed by its System Operators and shall implement the program. **1.1.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall create a list of BES company-specific reliability-related tasks performed by its System Operators. **1.1.1.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall update its list of BES company-specific reliability-related tasks performed by its System Operators each calendar year to	Requirement R1 parts 1.1.1., 1.1., 1.2., 1.3., and 1.4.	**R1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement a training program for its System Operators as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **1.1** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology. **1.1.2** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 1.1 each calendar year.

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 **NERC Board Approved**	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
identify new or modified tasks for inclusion in training. **1.2.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall design and develop learning objectives and training materials based on the task list created in R1.1. **1.3.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall deliver the training established in R1.2. **1.4**. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall conduct an annual evaluation of the training program established in R1, to identify any needed changes to the training program and shall implement the changes identified.		**1.2** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 1.1. **1.3** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall deliver training to its System Operators according to its training program. **1.4** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall implement the changes identified.
R2. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator's capabilities to perform each assigned task identified in R1.1 at least one time.	The old Requirement R2 is now Requirement R3.	**R3.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
2.1. Within six months of a modification of the BES company-specific reliability-related tasks, each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator's capabilities to perform the new or modified tasks.		Requirement R1 part 1.1 or Requirement R2 part 2.1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]* **3.1** Within six months of a modification or addition of a BES company-specific Real-time reliability-related task, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its personnel identified in Requirement R1 or Requirement R2 to perform the new or modified BES company-specific Real-time reliability-related tasks identified in Requirement R1 part 1.1 or Requirement R2 part 2.1.
R3. At least every 12 months each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each of its System Operators with at least 32 hours of emergency operations training applicable to its organization that reflects emergency operations topics, which includes system	This Requirement has been updated with deleting R3 and moving 3.1 from the approved standard to be the new R4. Part 4.1 in the proposed standard it	**R4.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1 or

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
restoration using drills, exercises or other training required to maintain qualified personnel. **3.1.** Each Reliability Coordinator, Balancing Authority and Transmission Operator that has operational authority or control over Facilities with established IROLs or has established operating guides or protection systems to mitigate IROL violations shall provide each System Operator with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES during normal and emergency conditions.	addresses the implementation of simulation technology.	Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **4.1.** A Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not previously meet the criteria of Requirement R4, shall comply with Requirement R4 within 12 months of meeting the criteria.
	This requirement is new to PER-005-2.	**R2.** Each Transmission Owner shall use a systematic approach to develop and implement a training program for its personnel identified in Applicability Section 4.1.4.1 of this standard as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
		2.1 Each Transmission Owner shall create a list of BES company-specific Real-time reliability-related tasks based on a defined and documented methodology. **1.1.2** Each Transmission Owner shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 2.1 each calendar year. **2.2** Each Transmission Owner shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 2.1. **2.3** Each Transmission Owner shall deliver training to its personnel identified in Applicability Section 4.1.4.1 of this standard according to its training program. **2.4** Each Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement R2 to identify any needed changes to the training program and shall implement the changes identified.

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
	This requirement is new to PER-005-2.	**R5.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **5.1** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training.

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
	This requirement is new to PER-005-2.	**6.** Each Generator Operator shall use a systematic approach to develop and implement training to its personnel identified in Applicability Section 4.1.5 of this standard, on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **6.1.** Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R6 to identify and implement changes to the training.

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Project 2010-01 Operations Personnel Training PER-005-2 Mapping Document

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
R1. Reliability Coordinator, Balancing Authority and Transmission Operator shall use a systematic approach to training to establish a training program for the BES company-specific reliability-related tasks performed by its System Operators and shall implement the program. **1.1.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall create a list of BES company-specific reliability-related tasks performed by its System Operators. **1.1.1.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall update its list of BES	Requirement R1 parts 1.1.1., 1.1., 1.2., 1.3., and 1.4.	**R1.** Each Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ and Transmission ~~Owner~~Operator shall use a systematic approach to ~~training to~~ develop and implement a training program for its System ~~Personnel~~[1]Operators as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **1.1** Each Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ and Transmission ~~Owner~~Operator shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology. **1.1.2** Each Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ and

~~[1] As used in this standard, the term "System Personnel" is defined as System Operators of a Reliability Coordinator, Transmission Operator or Balancing Authority, and the Transmission Owner personnel described in the Applicability Section of this standard.~~

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PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
company-specific reliability-related tasks performed by its System Operators each calendar year to identify new or modified tasks for inclusion in training. **1.2.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall design and develop learning objectives and training materials based on the task list created in R1.1. **1.3.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall deliver the training established in R1.2. **1.4**. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall conduct an annual evaluation of the training program established in R1, to identify any needed changes to the training program and shall implement the changes identified.		Transmission ~~Owner~~Operator shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 1.1 each calendar year. **1.2** Each Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ and Transmission ~~Owner~~Operator shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 1.1. **1.3** Each Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ and Transmission ~~Owner~~Operator shall deliver training to its System ~~Personnel~~Operators according to its training program. 1.4 Each Reliability Coordinator, Balancing Authority, ~~Transmission Operator,~~ and Transmission ~~Owner~~Operator shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	Transitions to the below Requirement in New Standard or Other Action	Proposed Standard PER-005-2
		to the training program and shall implement the changes identified.
R2. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator's capabilities to perform each assigned task identified in R1.1 at least one time. **2.1.** Within six months of a modification of the BES company-specific reliability-related tasks, each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator's capabilities to perform the new or modified tasks.	The old Requirement R2 ~~and 2.1~~is now Requirement R3.	**~~R2~~R3.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its ~~System Personnel~~personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1~~.~~ or Requirement R2 part 2.1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]* **3.1** Within six months of a modification or addition of a BES company-specific Real-time reliability-related ~~tasks~~task, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its ~~System Personnel~~personnel identified in Requirement R1 or Requirement R2 to perform the new or modified BES company-specific Real-time reliability-related tasks identified in Requirement R1 part 1.1~~.~~ or Requirement R2 part 2.1.

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
R3. At least every 12 months each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each of its System Operators with at least 32 hours of emergency operations training applicable to its organization that reflects emergency operations topics, which includes system restoration using drills, exercises or other training required to maintain qualified personnel. **3.1.** Each Reliability Coordinator, Balancing Authority and Transmission Operator that has operational authority or control over Facilities with established IROLs or has established operating guides or protection systems to mitigate IROL violations shall provide each System Operator with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that	This Requirement has been updated with deleting R3 and moving 3.1 from the approved standard to be the new ~~R3~~R4. Part ~~3~~4.1 in the proposed standard it addresses the implementation of simulation technology.	**~~R3~~R4.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs~~)~~), or (2) has established ~~operating guides or~~ protection systems or operating guides to mitigate IROL violations, shall provide its ~~System Personnel~~personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES~~, according to its training program. ~~. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **~~2.1~~** ~~When a~~**4.1.** A Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not ~~have an IROL gains operational authority or control over a Facility with an established IROL or establishes operating guides or protection systems to mitigate IROL violations, it~~previously meet the criteria of Requirement R4, shall comply with Requirement ~~R3~~R4 within 12

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
replicates the operational behavior of the BES during normal and emergency conditions.		months of ~~gaining that authority or control, or establishing such operating guides or protection systems.~~ meeting the criteria.
	This requirement is new to PER-005-2.	~~**R4**~~**R2.** Each ~~Reliability Coordinator, Balancing Authority, Transmission Operator, and~~ Transmission Owner shall use a systematic approach to ~~training to~~ develop and implement a training program for its ~~Operations Support Personnel[2] on the impact of their job function(s) to those Real-time reliability-related tasks~~ personnel identified ~~by the entity pursuant to Requirement R1 part 1.1.~~ in Applicability Section 4.1.4.1 of this standard as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **2.1** ~~**4.1**~~ Each ~~Reliability Coordinator, Balancing Authority,~~ Transmission Owner shall create a list of BES company-specific Real-time reliability-related

~~[2] As used in this standard, the term "Operations Support Personnel" is defined as Individuals, as identified by the Reliability Coordinators, Balancing Authorities, Transmission Operators, or Transmission Owners, who perform outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms, in direct support of Real-time, reliability-related tasks performed by System Operators.~~

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	Transitions to the below Requirement in New Standard or Other Action	Proposed Standard PER-005-2
		tasks based on a defined and documented methodology. **1.1.2** Each Transmission ~~Operator, and~~Owner shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 2.1 each calendar year. **2.2** Each Transmission Owner shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 2.1. **2.3** Each Transmission Owner shall deliver training to its personnel identified in Applicability Section 4.1.4.1 of this standard according to its training program. ~~2.2~~2.4 Each Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement ~~R4~~R2 to identify ~~and implement~~ any needed changes to the training~~.~~ program and shall implement the changes identified.

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PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
	This requirement is new to PER-005-2.	**R5.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **5.1** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training.

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
	This requirement is new to PER-005-2.	~~6.~~ **R6.** ~~R5.~~ Each Generator Operator shall use a systematic approach to develop and ~~deliver~~implement training to its personnel ~~described~~identified in Applicability Section 4.1.5 of this standard, on ~~the impact of~~how their job function(s) ~~as it pertains to~~impact the reliable operations of the BES during normal and emergency operations. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning-]* **6.1.** Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement ~~R5~~R6 to identify and implement changes to the training.

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Compliance Operations

Draft Reliability Standard Compliance Guidance for PER-005-2
October 1, 2013

Introduction
The NERC Compliance department (Compliance) worked with the PER-005 standard drafting team (SDT) to review the proposed standard PER-005-2. The purpose of the review was to discuss the requirements of the proposed standard to obtain an understanding of its intended purpose and the evidence necessary to support compliance. The purpose of this document is to address specific questions posed by the PER SDT in order to aid in the drafting of the requirements and provide a level of understanding regarding evidentiary support necessary to demonstrate compliance.

While all compliance evaluations require levels of auditor judgment, participating in these reviews allows Compliance to develop training and approaches to support a high level of consistency in audits conducted by the Regional Entities. The following questions and answers are intended to assist the SDT in further refining the standard and to serve as a resource in the development of training for auditors.

PER-005-2 Questions

Question 1
For Requirement R1, what criteria would an auditor use to determine if a registered entity uses a systematic approach to training for developing its training program?

Compliance Response to Question 1
A systematic approach to training is a concept or methodology. This version of the standard retains flexibility for the entity to determine how it will apply the principles of this concept to develop and implement its training program. There are different models of systematic approaches to training, and the standard does not specify a certain model that should be used.

Consistent with FERC orders[1] and current Electric Reliability Organization's practices, to determine whether the entity used a systematic approach to training, an auditor will evaluate whether the entity's training program follows the principles below:

- Assess training needs (analysis)
- Conduct the training activity (design, develop and implement)
- Evaluate the training activity (evaluate the effectiveness of the training)

[1] See FERC Order No. 742 at P 25 and Order No. 693 at P 1380, 1382.

Further, as provided in the Application Guidelines attached to the standard, an auditor will assess whether the entity's training program, using a systematic approach to training:

1. determined the skills and knowledge needed to perform Real-time reliability-related tasks;
2. determined what training is needed to achieve those skills and knowledge;
3. determined if the trainee can perform the Real-time reliability-related task(s) acceptably in either a training or on-the-job environment; and
4. determined if the training is effective, and makes adjustments as necessary.

Question 2
In Requirement R3, does an entity that has one or more IROLs have 12 months to conduct simulation technology training when it obtains another IROL?

Compliance Response to Question 2
No, if an entity currently has one or more IROLs, it has the ability to conduct simulation technology. The 12 months applies only to an entity that did not have any IROLs but obtains an IROL for the first time.

Question 3
Is an auditor to assess a registered entity based on a systematic approach to training for the Operations Support Personnel referenced in Requirement R4?

Compliance Response to Question 3
Yes. An auditor will evaluate the entity's systematic approach to training with regard to the <u>impact of the Operations Support Personnel's job function</u> on the Real-time reliability-related tasks, <u>NOT on the Operations Support Personnel's ability to conduct these tasks</u>.

Operations Support Personnel are required to receive training only on how their job functions impact the Real-time reliability-related tasks. Therefore, modifying the assessment outlined above in Question #1, rather than:

- determined the skills and knowledge needed to perform Real-time reliability-related tasks;

the auditor will determine if the entity's systematic approach to training:

- determined the skills and knowledge needed to understand the impact of the job function(s) on the Real-time reliability-related tasks.

Question 4
Since Requirement R5 does not include the same parts as Requirement R1 to define a systematic approach to training, do entities have to adhere to the Requirement R1 parts for Requirement R5?

Compliance Response to Question 4
No. However, an auditor would verify that an entity followed a systematic approach to training. An auditor will evaluate this systematic approach to training with regard to the impact of the Generator Operator's (GOP's) job function(s) on the reliable operations of the BES during normal and emergency operations.

Consistent with FERC orders[2] and current Electric Reliability Organization's practices, to determine whether the entity used a systematic approach to training, an auditor will evaluate whether the entity's training program follows the principles below:

- Assess training needs (analysis)
- Conduct the training activity (design, develop and implement)
- Evaluate the training activity (evaluate the effectiveness of the training)

Further, as provided in the Application Guidelines attached to the standard, an auditor will assess whether the entity's training program, using a systematic approach to training:

1. determined the skills and knowledge needed to understand the impact of the Generator Operator's job function(s) on the reliable operations of the BES during normal and emergency operations.
2. determined what training is needed to achieve those skills and knowledge;
3. determined if the trainee can support the reliable operation of the BES during normal and emergency operations acceptably in either a training or on-the-job environment; and
4. determined if the training is effective, and makes adjustments as necessary.

Conclusion
Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training. Attachment A represents the version of the proposed standard requirements referenced in this document.

[2] See FERC Order No. 742 at P 25 and Order No. 693 at P 1380, 1382.

Compliance Operations

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October 1, 2013

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- Assess training needs (analysis)
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- Evaluate the training activity (evaluate the effectiveness of the training)

[1] See FERC Order No. 742 at P 25 and Order No. 693 at P 1380, 1382.

Further, as provided in the Application Guidelines attached to the standard, an auditor will assess whether the entity's training program, using a systematic approach to training:

1. determined the skills and knowledge needed to perform ~~or support~~ Real-time reliability-related tasks;
2. determined what training is needed to achieve those skills and knowledge;
3. determined if the trainee can perform ~~or support~~ the Real-time reliability-related task(s) acceptably in either a training or on-the-job environment; and
4. determined if the training is effective, and makes adjustments as necessary.

Question 2
In Requirement R3, does an entity that has one or more IROLs have 12 months to conduct simulation technology training when it obtains another IROL?

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No, if an entity currently has one or more IROLs, it has the ability to conduct simulation technology. The 12 months applies only to an entity that did not have any IROLs but obtains an IROL for the first time.

Question 3
Is an auditor to assess a registered entity based on a systematic approach to training for the Operations Support Personnel referenced in Requirement R4?

Compliance Response to Question 3
Yes. An auditor will evaluate the entity's systematic approach to training with regard to the impact of the Operations Support Personnel's job function on the Real-time reliability-related tasks, NOT on the Operations Support Personnel's ability to conduct these tasks.

Operations Support Personnel are required to receive training only on how their job functions impact the Real-time reliability-related tasks~~reliable operations of the Bulk Electric System (BES)~~. Therefore, modifying the assessment outlined above in Question #1, rather than:

- determined the skills and knowledge needed to perform Real-time reliability-related tasks;

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Since Requirement R5 does not include the same parts as Requirement R1 to define a systematic approach to training, do entities have to adhere to the Requirement R1 parts for Requirement R5?

Compliance Response to Question 4

No. However, an auditor would verify that an entity followed a systematic approach to training. An auditor will evaluate this systematic approach to training with regard to the impact of the Generator Operator's (GOP's) job function(s) on the reliable operations of the BES during normal and emergency operations.

Consistent with FERC orders[2] and current Electric Reliability Organization's practices, to determine whether the entity used a systematic approach to training, an auditor will evaluate whether the entity's training program follows the principles below:

- Assess training needs (analysis)
- Conduct the training activity (design, develop and implement)
- Evaluate the training activity (evaluate the effectiveness of the training)

Further, as provided in the Application Guidelines attached to the standard, an auditor will assess whether the entity's training program, using a systematic approach to training:

1. determined the skills and knowledge needed to understand the impact of the Generator Operator's job function(s) on the reliable operations of the BES during normal and emergency operations.
2. determined what training is needed to achieve those skills and knowledge;
3. determined if the trainee can support the reliable operation of the BES during normal and emergency operations acceptably in either a training or on-the-job environment; and
4. determined if the training is effective, and makes adjustments as necessary.

Conclusion

Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training. Attachment A represents the version of the proposed standard requirements referenced in this document.

[2] See FERC Order No. 742 at P 25 and Order No. 693 at P 1380, 1382.

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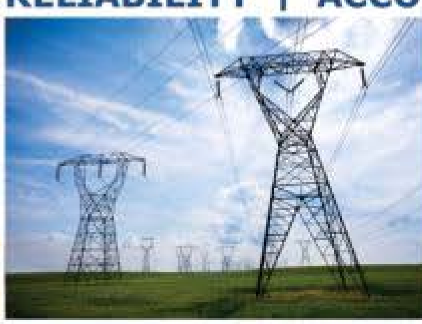
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

PER-005 Standards White Paper

July 18, 2013

RELIABILITY | ACCOUNTABILITY



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Executive Summary

A Personnel, Performance, Training, and Qualifications (PER) ad hoc group was formed to work with industry stakeholders to address five outstanding Federal Energy Regulatory Commission (FERC) directives.

The five outstanding FERC directives are as follows:

1. The Commission directs the Electric Reliability Organization (ERO) to develop specific requirements addressing the scope, content, and duration appropriate for Generator Operator (GOP) personnel (Order No. 693, P. 1363).
2. The Commission directs the ERO to develop a modification to PER-002-0 to require training of operations planning and operations support staff of Transmission Operators (TOPs) and Balancing Authorities (BAs) who have a direct impact on the reliable operation of the Bulk-Power System (BPS) (Order No. 693, P. 1372).
3. The Commission directs the ERO to consider personnel responsible for ensuring that critical reliability applications of the EMS, such as state estimator, contingency analysis and alarm processing packages, are available, up to date in terms of system data and produce useable results that can also have an impact on the reliable operation of the BPS (Order No. 693, P. 1373).
4. The Commission directs the ERO to consider the necessity of developing a similar implementation plan with respect to PER-005-1, Requirement R3.1 (Order No. 742, P. 24).
5. The Commission directs the ERO to develop through a separate reliability standards development project formal training requirements for local transmission control center operator personnel, and to develop a definition of "local transmission control center" in the standards development project (Order No. 742, P. 64).

The ERO is required to comply with FERC directives unless there is an equally effective and efficient method of addressing the reliability concern, or if there is evidence that the directive has been overcome by events or is no longer needed. These five directives were challenging due to the variance of industry opinion.

The PER informal development project reviewed the FERC directives, conducted outreach to industry stakeholders, and developed the pro forma standard. There were differing opinions from industry; some stated that the directives should be complied with while others stated there was sufficient justification as to why the directives were no longer needed. Although persuasive, the majority of the arguments as to why the directives were no longer needed had been addressed by FERC in prior orders as outlined in Appendix A. The discussion for each of the above directives are summarized as follows.

First, discussions were held regarding GOP dispatchers at a local control center. Through industry feedback, it became apparent that stakeholders needed a better understanding of the types of GOPs FERC was including in the directive. Initially it appeared that the directive would apply only to those GOPs that make independent decisions; however, FERC had addressed that narrow reading in FERC Order 693 P. 1359. The group's final determination was that even though GOPs at a local control center receive direction from their BA or TOP, those that take direction and then develop dispatch instructions for their plant operators are the specific GOPs the FERC Orders are attempting to capture. Therefore, the pro forma standard expanded the applicability in PER-005 to include these specific types of GOPs.

Second, the ad hoc group received strong feedback from industry that operations planning and operations support staff should not be included in the PER standard. Some of the reasons presented were: the System Operator is the one who impacts the Bulk Electric System (BES) and not the support personnel; support personnel do not make any Real-time decisions on BES operations; mandating training would distract training staff from the more critical functions of training System Operators; and this would create an administrative burden and would be too costly of a task on industry for the reliability protection it offers. Through further research it was determined that these were the same arguments previously presented and responded to by FERC in Orders 693 and 742 (see Appendix A). Therefore, as the informal development effort was not able to provide an argument that had not previously been rejected by FERC, the ad hoc group continued with the inclusion of support personnel in PER-005.

The third major discussion was in regard to the directive for the ERO to consider including personnel responsible for ensuring that critical reliability applications of the EMS, such as state estimator, contingency analysus and alarm processing packages, are available, up-to-date in terms of system data and produce useable results can also have an impact on the reliable operation of the BPS. Similar to the previously described discussions, many of the arguments had been addressed by FERC, but there was new evidence in this area. The argument for not including EMS personnel in the training standard at this time is based on a report provided by the Event Analysis Subcommittee (EAS). The EAS worked with the NERC Event Analysis (EA) staff to review the events that have been cause-coded since October 2010. The database has over 263 events; 208 of them were cause-coded to allow for trending and cluster analysis. The EAS and NERC EA staff queried the 208 events and looked in particular for cause codes that pertain to human errors and training that were less than adequate. The query produced 44 events that had the possibility for human errors or training being a contributing factor in the event. An analysis of those 44 events indicated that only 10 had human error or training as a contributing factor. Six of those 10 events were related to the loss of EMS or SCADA. Out of the six events, only two were deemed to be a training issue. Therefore, based on the information, the EAS and PER ad hoc group do not believe it is necessary at this time to require EMS support personnel to receive the level of training required of a BA, Reliability Coordinator (RC), and TOP by NERC standard PER-005.

Fourth, the ad hoc group and industry stakeholders agreed with the Commission on developing an implementation plan with respect to the simulation technology requirement. The ad hoc group determined that six months would suffice for an entity to become compliant with the simulation technology requirement in PER-005. No feedback has been received thus far from industry regarding this suggested change.

Last, the group addressed the local transmission control center directive by expanding the PER-005 applicability section to Transmission Owners (TO) and creating a standard-only definition. The group defined “local transmission control center” in the standard as *personnel in a transmission control center who operate a portion of the Bulk Electric System at the direction of its Transmission Operator.* This term will not become a part of the NERC Glossary of Terms used in NERC Reliability Standards at this time.

In summary, the PER ad hoc group created a pro forma standard (PER-005-2) extending the applicability to certain GOPs, support personnel, and TOs, excluding EMS support personnel. The 32-hour requirement has been removed as it is inherent to the systematic approach to training that training hours should be left up to each entity. The requirement for 32 hours of training meets the Paragraph 81 criteria for redundancy and was further not a results-based requirement and considered unnecessarily prescriptive. A new requirement R3.1 was created to develop the implementation of the simulation technology requirement.

The pro forma standard was drafted to provide maximum flexibility to industry while addressing the reliability concerns in the FERC directives. Under the pro forma standard, each entity has the ability to identify its reliability-related tasks, determine which of its personnel conduct those tasks, and determine the appropriate training and level of training for each employee. The ad hoc group understood the concerns from industry regarding the systematic approach to training, and each requirement has been left up to the entity to decide which approach should be used.

Purpose

The purpose of the PER-005 white paper is to provide the issues, rationale, and support for the revisions to the PER-005 standard. This white paper provides an explanation of how each of the FERC directives was addressed, including the issues that were raised during informal development and the rationale for proceeding or not proceeding with each. This paper will also provide technical justification and support for the revisions to the standard. The contents in this paper will provide the standard drafting team with the basis for the pro forma standard so they can begin the formal standard development process.

History of the PER-005 Informal Development

In February 2012, the North American Electric Reliability Corporation (NERC) Board of Trustees (Board) formed the Standards Process Input Group (SPIG) to address the widespread frustration with the duration of the standards development process.[1] In May 2012, SPIG submitted a report to the NERC Board recommending improving both the timeliness and quality of the standards. The process manual changes were approved by the Board in February 2013.[2] Since then, the Board issued a resolution requesting SPIG, the Members Representative Committee (MRC), NERC staff, and industry stakeholders to reform their standards development paradigm. Changes were integrated into the 2013–15 Reliability Standards Development Plan (RSDP) and Standards Committee (SC) Strategic Plan.[3]

The evolving standards process includes an informal development period in which NERC Standards developers work with an ad hoc group to gather information up front from industry regarding the FERC directives or other standards development project. There are three approaches to consider when addressing FERC directives: comply with the FERC directive, present an equally and effective alternative, or provide technical justification as to why the directive is no longer needed.

A PER ad hoc group was formed in January of 2013 to work with industry stakeholders to address five outstanding FERC directives. The ad hoc group addressed each directive through informal development, with the goal of filing a revised standard with FERC by December 31, 2013.

The PER ad hoc group held its first informal development meeting February 25–27, 2013, in Atlanta, Georgia. A small ad hoc group of industry subject matter experts (SMEs) representing RCs', BAs', GOPs', TOPs', and TOs' participated in discussions about the FERC directives and possible resolutions to address them. The ad hoc group created the first draft of a pro forma standard to address each directive. The ad hoc group conducted conference calls, workshops, and, to reach additional industry participants, two webinars: a March 15 informational webinar and an April 4 industry feedback webinar requesting feedback from industry regarding the PER ad hoc group suggestions. Multiple conference calls were held with the ad hoc group to keep all members aware of feedback received.

A second informal meeting was held April 22–23, 2013, at NERC's Atlanta office. The meeting was a continuation of the efforts of the first meeting with the addition of discussion on the information received through the outreach efforts. The ad hoc group discussed issues raised by industry and revised the pro forma standard based on that information. The group presented the revised pro forma standard to industry at the May 31 industry feedback webinar and other conference calls. During the webinar, polling questions were presented to participants, and 147 out of 323 people participated in the polling. The purpose of this polling was to gauge industry's support of the suggested PER-005 standard.

The last informal development meeting was held June 20–21, 2013 to develop the materials necessary to move into the formal process. This will entail submitting a Standard Authorization Request (SAR), the pro forma standard, input to a reliability standards audit worksheet (RSAW), an implementation plan, a mapping document, and a technical white paper to the NERC Standards Committee (SC).

A complete list of entities that participated during the informal development can be located in Appendix B.

[1] May 9, 2012 NERC Board minutes: http://www.nerc.com/gov/bot/Agenda%20Minutes%20and%20Highlights%20DL/2012/BOT_050912m_complete.pdf
[2] August 16, 2012 NERC Board minutes: http://www.nerc.com/gov/bot/Agenda%20Minutes%20and%20Highlights%20DL/2012/0-BOT08-12a-complete.pdf
[3] 2013–15 Reliability Standards Development Plan: http://www.nerc.com/pa/Stand/Standards%20Development%20Plan%20Library/2013-2015_RSDP_BOT_Approved_12-19-12.pdf

Outstanding FERC Directives and Technical Discussions

There are five outstanding FERC directives from Order 693[4] and Order 742.[5] Each directive was discussed in detail during the informal development stage, and below are the summaries of the discussions.

Applicability of the PER Standard to GOP Dispatchers

FERC Order 693 ¶ 1360-1361, 1363

P. 1360. We agree with FirstEnergy and others that some clarification is required regarding which generator operator personnel should be subject to formal training under the Reliability Standard. As noted above, a generator operator typically receives instructions from a balancing authority. Some generator operators are structured in such a way that they have a centrally-located dispatch center that receives direction and then develops specific dispatch instructions for plant operators under their control. For example, a balancing authority may direct a centrally-located dispatch center to deliver 300 MW to the grid, and the dispatch center would determine the best way to deliver that generation from its portfolio of units. In this type of structure, it is the personnel of the centrally located dispatch center that must receive formal training in accordance with the Reliability Standard. Plant operators located at the generator plant site also need to be trained but the responsibility for this training is outside the scope of the Reliability Standard.

P. 1361. Other generator operators may be structured in such a way that the dispatch center and the single generation plant are at the same site. In this structure as well, some personnel will perform dispatch activities while others are designated as plant operators. Again, it is the dispatch personnel that must receive formal training in accordance with the Reliability Standard. Plant operators also need to be trained but the responsibility for this training is outside the scope of the Reliability Standard.

P. 1363. Further, the Commission agrees with MidAmerican, SDG&E and others that the experience and knowledge required by transmission operators about Bulk-Power System operations goes well beyond what is needed by generation operators; therefore, training for generator operators need not be as extensive as that required for transmission operators. Accordingly, the training requirements developed by the ERO should be tailored in their scope, content and duration so as to be appropriate to generation operations personnel and the objective of promoting system reliability. Thus, in addition to modifying the Reliability Standard to identify generator operators as applicable entities, we direct the ERO to develop specific Requirements addressing the scope, content and duration appropriate for generator operator personnel.

FERC Order 742 ¶ 83-84

P. 83. EPSA requests clarification of several statements in the NOPR regarding the Order No. 693 directive related to expanding the applicability of the system operator training Reliability Standard to include certain generator operators. First, EPSA expresses concern that the NOPR discussion broadly addresses generator operator personnel in a way that could be construed as subjecting all generator operator personnel, regardless of the disposition of the generating unit and how it fits into the grid and the topology of the grid, to the system operator training requirements. Therefore EPSA seeks clarification that the Commission did not intend for the NOPR to expand the Order No. 693 directives. We confirm that we have not modified the scope of applicability of the Order No. 693 directive regarding generator operator training. As described in Order No. 693, the directive applies to generator operator personnel at a centrally-located dispatch center who receive direction and then develop specific dispatch instructions for plant operators under their control. Those generator operator personnel must receive formal training of the nature provided to system operators under PER-005-1. As clarified in Order No. 693, this group of personnel would include a generator operator's dispatch personnel where a single generator and dispatch center are located at the same site.

P. 84. EPSA also seeks clarification regarding the statement in the NOPR that: "[I]n the event communication is lost, the generator operator personnel must have had sufficient training to take appropriate action to ensure reliability of the Bulk-Power System." EPSA expresses concern that this statement suggests that if communication is lost with the grid operator, the generator operator must take unilateral action for which it requires training. EPSA notes that generator operators do not take such unilateral action nor do they have access to information to make such decisions. Therefore, EPSA asks the Id. Commission to make clear that while communication should be addressed in training requirements for centrally located generator operator dispatch employees, the Commission is not extending related responsibilities or training requirements to generator operator employees. We grant the requested clarification, and affirm that we are not modifying the Order No.

[4] *Mandatory Reliability Standards for the Bulk-Power System*, 118 FERC ¶ 61,218, FERC Stats. & Regs. ¶ 31,242 (Order No. 693), *order on reh'g, Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 (Order No. 693-A) (2007).

[5] FERC Order 742 PP 83-84

693 directive regarding training for certain generator operator dispatch personnel, nor are we expanding a generator operator's responsibilities.

Consideration of Directive

The PER ad hoc group considered all options (such as complying with the FERC directive, presenting an equally and effective alternative, or providing technical justification as to why the directive is no longer needed) when addressing GOPs at a centrally located dispatcher center who receive direction and then develop specific dispatch instructions for plant operators under their control.[6] The ad hoc group suggested a revised PER-005-1 standard that expands the applicability section to these specific GOPs, leaving it up to the entity to identify the reliability-related tasks its GOP personnel should be trained on. The group attempted to draw a bright line of GOPs that make independent decisions. Through subsequent discussions with FERC's OER staff, the group learned that this bright line, per the FERC orders, would not address the FERC directive. It appears that the intent of the FERC order is for GOPs at a control center who receive direction from their BAs or TOPs to develop specific dispatch instructions (not just that make an independent decision) for their plant operator. These are the people who should be captured under the standard. The group considered and suggested a revised PER-005 that extends applicability to these specific GOPs. The standard language allows the entity to decide which systematic approach to training should be used when training GOPs and includes coordination on training topics with the entity's RC, BA, TOP, and TO.

Technical Discussions

Many technical discussions were held regarding increasing the applicability of the PER standard to GOP dispatchers. The feedback provided in the list below are the reasons provided by industry as to why this directive was no longer needed for GOP dispatchers.

- All decisions that GOPs make that impact the reliability of the BES must be approved by the BA, TOP, or RC. Even in the case of an emergency situation, the GOP will not make any decisions until approved by the BA, TOP, or RC. It was further explained that there are GOPs that do not develop dispatch instruction and simply take the information received from the BA, TOP, or RC and relayed information directly to the plant operator.
- FERC limited emergency shutdowns of generation to occur at the plant level, not the dispatch level; at this time, the FERC order does not require plant operators to be trained.
- The NERC Functional Model was stated many times as a reason to show that GOP dispatchers follow the direction of the BA or TOP. The NERC Functional Model for GOPs states that GOPs in Real time:
    - Provide Real-time operating information to the Transmission Operators and the required Balancing Authority.
    - Adjust real and reactive power as directed by the Balancing Authority and Transmission Operators.[7]
- When a GOP would be making decisions that impact reliability, they are also registered as the BA or TOP.

Entities that agreed with GOPs being added to the standard made the following comments:

- Consider including some criteria regarding various sizes of generation like in CIP Version 5.
- Consider creating a new standard addressing GOP dispatchers.
- PPL Electric Utilities Corp., Louisville Gas and Electric Co., and PPL Generation LLC stated that the TOP or BA should prepare the GOP training modules since the goal is to ensure that dispatchers do what the TOP or BA wants in emergency situations.

The arguments provided above constitutes the same arguments that FERC rejected in Order Nos 693 and 742 (see Appendix A).

[6] FERC Order 742 P 83.
[7] NERC functional model: http://www.nerc.com/pa/Stand/Resources/Documents/FunctionalModelTechnicalDocumentV5Clean2009Dec1.pdf

FERC Order 693 P. 1393 clearly states that GOP dispatchers need to be trained using the systematic approach to training methodology.

> 1393. Accordingly, the Commission approves Reliability Standard PER-002-0. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to PER-002-0 through the Reliability Standards development process that: (1) identifies the expectations of the training for each job function; (2) develops training programs tailored to each job function with consideration of the individual training needs of the personnel; (3) expands the Applicability section to include (a) reliability coordinators, (b) local transmission control center operator personnel (as specified in the above discussion), **(c) generator operators centrally-located at a generation control center with a direct impact on the reliable operation of the Bulk-Power System and** (d) operations planning and operations support staff who carry out outage planning and assessments and those who develop SOLs, IROLs or operating nomograms for Real-time operations; **(4) uses the Systematic Approach to Training (SAT) methodology in its development of new training programs** and (5) includes the use of simulators by reliability coordinators, transmission operators and balancing authorities that have operational control over a significant portion of load and generation.[8]

The pro forma standard is written to require the use of a Systematic Approach to Training, but provides the entity the ability to determine the reliability-related tasks GOP dispatchers need to be trained on and the method of how the GOP dispatchers are trained.

There were discussions regarding whether training for GOPs should be in a separate standard, however the current PER-005 is a systematic approach to training based standard and thus it is logical to include the GOP dispatchers within the current standard.

Because the ad hoc group received the same feedback that was provided in FERC Order Nos. 693 and 742; the ad hoc group suggested expanding the applicability section in PER-005 to capture these certain GOP dispatchers using the systematic approach to training, which is left up to the entity.

Applicability of the PER Standard to Operations Planning and Operations Support Staff

FERC Order 693 ¶ 1366

P. 1366. As mentioned above, the Commission proposed in the NOPR to direct the ERO to develop a modification to PER-002-0 to require training of operations planning and operations support staff of transmission operators and balancing authorities who have a direct impact on the reliable operation of the Bulk-Power System.[9]

FERC Order 742 ¶ 82

P. 82. Associated Electric expressed concern that the NOPR definition of the "operations planning and operations support staff" who should receive training pursuant to the Order No. 693 directive is "broad and will encompass operations planning and operation support staff who engage in tasks that do not directly affect the reliable operation of the bulk electric system." The Commission clarifies that the scope of the Reliability Standard or modification to a Reliability Standard to address training for "operations planning and operations support staff" is limited by the qualifications stated in Order No. 693. Specifically, in Order No. 693, the Commission directed the ERO to develop a modification to PER-002-0 that extends applicability of the training requirements to the operations planning and operations support staff of transmission operators and balancing authorities. The Commission further clarified that such directive applies only to operations planning and operations support personnel who: "carry out outage coordination and assessments in accordance with Reliability Standards IRO-004-1 and TOP-002-2, and those who determine SOLs and IROLs or operating nomograms in accordance with Reliability Standards IRO-005-1 and TOP-004-0." The NOPR did not expand or alter the scope of this directive as set forth in Order No. 693.[10]

[8] FERC Order 693 P 1363.
[9] FERC Order 693 P 1366.
[10] FERC Order 742 P 82.

Consideration of Directive

The PER ad hoc group held multiple discussions regarding the impact that operations planning and operations support staff have on the BES. The feedback received from industry regarding this topic was deemed to be the same arguments provided in the NOPR and rejected in FERC Orders 693 and 742 (see Appendix A). Therefore, the ad hoc group group revised PER-005-1 to incorporate operations planning and support personnel in the standard.

Technical Discussions

Industry provided the following information regarding operations planning and operations support staff about why training is not needed for support personnel:

- Training will provide no reliability benefit because of the administrative burden on entities and costly burden on industry with uncertain benefits.
- Training will provide no reliability impact because System Operators make the final decision, and support personnel do not make Real-time decisions.
- Operations planning and planning support staff is ambiguous and should be clarified.
- Entities appear to already train their support personnel; therefore, it should not be a mandatory requirement.

Again, the feedback received was deemed to be the same arguments provided on FERC Orders 693 and 742; therefore, the ad hoc group revised PER-005-1 to incorporate operations planning and support personnel in the standard.

Applicability of the PER Standard to EMS Personnel
FERC Order 693 ¶ 1373

1373. In addition, the Commission is aware that the personnel responsible for ensuring that critical reliability applications of the EMS, such as state estimator, contingency analysis and alarm processing packages, are available, up-to-date in terms of system data and produce useable results can also have an impact on the Reliable Operation of the Bulk-Power System. Because these employees' impact on Reliable Operation is not as clear, we direct the ERO to consider, through the Reliability Standards development process, whether personnel that perform these additional functions should be included in mandatory training pursuant to PER-002-0.[11]

Consideration of Directive

Through discussion with industry, the ad hoc group determined that the report provided by the Event Analysis Subcommittee (EAS) serves as rationale for why EMS personnel should not be included in the PER standard at this time. The technical discussion section below provides more in-depth information regarding this determination.

Technical Discussions

As background, in Orders 693 and 742, the Commission directed NERC to consider whether there is a need to include EMS personnel in the training standard. In contrast to the directive for GOPs and operations support personnel, FERC did not conclude that it was necessary to include EMS personnel in the standard; rather, it directed the ERO to consider EMS personnel inclusion. The ad hoc group discussed the issue with industry stakeholders and concluded that the data does not support a need to include EMS personnel in the standard at this time.

Based on the information in the EMS report on cause-coded events, the EAS and PER ad hoc group do not believe it is necessary at this time to require EMS support personnel to receive the level of training required of a BA, Reliability Coordinator (RC), and TOP by NERC Reliability Standard PER-005.

Lastly, the EMS events will continue to be monitored, and if EMS events begin to indicate that training is a root or contributing cause, NERC will readdress inclusion of EMS personnel to PER-005. A request will be submitted to the Operating Committee (OC) to produce an EMS guideline for training EMS personnel.

[11] FERC Order 693 P 1373.

New Simulation Technology Implementation Plan
FERC Order 742 ¶ 24

With respect to EEI's comment regarding the effective date for entities that may become subject to the simulator training requirement in PER-005-1 R3.1, the Commission believes that this issue should be considered by the ERO. We note that, with respect to the Critical Infrastructure Protection (CIP) Reliability Standards, NERC has developed a separate implementation plan that essentially gives responsible entities some lead time before newly acquired assets must be in compliance with the effective CIP Reliability Standards. **We direct NERC to consider the necessity of developing a similar implementation plan with respect to PER-005-1, Requirement R3.1.**[12]

Consideration of Directive

The PER ad hoc group was in agreement that a new subrequirement 3.1 should be developed in the PER-005 standard to address entities that may become subject to simulator training in the future. Further discussion was held regarding the best time frame for entities to become compliant, and the general consensus was that six months is a reasonable timeframe. This information was presented at webinars, conferences, and face-to-face meetings, and no feedback was received regarding the implementation plan of simulator training for entities.

Technical Discussions

The ad hoc group did not receive feedback regarding the implementation plan for simulation technology.

Applicability of the PER Standard to Local Transmission Control Center
FERC Order 742 ¶ 64

Accordingly, we adopt our NOPR proposal and direct the ERO to develop through a separate Reliability Standards development project formal training requirements for local transmission control center operator personnel. Finally, given the numerous comments stating that term "local transmission control center" should be defined, we direct NERC to develop a definition of "local transmission control center" in the standards development project for developing the training requirements for local transmission control center operator personnel. We will not evaluate Associated Electric's proposed definition but, rather, leave it to the ERO to develop an appropriate definition that reflects the scope of local transmission control centers. The Commission will not opine on the appropriate definition of local transmission control center, as this definition can be addressed first using NERC's Reliability Standards Development Procedures.

Consideration of Directive

The ad hoc group considered whether to define local transmission control center in the NERC Glossary of Terms or create a standard-only definition. The group defined "local transmission control center" by extending the PER standard applicability to TOs and developing a definition that only applies to the PER standard. The suggested TO standard-only definition is *personnel in a transmission control center who operate a portion of the BES at the direction of its Transmission Operator*.

Technical Discussions

The group did not receive many comments regarding expanding formal training for local transmission control center operator personnel and defining local transmission control center. The group suggested a revision to PER-005-1 and created a standard-only definition of "local transmission control center."

Other Issues

Inconsistent usage of "each calendar year," "annual," and "at least every twelve months"

The PER ad hoc group changed all terms (such as "annual" and "at least every twelve months") to "each calendar year" due to "each calendar year" being better defined than the other two terms.

Definitions

System Operator

A SAR was submitted for GOPs to be removed from the System Operator definition. The ad hoc group removed the term and suggested a revised definition. The suggested definition is as follows: *An individual at a ~~c~~Control ~~c~~Center ~~(Balancing~~*

[12] FERC Order 742 P 64

~~*Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control*~~ *who operates or directs the operation of the Bulk ~~e~~Electric ~~s~~System in Real time.*

System Personnel

The term "System Personnel" was created as a standard-only definition for PER-005. The purpose of this definition is to capture certain applicable entities within the requirement instead of having to type each one out individually, multiple times, in a requirement. The suggested definition is as follows: *System Operators of a Reliability Coordinator, Transmission Operator, or Balancing Authority, and the Transmission Owner personnel described in the Applicability Section of this standard.*

Support Personnel

The term "System Personnel" was created as a standard-only definition for PER-005. The purpose of this definition is to capture certain applicable personnel within the requirement as a group for clarity. The suggested definition is as follows: *Individuals who carry out outage coordination and assessments, or determine SOLs, IROLs, or operating nomograms for Real-time operations.*

Conclusion

The informal development initiative provided key discussions regarding the outstanding PER FERC directives. This white paper encapsulates all of the components of what is needed for the Standards Committee to act on, discuss, and ultimately authorize the PER Standard Authorization Request.

Appendix A: Industry Arguments and FERC Responses

The below table shows initial arguments received from industry regarding FERC Orders 693 and 742. Also shown below are the arguments received from industry to-date that are deemed to be the same arguments found in both orders.

EXTENDING APPLICABILITY TO GOPS				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comment**
Clarification of Applicable GOPs Many commenters requested clarification as to which GOPs needed to be trained: 1) FirstEnergy supported GOP training but noted there was some confusion over the GOP classification, which is sometimes used to refer to dispatch personnel (or fleet operators at a control center) and other times used to refer to a plant or unit operator. FirstEnergy requested that the Commission direct NERC to recognize this distinction. 2) California PUC, Nevada Companies, Reliant, Dynegy, MISO, and Wisconsin Electric all presented various arguments as to why training should not be extended to plant operators. These entities did not argue against application of the training standard to dispatch personnel.	Order No. 693 at PP. 1350, 1352-54	FERC clarified that the directive to train GOPs only applies to GOPs located at a dispatch center that receives direction and then develops specific dispatch instructions for plant operators under their control. FERC clarified that plant operators need not be trained under the standard.	Order No. 693 at PP. 1360-61 See also Order No. 742 at P. 83.	

EXTENDING APPLICABILITY TO GOPS				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comment**
Decision-Making Arguments A number of commenters, including Xcel, argued that GOPs need not be trained because they do not make independent decision. They argued that GOPs simply take their direction from Transmission Operators, Balancing Authorities, and Reliability Coordinators, which limits their ability to exercise independent action impacting the reliability of the Bulk-Power System.	Order No. 693 at PP. 1351; 1354	FERC rejected this argument, stating: “Xcel and others oppose extending the applicability of PER-002-0 to generator operators, because they take directions from balancing authorities and others, which limits their ability to impact reliability. Although a generator may be given direction from the balancing authority, it is essential that generator operator personnel have appropriate training to understand those instructions, particularly in an emergency situation in which instructions may be succinct and require immediate action. Further, if communication is lost, the generator operator personnel should have had sufficient training to take appropriate action to ensure reliability of the Bulk-Power System. Thus, we direct the ERO to develop a modification to make PER-002-0 applicable to generator operators.	Order No. 693 at P. 1359	Decision-Making Arguments A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that all decisions that GOPs make that impact the BES must be approved by BA, TOP, or RC have the final say in the decisions being made.

EXTENDING APPLICABILITY TO GOPS				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comment**
No Reliability Benefit Argument Entergy, Xcel and Nevada companies further argued that generator operator training will provide limited benefit. Entergy further stated that that expanding the applicability to generator operators would provide little benefit to those personnel in the performance of their own functions, and could distract them from those functions.	Order No. 693 at P. 1351; 1357	FERC disagreed, stating that with the limitation of training to dispatch personnel, "the benefits to the Bulk-Power System will be maximized and the cost of formal training limited."	Order No. 693 at P. 1362	No Reliability Benefit Argument Creating training for GOPs will be costly and provide no benefit.
Scarcity of Resources and Cost Argument Entergy argued that training would be extremely costly and would divert necessary resources from more important reliability objectives. TAPS also opposed the expanded applicability, especially in the case of small systems, because it believes that the requirement would be costly with no benefits to reliability.	Order No. 693 at P. 1351; 1357	See above. FERC rejected these arguments, stating that the limitation to dispatch personnel would limit the cost of training.	Order No. 693 at P. 1362	Scarcity of Resources and Cost Argument A number of commenters, through verbal conversations and the chat feature during PER webinars stated that it will be costly to train GOPs. Smaller entities state it will be a costly to provide training to their GOPs and no major benefits will appear.
Scope of Training Arguments Many commenters discussed the scope of training for GOPs, arguing that the scope, content, and duration needs to be limited and tailored to their functions.	Order No. 693 at P. 1356	FERC agreed, stating that training for Generator Operators need not be as extensive as that required for Transmission Operators, and the training requirements developed by the ERO should be tailored in their scope, content, and duration so as to be appropriate to Generation Operations personnel and the objective of promoting system reliability.	Order No. 693 at P. 1363	Scope of Training Arguments Concerns about GOPs that do not develop dispatch instructions will be captured regardless.

EXTENDING APPLICABILITY TO GOPS				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comment**
Size Limitation Arguments APPA, TAPS, and the Process Electricity Committee requested a size limitation, arguing that while a generator plays an important role in the reliable operations of the Bulk Electric System, the Generator Operator takes commands from the Rransmission Operator, Balancing Authority, or Reliability Coordinator. Without a size limitation, the standard would require many small generators to enroll in a training program.	Order No. 693 at P. 1357	FERC responded that concerns regarding the need for a size limitation on Generator Operators should be satisfied by FERC's determination that the applicability of particular entities should be determined based on the ERO compliance registry criteria.	Order No. 693 at P. 1357	Size Limitation Arguments Comments received stated that a size limitation needs to be captured like CIP V5.
In response to the Order No. 742 NOPR, a number of commenters challenged the need for the directive.	Order No. 742 at P. 79	FERC rejected these arguments as beyond the scope of Order No. 742 and as collateral attacks on the ruling in Order No. 693 and refused to address the arguments again.	Order No. 742 at PP. 79, 81	

EXTENDING APPLICABILITY TO GOPS				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comment**
EPSA Clarification EPSA sought clarification regarding the statement in the NOPR, "[I]n the event communication is lost, the generator operator personnel must have had sufficient training to take appropriate action to ensure reliability of the Bulk-Power System." EPSA expressed concern that this statement suggests that if communication is lost with the grid operator, the Generator Operator must take unilateral action for which it requires training. EPSA notes that Generator Operators do not take such unilateral action, nor do they have access to information to make such decisions. EPSA asks the Commission to make clear that while communication should be addressed in training requirements for centrally located Generator Operator dispatch employees, the Commission is not extending related responsibilities or training requirements to Generator Operator employees.	Order No. 742 at P. 84	FERC granted the requested clarification and affirmed that it did not modify the Order No. 693 directive regarding training for certain Generator Operator dispatch personnel, nor expand a Generator Operator's responsibilities.	Order No. 742 at P. 84	

EXTENDING APPLICABILITY TO SUPPORT PERSONNEL				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comments**
No Reliability Benefit EEI states that the extension of the applicability to "operations support personnel" could result in a dramatic expansion of industry training requirements with uncertain benefits to system reliability.	Order No. 693 at P. 1368	FERC stated that because it is limiting training of support personnel to those who carry out outage coordination and assessments and those who determine SOLs and IROLs or operating nomograms, the directive is limited to those with a direct impact on reliability.	Order No. 693 at P. 1374	No Reliability Benefit A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that expanding PER-005 applicability to support personnel will capture a variety of people who do not impact the BES.
TOP makes decision Entergy argued that it is unnecessary to require all staff supporting the Transmission Operator to be trained in the Transmission Operator's Reliability Standards responsibilities, because as long as the supporting personnel work under the direction of a NERC-certified Transmission Operator, there is no need for duplicative training for supporting personnel.	Order No. 693 at P. 1370	FERC stated that because it is limiting training of support personnel to those who carry out outage coordination and assessments and those who determine SOLs and IROLs or operating nomograms, the directive is limited to those with a direct impact on reliability.	Order No. 693 at P. 1374	TOP makes decision A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that decisions are made by the NERC-Certified System Operators.
Administrative Burden APPA expressed concern about expanding the applicability to operations planning and operations support staff, especially if the Commission adopts its proposed interpretation of the Bulk Electric System, because this would become quite onerous for small utilities.	Order No. 693 at P. 1368	FERC limited the scope of what support personnel must be trained and clarified that training for support personnel should be tailored to the functions they perform and need not be trained to the same extent as Transmission Operators.	Order No. 693 at P 1375	Administrative Burden A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that this would be a huge administrative burden regarding the SAT process.

EXTENDING APPLICABILITY TO SUPPORT PERSONNEL				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comments**
<u>Directive is Ambiguous</u> Wisconsin Electric argued that the Commission's proposal does not address how to identify the operations planning and operations support personnel who would be subject to the Reliability Standard and how to develop compliance measures for them. It contended that the proposed modification is ambiguous and should not be implemented. Northern Indiana also argued that the terms "operations planning" and "operations support staff" should be clarified.	Order No. 693 at P. 1368	FERC clarified that the support personnel who need to be trained are those who carry out outage coordination and assessments in accordance with Reliability Standards IRO-004-1 and TOP-002-2, and those who determine SOLs and IROLs or operating nomograms in accordance with Reliability Standards IRO-005-1 and TOP-004-0. FERC said that because the reliability impact of EMS personnel are unclear, it directed NERC to consider whether such personnel need to be trained.	Order No. 693 at P. 1372	<u>Directive is Ambiguous</u> A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that "operations planning" and "operations support" are too broad.
<u>Scope of Training</u> Entergy commented that if training is required, it should focus on the functions operations planning and operations support staff must perform, not on the functions that others perform.	Order No. 693 at P. 1370	FERC clarified that training for support personnel should be tailored to the functions they perform and need not be trained to the same extent as transmission operators.		<u>Scope of Training</u>

EXTENDING APPLICABILITY TO SUPPORT PERSONNEL				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comments**
No Reliability Benefit In response to the Order No. 742 NOPR, a number of commenters challenged the need for the directive. For example, Associated Electric urged the Commission to direct NERC to adopt a definition of "operations planning" and "operations support staff" that more narrowly identifies those personnel who will be subject to the training standard. Associated Electric stated that the directive in Order No. 693 is broad and will encompass operations planning and operation support staff who engage in tasks that do not directly affect the reliable operation of the Bulk Electric System. GSOC and GTC do not support expanding the applicability of the PER-005-1 training requirements to any other personnel and argue that time spent expanding training requirements to other personnel will take away from their job of supporting their operating personnel—a use of time and resources that could actually decrease reliability.	Order No. 742 at P. 80	FERC rejected these arguments as beyond the scope of Order No. 742 and as collateral attacks on the ruling in Order No. 693 and refused to address the arguments again.	Order No. 742 at PP. 79, 81	No Reliability Benefit A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that tasks performed by support personnel do not directly affect the BES. Support personnel may guide, but do not operate.

Appendix B: Entity Participants

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

Table 2: Entity Participation in PER Informal Development

ACES Power	CPS Energy	IESO	NV Energy	Southern Co.
AECI	CSU	IMPA	OGE	STEC
AEP	CWLP	Integry Group	OMU	Sunflower
AES	DC PUD	IREA	ORU	Sycamore
ALCOA	Detroit Renewable	ISO-NE	OUC	TID
Alliant Energy	Direct Energy	ITC	OXY	Tri-State G&T
Ameren	Dominion	KCPL	PacifiCorp	TVA
AMP Partners	DTE Energy	KUA	PEPCO	
APS	Duke Energy	LCEC	PGE	
ATC	Dynegy	LCRA	PGN	**Regional Entities**
Austin Energy	Energy GRP	LES	PJM	FRCC
Blackhills Corp	Entergy	LGE-KU	PNM	MRO
BPA	EP Electric	Luminant	PNM Resources	NPCC
Brazos Electric	ERCOT	MGE	PPL	RFC
Brownsville PUD	Essential Power LLC	MidAmerican	Seattle Power & Light	SERC
CAISO	Exelon Corp	Minnkota Power	Sempra Utilities	SPP
CB Power	FMTN	MISO Energy	Sharyland	TRE
Center Point Energy	FPL	NaturEner	SMEPA	WECC
Chelan PUD	GASOC	NIPSCO	SMMPA	
City of Tacoma	GC Pud	Northwestern	SMUD	
City Utilities	Hydro Manitoba	NRECA	Snohomish PUD	
Cleco Corporation	Hydro-Quebec	NU	South Westgen	

Table 3: Presentations and Events

NERC Operating Committee	FRCC Compliance Workshop
NERC EAS	WECC Operations Training Subcommittee
NERC Standards and Compliance Workshop	WECC Standing Committees
NERC News	TRE Standards Discussion Forum

Proposed Timeline for the
Project 2010-01 Standard Drafting Team (SDT)

Anticipated Date	Location	Event
July 2013	-	SC Authorizes SAR and Pro Forma Standard for Posting
July 2013		Conduct Nominations for Project 2012-05 SDT
July 2013	-	Post SAR and Pro Forma standard for 45-Day Comment Period
August 2013	-	Conduct Ballot
September 2013	-	45-Day Comment Period and Ballot Closes
September 2013	San Francisco	PER Standard Drafting Team Face to Face Meeting to Respond to Initial Comments and Make Possible Revisions
October 7, 2013	Webinar	PER Industry Webinar
November 21-22 2013	Atlanta, GA	PER Standard Drafting Team Face to Face Meeting to Respond to Initial Comments and Make Possible Revisions
December 4, 2013 – January 17, 2014	-	45-Day Comment Period and Ballot
January 21-23, 2014	Miami, FL	PER Standard Drafting Team Face to Face Meeting to Respond to Initial Comments and Make Possible Revisions
January 2014	-	Conduct Final Ballot
February 2014	-	NERC Board of Trustees Adoption
February 2014 (Targeted)	-	NERC Files Petition with the Applicable Governmental Authorities

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

DRAFT Reliability Standard Audit Worksheet[1]

PER-005-2 – Operations Personnel Training

This section to be completed by the Compliance Enforcement Authority.

Audit ID:	Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity:	Registered name of entity being audited
NCR Number:	NCRnnnnn
Compliance Enforcement Authority:	Region or NERC performing audit
Compliance Assessment Date(s)[2]:	Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method:	Audit
Names of Auditors:	Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1	X								X			X[3]			
R2												X[3]			
R3	X								X			X[3]	X		
R4	X								X			X[3]	X		
R5	X								X			X[3]			
R6				X[4]											

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.
[3] Applicable to Transmission Owner that has personnel, excluding field switching personnel, who can act independently to operate or direct the operation of its Bulk Electric System transmission facilities in Real-time.
[4] Applicable to Generator Operator that has dispatch personnel at a centrally located dispatch center who receive directions from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control. These personnel do not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions, without making any modifications.

Subject Matter Experts

Identify Subject Matter Expert(s) responsible for this Reliability Standard. (Insert additional rows if necessary)

Registered Entity Response (Required):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement a training program for its System Operators as follows:

1.1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology.

1.1.1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 1.1 each calendar year.

1.2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 1.1.

1.3. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall deliver training to its System Operator according to its training program.

1.4. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall implement the changes identified.

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence of using a systematic approach to develop and implement a training program, as specified in Requirement R1.

M1.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection its methodology and its BES company-specific Real-time reliability-related task list, with the date of the last review, as specified in Requirement R1 part 1.1 and part 1.1.1.

M1.2 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection training materials, as specified in Requirement R1 part 1.2.

M1.3 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection System Operator training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R1 part 1.3.

M1.4 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation of its training program each calendar year, as specified in Requirement R1 part 1.4.

Definition of System Operator

An individual at a Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System in Real-Time.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[5]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
(part 1.1) List of BES company-specific Real-time reliability-related tasks and documented methodology for developing task list.
(part 1.1.1) Evidence, such as a memo, meeting minutes, or dated task list, of review of the task list each calendar year.
(part 1.2) Samples of training materials as requested by the auditor.
(part 1.3) An organization chart or other list identifying all System Operator and the BES company-specific Real-time reliability-related tasks they perform. List of training delivered and attendance logs for a sample of training sessions requested by the auditor.
(part 1.4) Evidence, such as a memo, meeting minutes, or other information as specified in M1.4 demonstrating that the review of the training program occurred every calendar year and a list of needed changes to the training program based on the review.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

[5] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Compliance Assessment Approach Specific to PER-005-2, R1

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process.
	(part 1.1) and (part 1.1.1) Verify entity's list of BES company-specific Real-time reliability-related tasks, related methodology, and evidence of review each calendar year. Ensure list of BES company-specific Real-time reliability-related tasks was created pursuant to their methodology.
	(part 1.2) Review sample of training materials provided to determine if they support the BES company-specific Real-time reliability-related task list.
	(part 1.3) Agree specific System Operators, as selected by the auditor from the organization chart, back to attendance logs for training that was delivered related to the BES company-specific Real-time reliability-related tasks they perform pursuant to its program.
	(part 1.4) Review evidence that the review of the training program occurred every calendar year. Review list of changes to the training program based on the review and examine training materials, or other documents, to gain reasonable assurance that changes identified were implemented into the training program.

Note to Auditor: The training staff do not have to be internal staff of the entity.

Auditors are not to assess an entity's use of a systematic approach to training against any specific framework such as the ADDIE model. Rather, t~~While t~~he sub-requirements for Requirement R1 address the elements of a systematic approach consistent with FERC orders No.742 at P25 and No. 693 at P1380 and P1382~~,~~. ~~a~~An auditor will evaluate whether the entity's overall training program follows the principles below:

- Assess training needs (analysis)
- Conduct the training activity (design, develop and implement)
- Evaluate the training activity (evaluate the effectiveness of the training)

Auditors are to interpret a calendar year as January 1 to December 31.

Changes such as simply rewording for clarification, that do not affect the task performance or knowledge requirements, are not considered a modified task.

It is acceptable to group tasks under a job position, and then identify the System Operators that perform that job position, in lieu of assigning tasks to each individual System Operator.

~~The nature and extent of audit procedures applied related to this requirement will vary depending on certain risk factors to the Bulk Electric System. In general, more extensive audit procedures will be applied where risks to the Bulk Electric System are higher based on compliance with this requirement.~~

~~Based on the assessment of risk, as described above, specific audit procedures applied for this requirement may range from exclusion of this requirement from audit scope to the auditor reviewing training records for an entity's entire population of System Operators.~~

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each Transmission Owner shall use a systematic approach to develop and implement a training program for its personnel identified in Applicability Section 4.1.4.1 of this standard as follows: ~~[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]~~

2.1. Each Transmission Owner shall create a list of BES company-specific Real-time reliability-related tasks based on a defined and documented methodology.

2.1.1. Each Transmission Owner shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 2.1 each calendar year.

2.2. Each Transmission Owner shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 2.1.

2.3. Each Transmission Owner shall deliver training to its personnel identified in Applicability Section 4.1.4.1 of this standard according to its training program.

2.4. Each Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement R2 to identify any needed changes to the training program and shall implement the changes identified.

M2. Each Transmission Owner shall have available for inspection evidence of using a systematic approach to training to develop and implement a training program for its applicable personnel, as specified in Requirement R2.

M2.1 Each Transmission Owner shall have available for inspection its methodology and its BES company-specific Real-time reliability-related task list, with the date of the last review, as specified in Requirement R2 part 2.1.

M2.2 Each Transmission Owner shall have available for inspection training materials, as specified in Requirement R2 part 2.2.

M2.3 Each Transmission Owner shall have available for inspection training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R2 part 2.3.

M2.4 Each Transmission Owner shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation of its training program each calendar year, as specified in Requirement R2 part 2.4.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the

appropriate page, are recommended.

Evidence Requested[6]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
(part 2.1) List of BES company-specific Real-time reliability-related tasks and documented methodology for developing task list.
(part 2.1.1) Evidence, such as a memo, meeting minutes, or dated task list, of review of the task list each calendar year.
(part 2.2) Samples of training materials as requested by the auditor.
(part 2.3) An organization chart or other list identifying all personnel applicable to Requirement R2 and the tasks they perform. List of training delivered and attendance logs for a sample of training sessions requested by the auditor.
(part 2.4) Evidence, such as a memo, meeting minutes, or other information as specified in M2.4 demonstrating that the review of the training program occurred every calendar year and a list of needed changes to the training program based on the review.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PER-005-2, R2

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process.
	(part 2.1) and (part 2.1.1) Verify entity's list of BES company-specific Real-time reliability-related tasks, related methodology, and evidence of review each calendar year. Ensure list of BES company-specific

[6] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

	Real-time reliability-related tasks was created pursuant to their methodology.
	(part 2.2) Review sample of training materials provided to determine if they support the BES company-specific Real-time reliability-related task list.
	(part 2.3) Agree specific System Operator, as selected by the auditor from the organization chart, back to attendance logs for training that was delivered related to the BES company-specific Real-time reliability-related tasks they perform pursuant to its program.
	(part 1.4) Review evidence that the review of the training program occurred every calendar year. Review list of changes to the training program based on the review and examine training materials, or other documents, to gain reasonable assurance that changes identified were implemented into the training program.

Note to Auditor: The training staff do not have to be internal staff of the entity.

Auditors are not to assess an entity's use of a systematic approach against any specific framework such as the ADDIE model. Rather, consistent with FERC orders No.742 at P25 and No. 693 at P1380 and P1382.~~, a~~An auditor will evaluate whether the entity's overall training program follows the principles below:

- Assess training needs (analysis)
- Conduct the training activity (design, develop and implement)
- Evaluate the training activity (evaluate the effectiveness of the training)

~~While the sub-requirements for Requirement R2 address the elements of a systematic approach consistent with FERC orders No.742 at P25 and No. 693 at P1380 and P1382, an auditor will evaluate whether the entity's overall training program follows the principles below:~~

- ~~Assess training needs (analysis)~~
- ~~Conduct the training activity (design, develop and implement)~~
- ~~Evaluate the training activity (evaluate the effectiveness of the training)~~

Auditors are to interpret a calendar year as January 1 to December 31.

Changes such as simply rewording for clarification, that do not affect the task performance or knowledge requirements, are not considered a modified task.

It is acceptable to group tasks under a job position, and then identify the personnel that perform that job position, in lieu of assigning tasks to each individual.

~~The nature and extent of audit procedures applied related to this requirement will vary depending on certain risk factors to the Bulk Electric System and the auditor's assessment of management practices specific to this requirement. In general, more extensive audit procedures will be applied where risks to the Bulk Electric System are higher and management practices are determined to be less effective.~~

~~Based on the assessment of risk and internal controls, as described above, specific audit procedures applied for this requirement may range from exclusion of this requirement from audit scope to the auditor reviewing training records for an entity's entire population of applicable personnel.~~

Auditor Notes:

R3 Supporting Evidence and Documentation

R3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1 or Requirement R2 part 2.1

3.1. Within six months of a modification or addition of a BES company-specific Real-time reliability-related task, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its personnel identified in Requirement R1 or Requirement R2 to perform the new or modified BES company-specific Real-time reliability-related tasks identified in Requirement R1 part 1.1 and Requirement R2 part 2.1.

M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence to show that it verified the capabilities of each of its personnel identified in Requirement R1 and Requirement R2 assigned to perform each of the BES company-specific Real-time reliability-related task identified under Requirement R1 part 1.1 or Requirement R2 part 2.1. This evidence may be documents such as records showing capability to perform BES company-specific Real-time reliability-related tasks with the employee name and date; supervisor check sheets showing the employee name, date, and BES company-specific Real-time reliability-related task completed; or the results of learning assessments.

M3.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner shall have available for inspection evidence that it verified the capabilities of applicable personnel to perform new or modified BES company-specific Real-time reliability-related tasks within 6 months of a modification or addition of a BES company specific Real-time reliability-related task.

Registered Entity Response (Required):

Question: Has entity modified or added a Real-time reliability-related task, since the Requirement R1 part 1.1 or Requirement R2 part 2.1 task lists were initially developed? ☐ Yes ☐ No

If so, when was task added, or what task was modified and when?

Include additional information regarding the Question in gray area below, including the type of response and format of the response requested, as appropriate.
Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.

Registered Entity Response to General Compliance with this Requirement (Required):

Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[7]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
(R3) Documentation, such as provided in M3, evidencing selected personnel's capabilities to perform the BES company-specific Real-time reliability-related tasks selected by the auditor based on tasks identified under Requirements R1 part 1.1 and R2 part 2.1.
(part 3.1) A list of modifications or additions to BES company-specific Real-time reliability-related tasks. Entity's previous list of BES company-specific Real-time reliability-related tasks. Documentation, such as provided in M3, evidencing selected personnel's capability to perform modified or new tasks, as selected by the auditor.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PER-005-2, R3

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R3) For a sample of personnel and BES company-specific Real-time reliability-related tasks, review documentation verifying the personnel's capabilities to perform the task at least one time.
	(part 3.1) Determine if entity added any BES company-specific Real-time reliability-related tasks, which can be gleaned from auditor's knowledge of the entity's history and operations based on experience and specific facts discovered during the audit scoping process as confirmed with the entity, the entity's own assertions, a comparison of the current task list with a previous task list (also see parts 1.4 and 2.4), or any combination thereof. For a sample of additions, examine dated documentation to verify each of its

[7] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

	personnel's capabilities occurred within six months of the modification or addition.

Note to Auditor: Note entity's response to above Questions.

~~The nature and extent of audit procedures applied related to this requirement will vary depending on certain risk factors to the Bulk Electric System. In general, more extensive audit procedures will be applied where risks to the Bulk Electric System are higher based on compliance with this requirement.~~

~~Based on the assessment of risk, as described above, specific audit procedures applied for this requirement may range from exclusion of this requirement from audit scope to the auditor reviewing training records for an entity's entire population of applicable personnel.~~

Auditor Notes:

R4 Supporting Evidence and Documentation

R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs) or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1 and Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES.

4.1. A Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not previously meet the criteria of Requirement R4 shall comply with Requirement R4 within 12 months of meeting the criteria.

M4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that personnel identified in Requirement R1 and Requirement R2completed training that includes the use of simulation technology, as specified in Requirement R4.

M4.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that personnel identified in Requirement R1 and Requirement R2 completed training that included the use of simulation technology, as specified in Requirement R4, within 12 months of meeting the criteria of Requirement R4.

Registered Entity Response (Required):
Question: Has entity gone from a situation of not having previously met the criteria of Requirement R4 to having to comply with it? ☐ Yes ☐ No

Include additional information regarding the Question in gray area below, including the type of response and format of the response requested, as appropriate.
Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[8]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
(R4) Documentation such as training materials and attendance logs, evidencing emergency operations training using simulation technology replicating the operational behavior of the BES, for a sample of applicable personnel selected by the auditor.
(part 4.1) A dated list of IROLs acquired in accordance with Requirement R4.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PER-005-2, R4
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R4) Review training materials and interview entity personnel to verify that the entity trained applicable personnel using simulation technology that replicated the operational behavior of the BES. Agree specific applicable personnel, as selected by the auditor from the organization chart (evidence for parts 1.3 and

[8] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

	2.3), back to attendance logs for training using simulation technology.
	(part 4.1) Determine if entity obtained an IROL as outlined in Requirement R4, which can be gleaned from auditor's knowledge of the entity's history and operations based on experience and specific facts discovered during the audit scoping process as confirmed with the entity, the entity's own operating records and assertions, or any combination thereof. For a sample of applicable personnel, examine dated training materials and attendance records to verify training occurred within 12 months.

Note to Auditor: Note entity's response to above Questions.

Only applicable to entities that have operational authority or control over Facilities with IROLs, or protection systems or operating guides to mitigate IROL violations.

12 month window to execute simulation training only applies to entities newly acquiring IROLs (per above), since entities with existing IROLs should already have access to simulation technology.

~~The nature and extent of audit procedures applied related to this requirement will vary depending on certain risk factors to the Bulk Electric System. In general, more extensive audit procedures will be applied where risks to the Bulk Electric System are higher based on compliance with this requirement.~~

~~Based on the assessment of risk, as described above, specific audit procedures applied for this requirement may range from exclusion of this requirement from audit scope to the auditor reviewing training records for an entity's entire population of applicable personnel.~~

Auditor Notes:

R5 Supporting Evidence and Documentation

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact on those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1.

5.1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence that Operations Support Personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training. Documentation of training shall include employee name and date of training.

M5.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation each calendar year, as specified in Requirement R5 part 5.1.

Definition of Operations Support Personnel
Individuals, who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms, in direct support of Real-time, operations of the Bulk Electric System.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[9]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
(R5) A list of the entity's Operations Support Personnel with a description of their role within the organization along with the BES company-specific Real-time reliability-related tasks they impact. Evidence that that training was developed using a systematic approach, and a list of training that has been delivered for Operations Support Personnel along with attendance logs for a sample of training sessions requested by the auditor.
(part 5.1) Evidence, such as a memo, meeting minutes, or other information as specified in M5 demonstrating the review of the training occurred every calendar year and a list of needed changes to the training program based on the review.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

[9] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Compliance Assessment Approach Specific to PER-005-2, R5

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R5) Interview entity to understand their process for determining training requirements for Operations Support Personnel. Select a sample of Operations Support Personnel and training materials for training specific to Operations Support Personnel. Vouch a sample of personnel back to attendance logs and review the sample of training materials.
	(part 5.1) Review evidence that the review of the training occurred every calendar year. Review list of changes to the training based on the review and examine training materials, or other documents, to gain reasonable assurance that changes identified were implemented into the training.

Note to Auditor: An auditor will evaluate the entity's systematic approach with regard to the impact of the Operations Support Personnel's job function on the BES company-specific Real-time reliability-related tasks.

Operations Support Personnel are required to receive training only on how their job functions impact the Real-time reliability-related tasks, not on the Operations Support Personnel's ability to conduct these tasks. Therefore, the auditor will only determine if the entity's systematic approach determined the skills and knowledge needed to understand the impact of the job function(s) on the BES company-specific Real-time reliability-related tasks.

Auditors are not to assess an entity's use of a systematic approach against any specific framework such as the ADDIE model. Rather, consistent with FERC orders No.742 at P25 and No. 693 at P1380 and P1382.~~, a~~An auditor will evaluate whether the entity's overall training program follows the principles below:

- Assess training needs (analysis)
- Conduct the training activity (design, develop and implement)
- Evaluate the training activity (evaluate the effectiveness of the training)

~~Consistent with FERC orders No.742 at P25 and No. 693 at P1380 and P1382 and current Electric Reliability Organization's practices, to determine whether the entity used a systematic approach, an auditor will evaluate whether the entity's training program follows the principles below:~~

- ~~Assess training needs (analysis)~~
- ~~Conduct the training activity (design, develop and implement)~~
- ~~Evaluate the training activity (evaluate the effectiveness of the training)~~

Auditors are to interpret a calendar year as January 1 to December 31.

~~The nature and extent of audit procedures applied related to this requirement will vary depending on certain risk factors to the Bulk Electric System. In general, more extensive audit procedures will be applied where risks to the Bulk Electric System are higher based on compliance with this requirement.~~

~~Based on the assessment of risk, as described above, specific audit procedures applied for this requirement may range from exclusion of this requirement from audit scope to the auditor reviewing training records for~~

~~an entity's entire population of Operations Support Personnel~~.

Auditor Notes:

R6 Supporting Evidence and Documentation

R6. Each Generator Operator shall use a systematic approach to develop and implement training to its personnel identified in Applicability Section 4.1.5 of this standard, on how their job function(s) impact the reliable operations of the BES during normal and emergency operations.

6.1 Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R6 to identify and implement changes to the training.

M6. Each Generator Operator shall have available for inspection evidence that its applicable personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training. Documentation of training shall include employee name and date of training.

M6.1 Each Generator Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation each calendar year, as specified in Requirement R6 part 6.1.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[10]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
(R6) A list of personnel in accordance with Applicability Section 4.1.5 and 4.1.5.1 of this Reliability Standard with a description of their role and position within the organization. Evidence that training was developed using a systematic approach, and a list of training delivered for such personnel along with attendance logs for a sample of training sessions requested by the auditor.
(part 6.1) Evidence, such as a memo, meeting minutes, or other information as specified in M6.1 demonstrating the review of the training occurred every calendar year and a list of needed changes to the training program based on the review.

[10] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PER-005-2, R6

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R6) Interview entity to understand their process for determining training requirements for applicable personnel. Select a sample of personnel and training materials for training specific to their impact on the reliable operations of the BES during normal and emergency operations. Agree a sample of personnel to attendance logs and review the sample of training materials.
	(part 6.1) Review evidence that the review of the training occurred every calendar year. Review list of changes to the training based on the review and examine training materials, or other documents, to gain reasonable assurance that changes identified were implemented into the training.

Note to Auditor: An auditor will evaluate the systematic approach with regard to the impact of the Generator Operator's job function(s) on the reliable operations of the BES during normal and emergency operations.

Auditors are not to assess an entity's use of a systematic approach against any specific framework such as the ADDIE model. Rather, consistent with FERC orders No.742 at P25 and No. 693 at P1380 and P1382~~,~~. ~~a~~An auditor will evaluate whether the entity's overall training program follows the principles below:

- Assess training needs (analysis)
- Conduct the training activity (design, develop and implement)
- Evaluate the training activity (evaluate the effectiveness of the training)

~~Consistent with FERC orders No.742 at P25 and No. 693 at P1380 and P1382 and current Electric Reliability Organization's practices, to determine whether the entity used a systematic approach, an auditor will evaluate whether the entity's training program follows the principles below:~~

- ~~Assess training needs (analysis)~~
- ~~Conduct the training activity (design, develop and implement)~~
- ~~Evaluate the training activity (evaluate the effectiveness of the training~~)

A calendar year is January 1 through December 31.

~~The nature and extent of audit procedures applied related to this requirement will vary depending on certain risk factors to the Bulk Electric System. In general, more extensive audit procedures will be applied where risks to the Bulk Electric System are higher based on compliance with this requirement.~~

~~Based on the assessment of risk, as described above, specific audit procedures applied for this requirement may range from exclusion of this requirement from audit scope to the auditor reviewing training records for an entity's entire population of Generator Operators.~~

Auditor Notes:

Revision History

Version	Date	Reviewers	Revision Description
1	12/17/2013	NERC Compliance, Standards	New Document
2	1/27/2014	NERC Compliance, Standards	Revisions based on RSAW feedback received during comment period for PER-005-2.

Violation Risk Factor and Violation Severity Level Justifications

PER-005-2 – Operations Personnel Training

This document provides the Standard Drafting Team's (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PER-005-2 – Operations Personnel Training. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project. To review the VRFs and VSLs for PER-005-2, please go to the standards webpage (PER-005-2 Standard Webpage link).

NERC Criteria - Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

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

Lower Risk Requirement

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

FERC Violation Risk Factor Guidelines

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

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

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

• Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

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

Guideline (3) – Consistency among Reliability Standards

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

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

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

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

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

NERC Criteria - Violation Severity Levels

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

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

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

FERC Order of Violation Severity Levels

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

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

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

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

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

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

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

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

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VRF Justification – PER-005-2 Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is consistent with the NERC VRF definition. Requirement R1 requires that Reliability Coordinators (RCs), Balancing Authorities (Bas) and Transmission Operators (TOPs) train their System Operators and prescribes that they use a systematic approach when developing a training program for their System Operators. While a violation of this requirement is unlikely to directly lead to Bulk Electric System instability, separation, or a cascading sequence of failures, a failure to adequately train System Operators could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. Additionally, the Medium VRF is consistent with the prior version of Requirement R1 in the currently effective version of the standard, PER-005-1. PER-005-1 will be retired upon the effective date of PER-005-2.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: While the Blackout report identified training for operator personnel to have a severe VRF, it is unlikely that failure to use a systematic approach to develop and implement training for System Operators would directly lead to bulk power system instability, separation or cascading failures or hinder restoration to a normal condition. Therefore, the Medium VRF assignment is appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The Medium VRF is applicable to all parts of Requirement R1 and is consistent with other requirements in the Reliability Standard.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with the prior version of Requirement R1 in the currently effective version of the standard, PER-005-1. PER-005-1 will be retired upon the effective date of PER-005-2.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs:

	The VRF is consistent with the NERC definition because developing a training program for System Operators could be conducted without the use of a systematic approach. Therefore, a violation of this requirement is unlikely to lead to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This VRF has one objective – to develop and implement training using a systematic approach - and thus does not co-mingle multiple objectives. It appropriately has one VRF for its single objective.

VSL Justification – PER-005-2 Requirement R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines, the VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered by the proposed Medium VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

Guideline 2a: The single VSL assignment category for “Binary” Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirements.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justification – PER-005-2 Requirement R2	
Proposed VRF	**Medium**

NERC VRF Discussion	A VRF of Medium is consistent with the NERC VRF definition. Requirement R2 prescribes a certain process for Transmission Owners to use when developing a training program for its local control center operator personnel, and training could be conducted without the use of a systematic approach. Therefore, a violation of this requirement is unlikely to lead to BES instability, separation, or a cascading sequence of failures. While a failure to adequately train Transmission Owners could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES, the requirement for applicable entities to use a systematic approach to develop and implement a training program requires that each applicable entity: • Assess training needs (analysis) • Conduct the training activity (design, develop and implement) • Evaluate the training activity (evaluate the effectiveness of the training) Thus, failure to adequately train System Operators would be a failure to use a systematic approach to training.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: While the Blackout report identified training for operator personnel to have a severe VRF, in this case it is not probable that failure to use a systematic approach to develop and implement training for Transmission Owners would lead to bulk power system instability, separation or cascading failures or hinder restoration to a normal condition. Therefore, the Medium VRF assignment was appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The VRF is applicable for all of the parts within Requirement R2 and thus are consistent with one another. Requirement R2 contains the similar requirements as Requirement R1, Requirement R5 and Requirement R6, but applies to Transmission Owners. Therefore, to be consistent within the Reliability Standard, the VRF for Requirement R2 reflects the VRFs of Requirement R1, Requirement R4, Requirement R5 and Requirement R6. Further, the Medium VRF is consistent with Requirement R1 of the FERC approved prior version of the standard, PER-005-1. PER-005-1 will be retired upon the effective date of PER-005-2.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with Requirement R1 of the FERC approved prior version of the standard, PER-005-1. PER-005-1 will be retired upon the effective date of PER-005-2. Although this is a new requirement to PER-005-2, it requires the same actions for a different functional entity.

FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition because developing a training program for Transmission Owners could be conducted without the use of a systematic approach. Therefore, a violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This VRF has one objective – to develop and implement training for local control center operators using a systematic approach - and thus does not co-mingle multiple objectives. It appropriately has one VRF for its single objective.

VSL Justification – PER-005-2 Requirement R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines, the VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary.

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

VRF Justification – PER-005-2 Requirement R3	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of high is consistent with the NERC VRF definition. Requirement R3 requires Reliability Coordinators, Balancing Authorities, Transmission Operators and Transmission Owners to verify the capabilities of their System Operators or local control center operators. If such personnel are not able to complete their tasks, the

	situation could lead to BES instability, separation or cascading failures or hinder restoration to a normal condition. Additionally, the High VRF is consistent with the requirement in the currently effective version of the standard, PER-005-1, addressing verification of System Operator personnel capabilities. PER-005-1 will be retired upon the effective date of PER-005-2.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: The High VRF is consistent with the Blackout Report listing of operator personnel training as a critical impact area. The Blackout report listed training as a mechanism to have competent personnel in operator positions; Requirement R3 mandates that applicable entities verify the capabilities of its personnel identified in Requirement R1 and Requirement R2 to perform assigned tasks. Failure for personnel to perform assigned reliability-related tasks could lead to bulk power system instability, separation or cascading failures or hinder restoration to a normal condition.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The VRF for all of the parts within Requirement R3 are consistent with one another.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The High VRF is consistent with other requirements containing actions identified in the Blackout report.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition because it is important that personnel are capable of performing each of the BES company-specific Real-time reliability-related tasks. A violation of this Requirement could lead to BES instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This VRF has one objective – to verify the capabilities of an entity's applicable personnel to perform reliability-related tasks – and thus does not co-mingle multiple objectives. It appropriately has one VRF for its single objective.

VSL Justification – PER-005-2 Requirement R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines, the VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the	The VSL level is consistent with the requirement.

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

VRF Justification – PER-005-2 Requirement R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is consistent with the NERC VRF definition. The need to conduct emergency operations training is inherent under Requirement R1 and Requirement R4 requires that entities use simulation technology to conduct such training. It is unlikely that failure to provide training using simulation technology would lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Specifically, if an entity did not provide emergency operations using a simulator an entity is still required to conduct other forms of operations training under Requirement R1 and Requirement R2, as emergency operations would be considered a Real-time reliability-related task.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: While the Blackout report identified training for operator personnel to have a severe VRF, in this case it is difficult to argue that a failure to use a simulator, virtual technology, or other technology that replicates the operational behavior of the BES will directly lead to instability, separation, or Cascading. NERC staff believes that the Medium VRF assignment was appropriate.

FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: All of the parts within Requirement R4 are consistent with one another and are commensurate with Requirements R1 and Requirement R2.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with Requirement R4 of the FERC approved prior version of the standard, PER-005-1. PER-005-1 will be retired upon the effective date of PER-005-2.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition because it is important to provide emergency operations training using simulation technology. A violation of this Requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This VRF has one objective – to provide emergency operations training using technology that replicates the operational behavior of the BES – and thus does not co-mingle multiple objectives. It appropriately has one VRF for its single objective.

VSL Justification – PER-005-2 Requirement R4	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines, the VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering	The current level of compliance is not lowered with the proposed VSL.

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

Not on A Cumulative Number of Violations	

VRF Justification – PER-005-2 Requirement R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is consistent with the NERC VRF definition. Requirement R5 prescribes a certain process for applicable entities to use when developing training for its Operations Support Personnel A violation of this requirement is unlikely to lead BES instability, separation, or a cascading sequence of failures. However, a failure to adequately train Operations Support Personnel on the impact of their job functions on Real-time reliability-related tasks could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: While the Blackout report identified training for operator personnel to have a severe VRF, it is unlikely that failure to use a systematic approach to develop and implement training for Operations Support Personnel would lead to bulk power system instability, separation or cascading failures or hinder restoration to a normal condition. Therefore, the Medium VRF assignment was appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The VRF is applicable to all of the parts within Requirement R5 and thus are consistent with one another. Requirement R5 contains the similar requirements as Requirement R1, Requirement R2, and Requirement R6, but applies to Operations Support Personnel. Therefore, to be consistent within the Reliability Standard, the VRF for Requirement R5 should reflect the VRFs of Requirement R1, Requirement R2 and Requirement R6. Further, the Medium VRF is consistent with Requirement R1 of the FERC approved prior version of the standard, PER-005-1. PER-005-1 will be retired upon the effective date of PER-005-2.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards:

	The Medium VRF is consistent with Requirement R1 of the FERC approved prior version of the standard, PER-005-1 to use a systematic approach to training. PER-005-1 will be retired upon the effective date of PER-005-2. Although this is a new requirement to PER-005-2, it requires the similar actions for a different functional entity.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition because developing a training program for Operations Support Personnel could be conducted without the use of a systematic approach. Therefore, a violation is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This VRF has one objective – to develop and implement training for its Operations Support Personnel using a systematic approach – and thus does not co-mingle multiple objectives. It appropriately has one VRF for its single objective.

VSL Justification – PER-005-2 Requirement R5	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines, the VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.

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

VRF Justification – PER-005-2 Requirement R6	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is consistent with the NERC VRF definition. Requirement R6 prescribes a certain process for Generator Operators to use when developing training for certain dispatch personnel. A violation of this requirement is unlikely to lead to BES instability, separation, or a cascading sequence of failures. However, a Generator Operator's failure to adequately train its applicable personnel on the impact of their job functions on the reliable operations of the BES could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: While the Blackout report identified training for operator personnel to have a severe VRF, it is unlikely that failure to use a systematic approach to develop and implement training for applicable Generator Operator personnel would lead to bulk power system instability, separation or cascading failures or hinder restoration to a normal condition. Therefore, the Medium VRF assignment was appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The VRF is applicable for all of the parts within Requirement R6 and thus are consistent with one another. Requirement R6 contains the similar requirements as Requirement R1, Requirement R2, and Requirement R5, but applies to Generator Operator applicable personnel. Therefore, to be consistent within the Reliability Standard, the VRF for Requirement R6 should reflect the VRFs of Requirement R1, Requirement R2, and Requirement R5. Further, the Medium VRF is consistent with Requirement R1 of the FERC approved prior version of the standard, PER-005-1 to use a systematic approach to training. PER-005-1 will be retired upon the effective date of PER-005-2. Although this is a new requirement to PER-005-2, it requires the similar actions for a different functional entity.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with Requirement R1 of the FERC approved prior version of the standard, PER-005-1. PER-005-1 will be retired upon the effective date of PER-005-2.Guideline 5 – There is no co-mingling factors. Therefore the standard is not watered down.

FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition because developing a training program for Generator Operators could be conducted without the use of a systematic approach. Therefore, a violation is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This VRF has one objective – to develop and implement training for applicable Generator Operator personnel using a systematic approach – and thus does not co-mingle multiple objectives. It appropriately has one VRF for its single objective.

VSL Justification – PER-005-2 Requirement R6	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines, the VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL level is consistent with the requirement.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on cumulative number of violations.

Standards Announcement Reminder

Project 2010-01 Training (PER)
PER-005-2

An Additional Ballot and Non-Binding Poll is now open through January 17, 2014

Now Available

An additional ballot for **PER-005-2** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels is now open through **8 p.m. Eastern on Friday, January 17, 2014.**

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

Instructions for Commenting

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

Next Steps

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

Standards Development Process

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

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

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Standards Announcement

Project 2010-01 Training (PER)
PER-005-2

Comment Period: December 4, 2013 – January 17, 2014

Upcoming:
Additional Ballot and Non-Binding Poll: January 8-17, 2014

Now Available

A 45-day formal comment period for **PER-005-2** is now open through **8 p.m. Eastern on Friday, January 17, 2014.**

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

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Friday, January 17, 2014.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

An additional ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted as outlined above.

Standards Development Process

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Standards Announcement

Project 2010-01 Training (PER)
PER-005-2

Comment Period: December 4, 2013 – January 17, 2014

Upcoming:
Additional Ballot and Non-Binding Poll: January 8-17, 2014

Now Available

A 45-day formal comment period for **PER-005-2** is now open through **8 p.m. Eastern on Friday, January 17, 2014.**

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

Instructions for Commenting
A formal comment period is open through **8 p.m. Eastern on Friday, January 17, 2014.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps
An additional ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted as outlined above.

Standards Development Process
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Standards Announcement

Project 2010-01 Training (PER-005-2)

Additional Ballot and Non-Binding Poll Results

Now Available

An additional ballot for **PER-005-2 – Operations Personnel Training** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Tuesday, January 21, 2014.**

The standard achieved a quorum and sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Ballot Results	Non-Binding Poll Results
Quorum: 79.12%	Quorum: 76.07%
Approval: 74.63%	Supportive Opinions: 71.63%

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

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments do not show the need for significant revisions, the standard will then proceed to a final ballot.

Standards Development Process

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

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

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Ballot Results	
Ballot Name:	Project 2010-01 Training PER-005-2
Ballot Period:	1/8/2014 - 1/21/2014
Ballot Type:	**Additional Ballot**
Total # Votes:	307
Total Ballot Pool:	388
Quorum:	**79.12 % The Quorum has been reached**
Weighted Segment Vote:	74.63 %
Ballot Results:	**The ballot has closed.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	105	1	61	0.735	22	0.265	0	3	19
2 - Segment 2	9	0.8	6	0.6	2	0.2	0	1	0
3 - Segment 3	86	1	54	0.771	16	0.229	0	0	16
4 - Segment 4	31	1	16	0.727	6	0.273	0	0	9
5 - Segment 5	89	1	43	0.694	19	0.306	0	3	24
6 - Segment 6	52	1	34	0.773	10	0.227	0	2	6
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	5	0.1	1	0.1	0	0	0	0	4
9 - Segment	2	0	0	0	0	0	0	0	2

9									
10 - Segment 10	9	0.8	6	0.6	2	0.2	0	0	1
Totals	**388**	**6.7**	**221**	**5**	**77**	**1.7**	**0**	**9**	**81**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren Comments)
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	COMMENT RECEIVED
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate		
1	Entergy Transmission	Oliver A Burke	Abstain	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	

1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Negative	COMMENT RECEIVED
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid supports NPCC's comments.)
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	SUPPORTS THIRD PARTY COMMENTS - (See NPCC RSC comments)
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	COMMENT RECEIVED
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool Standards Review Team)
1	Omaha Public Power District	Doug Peterchuck		
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Negative	SUPPORTS THIRD PARTY COMMENTS - (Consolidated Edison Co. of, NY)
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	

1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid)
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Texas Municipal Power Agency	Brent J Hebert		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Negative	COMMENT RECEIVED
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	COMMENT RECEIVED
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Negative	COMMENT RECEIVED
3	American Public Power Association	Nathan Mitchell	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blue Ridge Electric	James L Layton	Negative	COMMENT RECEIVED
3	Bonneville Power Administration	Rebecca Berdahl	Negative	COMMENT RECEIVED
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	

3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Garland	Ronnie C Hoeinghaus		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	COMMENT RECEIVED
3	City Water, Light & Power of Springfield	Roger Powers	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	COMMENT RECEIVED
3	Consumers Energy Company	Gerald G Farringer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dean Fox)
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster		
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC comments)
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Comments)
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (Julie Dyke)
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Electric Utility	David Anderson		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)

3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Consolidated Edison Co. of, NY)
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River project)
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Matt Beilfuss)
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy Company	Tracy Goble	Negative	COMMENT RECEIVED
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Fort Pierce Utilities Authority	Cairo Vanegas	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED

4	Integrys Energy Group, Inc.	Christopher Plante		
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	North Carolina Electric Membership Corp.	John Lemire	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments of Seminole Electric Cooperative submitted by Seminole's Corporate Compliance Department)
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	COMMENT RECEIVED
4	Wisconsin Energy Corp.	Anthony Jankowski		
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren comments)
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Arkansas Electric Cooperative Corporation	Brent R Carr		
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Negative	COMMENT RECEIVED
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	COMMENT RECEIVED
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	COMMENT RECEIVED
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dean Fox)
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs		

5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer	Negative	SUPPORTS THIRD PARTY COMMENTS - (LCRA Transmission Services Corporation)
5	Luminant Generation Company LLC	Rick Terrill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Luminant Energy Company LLC)
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC comments)
5	NextEra Energy	Allen D Schriver	Affirmative	
5	NiSource	Huston Ferguson		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Occidental Chemical	Michelle R DAntuono		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	PacifiCorp	Ryan Millard		
5	Portland General Electric Co.	Matt E. Jastram	Negative	COMMENT RECEIVED
5	PowerSouth Energy Cooperative	Tim Hattaway		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	SUPPORTS THIRD PARTY COMMENTS - (USBR)

5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Feather Power Project	Kathryn Zancanella		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Abstain	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS - (Matt Beilfuss)
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Alabama Electric Coop. Inc.	Ron Graham		
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	COMMENT RECEIVED
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Negative	COMMENT RECEIVED
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Luminant Energy	Brenda Hampton	Negative	COMMENT RECEIVED
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	

6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS - (Julie Dyke NIPSCO)
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments will be submitted by Seminole's Corporate Compliance department)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Edward C Stein		
8		Merle Ashton		
8		Roger C Zaklukiewicz		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
10	Florida Reliability Coordinating Council	Linda Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Negative	COMMENT RECEIVED
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Account Log-In/Register

Non-Binding Poll Results

Project 2010-01 PER-005-2

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2010-01 Training PER-005-2
Poll Period:	1/8/2014 - 1/21/2014
Total # Opinions:	267
Total Ballot Pool:	351
Summary Results:	76.07% of those who registered to participate provided an opinion or an abstention; 71.63% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinion	Comments
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES Power Marketing)
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid)
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper	Affirmative	

NERC

1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	COMMENT RECEIVED
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate		
1	Entergy Transmission	Oliver A Burke	Abstain	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA) - (NRECA)
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency (FMPA))
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Lower Colorado River Authority	Martyn Turner	Negative	COMMENT RECEIVED
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	

1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid supports NPCC's comments.)
1	Nebraska Public Power District	Cole C Brodine	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski		
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	COMMENT RECEIVED
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool Standards Review Team)
1	Omaha Public Power District	Doug Peterchuck		
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Negative	SUPPORTS THIRD PARTY COMMENTS - (Consolidated Edison Co. of, NY)
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	

1	Salt River Project	Robert Kondziolka	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson		
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Texas Municipal Power Agency	Brent J Hebert		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	COMMENT RECEIVED
2	Southwest Power Pool, Inc.	Charles H. Yeung	Abstain	
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Abstain	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	COMMENT RECEIVED
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	

3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Garland	Ronnie C Hoeinghaus		
3	City of Tallahassee	Bill R Fowler	Negative	COMMENT RECEIVED
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	COMMENT RECEIVED
3	Consumers Energy Company	Gerald G Farringer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dean Fox)
3	CPS Energy	Jose Escamilla		
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C Esquerre		
3	Florida Power Corporation	Lee Schuster		
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Abstain	

3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC Comments)
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Comments)
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS - (Julie Dyke)
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Consolidated Edison Co. of, NY)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
3	Santee Cooper	James M Poston	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	

3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller		
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Clewiston	Kevin McCarthy		
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Negative	COMMENT RECEIVED
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke		
4	North Carolina Electric Membership Corp.	John Lemire	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (Seminole Electric Cooperative comments submitted by Seminole's Corporate Compliance Department)
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	

4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony Jankowski		
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Arkansas Electric Cooperative Corporation	Brent R Carr		
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	BC Hydro and Power Authority	Clement Ma		
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Negative	COMMENT RECEIVED
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	COMMENT RECEIVED
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	COMMENT RECEIVED
5	Consumers Energy Company	David C Greyerbiehl	Negative	SUPPORTS THIRD PARTY COMMENTS - (Dean Fox)
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown		
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	

5	Hydro-Québec Production	Roger Dufresne	Abstain	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer	Negative	SUPPORTS THIRD PARTY COMMENTS - (LCRA Transmission Services Corporation)
5	Luminant Generation Company LLC	Rick Terrill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Luminant Energy Company LLC)
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC comments)
5	NextEra Energy	Allen D Schriver	Affirmative	
5	NiSource	Huston Ferguson		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Occidental Chemical	Michelle R DAntuono		
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Orlando Utilities Commission	Richard K Kinas		

5	PacifiCorp	Bonnie Marino-Blair		
5	Pattern Gulf Wind LLC	Grit Schmieder-Copeland		
5	Portland General Electric Co.	Matt E. Jastram	Negative	COMMENT RECEIVED
5	PowerSouth Energy Cooperative	Tim Hattaway		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	SUPPORTS THIRD PARTY COMMENTS - (ericka doot, USBR)
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Abstain	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Feather Power Project	Kathryn Zancanella		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Abstain	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Negative	COMMENT RECEIVED
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn		
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	

6	Con Edison Company of New York	David Balban	Negative	COMMENT RECEIVED
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS - (Julie Dyke NIPSCO)
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Kelly Cumiskey		
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Abstain	
6	Salt River Project	Steven J Hulet	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	

6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (Comments will be provided by Seminole's Corporate Compliance department)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
8		Edward C Stein		
8		Roger C Zaklukiewicz		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		
10	Florida Reliability Coordinating Council	Linda Campbell		
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Negative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Abstain	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	

Individual or group. (47 Responses)
Name (30 Responses)
Organization (30 Responses)
Group Name (17 Responses)
Lead Contact (17 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (7 Responses)
Comments (47 Responses)
Question 1 (37 Responses)
Question 1 Comments (40 Responses)
Question 2 (40 Responses)
Question 2 Comments (40 Responses)

Individual
Lee Layton
Blue Ridge Electric
No
The team has made a good start at limiting the scope of the Standard to transmission operators. However, the Standard still references TO's without an explanation of why TO's should be included in this Standard. Some TO's have no impact on the BES and this standard is over-reaching.
No
Eliminate references to TO's and instead reference transmission operators.
Group
Northeast Power Coordianting Council
Guy Zito
No
The proposed System Operator definition could apply to a segment of Operators that, while located in a Control Center, only operate BES elements at the direction of NERC Certified operators. The term ‘operate’ is too broad and may unnecessarily include personnel who do not perform the System Operator function. A System Operator is responsible for the Reliable Operation of the BES, and performs this function by controlling or directing the operation of the BES in Real-time. The currently proposed definition would expand the applicability of Requirement 1 to Operators that are not responsible for independently performing real time reliability tasks. These Operators only perform switching of BES elements at the direction of certified Operators. In order to eliminate this unintended applicability, consider that the word “independently” be inserted immediately prior to the word “operates” in the System

Operator definition. The definition would then become: “An individual at a Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who independently operates, or directs, the operation of the Bulk Electric System in Real-time.” The Drafting Team must consider how emergencies are handled. For example, if there is a situation in the field that involves the safety of the public or industry personnel, there are entities that allow field personnel to do emergency switching. By the definition they would be considered System Operators.
No
The term ‘operate’ is too broad. In Order No. 742 at P62, FERC clarified its understanding that local control center personnel “exercise control over a significant portion of the Bulk-Power System under the supervision of the personnel of the registered transmission operator.” This draft was to address the local transmission owners, however the SDT chose to use the term ‘operate,’ whereas Order 742 used ‘control.’ This term should be added to the NERC Glossary. Suggest rewording the Applicability as follows to be in accordance with the FERC understanding: 4.1.4 Transmission Owner that has: 4.1.4.1 Personnel, excluding field switching personnel, who can act independently to control or direct the operation of the Transmission Owner’s Bulk Electric System Transmission facilities in Real-time Suggest deleting Requirement R5. EMS personnel have been excluded because the data does not support their inclusion. From page 4 of the White Paper (July 15, 2013): “The argument for not including EMS personnel in the training standard at this time is based on a report provided by the Event Analysis Subcommittee (EAS). The EAS worked with the NERC Event Analysis (EA) staff to review the events that have been cause-coded since October 2010. The database has over 263 events; … [and] only two were deemed to be a training issue. Therefore, based on the information, the EAS and PER ad hoc group do not believe it is necessary at this time to require EMS support personnel to receive the level of training required of a BA, Reliability Coordinator (RC), and TOP by NERC standard PER-005.” A data analysis would show that Operations Support Personnel should be excluded as well. If only two (of the 263 events) were deemed to be a training issue, then how can there be a reliability gap with the training of Operation Support Personnel? If it is decided to keep Requirement R5, suggest using the appropriate language to make it conform with the preceding. The applicability to Transmission Owner should be removed from the standard. This sets a precedent of applying “operator” requirements to entities that are “owners.” This could expand applicability for TOs into additional standards, such as those dealing with issuing Operating Instructions, or owning and operating Control Centers. As outlined by FERC directive in Order 742, these TOs are either following predefined procedures or specific directions from a TOP and should not be considered to have independent operation, control or authority of the BES and should not have applicability to standards related to the operation of the BES. If the Transmission Owner applicability remains, “facility” in 4.1.4.1 should be capitalized. The applicability to Transmission Owners is only to their “Bulk Electric System transmission facilities” and the definition of Facility is “[a] set of electrical equipment that operates as a single Bulk Electric System Element.” Since both the definition of Facility and the applicability are limited to the BES they are synonymous and not capilizing the term only adds confusion. If the applicability to Transmission Owner is retained, recommend removing

Transmission Owners from R4 which requires entities who control facilities with IROLs to use simulation technology during emergency operations training. In Order 693, FERC directed NERC to require Reliability Coordinators, Transmission Operators, and Balancing Authorities to use simulation technology during emergency operations training. The requirement to use simulation technology does not make sense for Transmission Owners who do not have a wide area view of the BES and do not determine actions necessary to relieve IROLs. Transmission Owners should not be required to use simulation technology during emergency operations training because, like Generator Operators, they will receive operational instructions from Transmission Operators, Balancing Authorities or Reliability Coordinators during emergencies. The Applicability section for Generator Operator, Section 4.1.5.1 should use the term “Control Center” as the NERC definition of Control Center, “One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of:... 4) a Generator Operator for generation Facilities at two or more locations” is consistent with the idea of a “centrally located dispatch center” as outlined in the applicability section. The requirement for Transmission Owners to develop a training program using the systematic approach to training in R2 will result in training that is better tailored to individual Transmission Owner BES reliability related tasks. There is a disconnect between PER-005-2 and the draft COM-002-4 Applicability. The COM-002-4 draft is applicable to DP’s while PER-005-2 is applicable to the TO local control center personnel. It is incongruous that the COM standard expects these operating instructions to go to DP but PER-005 expects them to go to TO’s. What is the measure of “independently” in Applicability 4.1.4.1. “Independently” of what? Extend the second HIGH VSL condition for R6 by adding “to develop and implement training for its personnel” after “systematic approach” to conform with the language used in R6.
Group
Arizona Public Service
Janet Smith
Yes
Yes
Individual
John Brockhan
CenterPoint Energy Houston Electric LLC.
Yes
CenterPoint Energy agrees with the revisions to Operations Support Personnel and System Operator definitions.
Yes

CenterPoint Energy would like to thank the PER-005-2 Standard Drafting Team and appreciates the SDT's time and effort dedicated in the development of this standard, in engaging the industry, and incorporating industry feedback. CenterPoint Energy suggests that the SDT consider the following revisions to align the Measures with the requirement language. In M2 the words "to training" as it is used in, "…evidence using a systematic approach to training to develop and implement a training program…" should be deleted and the revised M2 would read "…evidence using a systematic approach to develop and implement a training program…" CenterPoint believes this revision would align the measure with the requirement language regarding the Standards recent shift of the use of "systematic approach to training" versus training that is in accordance with its "systematic approach".
Individual
Brian Reich
Idaho Power Co.
Yes
Yes
Individual
c
d
Agree
ssssw
Individual
Kathleen Goodman
ISO New England Inc.
Yes
No
Suggestion rewording R5 to better line up with R1 and the R5 Measures: "R5. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner Operator shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on the impact of how their job task(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. 5.1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Operator shall create a list of Operations Support Personnel Tasks that impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. 5.2 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Operator shall review, and update if

necessary, its list of Operations Support Personnel Tasks identified in part 5.1 each calendar year."
Individual
Martyn Turner
LCRA Transmission Services Corporation
No
The definition of Operations Support personnel is too vague. During previous WebEx's on the definition, members of the standards drafting team explained that the purpose of the definition was to limit the scope of any training to those tasks performed by support personnel to tasks that relate to, or are a critical component of, R-R tasks performed by System Operators. This new definition goes far beyond that: "…in direct support of real-time operations...". That language opens the scope of this new standard much wider than ever before. It is unmanageable in its current definition as it is far too broad. There are numerous tasks a System Operator performs in real-time that are not Reliability-Related and are supported by various other control room staff, yet this new definition does not differentiate between the two. The standards drafting team MUST work on this definition until it is near perfect because it is critical to defining what type of, and how much training for these support personnel will be required.
No
See Question 1
Group
US Bureau of Reclamation
Erika Doot
Yes
The Bureau of Reclamation (Reclamation) agrees with the drafting team's decision to remove Transmission Owners from R5 to clarify that Operations Support Personnel are involved in current day or next-day outage planning, or SOL, IROL, or nomogram development for Reliability Coordinators, Balancing Authorities, or Transmission Operators.
No
(1) Reclamation requests that the drafting team remove Transmission Owners from R4, which requires entities who control facilities with IROLs to use simulation technology during emergency operations training. In Order 693, FERC directed NERC to require reliability coordinators, transmission operators, and balancing authorities to use simulation technology during emergency operations training. The requirement to use simulation technology does not make sense for Transmission Owners who do not have a wide area view of the BES and do not determine actions necessary to relieve IROLs. Transmission Owners should not be required to use simulation technology during emergency operations training because, like Generator Operators, they will receive operational instructions from Transmission Operators, Balancing Authorities or Reliability Coordinators during emergencies. Therefore, Reclamation

believes the proposed requirement would result in high costs with little reliability benefit. The requirement for Transmission Owners to develop a training program using the systematic approach to training in R2 will result in emergency operations training that is better tailored to individual Transmission Owner training needs. (2) Reclamation suggests that the drafting team update the Guidelines and Technical basis section to refer to both R1 and R2 because both requirements now reference using a systematic approach to develop and implement a training program based on BES company-specific Real-time reliability related tasks.
Individual
Sheldon Hunter
Sunflower Electric
Agree
ACES
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
Yes
Yes
Individual
Brett Holland
Kansas City Power & Light
Agree
SPP - Robert Rhodes
Individual
x
x
Agree
Individual
Shirley Mayadewi
Manitoba Hydro
Yes
Yes

Although Manitoba Hydro is in general agreement with the standard, we have the following comments: (1) M2 – the words ‘to training’ should be deleted following ‘systematic approach’ to be consistent with M1. (2) R3 – unclear what ‘at least once’ will entail in terms of a timeframe. Is it at least once during the employment of a particular personnel, at least once during the life of the training program, etc? (3) R4, M4 – presumably the ‘criteria of Requirement R4’ means items (1) and (2) listed in R4. It would be more clear if the word ‘criteria’ was actually used in describing same, i.e. “Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that meets one of the following criteria: (1)…” (4) R6 – reference should be to 4.1.5.1 to be consistent with references used in R2. (5) VSLS, R1, R2, Moderate VSL – the requirement in 1.4 and 2.4 to evaluate and implement any identified changes is broken into two separate violations. However, the requirement in 1.1.1 to review and update if necessary is not, which seems inconsistent. (6) VSLs, R4 – is missing the reference to emergency operations training that is in the requirement itself.
Individual
David Jendras
Ameren
Yes
No
With PER-002-0 being retired PER-005 has had to fill the gaps. PER-005-2 keeps referencing a “training program”. We believe that the “training program” in PER-005-2 is not the same definition of a “training program” that was established in PER-002-0. PER-005-2 is being re-written and needs clarification when referring to a “training program” which references items below from PER-002-0 which need to be addressed. (Applicability Section 4.1.4) We request the drafting team change “Transmission Owner” to “Local Control Center”, since this is mentioned in the Rational for TO notes. (a) Transmission Owner as defined in the NERC Glossary of Terms is an entity that owns and maintains transmission facilities. (b) We believe that Local Control Center Personnel would also need to be defined. (R1) We request that the drafting team leave the wording the way it was originally, but add Local Control Center. We believe that a good training program is developed using the Systematic Approach to Training (SAT), not Systematic Approach (SA). (R1.1) we request that the drafting team leave the wording the way it was in PER-005-0, but nowtadd to it the term Local Control Center. We believe that it is not necessary to add “based on a defined and documented methodology”, as the SAT process has already established this. The first part of any SAT process is Task Listing. (R1.2) Delete or clarify the phrase “according to its training program”. We are not sure what is the drafting team is trying to reference. Is the “training program” referring to the one in the retired PER-002-0 or the “training program” for BES reliability related tasks? (R1.3) We request that the drafting team leave the wording the way it was in PER-005-0, but not add to it the term Local Control Center. In our opinion the way it is currently worded is very vague needing clarification. What training should be delivered and what training program is it

referring to? (R2) We request that the drafting team leave the wording the way it was originally but add Local Control Center. In our opinion R2 can be removed there is no need to include a whole section just for addressing personnel in a Local Control Center is needed. (R3) If R2 is deleted as we have requested then logically this requirement now becomes R2. (R3 - Request that PER-005-0 R3 language is used) (a) We request that the drafting team leave the wording the way it was originally as it only applies to System Operators. (b) We disagree with the drafting team rationale below for getting rid of the 32 hours of EOP training. (c) We believe that the appropriate number of hours would be identified as part of the systematic approach in Requirement R1 and Requirement R2 through the analysis phase and outlined in a continuous education section of their training program. Any additional hours may be duplicative or repetitive for the entity in providing training to its personnel. (d) Again the 32 hours of EOP training came from the Retired PER-002-0 standard and was implemented in part because of the August 2003 Blackout. (e) Requirement R1 requires a training program to only be developed on BES Company specific Reliability Related tasks. Yes this training program will include some Emergency Operations Tasks. The training has to be delivered and the personnel must be verified that they can perform the tasks “at least once” unless the task is new or has been modified. (f) We believe that this rationale again seems to be referring to the “training program” of retired PER-002-0. (g) If this is taken out of the Standard, what requirement is there for doing EOP training on a yearly basis other than on your Company’s System Restoration Plan and on the Loss of Control Center Functionality? (R3.1) If R2 is deleted as we have requested then logically this requirement now becomes R2.1. We propose to the drafting team the following language for clarification. Within six months of a modification or addition of a BES company-specific Real-Time reliability-related task, each Reliability Coordinator, Balancing Authority, Transmission Operator and Local Control Center shall verify the capabilities of each of its personnel; that they are able to perform, the new or modified tasks identified in Requirement R1.1. (R3.2) We believe that the training program must include a plan for the initial and continuing training of Transmission Operator and Balancing Authority operating personnel. The training program referenced in PER-005-2 only applies to Company Specific Reliability Related Tasks. (R3.3) We believe that the training program must include training time for all Transmission Operator and Balancing Authority operating personnel to ensure their operating proficiency. We believe that there needs to be mention in PER-005-2 about providing time for training. (R3.4) We believe that the training staff must be identified, and the staff must be able to demonstrate it is competent in knowledge of system operations and instructional capabilities. (R4) For personnel identified in Requirement R2, each Transmission Operator and Balancing Authority shall provide its operating personnel at least five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel. (a) We believe that this was included as R3 in PER-005-0 in anticipation of PER-002-0 being retired and the five days were changed to 32 hours. (b) We believe that this came about in part because of the August 2003 Blackout. In the FERC August 2003 Blackout report some items that needed to be addressed were Tools, Trees and Training. (R4) If R2 is deleted as we have requested then logically this requirement now becomes R3.1 again. We request that the drafting team change “Transmission Owner” to “Local Control Center”. (R4.1)

If R2 is deleted as we have requested then logically this requirement now become R3.2. We request that the drafting team change "Transmission Owner" to "Local Control Center". (R5) If R2 is deleted as we have requested then logically this requirement now becomes R4. We request that the drafting team add "to training" to systematic approach. (R5.1) If R2 is deleted as we have requested then logically this requirement now becomes R4.1. We request that the drafting team change reference to Requirement R5 back to R4. (R6) If R2 is deleted as we have requested then logically this requirement now becomes R5. We request that the drafting team add "to training" to systematic approach. (R6.1) If R2 is deleted as we have requested then logically this requirement now becomes R5.1. We request that the drafting team change reference to R6 back to R5.
Individual
Julaine Dyke
Northern Indiana Public Service Company (NIPSCO)
No
The applicability to TO and Operations Support Personnel is vage. Suggested revision: Remove the 'can' that was added to the Operator Support Personnel definition.
No
The revised standard does not recognize that TOPs with local control centers may have previous qualified personnel under collective bargaining agreements with multi-year terms that cannot be modified within the implementation schedule.
Individual
Jonathan Appelbaum
The United Illuminating Company
No
A.... We like the change in applicability for the Transmission Owner but are concerned with ambiguity of the word independently. Independent of what or whom? Many Transmission Owners are required by agreements not to ever act on or change state of a BES element without direction from the TOP. What is the measure of independence. We suggest adding a follow-up subitem- Entities that (i) do not dispatch BES Generators and (ii) that have by agreement with a TOP stated they will not operate or direct the operation of the Transmission Owner's Bulk Electric System transmission facilities in Real-time without TOP System Operator permission are excluded from applicability. B.... There is a disconnect between PER-005-2 and draft COM-002-4 applicability. The COM-00204 draft is applicable to DP's while PER-005-2 is applicable to the TO LCC. It is incongruous that the COM standard expects these operating instructions to go to DP but PER-005 expects them to go to TO's. C.... Consider removing the R4 applicability to Transmisison Owners. Personnel at a TO would not benefit from virtual simulation of opening and closing breakers for IROL's. Order 742 did not require the use of simulators to be extended to local control centers. We think R4 is properly scoped to TOP, RC,

and BA. The requirement to use simulation technology does not make sense for Transmission Owners who do not have a wide area view of the BES and do not determine actions necessary to relieve IROLs. Transmission Owners should not be required to use simulation technology during emergency operations training because they will receive operational instructions from Transmission Operators during emergencies. D... In the applicability 4.1.4.1 capitalize facilities.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
Yes
a. We suggest to extend the second HIGH VSL condition for R5 by adding “to develop and implement training for its Operations Support Personnel” after “systematic approach” to conform with the language used in R5. b. We suggest to extend the second HIGH VSL condition for R6 by adding “to develop and implement training for its personnel” after “systematic approach” to conform with the language used in R6.
Individual
Anthony Jablonski
ReliabilityFirst
Yes
No
ReliabilityFirst votes in the negative due to the following concerns which were not addressed during the last comment period. 1. Requirement R1, Part 1.2 - ReliabilityFirst believes there should be a time period associated with Requirement R1, Part 1.2. As written, if an entity adds a new Real-time reliability-related task to their list, it would be left to the discretion of the entity on when they want to include the new training in their program. ReliabilityFirst recommends the following for consideration: "Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 1.1. [Newly updated BES company-specific Real-time reliability-related tasks identified in part 1.1.1 shall be included in the training program within 45 calendar days of identification.]” 2. Requirement R3 - ReliabilityFirst questions the intent of the phrase "at least once" within Requirement R3. Is it the intent that the capabilities of its System Personnel only need to be verified once before they are able to go on shift? ReliabilityFirst believes System Personnel should be trained prior to being able to go on shift and then annually thereafter. ReliabilityFirst recommends the following for consideration: "Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall

verify, at least once [prior to going on shift and annually thereafter], the capabilities of its personnel assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1 or Requirement R2 part 2.1.
Individual
Alice Ireland
Xcel Energy
Yes
Yes
Xcel Energy is in support of the current draft. However, clarification is requested regarding R5: Specifically, it is not clear as to whether continuing training for Operations Support Personnel is required even if the annual evaluation determines there are no changes needed to be incorporated into the training.
Group
Salt River Project
Bob Steiger
No
The proposed System Operator definition could apply to a segment of Operators that, while located in a Control Center, only operate BES elements at the direction of NERC Certified operators. The term ‘operate’ is too broad and may unnecessarily include personnel who do not perform the System Operator function. A System Operator is responsible for the Reliable Operation of the BES, and performs this function by controlling or directing the operation of the BES in Real-Time. The currently proposed definition would expand the applicability of Requirement 1 to Operators that are not responsible for independently performing real time reliability tasks. These Operators only perform switching of BES elements at the direction of certified Operators. In order to eliminate this unintended applicability, recommend that the word “independently” be inserted immediately prior to the word “operates” in the System Operator definition. Another acceptable alternative is "An individual, IN A POSITION REQUIRING NERC CERTIFICATION, at a Control Center (capital since it is a defined term) of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System in Real-time.
No
The term ‘operate’ is too broad. In Order No. 742 at P 62, FERC clarified its understanding that local control center personnel “exercise control over a significant portion of the Bulk-Power System under the supervision of the personnel of the registered transmission operator.” This draft was to address the local transmission owners, however the SDT chose to use the term ‘operate,’ whereas Order 742 used ‘control.’ This term should be added to the NERC Glossary. The applicability to Transmission Owner should be removed from the standard. This sets a precedent of applying “operator” requirements to entities that are “owners.” This could

expand applicability for TOs into additional standards, such as those dealing with issuing Operating Instructions, or owning and operating Control Centers. As outlined by FERC directive in Order 742, these TOs are either following predefined procedures or specific directions from a TOP and should not be considered to have independent operation, control or authority of the BES and should not have applicability to standards related to the operation of the BES. If the applicability to Transmission Owner is retained, recommend removing Transmission Owners from R4 which requires entities who control facilities with IROLs to use simulation technology during emergency operations training. In Order 693, FERC directed NERC to require Reliability Coordinators, Transmission Operators, and Balancing Authorities to use simulation technology during emergency operations training. The requirement to use simulation technology does not make sense for Transmission Owners who do not have a wide area view of the BES and do not determine actions necessary to relieve IROLs. Transmission Owners should not be required to use simulation technology during emergency operations training because, like Generator Operators, they will receive operational instructions from Transmission Operators, Balancing Authorities or Reliability Coordinators during emergencies. Suggest rewording the Applicability as follows to be in accordance with the FERC understanding: 4.1.4 Transmission Owner that has: 4.1.4.1 Personnel, excluding field switching personnel, who can act independently to control or direct the operation of the Transmission Owner's Bulk Electric System Transmission facilities in Real-time
Group
Tennessee Valley Authority
Brandy Spraker
Agree
SERC OC Review Group
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Agree
SERC OC Review Group
Individual
Thomas Foltz
American Electric Power
Yes
Operations Support Personnel – By genericizing the definition, it could be misinterpreted as including individuals outside of Transmission functional areas. We do not believe it was the intent of the drafting team to widen the scope of the definition. In addition, we recommend removing the word "or" from "outage coordination or assessments" and it so that it reads "who perform current day or next day outage coordination assessments…".
Yes

AEP recommends changing 4.1.4 in the Applicability section so that it states: “Transmission Owner who is not also a Tranmission Operator and who has… Personnel, excluding field switching personnel…”.
Individual
Scott Berry
Indiana Municipal Power Agency
No
The use of “systematic approach” in requirement R1, R2, R5 and R6 is problematic. An entity and an auditor may have a different definition or idea of what a “systematic approach” to training means in these requirements and this could lead to many potential violations or a need for an interpretation. The SDT should give examples of what it is looking for when using this term or just remove it.
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
No
The Drafting Team must consider how emergencies are handled. For example, if there is a situation in the field that involves the safety of the public or industry personnel, there are entities that allow control room personnel (‘non-System Operators’) to do emergency switching. However, these control room personnel under normal conditions perform no independent actions, no Reliable Operation functions or any functions related to reliability. During emergencies, in the interest of safety and expediency, these control room personnel will take independent actions to remove a BES component from service. PER-005 -002 would be applicable to these people unnecessarily. The above issue impacts two issues on Rev 2. Definitions: “System Operator - An individual at a Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who independently [Delete: operate] (Insert: controls) or directs the operation of the Bulk Electric System in Real-time.” - Either change the word “operate” to control or delete the word altogether. Applicability 4.1.4 Transmission Owner that has: 4.1.4.1 Personnel, excluding field switching personnel, who can act independently to [Delete: operate] (Insert: control) or direct the operation of the Transmission Owner’s Bulk Electric System Transmission facilities in Real-time - Either change the word “operate” to control or delete the word altogether.
No
We suggest deleting Requirement R5. EMS personnel have been excluded because the data does not support their inclusion. From page 4 of the White Paper (July 15, 2013): “The argument for not including EMS personnel in the training standard at this time is based on a report provided by the Event Analysis Subcommittee (EAS). The EAS worked with the NERC Event Analysis (EA) staff to review the events that have been cause-coded since October

2010. The database has over 263 events; … [and] only two were deemed to be a training issue. Therefore, based on the information, the EAS and PER ad hoc group do not believe it is necessary at this time to require EMS support personnel to receive the level of training required of a BA, Reliability Coordinator (RC), and TOP by NERC standard PER-005." A data analysis will probably show that Operations Support Personnel should be excluded as well. If only two (of the 263 events) were deemed to be a training issue, then how can there be a reliability gap with the training of Operation Support Personnel?
Group
Florida Municipal Power Agency
Frank Gaffney
Yes
No
FMPA appreciates that the SDT made changes, based on stakeholder comments, to the draft PER 005-2 standard. The reason for voting "no" on the standard is based on the RSAW language and lack of criteria on how an entity will be assessed and audited. There is language in the RSAW that is repeated for every requirement (R1-R6) as "Notes to Auditor". (see below) This language is not clear regarding the nature and extent of audit procedures that will be applied. There is reference to scoping the audit based on "certain risk factors to the Bulk Electric System". It is not clear what "risk factors" will be used and auditing can range from "exclusion of the requirement" to "review training records for an entity's entire population of System Operators, applicable personnel, Generator Operators…" etc. This appears to be an attempt to apply Reliability Assurance Initiative (RAI) concepts that have not been finalized and communicated to the industry. It is uncertain whether these concepts have been fully developed yet; and therefore, this leaves too much auditor discretion, without providing the industry information or criteria on how "risk" will be assessed. Stakeholders continue to await the details of these RAI concepts that are being utilized in RSAWS. Clarity is needed around how an entity's risk to the BES will be assessed due to compliance or non-compliance with this standard. This would also beneficial for an entity to know, so that they can lessen that risk, as appropriate. Language from RSAW Notes to Auditor: "The nature and extent of audit procedures applied related to this requirement will vary depending on certain risk factors to the Bulk Electric System. In general, more extensive audit procedures will be applied where risks to the Bulk Electric System are higher based on compliance with this requirement. Based on the assessment of risk, as described above, specific audit procedures applied for this requirement may range from exclusion of this requirement from audit scope to the auditor reviewing training records for an entity's entire population of System Operators." (Emphasis added)
Group
IRC/Standards Review Committee
Greg Campoli

Yes
None
Yes
SRC appreciates the SDT's efforts to revise the standard to address concerns raised in the last posting. The current version is much improved compared to the last posting. However, there are still minor improvements that can be made to the standard to better clarify what is expected on Operations Support Training: R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. 5.1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall create a list of Operations Support Personnel Tasks that impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. 5.2 Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall review, and update if necessary, its list of Operations Support Personnel Tasks identified in part 5.1 each calendar year. 5.3. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall design and develop training materials according to its training program, based on list of Operations Support Personnel Tasks identified in part 5.1. 5.4. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall deliver training to its Operations Support Personnel according to its training program. 5.5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify any needed changes to the training program and shall implement the changes identified.
Individual
Catherine Wesley
PJM Interconnection
Yes
No
While PJM appreciates the efforts of the SDT, we continue to feel as we have from the beginning, that "equally effective and efficient solutions" outside the reliability standards process are available. The approach used by other industries using a systematic approach to training should be used as a guide. Alternative approaches would help ensure training programs have the flexibility to target requirements on the proper entities and people, even as the entities and people involved in the operation of the BES change. An example of how this standard works against those interests is the explicit exclusion of plant operators. A current trend is for new generation owners to push the reliability related tasks of communicating and interacting with the RC, BA, and TOP, (tasks once performed by generation dispatch personnel at a control center) down to the plant operators. While we

appreciate RTO training requirements can be established through operating agreements (and thus not require a NERC Standard), the explicit exclusion of all plant operators is not appropriate and sends the wrong message. Again, this is not to suggest all plant operators should be included in this standard. We understand and agree with the SDT motives for this exclusion within the scope of a reliability standard. It simply highlights the current state of the industry requires a more nuanced approach for identifying entities and personnel for reliability related training requirements.
Group
SERC OC Review Group
Stuart Goza
Yes
Bringing back the capitalization of Control Center in the System Operator definition seems appropriate and we agree it does not present any inconsistency with the inclusion of GOP in the Control Center definition. The Operations Support Personnel definition is an improvement to better identify personnel to whom the standard applies. We agree with the removal of the former “standard-only” definitions and the elimination of the aggregator term System Personnel.
Yes
This review group generally supports the revisions in this posting and appreciates the efforts of the Standard Drafting Team to incorporate industry comments. We would like to suggest some wording changes and simplifications to the current draft of the standard. For R1.2 and 2.2 change “design and develop training materials according to its training program” to: “design and develop training materials for ADD: “inclusion” in its training program” M4: Change “Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection…..” to: “Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner ADD: “that meets the criteria of Requirement R4” shall have available for inspection….. R5: At the end of the requirement statement, change: “Real-time reliability- related tasks identified by the entity pursuant to Requirement R1 part 1.1.” to “Real-time reliability-related tasks identified by the entity ADD: “consistent with” Requirement R1 part 1.1.”. (Replace the legal phrase “pursuant to” with the phrase “consistent with”). R6: At the end of the requirement statement, change “reliable operations of the BES “during normal and emergency operations” to “reliable operations of the BES.” We feel that including the phrase “during normal and emergency operations” does not add any specificity to the requirement statement and should be removed. R5.1 and R6.1: We question why only the “evaluation” phase is included in the R5 and R6 sub-requirements, while other elements of systematic approach (develop and implement) are included in the R5 and R6 statements themselves. To simplify R5 and R6, we suggest folding the “evaluation” requirement into the R5 and R6 statements and eliminating sub-requirements R5.1 and R6.1. The proposed re-writes below include changes to R5 and R6 suggested above. R5: “Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to design, develop, implement, and (each calendar

year) evaluate and update (if necessary) training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity consistent with Requirement R1 part 1.1.” R6: “Each Generator Operator shall use a systematic approach to design, develop, implement, and (each calendar year) evaluate and update (if necessary) training to its personnel identified in Applicability Section 4.1.5 of this standard, on how their job function(s) impact the reliable operations of the BES.” Measures for R5 & R6 would need to be adjusted accordingly if the changes above are accepted. Please also note that the date in the filename of the standard redline version is incorrect. It should be “20131204” The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Group
Dominion
Mike Garton
Yes
Yes
Individual
Dean Fox
Consumers Energy Company
Yes
No
Requirements R5 and R6 both require the use of a systematic approach to training to train personnel on how their job function(s) impact company- specific Real-time reliability tasks. This could be accomplished with some awareness training not the full systematic approach to training process. Requiring the systematic approach to training process for generator operators and support personnel training requirements we believe causes more administrative overhead without a reliability gain.
Group
DTE Electric
Kathleen Black
Yes
Yes

We feel overall our concerns have been clarified in the revised standard. We would like to thank the SDT for understanding and addressing our comments/concerns.
Individual
Matthew Beilfuss
Wisconsin Electric Power Company
Yes
No
Expanding the scope of GOP training to encompass a systematic approach to training (SAT) will likely identify tasks where GOP training is already required within existing standards. Also, the content and rigor of the VAR standards create explicit procedural requirements that address GOP impact on reliable operations of the BES during normal and emergency operations. Given that no individual Generator has a reliability impact on the BES, training requirements to address specific instances where BES reliability is potentially impacted by a GOP has been appropriately addressed within the standards. Additionally, a requirement for a GOP systematic approach to training within PER-005-2 is an odd fit given that the balance of the standard is written to address System Personnel and Real-time reliability-related tasks. If it is viewed as necessary to require a SAT program for GOPs, this can better be addressed by a standalone standard. As PER-005-2 is written, the compliance framework and requirements applicable to managing the System Operator SAT are different than the GOP SAT. The scope limited definitions of Transmission Owners and Generator Operators will create confusion. The GOP definition is particularly problematic. A centrally located GOP conducting testing of generator may “coordinate” with a BA or TOP, however, it wouldn’t be relaying instructions as they are initiating action. Additionally, the quoted text from Order No. 693 at P1389 includes, “although a generator operator typically receives instructions from a balancing authority, it is essential that generator operator personnel have appropriate training to understand those instructions, particularly in an emergency situation in which instructions may be succinct and require immediate action.” The language in the order implies some GOP training is viewed as necessary regardless of GOP / BA roles. The standard as written appears to side-step the intent of order.
Group
ACES Standards Collaborators
Brian Van Gheem
No
(1) We appreciate the Standard Drafting Team’s revisions to this standard and the efforts in attempting to address the applicability issues. We also appreciate the recent approach of moving the proposed standard-specific definitions to the NERC Glossary of Terms. In particular, we feel the definition assigned to “System Operator” is adequate, concise, and clearly identifies which reliability entities are accountable. (2) However, we are concerned

that the definition of “Operations Support Personnel” is too broad. The definition is ambiguous and provides an opportunity for multiple compliance interpretations that may lead to including unnecessary personnel. We propose the Standard Drafting Team revise the definition to read “Individuals who perform current-day or next-day outage coordination or assessments, or individuals who acknowledge established SOLs, IROLs, or operating nomograms, for use in the real-time operations of the Bulk Electric System.” We feel that this proposed definition focuses on Reliability Coordinators, Balancing Authorities, and Transmission Operators and better aligns with the applicability of Requirement R5. (3) We continue to be concerned with the applicability of Transmission Owners. This inclusion appears to address regional variance for “local transmission control centers.” We recommend that the drafting team consider removing the TO function from the applicability section and providing technical justification that the NERC Rules of Procedure govern the registration process. This is not an issue that should be resolved in a standard; rather, NERC should utilize its tools that are already in place to properly register entities with appropriate functions. This registration issue could be better handled by ERO compliance staff when facts and circumstances arise.
No
(1) We appreciate the Standard Drafting Team’s actions taken in response to ours and other industry comments regarding the previous draft standard. In particular, we would like to recognize the SDT’s attempt to differentiate the TO responsibilities from that of RCs, BAs, and TOPs. We also appreciate the alignment of outstanding FERC Directives and the removal the 32-hour requirement for emergency operations training. (2) However, we have several concerns with the direction taken in this revision. The title of the Standard should simply state that this is a “Personnel Training” standard and avoid references to “Operations” altogether. We feel that this would better align with the purpose of this standard, to focus on those personnel who perform and support the real-time operations of the Bulk Electric System. (3) Requirement R2 does not align with the applicability section of this Standard. As it is currently worded, each Transmission Owner would be required to first demonstrate that it has developed and implemented a training program using a systematic approach, and then provide proof regarding which personnel would align with the description of the Applicability Section 4.1.4.1. While an individual, non-applicable Transmission Owner may already have a training program that uses a systematic approach, we feel this opens the door to auditor interpretation regarding the applicability of Requirement R2. Instead, we propose the SDT to revise Requirement R2 to read, “Each Transmission Owner, with personnel identified in Applicability Section 4.1.4.1, shall use a systematic approach to develop and implement a training program for these identified personnel as follows.” (4) We also feel the applicability of the individual parts of Requirement R2 does not align with the intent of the SDT to list TOs under the applicability section of this Standard. We believe a clarification is needed in each part to reduce the possibility of confusion in the future, especially if each part is evaluated out of context. We propose including the word “applicable” before each reference to Transmission Owner or to provide further clarification by stating “each TO, with personnel identified in Applicability Section 4.1.4.1.” (5) Similar to Requirement R2, we feel the applicability of Requirement R3 does not align with the applicability section of this standard.

As it is currently worded, each Transmission Owner would be required to first demonstrate the validity of its training program followed by the identification of its personnel who are applicable to Requirement R2, and then provide proof that it has verified the capabilities of such personnel. Instead, we propose Requirement R3 to read "Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner, with personnel identified in Requirement R1 or Requirement R2, shall verify, at least once, the capabilities of these personnel assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1, part 1.1, or Requirement R2, part 2.1." (6) We feel the applicability of Requirement R6 does not align with applicability section of this standard for Generator Operators. As it is currently worded, each GOP would be required to first demonstrate that it has developed and implemented a training program using a systematic approach, and then provide proof regarding which personnel would align with Applicability Section 4.1.5.1 of this Standard. While an individual, non-applicable Generator Operator may already have a training program that uses a systematic approach, we feel this opens the door to auditor interpretation regarding the applicability of this requirement. Instead, we propose Requirement R6 to read, "Each Generator Operator, with personnel identified in Applicability Section 4.1.5.1, shall use a systematic approach to develop and implement training to these personnel on how their job function(s) impact the reliable operations of the BES during normal and emergency operations." (7) We also feel the individual parts of Requirement R6 do not align with the applicability section of this Standard. We believe a clarification is needed to each part to reduce the possibility of confusion in the future, especially if each part is evaluated out of context. We propose including the word "applicable" before each reference to Generator Operator or "each Generator Operator, with personnel identified in Applicability Section 4.1.5.1." (8) We believe R1, R2, R5, and R6 are proposing unnecessary requirements for an entity to review its training program each calendar year. A program using a systematic approach to training will already have such criteria in place. We feel that this is an administrative task which meets Paragraph 81 criteria. Please remove the annual review requirement. (9) The Violations Severity Levels for Requirement R4 are binary in nature and should be modified to a graduated severity level. The SDT should follow a similar structure of the Requirement R2's Violations Severity Levels by including percentages of System Personnel that have received simulation technology training. (10) We complement the Standard Drafting Team's efforts to sanitize the contents of the attached Application Guidelines. We would like to pass along an observation regarding Reference #2 and a broken hyperlink for the resource, DOE-HDBK-1074-95. (11) The Compliance Enforcement Authority sections of the RSAW still expects an entity to maintain an organizational chart which identifies what employees it considers as "System Operator" to meet compliance with this Standard. We believe this was inadvertently missed by the SDT, following a recent revision to the RSAW, which addressed other references to organizational charts as compliance evidence. We feel organizational charts are a zero-defect approach to compliance, and we are concerned that auditors would argue over the list of System Operators who were not identified to receive training, thus leading to a possible violation for each instance. The standard should focus on internal controls and management practices

consistent with NERC’s Reliability Assurance Initiative (RAI). (12) Thank you for the opportunity to comment.
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Pamela Hunter
Yes
Yes
Group
Luminant
Brenda Hampton
No
The rationale for Operations Support Personnel indicates that Operations Support Personnel are personnel of the RC, BA or TOP. If this is intended target for this definition then the definition should state that, similar to the way the System Operator definition does.
No
In R5 & R6, the applicable entities are required to use a "systematic approach" to training without any further explanation on what that "systematic approach" to training entails. The RSAW for R5 and R6 requires to the auditor to determine if the "systematic approach" to training included an Analysis step, an Implementation step and an Evaluation step. If these are the required components of a "systematic approach", then this should be clearly defined in the standard, rather than "required" via the RSAW.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Agree
SERC OC
Individual
Cheryl Moseley
Electric Reliability Council of Texas, Inc.
Yes
ERCOT is generally supportive of the SDT definitions as written.
No

Applicability: Per the NERC Functional Model, entities that operate or direct the operation of BES transmission facilities are technically Transmission Operators and should be registered as such. Therefore, there is no need to include Transmission Owners in this Standard. Inclusion of Transmission Owners in a requirement would create conflicts with other NERC reliability standards. Requirements: Requirement R5 – ERCOT is voting Affirmative on the Standard, but does not believe that a systematic approach to training (SAT) should be required for training of Operations Support Personnel. The FERC Orders clarified that training for support personnel should be tailored to the functions they perform and that they need not be trained to the same extent as System Operators. The SAT has been linked with the DOE Training Handbook that included the Analysis, Design, Development, Implementation, and Evaluation (ADDIE) process. Expanding training requirements for the Operations Support Personnel to include the SAT process will add additional costs to training programs that FERC was trying to avoid in their order. ERCOT does not believe that this adds any additional reliability benefit. Entities should have the flexibility to determine the training necessary to ensure reliabile operation of the BES. ERCOT recommends that the SDT revise R5 to state: R5 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] Measures: ERCOT does not agree with the specificity in Measures M1.3 and M2.3 as to what entities are to provide as evidence and recommends the Measures be revised to read: M1.3 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have evidence available for inspection of System Operator training records indicating the training delivered in accordance with Requirement R1 part R1.3. M2.3 Each Transmission Owner shall have evidence available for inspection of training records indicating training was delivered in accordance with Requirement R2 part R2.3.
Individual
Brian Evans-Mongeon
Utility Services, Inc
No
Transmission Owner applicability should be removed or significantly limited. Applicability Section 4.1.4.1 states that Transmission Owners act independently to "operate[] or direct[] the operations of the Transmission Owner's BES." However, FERC Order No. 742 recognizes that a Transmission Owner is following pre-defined procedures or specific directives under the supervision of the Transmission Operator. Following a pre-defined procedure under supervision is not independent operation as suggested in the applicability section. The definition of TOP from the NERC Glossary of Terms is as follows: "The entity responsible for the reliability of its 'local' transmission system, and that operates or directs the operations of the transmission facilities." The only difference between the applicability statement in Section 4.1.4.1 and the definition is the acceptance of responsibility "…for the reliability of its 'local'

transmission system…" Entities that are acting "independently" as the applicability section of the proposed standard states would inherently accept the responsibility for the reliability of the system. Since this is not the case for the local control center based Transmission Owners in question the training requirements should be significantly limited to only include the pre-defined procedures issued by the TOP and following directive from the TOP. Conversely, if the Transmission Owner does in fact operate independently of the TOP and, therefore, has responsibility for the reliability of its local transmission system, perhaps additional registration should be considered for those entities. If this is the case, these Transmission Owners are more than simply "[t]he entity that owns and maintains transmission facilities" as Tranmission Owner is defined in the NERC Glossary of Terms. Perhaps developing a new functional registration would be more appropriate method of proceeding forward, such as a "Local Control Center." This functional registration could include both the Transmission Owners and Generator Operators that are outlined in the applicability section of PER-005, as the idea of these entities independently operating a significant portion of the BES from a central location is consistent between them. Adding Transmission Owners to this standard has other additional implications as well. First, there is the administrative burden that will automatically be placed on all Transmission Owners who are not applicable. These Transmission Owners will have to provide documentation or evidence to demonstrate they are not applicable. "Proving the negative" is a difficult task that should not be overlooked. Second, if these entities do in fact need to be added to PER-005 applicability because they direct the operation of BES Facilities applicability to other standards should be added as well. The additional standards would include applicability to the version of COM-002-4 currently in development. These entities could potentially be both "Issuers" and "Receivers" or Operating Instructions as outlined in COM-002-4. Also, these entities could be applicable to the following additional standards: TOP-001-1: R4: the TO would need authority to issue reliability directives to DPs and LSEs interconnected though their transmission Facilities. R7: if under the TOs direction Facilities could be removed from service they need to have applicability to this requirement. CIP Standards: The Transmission Owners are operating the BES from a "control center," which is not consistent with the definition of "Control Center" in the NERC Glossary of Terms because only BA, RC, TOP and GOPs fit within the definition. This results in facilities that are critical to the operation of the potentially being designated as non-Critical Assets (current CIP) or being in a lower category in CIP Version 5 (potentially Low or Medium instead of High). If the Transmission Owner applicability remains, "facility" in 4.1.4.1 should be capitalized. The rational is that "[t]here may be a facility that is not included in the NERC glossary term 'Facility'" is flawed. The applicability to Transmission Owners is only to their "Bulk Electric System transmission facilities" and the definition of Facility is "[a] set of electrical equipment that operates as a single Bulk Electric System Element." Since both the definition of Facility and the applicability are limited to the BES they are synomomus and not capilizing the term only adds confusion. The Applicability section for Generator Operator, Section 4.1.5.1 should use the term "Control Center" as the NERC definition of Control Center, "One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of:... 4) a

Generator Operator for generation Facilities at two or more locations" is consistenet with the idea of a "centrally located dispatch center" as outlined in the applicability section.
Group
SPP Standards Review Group
Robert Rhodes
No
We have a concern regarding the lack of clarity in the language within the RSAW that requires an auditor to focus upon support personnel who are directly involved in Real-time operations of the BES. Potentially every employee in an entity is linked to the System Operator's role in operating the system. Such a linkage is overwhelming and creates a burdensome task on the industry. We do not believe this is the intent of the drafting team and encourage the drafting team to work closely with NERC Compliance staff to develop RSAW language which restricts an auditor's review to the personnel the entity has identified.
Yes
Although there was no RSAW comment form included with the document posting, we do have a specific comment regarding the RSAW. In the Note to Auditor sections for R1, R2, R5 and R6 a specific reference to ADDIE is implied in the parentheticals following the bullet points. An effort has been made to eliminate any reference to a specific methodology on how to approach a systematic approach to training and the potential for an auditor to tie compliance to a specific methodology. It is left up to the responsible entity to develop its own methodology. It is the responsibility of the auditor to limit his review to that methodology. At the very least, the parentheticals should be deleted which will remove the implied reference. Compliance audits should be restricted to the requirements as contained in a standard and not based on language which exists in some other document such as the RSAW. Standards should be written such that they are very clear on what the requirments are and what is required to establish compliance. There have been instances where when questions were asked regarding specific compliance issues, entities have been referred to the RSAW for additional information on what is needed for compliance. This additional information needs to be incorporated into the requirements of the standard such that they stand alone and do not need additional support from other documentation. We need to be sure that RSAWs or other documentation do not expand the scope of a given standard. For example, the existing RSAW for PER-005-1 includes requirements for training staff compentency which are not in the standard itself. Change the '…to develop and implement training to…' in R6 to '…to develop and implement training for…'. This language is consistent with that used in R1, R2 and R5. Change the '…evidence of using a systematic approach to training to develop…' in M2 to '…evidence of using a systematic approach to develop…'. This language is consistent with that used in the Purpose, R1, M1, R2 and other locations throughout the standard. In the first bullet at the top of Page 2 in the Applicable Entities section of the Implementation Plan, change 'Transmission Owners that has…' to 'Transmission Owners that have…'.
Group
Duke Energy

Michael Lowman
Yes
(1) Duke Energy recommends the following revision to Operations Support Personnel: Operations Support Personnel: Individuals, in direct support of Real-time operations of the Bulk Electric System, who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms.
Yes
(1) While Duke Energy understands the position of the SDT for not including coordination between a GOP and RC/BA/TOP in R6 of the current draft of PER-005-2, Duke Energy continues to have concerns that the removal of this coordination would not satisfy the FERC Order and would not be tailored in scope, content, and duration so as to be appropriate to Generation Operations personnel and the objective of promoting system reliability. Duke Energy maintains its recommendation of reinserting the language for coordination as used in draft 1 of this standard project.
Individual
Karen Webb
City of Tallahassee - Electric Utility
No
The City of Tallahassee (TAL) is concerned with the proposed standard's expansion of training requirements to include the planners performing the current and next day studies, as well as those personnel determining the system operating limits. There is no evidence to suggest a reliability gap exists.
No
TAL is generally concerned with clarity in the proposed standard and the consistency with which the proposed standard could be audited. As written, considerable discretion is afforded entities in developing the reliability-related tasks. To truly support and improve reliability of the bulk electric system, additional guidance is needed for registered and regional entities. Without this guidance, an entity may elect to identify fewer tasks than reasonably appropriate in an effort to ensure compliance and keep training costs to a minimum.
Individual
Bill Fowler
City of Tallahassee
No
The City of Tallahassee (TAL) is concerned with the proposed standard's expansion of training requirements to include the planners performing the current and next day studies, as well as those personnel determining the system operating limits. There is no evidence to suggest a reliability gap exists.

No
TAL is generally concerned with clarity in the proposed standard and the consistency with which the proposed standard could be audited. As written, considerable discretion is afforded entities in developing the reliability-related tasks. To truly support and improve reliability of the bulk electric system, additional guidance is needed for registered and regional entities. Without this guidance, an entity may elect to identify fewer tasks than reasonably appropriate in an effort to ensure compliance and keep training costs to a minimum.
Group
Bonneville Power Administration
Jamison Dye
Yes
No
BPA recommends removing R2 and incorporating it back into R1. BPA feels that as presently written, this Requirement will create a situation where an entity that is a Transmission Owner (TO) and Balancing Authority (BA) / Transmission Operator (TOP) will be penalized twice for the same violation (R1 and R2). BPA feels that by combining the two requirements, this removes any potential for double jeopardy. BPA recommends that the standard drafting team create a definition for a “Bulk Electric System company- specific, reliability-related task.” Although BPA understands the benefit of having the flexibility to create a company-specific definition — as well as the ability to create a task-list based on that definition — BPA maintains without such a definition, that this would allow auditors to make different and inconsistent interpretations. BPA understands that the auditors’ interpretations are outside the control of the drafting team — and this is precisely why BPA recommends the definition in order to create more clarity in the standard.
Individual
Scott Langston
City of Tallahassee
No
The City of Tallahassee (TAL) is concerned with the proposed standard’s expansion of training requirements to include the planners performing the current and next day studies, as well as those personnel determining the system operating limits. There is no evidence to suggest a reliability gap exists.
No
TAL is generally concerned with clarity in the proposed standard and the consistency with which the proposed standard could be audited. As written, considerable discretion is afforded entities in developing the reliability-related tasks. To truly support and improve reliability of the bulk electric system, additional guidance is needed for registered and regional entities.

Without this guidance, an entity may elect to identify fewer tasks than reasonably appropriate in an effort to ensure compliance and keep training costs to a minimum.
Individual
Jen Fiegel
Oncor Electric Delivery Company LLC
No
Oncor has concerns on the lack of clarity in the language in the revised Standard as well as the RSAW; In order to ensure the intent of the SDT is clear, the language below should be addressed to avoid misinterpretation by personnel handling compliance monitoring functions, specifically, -"based on a defined and documented methodology" - this language could be interpreted in multiple ways and needs to be clarified the methodology utilized to develop training is to be documented -"support personnel" define in the RSAW - this could be interpreted as all personnel who in some form support the control room.
No
Appears to be the same question as #1 so please refer to prior response. From an "Other" comment perspective, Oncor recommends the RSAW be reviewed in conjunction with the Standard. In the RSAW Note to Auditor sections for R1, R2, R5 and R6 a specific reference to ADDIE is implied in the parentheticals following the bullet points. An effort has been made to eliminate any reference to a specific methodology on how to approach a systematic approach to training and the potential for an auditor to tie compliance to a specific methodology. It is left up to the responsible entity to develop its own methodology. It is the responsibility of the auditor to limit his review to that methodology. At the very least, the parentheticals should be deleted which will remove the implied reference. Compliance audits should be restricted to the requirements as contained in a standard and not based on language which exists in some other document such as the RSAW. Standards should be written such that they are very clear on what the requirments are and what is required to establish compliance. There have been instances where when questions were asked regarding specific compliance issues, entities have been referred to the RSAW for additional information on what is needed for compliance. This additional information needs to be incorporated into the requirements of the standard such that they stand alone and do not need additional support from other documentation. We need to be sure that RSAWs or other documentation do not expand the scope of a given standard. For example, the existing RSAW for PER-005-1 includes requirements for training staff compentency which are not in the standard itself.

Additional Comments

Michael Haff
Seminole Electric Cooperative, Inc.

COMMENTS

(1) In the Rationale box for “Operations Support Personnel,” it appears that in the first line “personnel” should be capitalized in the redline version of the Standard. However, in the clean version of the Standard “personnel” is capitalized. This is a general request that the NERC STDs please reflect all changes in the redline version that appear in the clean version. In this instance the discrepancy is minor, however, Seminole has seen this done on other draft Standards, and so Seminole is requesting that the NERC SDTs be diligent on the effort to have all changes depicted in the redline versions.
(2) The definition of Operations Support Personnel includes “Individuals… who determine SOLs, IROLs, or operating nomograms, in direct support of Real-time operations of the [BES].” Seminole reasons that this description of affected personnel could include long-range transmission planners and those engineers assisting with the development of facility ratings per FAC-008 as long as their work supports the actions of Real-time personnel. Please respond to this concern as to whether these individuals with the actions described above could be included in this Standard.
(3) The Rationale box for the TO applicability function specifically cites the FERC language relating to personnel who control “a significant portion of the [BPS]…” Seminole fails to see where the SDT incorporated the language relating to the importance that the TO be responsible for a “significant portion” of the BPS and not merely an insignificant portion of the BPS. Please incorporate language into the Standard that exempts those TOs that own an insignificant portion of the BPS as FERC directed in Order 693.
(4) Requirement R1 part 1.4 requires the RC, BA, and TOP to implement changes identified during a calendar year evaluation. However, Measure M1.4 does not require the changes to be implemented nor does the VSL/VRF penalty matrix. Please clarify whether an entity is required to implement changes identified and by what timeframe the entity must implement the identified changes. Note – this comment concerns similar language throughout many of the Requirements and Measures. Please make any changes consistent throughout the Standard.
(5) In Measure M3.1, there is a reference to “6 months.” If a modification occurs on January 10, 2017, does the entity have until July 10, 2017 or August 1, 2017 to verify personnel capabilities? Please comment on how “6 months” is supposed to be calculated, i.e., six new full months, 180 calendar days, etc.
(6) In the Rationale Box for R4, it appears the word “within” should be added before “12 months” in the third line.
(7) In Section C Compliance, Part 1.2 Evidence Retention, this section requires entities to retain data and evidence for three years or since the last compliance audit, whichever time frame is “greater.” Appendix 4, Section 3.1.4.2 of the NERC Rules of Procedure state the following:

> The audit period begins the day after the End Date of the prior Compliance Audit by the Compliance Enforcement Authority (or the later of June 18, 2007, or the date the Registered Entity became subject to Reliability Standards if the Registered Entity has not previously been subject to a Compliance Audit). The ‘audit period will not begin prior to the End Date of the previous Compliance Audit.’

This Standard requires an entity to retain data past the last compliance audit if it is less than three years back. Seminole believes this section of Section C should read “requires entities to retain data and evidence for three years or since the last compliance audit, whichever time frame is ‘less.’”

Consideration of Comments

Project 2010-01 Training (PER) Revisions

The Project 2010-01 Training (PER) Revisions Drafting Team thanks all commenters who submitted comments on the draft PER-005-2 standard. This standard was posted for a 45-day public comment period through Friday, January 17, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 45 sets of comments, including comments from approximately 126 different people from approximately 82 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

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

Index to Questions, Comments, and Responses

Index to Questions, Comments, and Responses 2

1. **The drafting team has revised PER-005-2 in response to stakeholder comments. Do you agree with the revised Operations Support Personnel and System Operator definitions? If you do not agree or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.** 11
2. **The drafting team has revised PER-005-2 in response to stakeholder comments. Do you agree with the revised standard? If you do not agree or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.** 23

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

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

10 — Regional Reliability Organizations, Regional Entities

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1

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

11.	Christina Koncz	PSEG Power LLC	NPCC	5
12.	Helen Lainis	Independent Electricity System Operator	NPCC	2
13.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
14.	Alan MacNaughton	New Brunswick Power	NPCC	9
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Silvia Parada Mitchell	NextEra energy, LLC	NPCC	5
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
21.	Brian Robinson	Utility Services	NPCC	8
22.	Ayesha Sabouba	Hydro One Networks Inc,	NPCC	1
23.	Brian Shanahan	National Grid	NPCC	1
24.	Wayne Sipperly	New York Power Authority	NPCC	5
25.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1

				1	2	3	4	5	6	7	8	9	10
2.	Group	Janet Smith	Arizona Public Service	X		X		X	X				
No Additional Responses													
3.	Group	Erika Doot	US Bureau of Reclamation	X				X					
No Additional Responses													
4.	Group	Bob Steiger	Salt River Project	X		X		X	X				
No Additional Responses													
5.	Group	Brandy Spraker	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ian Grant		SERC	3
2.	Marjorie Parsons		SERC	6
3.	David Thompson		SERC	5
4.	DeWayne Scott		SERC	1
5.	Stuart Goza		SERC	1
6.	Paul Palmer		SERC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
6.	Group	David Dockery	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6.	Randy Hahn	Ocala Utility Services	FRCC	3
7.	Don Cuevas	Beaches Energy Services	FRCC	1
8.	Stan Rzad	Keys Energy Services	FRCC	1
9.	Mark Schultz	Green Cove Springs	FRCC	3

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ali Miremadi	California ISO	WECC	2
2.	Ben Li	IESO	NPCC	2
3.	Charles Yeung	SPP	SPP	2
4.	Kathleen Goodman	ISO-NE	NPCC	2
5.	Terry Bilke	MISO	MRO	2
6.	Al diCaprio	PJM	RFC	2

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Stuart Goza	SERC OC Review Group	X		X		X	X				

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jeff Harrison	AECI	SERC	1, 3, 5, 6
2.	Cindy Martin	Southern	SERC	1, 5
3.	William Berry	OMU	SERC	3
4.	Ray Phillips	AMEA	SERC	4
5.	Dan Roethemeyer	Dynegy	SERC	5
6.	Thomas Hanzlik	SCE&G	SERC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Mike Garton	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion Resources Services, Inc.	RFC	5, 6
2.	Randi Heise	Dominion Resources Services, Inc.	MRO	6
3.	Connie Lowe	Dominion Resources, Inc.	NPCC	5, 6
4.	Michael Crowley	Virginia Electric and Power Company	SERC	1, 3, 5, 6

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

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

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Brian Van Gheem	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
2.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
3.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
4.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Pamela Hunter	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
			Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing										

No Additional Responses

				1	2	3	4	5	6	7	8	9	10
14.	Group	Brenda Hampton	Luminant						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rick Terrill	Luminant Generation Company LLC	ERCOT	5

				1	2	3	4	5	6	7	8	9	10
15.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Margaret Adams	Southwest Power Pool	SPP	2
2.	Michelle Corley	Cleco Power	SPP	1, 3, 5
3.	Chris Dodds	Westar Energy	SPP	1, 3, 5, 6
4.	Allan George	Sunflower Electric Power Corporation	SPP	1
5.	Donald Hargrove	Oklahoma Gas & Electric	SPP	1, 3, 5
6.	Robert Hirchak	Cleco Power	SPP	1, 3, 5
7.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
8.	Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
9.	Scott Labit	Grand River Dam Authority	SPP	1, 3, 5
10.	Greg McAuley	Oklahoma Gas & Electric	SPP	1, 3, 5
11.	Shannon Mickens	Southwest Power Pool	SPP	2
12.	James Nail	City of Independence, MO	SPP	3
13.	Terri Pyle	Oklahoma Gas & Electric	SPP	1, 3, 5
14.	Sean Simpson	Board of Public Utilities, City of McPherson	NA - Not Applicable	NA
15.	Sing Tay	Oklahoma Gas & Electric	SPP	1, 3, 5
16.	Alex Vitt	Westar Energy	SPP	1, 3, 5, 6
17.	Keeth Works	Southwestern Power Administration	SPP	1, 5

				1	2	3	4	5	6	7	8	9	10
16.	Group	Michael Lowman	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils		RFC	1

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

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

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	James Murphy	Dispatch	WECC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Individual	Lee Layton	Blue Ridge Electric	X		X							
19.	Individual	John Brockhan	CenterPoint Energy Houston Electric LLC.	X		X							
20.	Individual	Brian Reich	Idaho Power Co.	X									
21.	Individual	Kathleen Goodman	ISO New England Inc.		X								
22.	Individual	Martyn Turner	LCRA Transmission Services Corporation	X									
23.	Individual	Sheldon Hunter	Sunflower Electric	X		X							
24.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
25.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
26.	Individual	Shirley Mayadewi	Manitoba Hydro	X		X		X	X				
27.	Individual	David Jendras	Ameren	X		X		X	X				
28.	Individual	Julaine Dyke	Northern Indiana Public Service Company (NIPSCO)	X		X		X	X				
29.	Individual	Jonathan Appelbaum	The United Illuminating Company	X									
30.	Individual	Michael Falvo	Independent Electricity System Operator		X								
31.	Individual	Anthony Jablonski	ReliabilityFirst										X
32.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
33.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
34.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
35.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
36.	Individual	Catherine Wesley	PJM Interconnection		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
37.	Individual	Dean Fox	Consumers Energy Company			X		X					
38.	Individual	Matthew Beilfuss	Wisconsin Electric Power Company			X	X	X					
39.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
40.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								
41.	Individual	Brian Evans-Mongeon	Utility Services, Inc				X						
42.	Individual	Karen Webb	City of Tallahassee - Electric Utility					X					
43.	Individual	Bill Fowler	City of Tallahassee			X							
44.	Individual	Scott Langston	City of Tallahassee	X									
45.	Individual	Jen Fiegel	Oncor Electric Delivery Company LLC	X									

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

Summary Consideration:

Organization	Agree	Supporting Comments of "Entity Name"
Tennessee Valley Authority	Agree	SERC OC Review Group
Associated Electric Cooperative, Inc. - JRO00088	Agree	SERC OC Review Group
Sunflower Electric	Agree	ACES
Kansas City Power & Light	Agree	SPP - Robert Rhodes
South Carolina Electric and Gas	Agree	SERC OC

1. **The drafting team has revised PER-005-2 in response to stakeholder comments. Do you agree with the revised Operations Support Personnel and System Operator definitions? If you do not agree or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration:

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	The proposed System Operator definition could apply to a segment of Operators that, while located in a Control Center, only operate BES elements at the direction of NERC Certified operators. The term 'operate' is too broad and may unnecessarily include personnel who do not perform the System Operator function. A System Operator is responsible for the Reliable Operation of the BES, and performs this function by controlling or directing the operation of the BES in Real-time. The currently proposed definition would expand the applicability of Requirement 1 to Operators that are not responsible for independently performing real time reliability tasks. These Operators only perform switching of BES elements at the direction of certified Operators. In order to eliminate this unintended applicability, consider that the word "independently" be inserted immediately prior to the word "operates" in the System Operator definition. The definition would then become:"An individual at a Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who independently operates, or directs, the operation of the Bulk Electric System in Real-time."The Drafting Team must consider how emergencies are handled. For example, if there is a situation in the field that involves the safety of the public or industry personnel, there are entities that allow field personnel

		to do emergency switching. By the definition they would be considered System Operators.

Response: Thank you for your comments. The Standard drafting team (SDT) does not agree that the addition of the word "independent" provides any additional clarity. The definition of System Operator as those who "operate or direct the operation" of the Bulk Electric System (BES) would not include personnel who do not perform System Operator functions. First, personnel located outside of a Control Center would not be included in the definition as it clearly states that System Operators are "individuals at a Control Center." Additionally, the term "operate" is used to describe those who have the independent authority to operate the BES. Those individuals that perform certain tasks under the direct supervision of the NERC-certified operator (who is the individual that has the ultimate authority to operate the BES) would not be "operating" the BES. As noted in footnote PER-003-1, "[n]on-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks."

Salt River Project	No	The proposed System Operator definition could apply to a segment of Operators that, while located in a Control Center, only operate BES elements at the direction of NERC Certified operators. The term 'operate' is too broad and may unnecessarily include personnel who do not perform the System Operator function. A System Operator is responsible for the Reliable Operation of the BES, and performs this function by controlling or directing the operation of the BES in Real-Time. The currently proposed definition would expand the applicability of Requirement 1 to Operators that are not responsible for independently performing real time reliability tasks. These Operators only perform switching of BES elements at the direction of certified Operators. In order to eliminate this unintended applicability, recommend that the word "independently" be inserted immediately prior to the word "operates" in the System Operator definition. Another acceptable alternative is "An individual, IN A POSITION REQUIRING NERC CERTIFICATION, at a Control Center (capital since it is a defined term) of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System in Real-time.

Response: Thank you for your comments. The Standard drafting team (SDT) does not agree that the addition of the word "independent" provides any additional clarity. The definition of System Operator as those who "operate or direct the operation" of the Bulk Electric System (BES) would not include personnel who do not perform System Operator functions. First, personnel located outside of a Control Center would not be included in the definition as it clearly states that System Operators are "individuals at a Control Center." Additionally, the term "operate" is used to describe those who have the independent authority to operate the BES. Those individuals that perform certain tasks under the direct supervision of the NERC-certified operator (who is the individual that has the ultimate authority to operate the BES) would not be "operating" the BES. As noted in footnote PER-003-1, "[n]on-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability-related tasks."

ACES Standards Collaborators	No	(1) We appreciate the Standard Drafting Team's revisions to this standard and the efforts in attempting to address the applicability issues. We also appreciate the recent approach of moving the proposed standard-specific definitions to the NERC Glossary of Terms. In particular, we feel the definition assigned to "System Operator" is adequate, concise, and clearly identifies which reliability entities are accountable. (2) However, we are concerned that the definition of "Operations Support Personnel" is too broad. The definition is ambiguous and provides an opportunity for multiple compliance interpretations that may lead to including unnecessary personnel. We propose the Standard Drafting Team revise the definition to read "Individuals who perform current-day or next-day outage coordination or assessments, or individuals who acknowledge established SOLs, IROLs, or operating nomograms, for use in the real-time operations of the Bulk Electric System." We feel that this proposed definition focuses on Reliability Coordinators, Balancing Authorities, and Transmission Operators and better aligns with the applicability of Requirement R5.(3) We continue to be concerned with the applicability of Transmission Owners. This inclusion appears to address regional variance for "local transmission control centers." We recommend that the drafting team consider removing the TO function from the applicability section and providing technical justification that the NERC Rules of Procedure

		govern the registration process. This is not an issue that should be resolved in a standard; rather, NERC should utilize its tools that are already in place to properly register entities with appropriate functions. This registration issue could be better handled by ERO compliance staff when facts and circumstances arise.

Response: Thank you for your comments. The SDT team concluded that the use of the of the word "determine," as opposed to "acknowledge established," more accurately describes the role of Operations Support Personnel and the personnel that need to be trained under the standard, which is consistent with FERC's directive.

With respect to Transmission Owners (TOs), the SDT concluded, consistent with FERCs directive, that the personnel described in section 4.1.4.1, should receive formal training under the standard consistent with their roles, responsibilities and tasks. As FERC noted (Order No. 693 at P 1343), these personnel may affect the reliability of the BES. These entities may take independent action under certain circumstances, to protect assets, personnel safety and during system restorations. The SDT determined that the optimal way to respond to FERC's directive to train local control center transmission operators was to broaden the scope of the standard to include those personnel of a TO identified in 4.1.4.1.

Additionally, there are several ways that a registered entity's functional responsibilities can be transferred to another entity: through an agreement or through registration – either a coordinated functional registration (CFR), or as a joint registration organization (JRO). For this standard, the objective is to ensure that local control center transmission operator personnel are trained regardless of how the entity is registered.

The SDT notes that section 501 of the NERC Rules of Procedure (ROP) provides that the NERC Compliance Registry (NCR) will set forth the identity and functions performed for each organization responsible for meeting requirements/sub-requirements of the Reliability Standards. A generation or transmission cooperative, a joint-action agency or another organization may register as a Joint Registration Organization (JRO), in lieu of each of the JRO's members or related entities being registered individually for one or more functions. Additionally, multiple entities may each register using a Coordinated Functional Registration (CFR) for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function pursuant to a written agreement for the division of compliance responsibility.

Luminant	No	The rationale for Operations Support Personnel indicates that Operations Support Personnel are personnel of the RC, BA or TOP. If this is intended target for this definition then the definition should state that, similar to the way the System Operator definition does.

Response: Thank you for your comments. The SDT determined that it was unnecessary to include the functional entities in the definition of Operations Support Personnel because (1) the requirement applicable to such personnel only applies to RCs, BAs, and TOPs, and (2) the definition is limited to individuals that perform specific tasks. Including the functional entities would thus be redundant. In contrast, functional entities are listed in the definition of System Operator to clarify that GOP personnel would not be considered System Operators.

SPP Standards Review Group	No	We have a concern regarding the lack of clarity in the language within the RSAW that requires an auditor to focus upon support personnel who are directly involved in Real-time operations of the BES. Potentially every employee in an entity is linked to the System Operator's role in operating the system. Such a linkage is overwhelming and creates a burdensome task on the industry. We do not believe this is the intent of the drafting team and encourage the drafting team to work closely with NERC Compliance staff to develop RSAW language which restricts an auditor's review to the personnel the entity has identified.

Response: The SDT thanks you for your comments and will continue to work with NERC compliance staff to consider your concerns.

Blue Ridge Electric	No	The team has made a good start at limiting the scope of the Standard to transmission operators. However, the Standard still references TO's without an explanation of why TO's should be included in this Standard. Some TO's have no impact on the BES and this standard is over-reaching.

Response: Thank you for your comments. The SDT concluded, consistent with FERCs directive, that the personnel described in section 4.1.4.1, should receive formal training under the standard consistent with their roles, responsibilities and tasks. As FERC noted (Order No. 693 at P 1343), these personnel may affect the reliability of the BES. These entities may take independent action under certain circumstances, to protect assets, personnel safety and during system restorations. The SDT determined that the optimal way to respond to FERCs directives to train local control center transmission operators was to broaden the scope of the standard to include those personnel of TOs identified in 4.1.4.1.

LCRA Transmission Services Corporation	No	The definition of Operations Support personnel is too vague. During previous WebEx's on the definition, members of the standards drafting

		team explained that the purpose of the definition was to limit the scope of any training to those tasks performed by support personnel to tasks that relate to, or are a critical component of, R-R tasks performed by System Operators. This new definition goes far beyond that: "...in direct support of real-time operations...". That language opens the scope of this new standard much wider than ever before. It is unmanageable in its current definition as it is far too broad. There are numerous tasks a System Operator performs in real-time that are not Reliability-Related and are supported by various other control room staff, yet this new definition does not differentiate between the two. The standards drafting team MUST work on this definition until it is near perfect because it is critical to defining what type of, and how much training for these support personnel will be required.

Response: Thank you for your comments. The definition of Operations Support Personnel continues to be limited to those personnel that "perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms." As such, the SDT has appropriately limited the scope of those support personnel to be trained under the standard. Additionally, Requirement R5 limits the training of Operations Support Personnel to "how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1."

Northern Indiana Public Service Company (NIPSCO)	No	The applicability to TO and Operations Support Personnel is vage. Suggested revision: Remove the 'can' that was added to the Operator Support Personnel definition.

Response: Thank you for your comments. The definition of Operations Support Personnel continues to be limited to those personnel that "perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms." As such, the SDT has appropriately limited the scope of those support personnel to be trained under the standard. Additionally, Requirement R5 limits the training of Operations Support Personnel to "how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1."

As FERC recognized local control center operators have the ability to act independently. The SDT included the word "can" in section 4.1.4.1 to reflect that ability (note that it is the TO applicability section that has the word "can," not the definition of Operations

Support Personnel). TOs typically do not act independently, but in practice it has been identified that TOs may act independently. If you remove the word “can” it implies that TOs always acts independently.

Consolidated Edison Co. of NY, Inc.	No	The Drafting Team must consider how emergencies are handled. For example, if there is a situation in the field that involves the safety of the public or industry personnel, there are entities that allow control room personnel (‘non-System Operators’) to do emergency switching. However, these control room personnel under normal conditions perform no independent actions, no Reliable Operation functions or any functions related to reliability. During emergencies, in the interest of safety and expediency, these control room personnel will take independent actions to remove a BES component from service. PER-005 -002 would be applicable to these people unnecessarily. The above issue impacts two issues on Rev 2.Definitions:”System Operator - An individual at a Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who independently [Delete: operate] (Insert: controls) or directs the operation of the Bulk Electric System in Real-time.”- Either change the word “operate” to control or delete the word altogether. Applicability4.1.4 Transmission Owner that has: 4.1.4.1 Personnel, excluding field switching personnel, who can act independently to [Delete: operate] (Insert: control) or direct the operation of the Transmission Owner’s Bulk Electric System Transmission facilities in Real-time- Either change the word “operate” to control or delete the word altogether.

Response: Thank you for your comments. The SDT determined that elimination of the word “operate” would create a reliability gap for personnel that operates or directs the operations of BES in Real-time. Applicable personnel who operate the BES and are making independent decisions need to be capable of performing those actions, especially in emergencies, and thus need to be trained under Requirement R5. Note that this is different from being certified under PER-003.

Under Requirement R3 of PER-005-2, an entity is required to verify that its applicable personnel are capable of performing each of their assigned BES company-specific Real-time reliability-related tasks and have the ability under Requirement R1 to determine whether these personnel need additional or ongoing training.

The SDT notes that personnel that meet the Transmission Owner (TO) applicability criteria or are System Operators will be subject to PER-005-2.

City of Tallahassee - Electric Utility	No	The City of Tallahassee (TAL) is concerned with the proposed standard's expansion of training requirements to include the planners performing the current and next day studies, as well as those personnel determining the system operating limits. There is no evidence to suggest a reliability gap exists.

Response: Thank you for your comments. The SDT included "current and next day studies" to provide clarity to the FERC directive from Order 693 P 1393, which required that PER-005 be extended to include "…operations planning and operations support staff who carry out outage planning and assessments and those who develop SOLs or IROLs or operating nomograms for real-time operations." The language, which was requested in comments to a prior posting, specifically clarifies the phrase "carry out outage planning and assessments" so that it is limited to those activities that are conducted in Real-time.

City of Tallahassee	No	The City of Tallahassee (TAL) is concerned with the proposed standard's expansion of training requirements to include the planners performing the current and next day studies, as well as those personnel determining the system operating limits. There is no evidence to suggest a reliability gap exists.

Response: Thank you for your comments. The SDT included "current and next day studies" to provide clarity to the FERC directive from Order 693 P 1393, which required that PER-005 be extended to include "…operations planning and operations support staff who carry out outage planning and assessments and those who develop SOLs or IROLs or operating nomograms for real-time operations." The language, which was requested in comments to a prior posting, specifically clarifies the phrase "carry out outage planning and assessments" so that it is limited to those activities that are conducted in Real-time.

City of Tallahassee	No	The City of Tallahassee (TAL) is concerned with the proposed standard's expansion of training requirements to include the planners performing the current and next day studies, as well as those personnel determining the system operating limits. There is no evidence to suggest a reliability gap exists.

Response: Thank you for your comments. The SDT included "current and next day studies" to provide clarity to the FERC directive from Order 693 P 1393, which required that PER-005 be extended to include "…operations planning and operations support staff who carry out outage planning and assessments and those who develop SOLs or IROLs or operating nomograms for real-time operations." The language, which was requested in comments to a prior posting, specifically clarifies the phrase "carry out outage planning and assessments" so that it is limited to those activities that are conducted in Real-time.

Oncor Electric Delivery Company LLC	No	Oncor has concerns on the lack of clarity in the language in the revised Standard as well as the RSAW; In order to ensure the intent of the SDT is clear, the language below should be addressed to avoid misinterpretation by personnel handling compliance monitoring functions, specifically,- "based on a defined and documented methodology" - this language could be interpreted in multiple ways and needs to be clarified the methodology utilized to develop training is to be documented-"support personnel" define in the RSAW - this could be interpreted as all personnel who in some form support the control room.

Response: Thank you for your comments. The SDT does not agree that the use of the phrase "based on a defined and documented methodology" creates a lack of clarity. Rather the use of this phrase provides registered entities with the flexibility to determine how they will identify BES company-specific Real-time reliability-related tasks and document their methodology. Additionally, the SDT does not agree that personnel who are Operations Support Personnel is open for interpretation. Each of the personnel must be "individuals who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms, in direct support of Real-time operations of the Bulk Electric System", as identified by the RC, BA and TOP in Requirement R5.

US Bureau of Reclamation	Yes	The Bureau of Reclamation (Reclamation) agrees with the drafting team's decision to remove Transmission Owners from R5 to clarify that Operations Support Personnel are involved in current day or next-day outage planning, or SOL, IROL, or nomogram development for Reliability Coordinators, Balancing Authorities, or Transmission Operators.

Response: Thank you for your comments.

IRC/Standards Review Committee	Yes	None

SERC OC Review Group	Yes	Bringing back the capitalization of Control Center in the System Operator definition seems appropriate and we agree it does not present any inconsistency with the inclusion of GOP in the Control Center definition. The Operations Support Personnel definition is an improvement to better identify personnel to whom the standard applies. We agree with the removal of the former "standard-only" definitions and the elimination of the aggregator term System Personnel.
Response: Thank you for your comments.		
Duke Energy	Yes	(1) Duke Energy recommends the following revision to Operations Support Personnel: Operations Support Personnel: Individuals, in direct support of Real-time operations of the Bulk Electric System, who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms.
Response: Thank you for your comment. The team has reviewed and does not believe the suggested modification provides additional clarity to the Operations Support Personnel definition.		
CenterPoint Energy Houston Electric LLC.	Yes	CenterPoint Energy agrees with the revisions to Operations Support Personnel and System Operator definitions.
Response: Thank you for your comments.		
American Electric Power	Yes	Operations Support Personnel - By genericizing the definition, it could be misinterpreted as including individuals outside of Transmission functional areas. We do not believe it was the intent of the drafting team to widen the scope of the definition. In addition, we recommend removing the word "or" from "outage coordination or assessments" and it so that it reads "who perform current day or next day outage coordination assessments..."

Response: Thank you for your comments. The “or” was added to provide flexibility due to the various business practices of entities that will have to comply with this standard.

Electric Reliability Council of Texas, Inc.	Yes	ERCOT is generally supportive of the SDT definitions as written.

Response: Thank you for your comments.

Arizona Public Service	Yes	
Florida Municipal Power Agency	Yes	
Dominion	Yes	
DTE Electric	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
Bonneville Power Administration	Yes	
Idaho Power Co.	Yes	
ISO New England Inc.	Yes	
American Transmission Company, LLC	Yes	
Manitoba Hydro	Yes	

Ameren	Yes
Independent Electricity System Operator	Yes
ReliabilityFirst	Yes
Xcel Energy	Yes
PJM Interconnection	Yes
Consumers Energy Company	Yes
Wisconsin Electric Power Company	Yes

2. **The drafting team has revised PER-005-2 in response to stakeholder comments. Do you agree with the revised standard? If you do not agree or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration:

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	No	The term 'operate' is too broad. In Order No. 742 at P62, FERC clarified its understanding that local control center personnel "exercise control over a significant portion of the Bulk-Power System under the supervision of the personnel of the registered transmission operator." This draft was to address the local transmission owners, however the SDT chose to use the term 'operate,' whereas Order 742 used 'control.' This term should be added to the NERC Glossary.Suggest rewording the Applicability as follows to be in accordance with the FERC understanding: 4.1.4 Transmission Owner that has: 4.1.4.1 Personnel, excluding field switching personnel, who can act independently to control or direct the operation of the Transmission Owner's Bulk Electric System Transmission facilities in Real-time. Suggest deleting Requirement R5. EMS personnel have been excluded because the data does not support their inclusion. From page 4 of the White Paper (July 15, 2013):"The argument for not including EMS personnel in the training standard at this time is based on a report provided by the Event Analysis Subcommittee (EAS). The EAS worked with the NERC Event Analysis (EA) staff to review the events that have been cause-coded since October 2010. The database has over 263 events; ... [and] only two were deemed to be a training issue. Therefore, based on the information, the EAS and PER ad hoc group do not believe it is necessary at this time to require EMS support personnel to receive the level of training required of a BA, Reliability Coordinator (RC), and TOP by NERC standard PER-005."A data analysis would show

Organization	Yes or No	Question 2 Comment
		that Operations Support Personnel should be excluded as well. If only two (of the 263 events) were deemed to be a training issue, then how can there be a reliability gap with the training of Operation Support Personnel?If it is decided to keep Requirement R5, suggest using the appropriate language to make it conform with the preceding. The applicability to Transmission Owner should be removed from the standard. This sets a precedent of applying “operator” requirements to entities that are “owners.” This could expand applicability for TOs into additional standards, such as those dealing with issuing Operating Instructions, or owning and operating Control Centers. As outlined by FERC directive in Order 742, these TOs are either following predefined procedures or specific directions from a TOP and should not be considered to have independent operation, control or authority of the BES and should not have applicability to standards related to the operation of the BES. If the Transmission Owner applicability remains, “facility” in 4.1.4.1 should be capitalized. The applicability to Transmission Owners is only to their “Bulk Electric System transmission facilities” and the definition of Facility is “[a] set of electrical equipment that operates as a single Bulk Electric System Element.” Since both the definition of Facility and the applicability are limited to the BES they are synonymous and not capilizing the term only adds confusion.If the applicability to Transmission Owner is retained, recommend removing Transmission Owners from R4 which requires entities who control facilities with IROLs to use simulation technology during emergency operations training. In Order 693, FERC directed NERC to require Reliability Coordinators, Transmission Operators, and Balancing Authorities to use simulation technology during emergency operations training. The requirement to use simulation technology does not make sense for Transmission Owners who do not have a wide area view of the BES and do not determine actions necessary to relieve IROLs. Transmission Owners should not be required to use simulation technology during emergency operations training because, like Generator Operators, they will receive operational instructions from Transmission Operators, Balancing Authorities or Reliability Coordinators during emergencies.The Applicability section for Generator Operator, Section 4.1.5.1 should use the term “Control Center” as the NERC

Organization	Yes or No	Question 2 Comment
		definition of Control Center, "One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of:... 4) a Generator Operator for generation Facilities at two or more locations" is consistent with the idea of a "centrally located dispatch center" as outlined in the applicability section.The requirement for Transmission Owners to develop a training program using the systematic approach to training in R2 will result in training that is better tailored to individual Transmission Owner BES reliability related tasks.There is a disconnect between PER-005-2 and the draft COM-002-4 Applicability. The COM-002-4 draft is applicable to DP's while PER-005-2 is applicable to the TO local control center personnel. It is incongruous that the COM standard expects these operating instructions to go to DP but PER-005 expects them to go to TO's. What is the measure of "independently" in Applicability 4.1.4.1. "Independently" of what?Extend the second HIGH VSL condition for R6 by adding "to develop and implement training for its personnel" after "systematic approach" to conform with the language used in R6.

Response:

Thank you for your comments. Each concern is addressed below.

(1) The term "operate" is used to describe the actions taken by those individuals who have the independent authority to operate the BES. The SDT does not agree that the addition of the word "control" or the deletion of "operate" provides any additional clarity to the applicable TO personnel.

) With respect to the comment about Operations Support Personnel, in Order No. 742 the Commission noted that "…NERC, in developing proposed Reliability Standard PER-005-1, did not comply with the directive in Order No. 693 to expand the applicability of the personnel training Reliability Standard, PER-002-0, to include (i) generator operators centrally-located at a generation control center with a direct impact on the reliable operation of the Bulk-Power System, and (ii) operations planning and operations support staff who carry out outage planning and assessments and those who develop System Operating Limits (SOL), Interconnection Reliability Operating Limits (IROL) or operating nomograms for real-time operations." NERC may provide FERC with technical justification as to why a directive does not need to be implemented. This suggestion has been discussed throughout the standards development process of PER-005-1 and PER-005-2.

Organization	Yes or No	Question 2 Comment

However, industry stakeholders have not been able to provide the technical analysis needed to support removal of Operations Support Personnel from training requirements. During the course of developing PER-005-2, with the exception of arguments related to the directive to consider whether there is a need to train EMS personnel, the SDT did not identify any new arguments as to why it need not respond to the outstanding directives. As such, the SDT concluded it was obligated to draft a standard that responded to FERC's directive. The SDT has sought to respond to FERC's directive in a manner that is acceptable to industry and addresses concerns related to the scope of the training requirement. The SDT has worked diligently to draft the standard narrowly, as reflected in its responses to the questions raised at the webinar.

Additionally, following FERCs issuance in Order No. 693, industry stakeholders provided rationale as to why support personnel should not be subject to a training standard. FERC rejected industries rationale in Order No. 742 creating the heavy burden for industry to successfully demonstrate why this directive was not needed. The EMS technical justification does not provide conclusive evidence to support the exclusion of support personnel from PER-005-2.

(3) With respect to Transmission Owners (TOs), the SDT concluded, consistent with the FERC directive, that the personnel described in section 4.1.4.1, should receive formal training under the standard consistent with their roles, responsibilities and tasks. As FERC noted (Order No. 693 at P 1343), these personnel may affect the reliability of the BES. These entities may take independent action under certain circumstances, to protect assets, personnel safety and during system restorations. The SDT determined that the optimal way to respond to FERCs directives to train local control center personnel was to broaden the scope of the standard to include those personnel of TOs identified in 4.1.4.1.

Furthermore, the SDT used an equally efficient and effective method to address the FERC directive to define local control center by adding TOs with certain personnel to the applicability to PER-005-2.

(4) The SDT thanks you for bringing the inconsistency to SDT attention. The SDT intended to use the NERC Glossary term. The term "facilities" was inadvertently lower cased as evidenced by inclusion of the term "BES" prior to "transmission Facilities." The term "Facilities" is now in the standard. The capitalization of "Facilities" is consistent with the term in Requirement R4.

(5) The SDT disagrees. The inclusion of Transmission Owners in this requirement reflects the varying registrations and responsibilities of these local control centers. Such agreements between RTO's and TOPs may require mitigation and/or response from the local control center operator and therefore including TOs in this requirement is appropriate.

Organization	Yes or No	Question 2 Comment
If an applicable TO does not have "(1) operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) established protection systems or operating guides to mitigate IROL violations" then they would not be subject to Requirement R4 of PER-005-2. (6) The suggested modification to GOP applicability to replace "centrally located dispatch center" with the term "Control Center" is not supported by previous industry comments. (7) Addressing your concern regarding COM-002-4 is outside the scope of this project. (8) Within the electrical industry, "independently" means having the authority to act at one's own discretion. (9) The SDT has concluded that the current VSL is appropriate and no modifications will be made.		
US Bureau of Reclamation	No	(1) Reclamation requests that the drafting team remove Transmission Owners from R4, which requires entities who control facilities with IROLs to use simulation technology during emergency operations training. In Order 693, FERC directed NERC to require reliability coordinators, transmission operators, and balancing authorities to use simulation technology during emergency operations training. The requirement to use simulation technology does not make sense for Transmission Owners who do not have a wide area view of the BES and do not determine actions necessary to relieve IROLs. Transmission Owners should not be required to use simulation technology during emergency operations training because, like Generator Operators, they will receive operational instructions from Transmission Operators, Balancing Authorities or Reliability Coordinators during emergencies. Therefore, Reclamation believes the proposed requirement would result in high costs with little reliability benefit. The requirement for Transmission Owners to develop a training program using the systematic approach to training in R2 will result in emergency operations training that is better tailored to individual Transmission Owner training needs. (2) Reclamation suggests that the drafting team update the Guidelines and Technical basis section to refer to both R1 and R2 because both requirements now reference using a systematic approach to develop and implement a training program based on BES company-specific Real-time reliability related tasks.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. (1) The SDT disagrees. The inclusion of Transmission Owners in this requirement reflects the varying registrations and responsibilities of these local control centers. Such agreements with RTO's and TOPs may require mitigation and/or response from the local control center operator and therefore the inclusion in this standard is appropriate. However, the requirement is only applicable if an entity has (1) operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations. (2) The SDT thanks you for the comment and will update the Guidelines and Technical Basis Document.		
Salt River Project	No	The term 'operate' is too broad. In Order No. 742 at P 62, FERC clarified its understanding that local control center personnel "exercise control over a significant portion of the Bulkâ€Power System under the supervision of the personnel of the registered transmission operator." This draft was to address the local transmission owners, however the SDT chose to use the term 'operate,' whereas Order 742 used 'control.' This term should be added to the NERC Glossary.The applicability to Transmission Owner should be removed from the standard. This sets a precedent of applying "operator" requirements to entities that are "owners." This could expand applicability for TOs into additional standards, such as those dealing with issuing Operating Instructions, or owning and operating Control Centers. As outlined by FERC directive in Order 742, these TOs are either following predefined procedures or specific directions from a TOP and should not be considered to have independent operation, control or authority of the BES and should not have applicability to standards related to the operation of the BES. If the applicability to Transmission Owner is retained, recommend removing Transmission Owners from R4 which requires entities who control facilities with IROLs to use simulation technology during emergency operations training. In Order 693, FERC directed NERC to require Reliability Coordinators, Transmission Operators, and Balancing Authorities to use simulation technology during emergency operations training. The requirement to use simulation technology does not make sense for Transmission Owners who do not have a wide area view of the BES and do not determine actions necessary to relieve IROLs. Transmission Owners should not be required to use simulation technology

Organization	Yes or No	Question 2 Comment
		during emergency operations training because, like Generator Operators, they will receive operational instructions from Transmission Operators, Balancing Authorities or Reliability Coordinators during emergencies.Suggest rewording the Applicability as follows to be in accordance with the FERC understanding: 4.1.4 Transmission Owner that has: 4.1.4.1 Personnel, excluding field switching personnel, who can act independently to control or direct the operation of the Transmission Owner's Bulk Electric System Transmission facilities in Realâ€?time

Response:

Thank you for your comments. Each concern is addressed below.

(1) The term "operate" is used to describe the actions taken by those individuals who have the independent authority to operate the BES. The SDT does not agree that the addition of the word "control" or the deletion of "operate" provides any additional clarity to the applicable TO personnel.

(2) The Standard drafting team (SDT) does not agree that the addition of the word "independent" provides any additional clarity. The definition of System Operator as those who "operate or direct the operation" of the Bulk Electric System (BES) would not include personnel who do not perform System Operator functions. First, personnel located outside of a Control Center would not be included in the definition as it clearly states that System Operators are "individuals at a Control Center." Additionally, the term "operate" is used to describe those individuals that may take certain action under the direct supervision of an individual that have authority to operate the BES should not be considered to operate the BES. As noted in footnote PER-003-1, "[n]on-NERC certified personnel performing any reliability-related task of a real-time operating position must be under the direct supervision of a NERC Certified System Operator stationed at that operating position; the NERC Certified System Operator at that operating position has ultimate responsibility for the performance of the reliability related tasks."

(3) With respect to Transmission Owners (TOs), the SDT concluded, consistent with the FERC directive, that the personnel described in section 4.1.4.1, should receive formal training under the standard consistent with their roles and responsibilities and tasks. As FERC noted (Order No. 693 at P 1343), these personnel may affect the reliability of the BES. These entities may take independent action under certain circumstances, to protect assets, personnel safety and during system restorations. The SDT determined that the optimal way to respond to FERCs directives to train local control center personnel was to broaden the scope of the standard to include those personnel of TOs identified in 4.1.4.1.

Organization	Yes or No	Question 2 Comment
The inclusion of Transmission Owners in this requirement reflects the varying registrations and responsibilities of these local control centers. Such agreements with RTO's and TOPs may require mitigation and/or response from the local control center operator and therefore the inclusion in this standard is appropriate. However, the requirement is only applicable if an entity has (1) operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations.		
Florida Municipal Power Agency	No	FMPA appreciates that the SDT made changes, based on stakeholder comments, to the draft PER 005-2 standard. The reason for voting "no" on the standard is based on the RSAW language and lack of criteria on how an entity will be assessed and audited.There is language in the RSAW that is repeated for every requirement (R1-R6) as "Notes to Auditor". (see below) This language is not clear regarding the nature and extent of audit procedures that will be applied. There is reference to scoping the audit based on "certain risk factors to the Bulk Electric System". It is not clear what "risk factors" will be used and auditing can range from "exclusion of the requirement" to "review training records for an entity's entire population of System Operators, applicable personnel, Generator Operators..." etc. This appears to be an attempt to apply Reliability Assurance Initiative (RAI) concepts that have not been finalized and communicated to the industry. It is uncertain whether these concepts have been fully developed yet; and therefore, this leaves too much auditor discretion, without providing the industry information or criteria on how "risk" will be assessed. Stakeholders continue to await the details of these RAI concepts that are being utilized in RSAWS. Clarity is needed around how an entity's risk to the BES will be assessed due to compliance or non-compliance with this standard. This would also beneficial for an entity to know, so that they can lessen that risk, as appropriate.Language from RSAW Notes to Auditor:"The nature and extent of audit procedures applied related to this requirement will vary depending on certain risk factors to the Bulk Electric System. In general, more extensive audit procedures will be applied where risks to the Bulk Electric System are higher based on compliance with this requirement. Based on the assessment of risk, as described above, specific audit procedures applied for this requirement may range from exclusion of this

Organization	Yes or No	Question 2 Comment
		requirement from audit scope to the auditor reviewing training records for an entity's entire population of System Operators." (Emphasis added)
Response: The SDT thanks you for your comments and will continue to work with NERC Compliance staff to consider your concerns.		
ACES Standards Collaborators	No	(1) We appreciate the Standard Drafting Team's actions taken in response to ours and other industry comments regarding the previous draft standard. In particular, we would like to recognize the SDT's attempt to differentiate the TO responsibilities from that of RCs, BAs, and TOPs. We also appreciate the alignment of outstanding FERC Directives and the removal the 32-hour requirement for emergency operations training.(2) However, we have several concerns with the direction taken in this revision. The title of the Standard should simply state that this is a "Personnel Training" standard and avoid references to "Operations" altogether. We feel that this would better align with the purpose of this standard, to focus on those personnel who perform and support the real-time operations of the Bulk Electric System.(3) Requirement R2 does not align with the applicability section of this Standard. As it is currently worded, each Transmission Owner would be required to first demonstrate that it has developed and implemented a training program using a systematic approach, and then provide proof regarding which personnel would align with the description of the Applicability Section 4.1.4.1. While an individual, non-applicable Transmission Owner may already have a training program that uses a systematic approach, we feel this opens the door to auditor interpretation regarding the applicability of Requirement R2. Instead, we propose the SDT to revise Requirement R2 to read, "Each Transmission Owner, with personnel identified in Applicability Section 4.1.4.1, shall use a systematic approach to develop and implement a training program for these identified personnel as follows."(4) We also feel the applicability of the individual parts of Requirement R2 does not align with the intent of the SDT to list TOs under the applicability section of this Standard. We believe a clarification is needed in each part to reduce the possibility of confusion in the future, especially if each part is evaluated out of context. We propose including the word "applicable" before each reference to Transmission Owner or to provide further clarification by

Organization	Yes or No	Question 2 Comment
		stating “each TO, with personnel identified in Applicability Section 4.1.4.1.”(5) Similar to Requirement R2, we feel the applicability of Requirement R3 does not align with the applicability section of this standard. As it is currently worded, each Transmission Owner would be required to first demonstrate the validity of its training program followed by the identification of its personnel who are applicable to Requirement R2, and then provide proof that it has verified the capabilities of such personnel. Instead, we propose Requirement R3 to read “Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner, with personnel identified in Requirement R1 or Requirement R2, shall verify, at least once, the capabilities of these personnel assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1, part 1.1, or Requirement R2, part 2.1.”(6) We feel the applicability of Requirement R6 does not align with applicability section of this standard for Generator Operators. As it is currently worded, each GOP would be required to first demonstrate that it has developed and implemented a training program using a systematic approach, and then provide proof regarding which personnel would align with Applicability Section 4.1.5.1 of this Standard. While an individual, non-applicable Generator Operator may already have a training program that uses a systematic approach, we feel this opens the door to auditor interpretation regarding the applicability of this requirement. Instead, we propose Requirement R6 to read, “Each Generator Operator, with personnel identified in Applicability Section 4.1.5.1, shall use a systematic approach to develop and implement training to these personnel on how their job function(s) impact the reliable operations of the BES during normal and emergency operations.”(7) We also feel the individual parts of Requirement R6 do not align with the applicability section of this Standard. We believe a clarification is needed to each part to reduce the possibility of confusion in the future, especially if each part is evaluated out of context. We propose including the word “applicable” before each reference to Generator Operator or “each Generator Operator, with personnel identified in Applicability Section 4.1.5.1.”(8) We believe R1, R2, R5, and R6 are proposing unnecessary requirements for an entity to review its training program each calendar

Organization	Yes or No	Question 2 Comment
		year. A program using a systematic approach to training will already have such criteria in place. We feel that this is an administrative task which meets Paragraph 81 criteria. Please remove the annual review requirement.(9) The Violations Severity Levels for Requirement R4 are binary in nature and should be modified to a graduated severity level. The SDT should follow a similar structure of the Requirement R2's Violations Severity Levels by including percentages of System Personnel that have received simulation technology training.(10) We complement the Standard Drafting Team's efforts to sanitize the contents of the attached Application Guidelines. We would like to pass along an observation regarding Reference #2 and a broken hyperlink for the resource, DOE-HDBK-1074-95.(11) The Compliance Enforcement Authority sections of the RSAW still expects an entity to maintain an organizational chart which identifies what employees it considers as "System Operator" to meet compliance with this Standard. We believe this was inadvertently missed by the SDT, following a recent revision to the RSAW, which addressed other references to organizational charts as compliance evidence. We feel organizational charts are a zero-defect approach to compliance, and we are concerned that auditors would argue over the list of System Operators who were not identified to receive training, thus leading to a possible violation for each instance. The standard should focus on internal controls and management practices consistent with NERC's Reliability Assurance Initiative (RAI).(12) Thank you for the opportunity to comment.

Response:

(1) The SDT thanks you for your comments. Comments are addressed below.

(2) The old title is not applicable to the changes made to the new standard. The title was changed from System Personnel Training to Operations Personnel Training to encompass the various personnel that are now trained per the applicability of this standard.

(3, 4, 5, 6, & 7) The SDT has reviewed the proposed changes and has determined the suggested modifications do not provide additional clarity.

Organization	Yes or No	Question 2 Comment
(8) The SDT agrees that a review is inherent in a systematic approach to training; however, the SDT concluded that a review should be explicitly required each calendar year due to the importance of training the applicable personnel on reliably operating the BES. (9) The drafting team agrees that the VSL is binary. SDT believes that Requirement R4 should be at a severe level. Requirement R4 is consistent with the way it was drafted from the previous PER-005-1 standard. (10) The hyperlink will be corrected. (11) The RSAW states: "An organization chart **<u>or other list</u>** identifying all System Operator and the BES company-specific Real-time reliability-related tasks they perform. List of training delivered and attendance logs for a sample of training sessions requested by the auditor." Therefore, the RSAW provides flexibility for what type of evidence an entity should provide to the auditor.		
Luminant	No	In R5 & R6, the applicable entities are required to use a "systematic approach" to training without any further explanation on what that "systematic approach" to training entails. The RSAW for R5 and R6 requires to the auditor to determine if the "systematic approach" to training included an Analysis step, an Implementation step and an Evaluation step. If these are the required components of a "systematic approach", then this should be clearly defined in the standard, rather than "required" via the RSAW.
Response: The SDT thanks you for your comments. As the RSAW was being developed, the question was raised on how an auditor would determine whether an entity had used a systematic approach. These three concepts were suggested by industry stakeholders as key components that an auditor will evaluate when determining whether an entity used a systematic approach. An auditor will always take into consideration the individual facts and circumstances for each entity. The SDT will continue to work with NERC Compliance staff to consider your concerns.		
Bonneville Power Administration	No	BPA recommends removing R2 and incorporating it back into R1. BPA feels that as presently written, this Requirement will create a situation where an entity that is a Transmission Owner (TO) and Balancing Authority (BA) / Transmission Operator (TOP) will be penalized twice for the same violation (R1 and R2). BPA feels that by combining the two requirements, this removes any potential for double jeopardy. BPA recommends that the standard drafting team create a definition for a "Bulk Electric System company- specific, reliability-related task." Although BPA understands

Organization	Yes or No	Question 2 Comment
		the benefit of having the flexibility to create a company-specific definition - as well as the ability to create a task-list based on that definition - BPA maintains without such a definition, that this would allow auditors to make different and inconsistent interpretations. BPA understands that the auditors' interpretations are outside the control of the drafting team - and this is precisely why BPA recommends the definition in order to create more clarity in the standard.
Response: The SDT thanks you for your comments. Based on comments received in the prior draft, TOs were removed from Requirement R1, which now only applies to System Operators and Requirement R2 was developed for TOs. Only RCs, BAs, and TOPs could have a possible violation of Requirement R1 and only TOs could have a possible violation of Requirement R2; therefore, the drafting team does not believe there is double jeopardy in the compliance obligations of the applicable entities to the standard. Entities have varying reliability tasks and therefore would not have the same task list. It would not be possible to create one list that all entities would have to comply with. Therefore, the standard builds in flexibility for each entity to determine its own task list. Where an entity has a document methodology and task list, an auditor will verify compliance with those documents.		
Blue Ridge Electric	No	Eliminate references to TO's and instead reference transmission operators.
Response: Thank you for your comments. The SDT concluded, consistent with FERCs directive, that the personnel described in section 4.1.4.1, should receive formal training under the standard consistent with their roles, responsibilities and tasks. As FERC noted (Order No. 693 at P 1343), these personnel may affect the reliability of the BES. These entities may take independent action under certain circumstances, to protect assets, personnel safety and during system restorations. The SDT determined that the optimal way to respond to FERCs directives to train local control center transmission operators was to broaden the scope of the standard to include those personnel of TOs identified in 4.1.4.1.		
ISO New England Inc.	No	Suggestion rewording R5 to better line up with R1 and the R5 Measures:"R5. Each Reliability Coordinator, Balancing Authority, Transmission Operator, andTransmission Owner Operator shall use a systematic approach to developand implement training for its identified Operations Support Personnel on the impactof how their job task(s) impact those BES companyâ€specific Realâ€time reliabilityâ€related tasks identified by the entity pursuant to Requirement R1 part 1.1. 5.1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, andTransmission Operator

Organization	Yes or No	Question 2 Comment
		shall create a list of Operations Support PersonnelTasks that impact those BES companyâ€specific Realâ€time reliabilityâ€-related tasks identified by the entity pursuant to Requirement R1 part 1.1.5.2 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Operator shall review, and update if necessary, its list of Operations Support Personnel Tasks identified in part 5.1 each calendar year."
Response: Thank you for your comments. FERC Order No. 693 P 1375 states that "…[s]everal commenter express concern that the operations planning and operations support staffs will be required to be trained on the transmission operators' responsibilities. The Commission clarifies that this is not the case. Training programs for operations planning and operations support staff must be tailored to the needs of the function, the tasks performed and personnel involved." Accordingly, the SDT limited the training for Operations Support Personnel to "…how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1."		
LCRA Transmission Services Corporation	No	See Question 1
Response: See response in Question 1.		
Ameren	No	With PER-002-0 being retired PER-005 has had to fill the gaps. PER-005-2 keeps referencing a "training program". We believe that the "training program" in PER-005-2 is not the same definition of a "training program" that was established in PER-002-0. PER-005-2 is being re-written and needs clarification when referring to a "training program" which references items below from PER-002-0 which need to be addressed.(Applicability Section 4.1.4) We request the drafting team change "Transmission Owner" to "Local Control Center", since this is mentioned in the Rational for TO notes.(a) Transmission Owner as defined in the NERC Glossary of Terms is an entity that owns and maintains transmission facilities.(b) We believe that Local Control Center Personnel would also need to be defined.(R1) We request that the drafting team leave the wording the way it was originally, but add Local Control Center. We believe that a good training program is developed using the Systematic

Organization	Yes or No	Question 2 Comment
		Approach to Training (SAT), not Systematic Approach (SA).(R1.1) we request that the drafting team leave the wording the way it was in PER-005-0, but nowtadd to it the term Local Control Center. We believe that it is not necessary to add “based on a defined and documented methodology”, as the SAT process has already established this. The first part of any SAT process is Task Listing. R1.2) Delete or clarify the phrase “according to its training program”. We are not sure what is the drafting team is trying to reference. Is the “training program” referring to the one in the retired PER-002-0 or the “training program” for BES reliability related tasks?(R1.3) We request that the drafting team leave the wording the way it was in PER-005-0, but not add to it the term Local Control Center. In our opinion the way it is currently worded is very vague needing clarification. What training should be delivered and what training program is it referring to?(R2) We request that the drafting team leave the wording the way it was originally but add Local Control Center. In our opinion R2 can be removed there is no need to include a whole section just for addressing personnel in a Local Control Center is needed.(R3) If R2 is deleted as we have requested then logically this requirement now becomes R2.(R3 - Request that PER-005-0 R3 language is used) (a) We request that the drafting team leave the wording the way it was originally as it only applies to System Operators.(b) We disagree with the drafting team rationale below for getting rid of the 32 hours of EOP training.(c) We believe that the appropriate number of hours would be identified as part of the systematic approach in Requirement R1 and Requirement R2 through the analysis phase and outlined in a continuous education section of their training program. Any additional hours may be duplicative or repetitive for the entity in providing training to its personnel.(d) Again the 32 hours of EOP training came from the Retired PER-002-0 standard and was implemented in part because of the August 2003 Blackout.(e) Requirement R1 requires a training program to only be developed on BES Company specific Reliability Related tasks. Yes this training program will include some Emergency Operations Tasks. The training has to be delivered and the personnel must be verified that they can perform the tasks “at least once” unless the task is new or has been modified.(f) We believe that this

Organization	Yes or No	Question 2 Comment
		rationale again seems to be referring to the “training program” of retired PER-002-0.(g) If this is taken out of the Standard, what requirement is there for doing EOP training on a yearly basis other than on your Company’s System Restoration Plan and on the Loss of Control Center Functionality?(R3.1) If R2 is deleted as we have requested then logically this requirement now becomes R2.1. We propose to the drafting team the following language for clarification. Within six months of a modification or addition of a BES company-specific Real-Time reliability-related task, each Reliability Coordinator, Balancing Authority, Transmission Operator and Local Control Center shall verify the capabilities of each of its personnel; that they are able to perform, the new or modified tasks identified in Requirement R1.1.(R3.2) We believe that the training program must include a plan for the initial and continuing training of Transmission Operator and Balancing Authority operating personnel. The training program referenced in PER-005-2 only applies to Company Specific Reliability Related Tasks.(R3.3) We believe that the training program must include training time for all Transmission Operator and Balancing Authority operating personnel to ensure their operating proficiency. We believe that there needs to be mention in PER-005-2 about providing time for training.(R3.4) We believe that the training staff must be identified, and the staff must be able to demonstrate it is competent in knowledge of system operations and instructional capabilities. (R4) For personnel identified in Requirement R2, each Transmission Operator and Balancing Authority shall provide its operating personnel at least five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.(a) We believe that this was included as R3 in PER-005-0 in anticipation of PER-002-0 being retired and the five days were changed to 32 hours.(b) We believe that this came about in part because of the August 2003 Blackout. In the FERC August 2003 Blackout report some items that needed to be addressed were Tools, Trees and Training.â€ƒ(R4) If R2 is deleted as we have requested then logically this requirement now becomes R3.1 again. We request that the drafting team change “Transmission Owner” to “Local Control Center”.(R4.1) If R2 is deleted as we have requested then logically this

Organization	Yes or No	Question 2 Comment
		requirement now become R3.2. We request that the drafting team change “Transmission Owner” to “Local Control Center”.(R5) If R2 is deleted as we have requested then logically this requirement now becomes R4. We request that the drafting team add “to training” to systematic approach.(R5.1) If R2 is deleted as we have requested then logically this requirement now becomes R4.1. We request that the drafting team change reference to Requirement R5 back to R4.(R6) If R2 is deleted as we have requested then logically this requirement now becomes R5. We request that the drafting team add “to training" to systematic approach.((R6.1) If R2 is deleted as we have requested then logically this requirement now becomes R5.1. We request that the drafting team change reference to R6 back to R5.

Response: Thank you for your comments. The SDT has provided explanations below to address your concerns.

(1) The training program you are referencing is currently in effect in PER-005-1, which is FERC approved. Therefore, an entity’s present training program should meet the requirement of this standard other than the addition of TOs.

(2) The SDT determined that the optimal way to respond to FERCs directives to train local control center transmission operators was to broaden the scope of the standard to include those personnel of TOs identified in 4.1.4.1.

(3) The drafting team changed “systematic approach to training” to the phrase “systematic approach to develop and implement training” to address concerns that the use of the phrase “systematic approach to training” meant that there was a single methodology to be used. The phrase was re-worded to clarify that there are different types of training programs that can be used. Flexibility is provided to entities so they can use the type of methodology that works best for the entity. Key components of PER-005-1 still remains with PER-005-2. (“Systematic approach to training” and “systematic approach to develop and implement training” are intended to be synonymous.)

(4) Regarding the elimination of “based on a defined and documented methodology,” the SDT determined that, although creating a job task analysis (JTA) is inherent to a systematic approach, the creation of each entities BES company-specific Real-time reliability-related task list was the important enough to be delineated within PER-005-2.

(5) Regarding the confusion related to the phrase “according to its training program” in Requirement R1 part 1.2, the training program refers to the training program required in Requirement R1.

(6) To eliminate the standard only definition “System Personnel,” the SDT created a separate requirement for applicable TOs. The term System Operator is used in R1; R2 was created to address the applicable TO personnel since these personnel may not be a System Operator.

Organization	Yes or No	Question 2 Comment
(7) The SDT determined that it was not necessary to keep the 32-hours due to the inherent nature of utilizing a systematic approach to training which will identify the amount and frequency of training needed. (8) EOP training should be recognized through each entity's systematic approach to develop and implement training.		
Northern Indiana Public Service Company (NIPSCO)	No	The revised standard does not recognize that TOPs with local control centers may have previous qualified personnel under collective bargaining agreements with multi-year terms that cannot be modified within the implementation schedule.
Response: Thank you for your comments. The SDT does not believe that any of the requirements contained within the standard, including those requiring verification of applicable personnel capabilities and necessary training, would violate the terms of a collective bargaining agreement. Additionally, TOPs are already subject to the existing PER-005-1 standard.		
The United Illuminating Company	No	A.... We like the change in applicability for the Transmission Owner but are concerned with ambiguity of the word independently. Independent of what or whom? Many Transmission Owners are required by agreements not to ever act on or change state of a BES element without direction from the TOP. What is the measure of independence. We suggest adding a follow-up subitem- Entities that (i) do not dispatch BES Generators and (ii) that have by agreement with a TOP stated they will not operate or direct the operation of the Transmission Owner's Bulk Electric System transmission facilities in Realâ€time without TOP System Operator permission are excluded from applicability. B.... There is a disconnect between PER-005-2 and draft COM-002-4 applicability. The COM-00204 draft is applicable to DP's while PER-005-2 is applicable to the TO LCC. It is incongruous that the COM standard expects these operating instructions to go to DP but PER-005 expects them to go to TO's. C.... Consider removing the R4 applicability to Transmisison Owners. Personnel at a TO would not benefit from virtual simulation of opening and closing breakers for IROL's. Order 742 did not require the use of simulators to be extended to local control centers. We

Organization	Yes or No	Question 2 Comment
		think R4 is properly scoped to TOP, RC, and BA. The requirement to use simulation technology does not make sense for Transmission Owners who do not have a wide area view of the BES and do not determine actions necessary to relieve IROLs. Transmission Owners should not be required to use simulation technology during emergency operations training because they will receive operational instructions from Transmission Operators during emergencies. D... In the applicability 4.1.4.1 capitalize facilities.

Response: Thank you for your comments. The SDT responses as follows:

(1) Within the electrical industry, “independently” means having the authority to act at one’s own discretion.

(2) Addressing your concern regarding COM-002-4 is outside the scope of this project.

(3) With the respect to Transmission Owners (TOs), the SDT concluded, consistent with FERCs directive, that the personnel described in section 4.1.4.1, should receive formal training under the standard consistent with their roles, responsibilities and tasks. As FERC noted (Order No. 693 at P 1343), these personnel may affect the reliability of the BES. These entities may take independent action under certain circumstances, to protect assets, personnel safety and during system restorations. The SDT determined that the optimal way to respond to FERCs directives to train local control center transmission operators was to broaden the scope of the standard to include those personnel of TOs identified in 4.1.4.1.

There are several ways that a registered entity’s functional responsibilities can be transferred to another entity: through an agreement or through registration – either a coordinated functional registration (CFR), or as a joint registration organization (JRO). For this standard, the objective is to ensure that personnel performing the functions are trained.

Section 501 of the NERC ROP provides that the NERC Compliance Registry (NCR) will set forth the identity and functions performed for each organization responsible for meeting requirements/sub-requirements of the Reliability Standards. A generation or transmission cooperative, a joint-action agency or another organization may register as a Joint Registration Organization (JRO), in lieu of each of the JRO’s members or related entities being registered individually for one or more functions. Additionally, multiple entities may each register using a Coordinated Functional Registration (CFR) for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function pursuant to a written agreement for the division of compliance responsibility.

Organization	Yes or No	Question 2 Comment
(4) The SDT disagrees. The inclusion of Transmission Owners in this requirement reflects the varying registrations and responsibilities of these local control centers. Such agreements with RTO's and TOPs may require mitigation and/or response from the local control center operator and therefore the inclusion in this requirement is appropriate. However, the requirement is only applicable if an entity has (1) operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations. If a TO does not have an "(1) operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations" then they would not be subject to Requirement R4 of PER-005-2.		
ReliabilityFirst	No	ReliabilityFirst votes in the negative due to the following concerns which were not addressed during the last comment period. 1. Requirement R1, Part 1.2 - ReliabilityFirst believes there should be a time period associated with Requirement R1, Part 1.2. As written, if an entity adds a new Real-time reliability-related task to their list, it would be left to the discretion of the entity on when they want to include the new training in their program. ReliabilityFirst recommends the following for consideration: "Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall design and develop training materials according to its training program, based on the BES companyâ€specific Real-time reliability-related task list created in part 1.1. [Newly updated BES companyâ€specific Real-time reliability-related tasks identified in part 1.1.1 shall be included in the training program within 45 calendar days of identification.]" 2. Requirement R3 - ReliabilityFirst questions the intent of the phrase "at least once" within Requirement R3. Is it the intent that the capabilities of its System Personnel only need to be verified once before they are able to go on shift? ReliabilityFirst believes System Personnel should be trained prior to being able to go on shift and then annually thereafter. ReliabilityFirst recommends the following for consideration: "Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once [prior to going on shift

Organization	Yes or No	Question 2 Comment
		and annually thereafter], the capabilities of its personnel assigned to perform each of the BES companyâ€specific Real-time reliability-related tasks identified under Requirement R1 part 1.1 or Requirement R2 part 2.1.
Response: Thank you for your comments. (1) Each entity will determine the frequency of training as part of a systematic approach. Identified tasks at each entity will be different and an overall time period requirement would not be practical to add to the Standard. (2) Verification relates to the assigned task(s). If the personnel's task(s) changes then an entity would need to re-verify. If the tasks stay the same, then the entity would be required to verify each personnel's capabilities once under the standard. An entity is under no obligation to only verify once. The SDT discussed and agreed that any systematic approach used to develop and implement training and the inherent association with company-specific reliability-related tasks, an entity would verify competency to perform these tasks prior to personnel taking shift. In addition, the implementation plan of PER-005-1 required compliance with Requirement R3 by the effective date of the standard.		
Indiana Municipal Power Agency	No	The use of "systematic approach" in requirement R1, R2, R5 and R6 is problematic. An entity and an auditor may have a different definition or idea of what a "systematic approach" to training means in these requirements and this could lead to many potential violations or a need for an interpretation. The SDT should give examples of what it is looking for when using this term or just remove it.
Response: Thank you for your comments. NERC is planning to provide training to the auditors and industry on PER-005-2 in 2014, including discussion at the upcoming "Standards and Compliance Workshop" scheduled for September 23-25, 2014 in Atlanta, GA. The phrase "Systematic Approach to Training" was replaced with "systematic approach to develop and implement training" to promote consistency that auditors would not presume only one method was acceptable.		
Consolidated Edison Co. of NY, Inc.	No	We suggest deleting Requirement R5. EMS personnel have been excluded because the data does not support their inclusion. From page 4 of the White Paper (July 15, 2013):"The argument for not including EMS personnel in the training standard at this time is based on a report provided by the Event Analysis Subcommittee (EAS). The EAS worked with the NERC Event Analysis (EA) staff to review the events that have

Organization	Yes or No	Question 2 Comment
		been cause-coded since October 2010. The database has over 263 events; ... [and] only two were deemed to be a training issue. Therefore, based on the information, the EAS and PER ad hoc group do not believe it is necessary at this time to require EMS support personnel to receive the level of training required of a BA, Reliability Coordinator (RC), and TOP by NERC standard PER-005."A data analysis will probably show that Operations Support Personnel should be excluded as well. If only two (of the 263 events) were deemed to be a training issue, then how can there be a reliability gap with the training of Operation Support Personnel?

Response: Thank you for your comments.

To address your concern about Operations Support Personnel, in FERC Order No. 742, the Commission noted that "…NERC, in developing proposed Reliability Standard PER-005-1, did not comply with the directive in Order No. 693 to expand the applicability of the personnel training Reliability Standard, PER-002-0, to include (i) generator operators centrally-located at a generation control center with a direct impact on the reliable operation of the Bulk-Power System, and (ii) operations planning and operations support staff who carry out outage planning and assessments and those who develop System Operating Limits (SOL), Interconnection Reliability Operating Limits (IROL) or operating nomograms for real-time operations." NERC may provide FERC with technical justification as to why a directive does not need to be implemented. This suggestion has been discussed throughout the standards development process of PER-005-1 and PER-005-2.

However, industry stakeholders have not been able to provide the technical analysis needed to support removal of Operations Support Personnel from training requirements. During the course of developing PER-005-2, with the exception of arguments related to the directive to consider whether there is a need to train EMS personnel, the SDT did not identify any new arguments as to why it need not respond to the outstanding directives. As such, the SDT concluded it was obligated to draft a standard that responded to FERC's directive. The SDT has sought to respond to FERC's directive in a manner that is acceptable to industry and addresses concerns related to the scope of the training requirement. The SDT has worked diligently to draft the standard narrowly, as reflected in its responses to the questions raised at the webinar.

Additionally, following FERCs issuance in Order No. 693, industry stakeholders provided rationale as to why support personnel should not be subject to a training standard. FERC rejected industries rationale in Order No. 742 creating the heavy burden for industry to successfully demonstrate why this directive was not needed. The EMS technical justification does not provide conclusive evidence to support the exclusion of support personnel from PER-005-2.

Organization	Yes or No	Question 2 Comment
PJM Interconnection	No	While PJM appreciates the efforts of the SDT, we continue to feel as we have from the beginning, that "equally effective and efficient solutions" outside the reliability standards process are available. The approach used by other industries using a systematic approach to training should be used as a guide. Alternative approaches would help ensure training programs have the flexibility to target requirements on the proper entities and people, even as the entities and people involved in the operation of the BES change. An example of how this standard works against those interests is the explicit exclusion of plant operators. A current trend is for new generation owners to push the reliability related tasks of communicating and interacting with the RC, BA, and TOP, (tasks once performed by generation dispatch personnel at a control center) down to the plant operators. While we appreciate RTO training requirements can be established through operating agreements (and thus not require a NERC Standard), the explicit exclusion of all plant operators is not appropriate and sends the wrong message. Again, this is not to suggest all plant operators should be included in this standard. We understand and agree with the SDT motives for this exclusion within the scope of a reliability standard. It simply highlights the current state of the industry requires a more nuanced approach for identifying entities and personnel for reliability related training requirements.
Response: Thank you for your comments. Consistent with FERC order, plant operators do not need to be included in the standard. Therefore the SDT is not expanding the scope of this project. The use of a systematic approach to develop and implement training is an effective and efficient mechanism for training under the standard with FERC directives in Orders 693 and 742.		
Consumers Energy Company	No	Requirements R5 and R6 both require the use of a systematic approach to training to train personnel on how their job function(s) impact company- specific Real-time

Organization	Yes or No	Question 2 Comment
		reliability tasks. This could be accomplished with some awareness training not the full systematic approach to training process. Requiring the systematic approach to training process for generator operators and support personnel training requirements we believe causes more administrative overhead without a reliability gain.
Response: Thank you for your comments. As FERC recognized, Operations Support Personnel and certain GOP personnel can have a direct impact on the BES and should be trained under PER-005-2. As FERC also recognized, the training for applicable GOP personnel should be accomplished using a systematic approach to training but should be tailored to how the job functions of such personnel impact the reliable operations of the BES and need not match the training provided to System Operators under Requirement R1 and applicable TO personnel under Requirement R2. A systematic approach to training is a widely accepted methodology that helps ensure that training is efficiently and effectively conducted and is directly related to the needs of the position in question. The SDT concluded that Operations Support Personnel and applicable GOP personnel shall be trained using a systematic approach. The training for Operations Support Personnel and applicable GOP personnel should be tailored in its scope, content and duration so as to be appropriate to the applicable personnel. Under Requirements R5 and R6, the frequency, amount and type of training will be determined by the outcome of the entity's systematic approach to training.		
Wisconsin Electric Power Company	No	Expanding the scope of GOP training to encompass a systematic approach to training (SAT) will likely identify tasks where GOP training is already required within existing standards. Also, the content and rigor of the VAR standards create explicit procedural requirements that address GOP impact on reliable operations of the BES during normal and emergency operations. Given that no individual Generator has a reliability impact on the BES, training requirements to address specific instances where BES reliability is potentially impacted by a GOP has been appropriately addressed within the standards. Additionally, a requirement for a GOP systematic approach to training within PER-005-2 is an odd fit given that the balance of the standard is written to address System Personnel and Real-time reliability-related tasks. If it is viewed as necessary to require a SAT program for GOPs, this can better be addressed by a standalone standard. As PER-005-2 is written, the compliance

Organization	Yes or No	Question 2 Comment
		framework and requirements applicable to managing the System Operator SAT are different than the GOP SAT. The scope limited definitions of Transmission Owners and Generator Operators will create confusion. The GOP definition is particularly problematic. A centrally located GOP conducting testing of generator may "coordinate" with a BA or TOP, however, it wouldn't be relaying instructions as they are initiating action. Additionally, the quoted text from Order No. 693 at P1389 includes, "although a generator operator typically receives instructions from a balancing authority, it is essential that generator operator personnel have appropriate training to understand those instructions, particularly in an emergency situation in which instructions may be succinct and require immediate action." The language in the order implies some GOP training is viewed as necessary regardless of GOP / BA roles. The standard as written appears to side-step the intent of order.
Response: Thank you for your comments. As FERC recognized in Order No. 693 at PP 1359–1365, certain GOP personnel can have a direct impact on the BES and should be trained under PER-005-2. As FERC also recognized, the training for applicable GOP personnel should be accomplished using a systematic approach to training but need not be as extensive as that required for System Operators under Requirement R1. A systematic approach to training is a widely accepted methodology that helps ensure that training is efficiently and effectively conducted and is directly related to the needs of the position in question. The SDT concluded that applicable GOP personnel shall be trained using a systematic approach on how their job functions impact the reliable operations of the BES during normal and emergency operations. The training for applicable GOP personnel should be tailored in its scope, content and duration so as to be appropriate to the applicable GOP personnel. Under Requirement R6, the frequency, amount and type of training will be determined by the outcome of the entity's systematic approach to training. Any training required by other standards is specific to the issue(s) addressed by that standard and should work in concert with the training provided under PER-005-2.		
Electric Reliability Council of Texas, Inc.	No	Applicability: Per the NERC Functional Model, entities that operate or direct the operation of BES transmission facilities are technically Transmission Operators and should be registered as such. Therefore, there is no need to include Transmission Owners in this Standard. Inclusion of Transmission Owners in a requirement would create conflicts with other NERC reliability standards.

Organization	Yes or No	Question 2 Comment
		Requirements: Requirement R5 - ERCOT is voting Affirmative on the Standard, but does not believe that a systematic approach to training (SAT) should be required for training of Operations Support Personnel. The FERC Orders clarified that training for support personnel should be tailored to the functions they perform and that they need not be trained to the same extent as System Operators. The SAT has been linked with the DOE Training Handbook that included the Analysis, Design, Development, Implementation, and Evaluation (ADDIE) process. Expanding training requirements for the Operations Support Personnel to include the SAT process will add additional costs to training programs that FERC was trying to avoid in their order. ERCOT does not believe that this adds any additional reliability benefit. Entities should have the flexibility to determine the training necessary to ensure reliabile operation of the BES.ERCOT recommends that the SDT revise R5 to state:R5 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES companyâ€specific Realâ€time reliabilityâ€related tasks identified by the entity pursuant to Requirement R1 part 1.1. [Violation Risk Factor: Medium] [Time Horizon: Longâ€term Planning]Measures:ERCOT does not agree with the specificity in Measures M1.3 and M2.3 as to what entities are to provide as evidence and recommends the Measures be revised to read:M1.3 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have evidence available for inspection of System Operator training records indicating the training delivered in accordance with Requirement R1 part R1.3.M2.3 Each Transmission Owner shall have evidence available for inspection of training records indicating training was delivered in accordance with Requirement R2 part R2.3.

Response: Thank you for your comments. There are several ways that a registered entity's functional responsibilities can be transferred to another entity: through an agreement or through registration – either a coordinated functional registration (CFR), or as a joint registration organization (JRO). The actions of the TO pursuant to these agreements do not require it to be registered as a

Organization	Yes or No	Question 2 Comment
TOP. TOs were added to PER-005-2 to address situations where TOs are making decisions and therefore require training. FERC is aware of these situations, which led to the directive to add TOs (local control centers) to the PER-005 standard. For this standard, the objective is to ensure that personnel performing the functions are trained. Additionally, section 501 of the NERC Rules of Procedure (ROP) provides that the NERC Compliance Registry (NCR) will set forth the identity and functions performed for each organization responsible for meeting requirements/sub-requirements of the Reliability Standards. A generation or transmission cooperative, a joint-action agency or another organization may register as a Joint Registration Organization (JRO), in lieu of each of the JRO's members or related entities being registered individually for one or more functions. Additionally, multiple entities may each register using a Coordinated Functional Registration (CFR) for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function pursuant to a written agreement for the division of compliance responsibility. The use of a systematic approach to develop and implement training is an effective and efficient mechanism for training under the standard with FERC directive in FERC Orders 693 and 742. Regarding evidence, it is a non-exclusive list which helps provide industry and auditors with examples of what may be used to determine compliance.		
Utility Services, Inc	No	Transmission Owner applicability should be removed or significantly limited. Applicability Section 4.1.4.1 states that Transmission Owners act independently to "operate[] or direct[] the operations of the Transmission Owner's BES." However, FERC Order No. 742 recognizes that a Transmission Owner is following pre-defined procedures or specific directives under the supervision of the Transmission Operator. Following a pre-defined procedure under supervision is not independent operation as suggested in the applicability section. The definition of TOP from the NERC Glossary of Terms is as follows: "The entity responsible for the reliability of its 'local' transmission system, and that operates or directs the operations of the transmission facilities." The only difference between the applicability statement in Section 4.1.4.1 and the definition is the acceptance of responsibility "...for the reliability of its 'local' transmission system..." Entities that are acting "independently" as the applicability section of the proposed standard states would inherently accept the responsibility for

Organization	Yes or No	Question 2 Comment
		the reliability of the system. Since this is not the case for the local control center based Transmission Owners in question the training requirements should be significantly limited to only include the pre-defined procedures issued by the TOP and following directive from the TOP. Conversely, if the Transmission Owner does in fact operate independently of the TOP and, therefore, has responsibility for the reliability of its local transmission system, perhaps additional registration should be considered for those entities. If this is the case, these Transmission Owners are more than simply "[t]he entity that owns and maintains transmission facilities" as Transmission Owner is defined in the NERC Glossary of Terms. Perhaps developing a new functional registration would be more appropriate method of proceeding forward, such as a "Local Control Center." This functional registration could include both the Transmission Owners and Generator Operators that are outlined in the applicability section of PER-005, as the idea of these entities independently operating a significant portion of the BES from a central location is consistent between them. Adding Transmission Owners to this standard has other additional implications as well. First, there is the administrative burden that will automatically be placed on all Transmission Owners who are not applicable. These Transmission Owners will have to provide documentation or evidence to demonstrate they are not applicable. "Proving the negative" is a difficult task that should not be overlooked. Second, if these entities do in fact need to be added to PER-005 applicability because they direct the operation of BES Facilities applicability to other standards should be added as well. The additional standards would include applicability to the version of COM-002-4 currently in development. These entities could potentially be both "Issuers" and "Receivers" or Operating Instructions as outlined in COM-002-4. Also, these entities could be applicable to the following additional standards: TOP-001-1: R4: the TO would need authority to issue reliability directives to DPs and LSEs interconnected though their transmission Facilities. R7: if under the TOs direction Facilities could be removed from service they need to have applicability to this requirement. CIP Standards: The Transmission Owners are operating the BES from a "control center," which is not consistent with the definition of "Control Center" in the NERC Glossary

Organization	Yes or No	Question 2 Comment
		of Terms because only BA, RC, TOP and GOPs fit within the definition. This results in facilities that are critical to the operation of the potentially being designated as non-Critical Assets (current CIP) or being in a lower category in CIP Version 5 (potentially Low or Medium instead of High). If the Transmission Owner applicability remains, “facility” in 4.1.4.1 should be capitalized. The rational is that “[t]here may be a facility that is not included in the NERC glossary term ‘Facility’” is flawed. The applicability to Transmission Owners is only to their “Bulk Electric System transmission facilities” and the definition of Facility is “[a] set of electrical equipment that operates as a single Bulk Electric System Element.” Since both the definition of Facility and the applicability are limited to the BES they are synomomus and not capilizing the term only adds confusion.The Applicability section for Generator Operator, Section 4.1.5.1 should use the term “Control Center” as the NERC definition of Control Center, “One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of:... 4) a Generator Operator for generation Facilities at two or more locations” is consistenet with the idea of a “centrally located dispatch center” as outlined in the applicability section.

Response: Thank you for your comments.

(1) With the respect to Transmission Owners (TOs), the SDT concluded, consistent with FERCs directive, that the personnel described in section 4.1.4.1, should receive formal training under the standard consistent with their roles, responsibilities and tasks. As FERC noted (Order No. 693 at P 1343), these personnel may affect the reliability of the BES. These entities may take independent action under certain circumstances, to protect assets, personnel safety and during system restorations. The SDT determined that the optimal way to respond to FERCs directives to train local control center transmission operators was to broaden the scope of the standard to include those personnel of TOs identified in 4.1.4.1.

(2) Additionally, there are several ways that a registered entity’s functional responsibilities can be transferred to another entity: through an agreement or through registration – either a coordinated functional registration (CFR), or as a joint registration organization (JRO). For this standard, the objective is to ensure that personnel performing the functions are trained.

Organization	Yes or No	Question 2 Comment
Furthermore, section 501 of the NERC Rules of Procedure (ROP) provides that the NERC Compliance Registry (NCR) will set forth the identity and functions performed for each organization responsible for meeting requirements/sub-requirements of the Reliability Standards. A generation or transmission cooperative, a joint-action agency or another organization may register as a Joint Registration Organization (JRO), in lieu of each of the JRO's members or related entities being registered individually for one or more functions. Additionally, multiple entities may each register using a Coordinated Functional Registration (CFR) for one or more Reliability Standard(s) and/or for one or more Requirements/sub-Requirements within particular Reliability Standard(s) applicable to a specific function pursuant to a written agreement for the division of compliance responsibility. (3) Addressing your concern regarding COM-002-4 is outside the scope of this project. (4) The SDT thanks you for bringing the inconsistency to SDT attention. The SDT intended to use the NERC Glossary term. The term "facilities" was inadvertently lower cased as evidenced by inclusion of the term "BES" prior to "transmission Facilities." The term "Facilities" is now in the standard. The capitalization of "Facilities" is consistent with the term in Requirement R4.		
City of Tallahassee - Electric Utility	No	TAL is generally concerned with clarity in the proposed standard and the consistency with which the proposed standard could be audited. As written, considerable discretion is afforded entities in developing the reliability-related tasks. To truly support and improve reliability of the bulk electric system, additional guidance is needed for registered and regional entities. Without this guidance, an entity may elect to identify fewer tasks than reasonably appropriate in an effort to ensure compliance and keep training costs to a minimum.
Response: Thank you for your comments. Yes, PER-005-2 provides flexibility for an entity to determine their BES company-specific Real-time reliability-related tasks. The standard requires that an entity document its methodology for determining those tasks, which will place parameters around what tasks an entity includes.		
City of Tallahassee	No	TAL is generally concerned with clarity in the proposed standard and the consistency with which the proposed standard could be audited. As written, considerable discretion is afforded entities in developing the reliability-related tasks. To truly support and improve reliability of the bulk electric system, additional guidance is

Organization	Yes or No	Question 2 Comment
		needed for registered and regional entities. Without this guidance, an entity may elect to identify fewer tasks than reasonably appropriate in an effort to ensure compliance and keep training costs to a minimum.
Response: Thank you for your comments. Yes, PER-005-2 provides flexibility for an entity to determine their BES company-specific Real-time reliability-related tasks. The standard requires that an entity document its methodology for determining those tasks, which will place parameters around what tasks an entity includes.		
City of Tallahassee	No	TAL is generally concerned with clarity in the proposed standard and the consistency with which the proposed standard could be audited. As written, considerable discretion is afforded entities in developing the reliability-related tasks. To truly support and improve reliability of the bulk electric system, additional guidance is needed for registered and regional entities. Without this guidance, an entity may elect to identify fewer tasks than reasonably appropriate in an effort to ensure compliance and keep training costs to a minimum.
Response: Thank you for your comments. Yes, PER-005-2 provides flexibility for an entity to determine their BES company-specific Real-time reliability-related tasks. The standard requires that an entity document its methodology for determining those tasks, which will place parameters around what tasks an entity includes.		
Oncor Electric Delivery Company LLC	No	Appears to be the same question as #1 so please refer to prior response. From an "Other" comment perspective, Oncor recommends the RSAW be reviewed in conjunction with the Standard. In the RSAW Note to Auditor sections for R1, R2, R5 and R6 a specific reference to ADDIE is implied in the parentheticals following the bullet points. An effort has been made to eliminate any reference to a specific methodology on how to approach a systematic approach to training and the potential for an auditor to tie compliance to a specific methodology. It is left up to the responsible entity to develop its own methodology. It is the responsibility of the auditor to limit his review to that methodology. At the very least, the parentheticals should be deleted which will remove the implied reference. Compliance audits should be restricted to the requirements as contained in a standard and not based on

Organization	Yes or No	Question 2 Comment
		language which exists in some other document such as the RSAW. Standards should be written such that they are very clear on what the requirments are and what is required to establish compliance. There have been instances where when questions were asked regarding specific compliance issues, entities have been referred to the RSAW for additional information on what is needed for compliance. This additional information needs to be incorporated into the requirements of the standard such that they stand alone and do not need additional support from other documentation. We need to be sure that RSAWs or other documentation do not expand the scope of a given standard. For example, the existing RSAW for PER-005-1 includes requirements for training staff compentency which are not in the standard itself.

Response: Thank you for your comments.

In rreviewing comments associated with the draft RSAW, some industry stakeholders perceive that the RSAW implies that “ADDIE” is the only systematic approach to training process. The SDT maintains that other systematic approaches may be acceptable, and will continue to work with NERC Compliance staff to ensure our intentions and industry concerns are addressed.

As explained in the Guideline developed by the SDT, any systematic approach to training will determine: 1) the skills and knowledge needed to perform BES company-specific Real-time reliability-related tasks; 2) what training is needed to achieve those skills and knowledge; 3) if the learner can perform the BES company-specific Real-time reliability-related task(s) acceptably in either a training or on-the-job environment; and 4) if the training is effective, and make adjustments as necessary.

The SDT agrees that an RSAW does not expand the requirements of the standard. An RSAW provides transparency regarding how an auditor will determine compliance with the requirements of PER-005-2.

NERC is planning to provide training to the auditors and industry on PER-005-2 in 2014, including discussion at the upcoming “Standards and Compliance Workshop” scheduled for September 23-25, 2014 in Atlanta, GA.

Organization	Yes or No	Question 2 Comment
IRC/Standards Review Committee	Yes	SRC appreciates the SDT’s efforts to revise the standard to address concerns raised in the last posting. The current version is much improved compared to the last posting. However, there are still minor improvements that can be made to the standard to better clarify what is expected on Operations Support Training: R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES companyâ€�specific Realâ€�time reliabilityâ€�related tasks identified by the entity pursuant to Requirement R1 part 1.1. 5.1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall create a list of Operations Support Personnel Tasks that impact those BES companyâ€�specific Realâ€�time reliabilityâ€�related tasks identified by the entity pursuant to Requirement R1 part 1.1. 5.2 Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall review, and update if necessary, its list of Operations Support Personnel Tasks identified in part 5.1 each calendar year. 5.3. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall design and develop training materials according to its training program, based on list of Operations Support Personnel Tasks identified in part 5.1. 5.4. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall deliver training to its Operations Support Personnel according to its training program. 5.5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator, shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify any needed changes to the training program and shall implement the changes identified.

Response: Thank you for your comments. FERC Order No. 693 P 1375 states that “…[s]everal commenters express concern that the operations planning and operations support staffs will be required to be trained on the transmission operators’ responsibilities. The Commission clarifies that this is not the case. Training programs for operations planning and operations support staff must be tailored to the needs of the function, the tasks performed and personnel involved.” Additionally, in response to FERCs directive, the SDT limited the training for Operations Support Personnel to “…how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1.” In taking this approach the SDT does not believe it

Organization	Yes or No	Question 2 Comment
is necessary to include a requirement to develop a “list of Operations Support Personnel Tasks”, as the entity may use the BES company-specific Real-time reliability-related task list it developed under Requirement R1.		
SERC OC Review Group	Yes	This review group generally supports the revisions in this posting and appreciates the efforts of the Standard Drafting Team to incorporate industry comments. We would like to suggest some wording changes and simplifications to the current draft of the standard.For R1.2 and 2.2 change “design and develop training materials according to its training program” to: “design and develop training materials for ADD: “inclusion” in its training program”M4: Change “Each Reliability Coordinator, Balancing Authority, Transmission Operator, andTransmission Owner shall have available for inspection.....” to: “Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner ADD: “that meets the criteria of Requirement R4” shall have available for inspection.....R5: At the end of the requirement statement, change: “Realâ€time reliabilityâ€ related tasks identified by the entity pursuant to Requirement R1 part 1.1.” to “Realâ€time reliabilityâ€related tasks identified by the entity ADD: “consistent with” Requirement R1 part 1.1.”. (Replace the legal phrase “pursuant to” with the phrase “consistent with”). R6: At the end of the requirement statement, change “reliable operations of the BES “during normal and emergency operations” to “reliable operations of the BES.” We feel that including the phrase “during normal and emergency operations” does not add any specificity to the requirement statement and should be removed. R5.1 and R6.1: We question why only the “evaluation” phase is included in the R5 and R6 sub-requirements, while other elements of systematic approach (develop and implement) are included in the R5 and R6 statements themselves. To simplify R5 and R6, we suggest folding the “evaluation” requirement into the R5 and R6 statements and eliminating sub-requirements R5.1 and R6.1. The proposed re-writes below include changes to R5 and R6 suggested above.R5: “Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to design, develop, implement, and (each calendar year) evaluate and update (if necessary) training for its identified Operations Support Personnel on how their job function(s) impact those BES companyâ€specific Realâ€time reliabilityâ€related tasks identified by the

Organization	Yes or No	Question 2 Comment
		entity consistent with Requirement R1 part 1.1."R6: "Each Generator Operator shall use a systematic approach to design, develop, implement, and (each calendar year) evaluate and update (if necessary) training to its personnel identified in Applicability Section 4.1.5 of this standard, on how their job function(s) impact the reliable operations of the BES."Measures for R5 & R6 would need to be adjusted accordingly if the changes above are accepted.Please also note that the date in the filename of the standard redline version is incorrect. It should be "20131204"The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Response: Thank you for your comments. (1) The SDT understands your concerns; however, the SDT concluded that the suggested modification would not be prudent at this time. The "according to its program" provides an entity the flexibility to develop and deliver training in a timely manner and believe "inclusion in its program" is implied. (2) The SDT determined that adding the phrase "meets the criteria" does not provide additional clarity to the requirement. (3) The SDT concluded that adding the phrase "consistent with" does not provide additional clarity to the requirement, and would change the intent. (4) The SDT decided that the phrase "BES during normal and emergency operations" should remain in Requirement R6.		
DTE Electric	Yes	We feel overall our concerns have been clarified in the revised standard. We would like to thank the SDT for understanding and addressing our comments/concerns.
Response: Thank you for your comments.		
SPP Standards Review Group	Yes	Although there was no RSAW comment form included with the document posting, we do have a specific comment regarding the RSAW. In the Note to Auditor sections for R1, R2, R5 and R6 a specific reference to ADDIE is implied in the parentheticals following the bullet points. An effort has been made to eliminate any reference to a specific methodology on how to approach a systematic approach to training and the potential for an auditor to tie compliance to a specific methodology. It is left up to

Organization	Yes or No	Question 2 Comment
		the responsible entity to develop its own methodology. It is the responsibility of the auditor to limit his review to that methodology. At the very least, the parentheticals should be deleted which will remove the implied reference. Compliance audits should be restricted to the requirements as contained in a standard and not based on language which exists in some other document such as the RSAW. Standards should be written such that they are very clear on what the requirments are and what is required to establish compliance. There have been instances where when questions were asked regarding specific compliance issues, entities have been referred to the RSAW for additional information on what is needed for compliance. This additional information needs to be incorporated into the requirements of the standard such that they stand alone and do not need additional support from other documentation. We need to be sure that RSAWs or other documentation do not expand the scope of a given standard. For example, the existing RSAW for PER-005-1 includes requirements for training staff compentency which are not in the standard itself.Change the '...to develop and implement training to...' in R6 to '...to develop and implement training for...'. This language is consistent with that used in R1, R2 and R5.Change the '...evidence of using a systematic approach to training to develop...' in M2 to '...evidence of using a systematic approach to develop...'. This language is consistent with that used in the Purpose, R1, M1, R2 and other locations throughout the standard.In the first bullet at the top of Page 2 in the Applicable Entities section of the Implementation Plan, change 'Transmission Owners that has...' to 'Transmission Owners that have...'.

Response: Thank you for your comments. As the RSAW was being developed, the question was raised on how an auditor would determine whether an entity had used a systematic approach. These three concepts were suggested by industry stakeholders as key components that an auditor will evaluate when determining whether an entity used a systematic approach. Although, the three concepts are incorporated into the ADDIE process, they are elements of any systematic approach. An entity has the flexibility to determine what its systematic approach will consist of as long as it incorporates the three concepts. An auditor will always take into consideration the individual facts and circumstances for each entity.

Organization	Yes or No	Question 2 Comment
The SDT agrees that an RSAW does not expand the requirements of the standard. An RSAW provides transparency regarding how an auditor will determine compliance with the requirements of PER-005-2. In reviewing comments associated with the draft RSAW, some industry stakeholders perceived that the RSAW implies that "ADDIE" is the only systematic approach to training process. The SDT maintains that other systematic approaches may be acceptable, and will continue to work with NERC Compliance staff to ensure our intentions and industry concerns are addressed. As explained in the Guideline developed by the SDT, any systematic approach to training will determine: 1) the skills and knowledge needed to perform BES company-specific Real-time reliability-related tasks; 2) what training is needed to achieve those skills and knowledge; 3) if the learner can perform the BES company-specific Real-time reliability-related task(s) acceptably in either a training or on-the-job environment; and 4) if the training is effective, and make adjustments as necessary.		
Duke Energy	Yes	(1) While Duke Energy understands the position of the SDT for not including coordination between a GOP and RC/BA/TOP in R6 of the current draft of PER-005-2, Duke Energy continues to have concerns that the removal of this coordination would not satisfy the FERC Order and would not be tailored in scope, content, and duration so as to be appropriate to Generation Operations personnel and the objective of promoting system reliability.Duke Energy maintains its recommendation of reinserting the language for coordination as used in draft 1 of this standard project.
Response: Thank you for your comments. The SDT removed coordination from the previous draft based of industry comments regarding coordination between the RC, BA, TOP, TO and GOPs. GOPs explained that they were capable of independently developing training without the coordination with the RC, BA, and TOP.		

Organization	Yes or No	Question 2 Comment
CenterPoint Energy Houston Electric LLC.	Yes	CenterPoint Energy would like to thank the PER-005-2 Standard Drafting Team and appreciates the SDT's time and effort dedicated in the development of this standard, in engaging the industry, and incorporating industry feedback.CenterPoint Energy suggests that the SDT consider the following revisions to align the Measures with the requirement language. In M2 the words "to training" as it is used in, "...evidence using a systematic approach to training to develop and implement a training program..." should be deleted and the revised M2 would read "...evidence using a systematic approach to develop and implement a training program..." CenterPoint believes this revision would align the measure with the requirement language regarding the Standards recent shift of the use of "systematic approach to training" versus training that is in accordance with its "systematic approach".
Response: Thank you for your comments. The phrase "to training" has been removed from M2.		
Manitoba Hydro	Yes	Although Manitoba Hydro is in general agreement with the standard, we have the following comments: (1) M2 - the words 'to training' should be deleted following 'systematic approach' to be consistent with M1.(2) R3 - unclear what 'at least once' will entail in terms of a timeframe. Is it at least once during the employment of a particular personnel, at least once during the life of the training program, etc?(3) R4, M4 - presumably the 'criteria of Requirement R4' means items (1) and (2) listed in R4. It would be more clear if the word 'criteria' was actually used in describing same, i.e. "Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that meets one of the following criteria: (1)..."(4) R6 - reference should be to 4.1.5.1 to be consistent with references used in R2.(5) VSLS, R1, R2, Moderate VSL - the requirement in 1.4 and 2.4 to evaluate and implement any identified changes is broken into two separate violations. However, the requirement in 1.1.1 to review and update if necessary is not, which seems inconsistent. (6) VSLs, R4 - is missing the reference to emergency operations training that is in the requirement itself.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. “To training” has been removed. R3: Verification relates to the assigned task(s). If the personnel’s task(s) changes then an entity would need to re-verify. If the tasks stay the same, then the entity would be required to verify each personnel’s capabilities once under the standard. An entity is under no obligation to only verify once. The SDT discussed and agreed that any systematic approach used to develop and implement training and the inherent association with company-specific reliability-related tasks, an entity would verify competency to perform these tasks prior to personnel taking shift. In addition, the implementation plan of PER-005-1 required compliance with Requirement R3 by the effective date of the standard. R4: The drafting team does not feel that adding the word “criteria” provides additional clarity to the requirement. R6: 4.1.5.1 has been added to R6. VSL: The drafting team understands your concern; however, the team does not feel that this change is necessary. VSL R4: The phrase “emergency operations” will be added to Requirement R4 VSL.		
Independent Electricity System Operator	Yes	a. We suggest to extend the second HIGH VSL condition for R5 by adding “to develop and implement training for its Operations Support Personnel” after “systematic approach” to conform with the language used in R5. b. We suggest to extend the second HIGH VSL condition for R6 by adding “to develop and implement training for its personnel” after “systematic approach” to conform with the language used in R6.
Response: Thank you for your comments. The SDT concluded that failure to implement training creates a higher severity than failure to develop training.		
Xcel Energy	Yes	Xcel Energy is in support of the current draft. However, clarification is requested regarding R5:Specifically, it is not clear as to whether continuing training for Operations Support Personnel is required even if the annual evaluation determines there are no changes needed to be incorporated into the training.
Response: Thank you for your comments. The SDT notes that continual training is inherent to the systematic approach. FERC Order 742, P 34 states that “… that any systematic approach to training, including the systematic approach to training mandated by Reliability		

Organization	Yes or No	Question 2 Comment
Standard PER-005-1, would entail continual training to refresh system operators' knowledge and to cover any new tasks relevant to the operation of the Bulk-Power System."		
American Electric Power	Yes	AEP recommends changing 4.1.4 in the Applicability section so that it states: "Transmission Owner who is not also a Tranmission Operator and who has... Personnel, excluding field switching personnel...".
Response: Thank you for your comments. The applicability is limited to certain personnel of a TO and would not present a conflict if that entity is also a TOP.		
Dominion	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
Idaho Power Co.	Yes	
American Transmission Company, LLC	Yes	

Additional Comments:

Michael Haff
Seminole Electric Cooperative, Inc.

COMMENTS

(1) (1) In the Rationale box for "Operations Support Personnel," it appears that in the first line "personnel" should be capitalized in the redline version of the Standard. However, in the clean version of the Standard "personnel" is capitalized. This is a general request that the NERC STDs please reflect all changes in the redline version that appear in the clean version. In this instance the discrepancy is minor, however, Seminole has seen this done on other draft Standards, and so Seminole is requesting that the NERC SDTs be diligent on the effort to have all changes depicted in the redline versions.
Response: Thank you for your comments.

(2) The definition of Operations Support Personnel includes "Individuals… who determine SOLs, IROLs, or operating nomograms, in direct support of Real-time operations of the [BES]." Seminole reasons that this description of affected personnel could include long-range transmission planners and those engineers assisting with the development of facility ratings per FAC-008 as long as their work supports the actions of Real-time personnel. Please respond to this concern as to whether these individuals with the actions described above could be included in this Standard.

RESPONSE: Thank you for your comments. These personnel would only be included if they actually perform "current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms." If these personnel provide input to the personnel conducting those activities, they would not be subject to PER-005-2.

(3) The Rationale box for the TO applicability function specifically cites the FERC language relating to personnel who control "a significant portion of the [BPS]…" Seminole fails to see where the SDT incorporated the language relating to the importance that the TO be responsible for a "significant portion" of the BPS and not merely an insignificant portion of the BPS. Please incorporate language into the Standard that exempts those TOs that own an insignificant portion of the BPS as FERC directed in Order 693.

RESPONSE: The drafting team understands your concern; however, the standard does not differentiate based on the portion of the BPS that the entity controls (significant or insignificant). Therefore, the SDT determined that this change is not appropriate.

(4) Requirement R1 part 1.4 requires the RC, BA, and TOP to implement changes identified during a calendar year evaluation. However, Measure M1.4 does not require the changes to be implemented nor does the VSL/VRF penalty matrix. Please clarify

whether an entity is required to implement changes identified and by what timeframe the entity must implement the identified changes. Note – this comment concerns similar language throughout many of the Requirements and Measures. Please make any changes consistent throughout the Standard.

RESPONSE: Thank you for your comments. Any changes that the entity identifies during its calendar year evaluation would be implemented pursuant to its training program. The standard anticipates that the changes are incorporated into the training program. The SDT determined that failure to implement training pursuant to the entity's training program creates a higher severity than failure to develop training.

(5) In Measure M3.1, there is a reference to "6 months." If a modification occurs on January 10, 2017, does the entity have until July 10, 2017 or August 1, 2017 to verify personnel capabilities? Please comment on how "6 months" is supposed to be calculated, i.e., six new full months, 180 calendar days, etc.

RESPONSE: Requirement R3 part 3.1 specifies that an entity has six months from the modification or addition.

(6) In the Rationale Box for R4, it appears the word "within" should be added before "12 months" in the third line.

RESPONSE: Thank you for your comment. The modification will be made.

(7) In Section C Compliance, Part 1.2 Evidence Retention, this section requires entities to retain data and evidence for three years or since the last compliance audit, whichever time frame is "greater." Appendix 4, Section 3.1.4.2 of the NERC Rules of Procedure state the following:

The audit period begins the day after the End Date of the prior Compliance Audit by the Compliance Enforcement Authority (or the later of June 18, 2007, or the date the Registered Entity became subject to Reliability Standards if the Registered Entity has not previously been subject to a Compliance Audit). The 'audit period will not begin prior to the End Date of the previous Compliance Audit.'

This Standard requires an entity to retain data past the last compliance audit if it is less than three years back. Seminole believes this section of Section C should read "requires entities to retain data and evidence for three years or since the last compliance audit, whichever time frame is 'less.'"

RESPONSE: Thank you for your comment; however, the intention is for entities to retain evidence for one complete audit cycle. Some entities are audited every three years and some entities every six years.

END OF REPORT

Standard Development Timeline

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

Development Steps Completed

1. SAR and supporting package posted for comment (July 19, 2013 – September 3, 2013).
2. Draft standard posted for comments and ballot (July 19, 2013 – September 3, 2013).
3. Draft standard posted for additional comments and ballot (September 25, 2013 – November 9, 2013).
4. Draft standard posted for additional comments and ballot (December 4, 2013 – January 17, 2013).

Description of Current Draft

Anticipated Actions	Anticipated Date
Final ballot	January 2014
BOT adoption	February 2014

Definitions of Terms Used in Standard

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

Rationale for System Operator: The definition of the existing NERC Glossary Term "System Operator" has been modified to remove Generator Operator (GOP) in response to Project 2010-16.

The term "System Operator" contains another NERC Glossary term "Control Center", which was approved by FERC on November 22, 2013. The inclusion of GOPs within the approved definition of Control Center does not bring GOPs into the System Operator definition. The System Operator definition specifies that it only applies to Balancing Authority (BA), Transmission Operator (TOP) or Reliability Coordinator (RC) personnel.

The modifications to the definition of "System Operator" do not affect other standards; see the PER-005-2 White Paper, which cross checks System Operator with other NERC Standards.

System Operator: An individual at a Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System in Real-time.

Rationale for Operations Support Personnel: The term Operations Support Personnel is used to identify those support personnel of Reliability Coordinators (RC), Balancing Authorities (BA), or Transmission Operators (TOP) that FERC identified in Order No. 693.

Operations Support Personnel: Individuals who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms,[1] in direct support of Real-time operations of the Bulk Electric System.

[1] Nomograms are used in the WECC Region to describe element operating limits.

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

A. Introduction

1. **Title:** **Operations Personnel Training**
2. **Number:** PER-005-2
3. **Purpose:** To ensure that personnel performing or supporting Real-time operations on the Bulk Electric System are trained using a systematic approach.
4. **Applicability:**

4.1. Functional Entities:

4.1.1 Reliability Coordinator

4.1.2 Balancing Authority

4.1.3 Transmission Operator

Rationale for TO: Extending the applicability to TOs is necessary to address the FERC directive that the ERO develop formal training requirements for local transmission control center operator personnel. In Order No. 742 at P 62, the Commission clarified its understanding that local control center personnel *"exercise control over a significant portion of the Bulk-Power System under the supervision of the personnel of the registered transmission operator. The supervision may take the form of directive specific step-by-step instructions and at other times may take the form of the implementation of predefined operating procedures. In all cases, the Commission continued, the local transmission control center personnel must understand what they are required to do in the performance of their duties to perform them effectively on a timely basis. Thus, omitting such local transmission control center personnel from the PER-005-1 training requirements creates a reliability gap."* See FERC Order 693 at P 1343 and 1347.

4.1.4 Transmission Owner that has:

4.1.4.1 Personnel, excluding field switching personnel, who can act independently to operate or direct the operation of the Transmission Owner's Bulk Electric System transmission Facilities in Real-time.

Rationale for GOP: Extending the applicability to Generator Operators (GOPs) that have dispatch personnel at a centrally located dispatch center is necessary to address the FERC directive that the ERO develop specific requirements addressing the scope, content and duration appropriate for certain GOP personnel. The Commission explains in Order No. 693 at P 1359 that "*although a generator operator typically receives instructions from a balancing authority, it is essential that generator operator personnel have appropriate training to understand those instructions, particularly in an emergency situation in which instructions may be succinct and require immediate action."* Order No. 742 further clarified that the directive "*applies to generator operator personnel at a centrally-located dispatch center who receive direction and then develop specific dispatch instructions for plant operators under their control. Plant operators located at the generator plant site are not required to be trained in PER-005-2."* Based on the FERC order, this applicability section clarifies which GOP personnel are subject to the standard.

4.1.5 Generator Operator that has:

4.1.5.1 Dispatch personnel at a centrally located dispatch center who receive direction from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner, and may develop specific dispatch instructions for plant operators under their control. These personnel do not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions without making any modifications.

5. Effective Date:

5.1. This standard shall become effective the first day of the first calendar quarter that is 24 months beyond the date that this standard is approved by an applicable governmental authority or is otherwise provided for in a jurisdiction where approval by an applicable authority is required for a standard to go into effect.

Where approval by an applicable governmental authority is not required, this standard shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement a training program for its System Operators as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology.

1.1.1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 1.1 each calendar year.

1.2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 1.1.

1.3. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall deliver training to its System Operators according to its training program.

1.4. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall implement the changes identified.

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence of using a systematic approach to develop and implement a training program for its System Operators, as specified in Requirement R1.

M1.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection its methodology and its BES company-specific Real-time reliability-related task list, with the date of the last review, as specified in Requirement R1 part 1.1 and part 1.1.1.

M1.2 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection training materials, as specified in Requirement R1 part 1.2.

M1.3 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection System Operator training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R1 part 1.3.

M1.4 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation of its training program each calendar year, as specified in Requirement R1 part 1.4.

Rationale for changes to R2: Transmission Owners personnel at local transmission control centers have been added to the PER standard and are subject to Requirements R2, R3 and R4 of PER-005-2. The reason for adding Transmission Owners is to address Order No. 693 and Order No. 742 FERC directives to include local transmission control center operator personnel.

R2. Each Transmission Owner shall use a systematic approach to develop and implement a training program for its personnel identified in Applicability Section 4.1.4.1 of this standard as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall create a list of BES company-specific Real-time reliability-related tasks based on a defined and documented methodology.

2.1.1. Each Transmission Owner shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 2.1 each calendar year.

2.2. Each Transmission Owner shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 2.1.

2.3. Each Transmission Owner shall deliver training to its personnel identified in Applicability Section 4.1.4.1 of this standard according to its training program.

2.4. Each Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement R2 to identify any needed changes to the training program and shall implement the changes identified.

M2. Each Transmission Owner shall have available for inspection evidence of using a systematic approach to develop and implement a training program for its applicable personnel, as specified in Requirement R2.

M2.1 Each Transmission Owner shall have available for inspection its methodology and its BES company-specific Real-time reliability-related task list, with the date of the last review, as specified in Requirement R2 part 2.1.

M2.2 Each Transmission Owner shall have available for inspection training materials, as specified in Requirement R2 part 2.2.

M2.3 Each Transmission Owner shall have available for inspection training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R2 part 2.3.

M2.4 Each Transmission Owner shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation of its training program each calendar year, as specified in Requirement R2 part 2.4.

Rationale for R3: This Requirement was brought forward from the previous version with the addition of Transmission Owners. It provides an entity with an opportunity to create a baseline from which to assess training needs as it develops a systematic approach.

R3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1 or Requirement R2 part 2.1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

3.1. Within six months of a modification or addition of a BES company-specific Real-time reliability-related task, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its personnel identified in Requirement R1 or Requirement R2 to perform

the new or modified BES company-specific Real-time reliability-related tasks identified in Requirement R1 part 1.1 or Requirement R2 part 2.1.

M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence to show that it verified the capabilities of each of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1 or Requirement R2 part 2.1. This evidence may be documents such as records showing capability to perform BES company-specific Real-time reliability-related tasks with the employee name and date; supervisor check sheets showing the employee name, date, and BES company-specific Real-time reliability-related task completed; or the results of learning assessments.

M3.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner shall present evidence that it verified the capabilities of applicable personnel to perform new or modified BES company-specific Real-time reliability-related tasks within 6 months of a modification or addition of a BES company-specific Real-time reliability-related task.

Rationale for changes to R4: The requirement mandates the use of specific training technologies. It does not require training on Interconnection Reliability Operating Limits (IROLs). The standard allows entities that gain operational authority or control over a Facility with IROLs or established protection systems or operating guides to mitigate IROL violations within 12 months to comply with Requirement R4 to provide them sufficient time to obtain simulation technology.

The requirement to provide a minimum of 32 hours of Emergency Operations training has been removed since the appropriate number of hours would be identified as part of the systematic approach in Requirement R1 and Requirement R2 through the analysis phase and outlined in a continuous education section of their training program. Any additional hours may be duplicative or repetitive for the entity in providing training to its personnel. Requirement

R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. A Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not previously meet the criteria of Requirement R4, shall comply with Requirement R4 within 12 months of meeting the criteria.

M4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that personnel identified in Requirement R1 or Requirement R2 completed

training that includes the use of simulation technology, as specified in Requirement R4.

M4.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that personnel identified in Requirement R1 or Requirement R2 completed training that included the use of simulation technology, as specified in Requirement R4, within 12 months of meeting the criteria of Requirement R4.

Rationale for R5: This is a new requirement applicable to Operations Support Personnel. In FERC Order No. 742, the Commission noted that NERC, in developing Reliability Standard PER-005-1, did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include operations planning and operation support staff who carry out outage planning and assessments and those who develop System Operating Limits (SOL), Interconnection Reliability Operating Limits (IROL), or operating nomograms for Real-time operations. This requirement contemplates that entities will look to the systematic approach already developed under Requirement R1. The entity can use the list created from Requirement R1 and select the BES company-specific Real-time reliability-related tasks with which Operations Support Personnel are involved.

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence that Operations Support Personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training. Documentation of training shall include employee name and date of training.

M5.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation each calendar year, as specified in Requirement R5 part 5.1.

Rationale for R6: This requirement requires the training of certain GOP dispatch personnel on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. This requirement mandates the use of a systematic approach which allows for each entity to tailor its training to the needs of its organization.

This is a new requirement applicable to certain GOPs as described in the applicability section. In FERC Order No. 742, the Commission noted that in developing proposed Reliability Standard PER-005-1, NERC did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include GOPs centrally-located at a generation dispatch center with a direct impact on the reliable operation of the BES. The Commission acknowledged that the training for GOPs need not be as extensive as the training for TOPs and BAs. FERC also stated that the systematic approach to training methodology is flexible enough to build on existing training programs by validating and supplementing the existing training content, where necessary, using systematic methods.

R6. Each Generator Operator shall use a systematic approach to develop and implement training to its personnel identified in Applicability Section 4.1.5.1 of this standard, on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R6 to identify and implement changes to the training.

M6. Each Generator Operator shall have available for inspection evidence that its applicable personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training. Documentation of training shall include employee name and date of training.

M6.1 Each Generator Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation each calendar year, as specified in Requirement R6 part 6.1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the compliance enforcement authority may ask an entity to

provide other evidence to show that it was compliant for the full-time period since the last audit.

Each Reliability Coordinator, Balancing Authority, Transmission Operator Transmission Owner, and Generator Operator shall keep data or evidence to show compliance for three years or since its last compliance audit, whichever time frame is greater, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator, Balancing Authority, Transmission Operator Transmission Owner, or Generator Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-term Planning	Medium	None	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to review or update, if necessary, its BES company-specific Real-time reliability-related task list each calendar year. (1.1.1.) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator, failed to evaluate its training program each calendar year to identify needed changes to its training program(s). (1.4) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator, failed to implement the identified changes to the training program(s). (1.4.)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to use a systematic approach to develop and implement a training program. (R1) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to design and develop training materials based on the BES company-specific Real-time reliability-related task lists. (1.2)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to create a BES company-specific Real-time reliability-related task list. (1.1.) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to deliver training based on the BES company-specific Real-time reliability-related task lists. (1.3)
R2	Long-term Planning	Medium	None	The Transmission Owner failed to review or update, if necessary, its company-specific Real-time reliability-	The Transmission Owner failed to use a systematic approach to develop and implement a training program. (R2)	The Transmission Owner failed to create a BES company-specific Real-time reliability-related task list. (2.1.) OR

				related task list each calendar year. (2.1.1.) OR The Transmission Owner failed to evaluate its training program each calendar year to identify needed changes to its training program(s). (2.4) OR The Transmission Owner failed to implement the identified changes to the training program(s). (2.4.)	OR The Transmission Owner failed to design and develop training materials based on the BES company-specific Real-time reliability-related task lists. (2.2)	The Transmission Owner failed to deliver training based on the BES company-specific Real-time reliability-related task lists. (2.3)
R3	**Long-term Planning**	**High**	**None**	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of at least 90% but less than 100% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3)	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of at least 70% but less than 90% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner failed to verify the capabilities of its personnel identified in Requirements R1 or Requirement	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of less than 70% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3)

					R2 to perform each new or modified task within six months of making a modification to its BES company-specific Real-time reliability-related task list. (3.1)	
R4	**Long-term Planning**	**Medium**	**None**	**None**	**None**	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that meet the criteria of Requirement R4 did not provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. (R4) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner did not provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES within twelve months of meeting the criteria of Requirement R4. (R4.1)

R5	**Long-term Planning**	**Medium**	**None**	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to evaluate its training established in Requirement R5 each calendar year. (5.1)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to develop training for its Operations Support Personnel. (R5) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator developed training but failed to use a systematic approach. (R5)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to implement training for its Operations Support Personnel. (R5)
R6	**Long-term Planning**	**Medium**	**None**	The Generator Operator failed to evaluate its training established in Requirement R6 each calendar year. (6.1)	The Generator Operator failed to develop training for its personnel. (R6) OR The Generator Operator developed training but failed to use a systematic approach. (R6)	The Generator Operator failed to implement the training for its personnel identified in Requirement R6. (R6)

Guidelines and Technical Basis

Requirement R1 and R2:

Any systematic approach to training will determine: 1) the skills and knowledge needed to perform BES company-specific Real-time reliability-related tasks; 2) what training is needed to achieve those skills and knowledge; 3) if the learner can perform the BES company-specific Real-time reliability-related task(s) acceptably in either a training or on-the-job environment; and 4) if the training is effective, and make adjustments as necessary.

Reference #1: Determining Task Performance Requirements

The purpose of this reference is to provide guidance for a performance standard that describes the desired outcome of a task. A standard for acceptable performance should be in either measurable or observable terms. Clear standards of performance are necessary for an individual to know when he or she has completed the task and to ensure agreement between employees and their supervisors on the objective of a task. Performance standards answer the following questions:

How timely must the task be performed?

Or

How accurately must the task be performed?

Or

With what quality must it be performed?

Or

What response from the customer must be accomplished?

When a performance standard is quantifiable, successful performance is more easily demonstrated. For example, in the following task statement, the criteria for successful performance is to return system loading to within normal operating limits, which is a number that can be easily verified.

> Given a System Operating Limit violation on the transmission system, implement the correct procedure for the circumstances to mitigate loading to within normal operating limits.

Even when the outcome of a task cannot be measured as a number, it may still be observable. The next example contains performance criteria that is qualitative in nature, that is, it can be verified as either correct or not, but does not involve a numerical result.

> Given a tag submitted for scheduling, ensure that all transmission rights are assigned to the tag per the company Tariff and in compliance with NERC and NAESB standards.

Reference #2: Systematic Approach to Training References:
The following list of hyperlinks identifies references for the NERC Standard PER-005 to assist with the application of a systematic approach to training:

(1) DOE-HDBK-1078-94, A Systematic Approach to Training

http://www.publicpower.org/files/PDFs/DOEHandbookTrainingProgramSystematicApproach.pdf

(2) DOE-HDBK-1074-95, January 1995, Alternative Systematic Approaches to Training, U.S. Department of Energy, Washington, D.C. 20585 FSC 6910

http://www.catagle.com/112-1/download_php-spec_DOE-HDBK-1074-95_003254_1.htm

(3) ADDIE – 1975, Florida State University

http://www.nwlink.com/~donclark/history_isd/addie.html

(4) DOE Standard - Table-Top Needs Analysis
DOE-HDBK-1103-96

http://www.cms.doe.gov/sites/prod/files/2013/06/f2/hdbk1103.pdf

Reference #3: Recognized Operator Training Topics
See Appendix A – Recognized Operator Training Topics within the NERC System Operator Certification Program Manual.
http://www.nerc.com/pa/Train/SysOpCert/Documents/SOC_Program_Manual_February_2012_Final.pdf

Reference #4: Definitions of Simulation and Simulators

Georgia Institute of Technology – Modeling & Simulation for Systems Engineering
http://www.pe.gatech.edu/conted/servlet/edu.gatech.conted.course.ViewCourseDetails?COURSE_ID=840

University of Central Florida – Institute for Simulation & Training
Just what is "simulation" anyway (or, Simulation 101)?
And what about "modeling"?
But what does IST do with simulations?
http://www.ist.ucf.edu/overview.htm

Standard Development Timeline

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

Development Steps Completed

1. SAR and supporting package posted for comment (July 19, 2013 – September 3, 2013).
2. Draft standard posted for comments and ballot (July 19, 2013 – September 3, 2013).
3. Draft standard posted for additional comments and ballot (September 25, 2013 – November 9, 2013).
4. Draft standard posted for additional comments and ballot (December 4, 2013 – January 17, 2013).

Description of Current Draft

Anticipated Actions	Anticipated Date
Final ballot	January 2014
BOT adoption	February 2014

Definitions of Terms Used in Standard

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

Rationale for System Operator: The definition of the existing NERC Glossary Term "System Operator" has been modified to remove Generator Operator (GOP) in response to Project 2010-16.

The term "System Operator" contains another NERC Glossary term "Control Center", which was approved by FERC on November 22, 2013. The inclusion of GOPs within the approved definition of Control Center does not bring GOPs into the System Operator definition. The System Operator definition specifies that it only applies to Balancing Authority (BA), Transmission Operator (TOP) or Reliability Coordinator (RC) personnel.

The modifications to the definition of "System Operator" do not affect other standards; see the PER-005-2 White Paper, which cross checks System Operator with other NERC Standards.

System Operator: An individual at a Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System in Real-time.

Rationale for Operations Support Personnel: The term Operations Support Personnel is used to identify those support personnel of Reliability Coordinators (RC), Balancing Authorities (BA), or Transmission Operators (TOP) that FERC identified in Order No. 693.

Operations Support Personnel: Individuals who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms,[1] in direct support of Real-time operations of the Bulk Electric System.

[1] Nomograms are used in the WECC Region to describe element operating limits.

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

A. Introduction

1. **Title:** **Operations Personnel Training**
2. **Number:** PER-005-2
3. **Purpose:** To ensure that personnel performing or supporting Real-time operations on the Bulk Electric System are trained using a systematic approach.
4. **Applicability:**

4.1. Functional Entities:

4.1.1 Reliability Coordinator

4.1.2 Balancing Authority

4.1.3 Transmission Operator

Rationale for TO: Extending the applicability to TOs is necessary to address the FERC directive that the ERO develop formal training requirements for local transmission control center operator personnel. In Order No. 742 at P 62, the Commission clarified its understanding that local control center personnel *"exercise control over a significant portion of the Bulk-Power System under the supervision of the personnel of the registered transmission operator. The supervision may take the form of directive specific step-by-step instructions and at other times may take the form of the implementation of predefined operating procedures. In all cases, the Commission continued, the local transmission control center personnel must understand what they are required to do in the performance of their duties to perform them effectively on a timely basis. Thus, omitting such local transmission control center personnel from the PER-005-1 training requirements creates a reliability gap."* See FERC Order 693 at P 1343 and 1347.

~~The word facilities was intentionally left lower-case as there may be a facility that is not included in the NERC glossary term "Facility".~~

4.1.4 Transmission Owner that has:

4.1.4.1 Personnel, excluding field switching personnel, who can act independently to operate or direct the operation of the Transmission Owner's Bulk Electric System transmission Facilities in Real-time.

Rationale for GOP: Extending the applicability to Generator Operators (GOPs) that have dispatch personnel at a centrally located dispatch center is necessary to address the FERC directive that the ERO develop specific requirements addressing the scope, content and duration appropriate for certain GOP personnel. The Commission explains in Order No. 693 at P 1359 that "*although a generator operator typically receives instructions from a balancing authority, it is essential that generator operator personnel have appropriate training to understand those instructions, particularly in an emergency situation in which instructions may be succinct and require immediate action."* Order No. 742 further clarified that the directive "*applies to generator operator personnel at a centrally-located dispatch center who receive direction and then develop specific dispatch instructions for plant operators under their control. Plant operators located at the generator plant site are not required to be trained in PER-005-2."* Based on the FERC order, this applicability section clarifies which GOP personnel are subject to the standard.

4.1.5 Generator Operator that has:

4.1.5.1 Dispatch personnel at a centrally located dispatch center who receive direction from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner, and may develop specific dispatch instructions for plant operators under their control. These personnel do not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions without making any modifications.

5. Effective Date:

5.1. This standard shall become effective the first day of the first calendar quarter that is 24 months beyond the date that this standard is approved by an applicable governmental authority or is otherwise provided for in a jurisdiction where approval by an applicable authority is required for a standard to go into effect.

Where approval by an applicable governmental authority is not required, this standard shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

B. Requirements and Measures

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement a training program for its System Operators as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology.

1.1.1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 1.1 each calendar year.

1.2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 1.1.

1.3. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall deliver training to its System Operators according to its training program.

1.4. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall implement the changes identified.

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence of using a systematic approach to develop and implement a training program for its System Operators, as specified in Requirement R1.

M1.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection its methodology and its BES company-specific Real-time reliability-related task list, with the date of the last review, as specified in Requirement R1 part 1.1 and part 1.1.1.

M1.2 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection training materials, as specified in Requirement R1 part 1.2.

M1.3 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection System Operator training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R1 part 1.3.

M1.4 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation of its training program each calendar year, as specified in Requirement R1 part 1.4.

Rationale for changes to R2: Transmission Owners personnel at local transmission control centers have been added to the PER standard and are subject to Requirements R2, R3 and R4 of PER-005-2. The reason for adding Transmission Owners is to address Order No. 693 and Order No. 742 FERC directives to include local transmission control center operator personnel.

R2. Each Transmission Owner shall use a systematic approach to develop and implement a training program for its personnel identified in Applicability Section 4.1.4.1 of this standard as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

2.1. Each Transmission Owner shall create a list of BES company-specific Real-time reliability-related tasks based on a defined and documented methodology.

2.1.1. Each Transmission Owner shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 2.1 each calendar year.

2.2. Each Transmission Owner shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 2.1.

2.3. Each Transmission Owner shall deliver training to its personnel identified in Applicability Section 4.1.4.1 of this standard according to its training program.

2.4. Each Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement R2 to identify any needed changes to the training program and shall implement the changes identified.

M2. Each Transmission Owner shall have available for inspection evidence of using a systematic approach to develop and implement a training program for its applicable personnel, as specified in Requirement R2.

M2.1 Each Transmission Owner shall have available for inspection its methodology and its BES company-specific Real-time reliability-related task list, with the date of the last review, as specified in Requirement R2 part 2.1.

M2.2 Each Transmission Owner shall have available for inspection training materials, as specified in Requirement R2 part 2.2.

M2.3 Each Transmission Owner shall have available for inspection training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R2 part 2.3.

M2.4 Each Transmission Owner shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation of its training program each calendar year, as specified in Requirement R2 part 2.4.

Rationale for R3: This Requirement was brought forward from the previous version with the addition of Transmission Owners. It provides an entity with an opportunity to create a baseline from which to assess training needs as it develops a systematic approach.

R3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1 or Requirement R2 part 2.1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

3.1. Within six months of a modification or addition of a BES company-specific Real-time reliability-related task, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its personnel identified in Requirement R1 or Requirement R2 to perform

the new or modified BES company-specific Real-time reliability-related tasks identified in Requirement R1 part 1.1 or Requirement R2 part 2.1.

M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence to show that it verified the capabilities of each of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1 or Requirement R2 part 2.1. This evidence may be documents such as records showing capability to perform BES company-specific Real-time reliability-related tasks with the employee name and date; supervisor check sheets showing the employee name, date, and BES company-specific Real-time reliability-related task completed; or the results of learning assessments.

M3.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner shall present evidence that it verified the capabilities of applicable personnel to perform new or modified BES company-specific Real-time reliability-related tasks within 6 months of a modification or addition of a BES company-specific Real-time reliability-related task.

Rationale for changes to R4: The requirement mandates the use of specific training technologies. It does not require training on Interconnection Reliability Operating Limits (IROLs). The standard allows entities that gain operational authority or control over a Facility with IROLs or established protection systems or operating guides to mitigate IROL violations within 12 months to comply with Requirement R4 to provide them sufficient time to obtain simulation technology.

The requirement to provide a minimum of 32 hours of Emergency Operations training has been removed since the appropriate number of hours would be identified as part of the systematic approach in Requirement R1 and Requirement R2 through the analysis phase and outlined in a continuous education section of their training program. Any additional hours may be duplicative or repetitive for the entity in providing training to its personnel. Requirement

R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. A Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not previously meet the criteria of Requirement R4, shall comply with Requirement R4 within 12 months of meeting the criteria.

M4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that personnel identified in Requirement R1 or Requirement R2 completed

training that includes the use of simulation technology, as specified in Requirement R4.

M4.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that personnel identified in Requirement R1 or Requirement R2 completed training that included the use of simulation technology, as specified in Requirement R4, within 12 months of meeting the criteria of Requirement R4.

Rationale for R5: This is a new requirement applicable to Operations Support Personnel. In FERC Order No. 742, the Commission noted that NERC, in developing Reliability Standard PER-005-1, did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include operations planning and operation support staff who carry out outage planning and assessments and those who develop System Operating Limits (SOL), Interconnection Reliability Operating Limits (IROL), or operating nomograms for Real-time operations. This requirement contemplates that entities will look to the systematic approach already developed under Requirement R1. The entity can use the list created from Requirement R1 and select the BES company-specific Real-time reliability-related tasks with which Operations Support Personnel are involved.

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence that Operations Support Personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training. Documentation of training shall include employee name and date of training.

M5.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation each calendar year, as specified in Requirement R5 part 5.1.

Rationale for R6: This requirement requires the training of certain GOP dispatch personnel on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. This requirement mandates the use of a systematic approach which allows for each entity to tailor its training to the needs of its organization.

This is a new requirement applicable to certain GOPs as described in the applicability section. In FERC Order No. 742, the Commission noted that in developing proposed Reliability Standard PER-005-1, NERC did not comply with the directive in FERC Order No. 693 to expand the applicability of training requirements to include GOPs centrally-located at a generation dispatch center with a direct impact on the reliable operation of the BES. The Commission acknowledged that the training for GOPs need not be as extensive as the training for TOPs and BAs. FERC also stated that the systematic approach to training methodology is flexible enough to build on existing training programs by validating and supplementing the existing training content, where necessary, using systematic methods.

R6. Each Generator Operator shall use a systematic approach to develop and implement training to its personnel identified in Applicability Section 4.1.5.1 of this standard, on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

6.1. Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R6 to identify and implement changes to the training.

M6. Each Generator Operator shall have available for inspection evidence that its applicable personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training. Documentation of training shall include employee name and date of training.

M6.1 Each Generator Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation each calendar year, as specified in Requirement R6 part 6.1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the compliance enforcement authority may ask an entity to

provide other evidence to show that it was compliant for the full-time period since the last audit.

Each Reliability Coordinator, Balancing Authority, Transmission Operator Transmission Owner, and Generator Operator shall keep data or evidence to show compliance for three years or since its last compliance audit, whichever time frame is greater, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Reliability Coordinator, Balancing Authority, Transmission Operator Transmission Owner, or Generator Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Long-term Planning**	**Medium**	**None**	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to review or update, if necessary, its BES company-specific Real-time reliability-related task list each calendar year. (1.1.1.) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator, failed to evaluate its training program each calendar year to identify needed changes to its training program(s). (1.4) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator, failed to implement the identified changes to the training program(s). (1.4.)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to use a systematic approach to develop and implement a training program. (R1) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to design and develop training materials based on the BES company-specific Real-time reliability-related task lists. (1.2)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to create a BES company-specific Real-time reliability-related task list. (1.1.) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to deliver training based on the BES company-specific Real-time reliability-related task lists. (1.3)
R2	**Long-term Planning**	**Medium**	**None**	The Transmission Owner failed to review or update, if necessary, its company-specific Real-time reliability-	The Transmission Owner failed to use a systematic approach to develop and implement a training program. (R2)	The Transmission Owner failed to create a BES company-specific Real-time reliability-related task list. (2.1.) OR

				related task list each calendar year. (2.1.1.) OR The Transmission Owner failed to evaluate its training program each calendar year to identify needed changes to its training program(s). (2.4) OR The Transmission Owner failed to implement the identified changes to the training program(s). (2.4.)	OR The Transmission Owner failed to design and develop training materials based on the BES company-specific Real-time reliability-related task lists. (2.2)	The Transmission Owner failed to deliver training based on the BES company-specific Real-time reliability-related task lists. (2.3)
R3	**Long-term Planning**	**High**	**None**	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of at least 90% but less than 100% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3)	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of at least 70% but less than 90% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner failed to verify the capabilities of its personnel identified in Requirements R1 or Requirement	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner verified the capabilities of less than 70% of its personnel identified in Requirements R1 or Requirement R2 to perform all of their assigned BES company-specific Real-time reliability-related tasks. (R3)

					R2 to perform each new or modified task within six months of making a modification to its BES company-specific Real-time reliability-related task list. (3.1)	
R4	**Long-term Planning**	**Medium**	**None**	**None**	**None**	The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that meet the criteria of Requirement R4 did not provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. (R4) OR The Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner did not provide its personnel identified in Requirement R1 or Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES within twelve months of meeting the criteria of Requirement R4. (R4.1)

R5	**Long-term Planning**	**Medium**	**None**	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to evaluate its training established in Requirement R5 each calendar year. (5.1)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to develop training for its Operations Support Personnel. (R5) OR The Reliability Coordinator, Balancing Authority, or Transmission Operator developed training but failed to use a systematic approach. (R5)	The Reliability Coordinator, Balancing Authority, or Transmission Operator failed to implement training for its Operations Support Personnel. (R5)
R6	**Long-term Planning**	**Medium**	**None**	The Generator Operator failed to evaluate its training established in Requirement R6 each calendar year. (6.1)	The Generator Operator failed to develop training for its personnel. (R6) OR The Generator Operator developed training but failed to use a systematic approach. (R6)	The Generator Operator failed to implement the training for its personnel identified in Requirement R6. (R6)

Guidelines and Technical Basis

Requirement R1 and R2:

Any systematic approach to training will determine: 1) the skills and knowledge needed to perform BES company-specific Real-time reliability-related tasks; 2) what training is needed to achieve those skills and knowledge; 3) if the learner can perform the BES company-specific Real-time reliability-related task(s) acceptably in either a training or on-the-job environment; and 4) if the training is effective, and make adjustments as necessary.

Reference #1: Determining Task Performance Requirements

The purpose of this reference is to provide guidance for a performance standard that describes the desired outcome of a task. A standard for acceptable performance should be in either measurable or observable terms. Clear standards of performance are necessary for an individual to know when he or she has completed the task and to ensure agreement between employees and their supervisors on the objective of a task. Performance standards answer the following questions:

How timely must the task be performed?

Or

How accurately must the task be performed?

Or

With what quality must it be performed?

Or

What response from the customer must be accomplished?

When a performance standard is quantifiable, successful performance is more easily demonstrated. For example, in the following task statement, the criteria for successful performance is to return system loading to within normal operating limits, which is a number that can be easily verified.

> Given a System Operating Limit violation on the transmission system, implement the correct procedure for the circumstances to mitigate loading to within normal operating limits.

Even when the outcome of a task cannot be measured as a number, it may still be observable. The next example contains performance criteria that is qualitative in nature, that is, it can be verified as either correct or not, but does not involve a numerical result.

> Given a tag submitted for scheduling, ensure that all transmission rights are assigned to the tag per the company Tariff and in compliance with NERC and NAESB standards.

Reference #2: Systematic Approach to Training References:

The following list of hyperlinks identifies references for the NERC Standard PER-005 to assist with the application of a systematic approach to training:

(1) DOE-HDBK-1078-94, A Systematic Approach to Training

http://www.publicpower.org/files/PDFs/DOEHandbookTrainingProgramSystematicApproach.pdf

(2) DOE-HDBK-1074-95, January 1995, Alternative Systematic Approaches to Training, U.S. Department of Energy, Washington, D.C. 20585 FSC 6910

http://www.catagle.com/112-1/download_php-spec_DOE-HDBK-1074-95_003254_1.htm

(3) ADDIE – 1975, Florida State University

http://www.nwlink.com/~donclark/history_isd/addie.html

(4) DOE Standard - Table-Top Needs Analysis
DOE-HDBK-1103-96

http://www.cms.doe.gov/sites/prod/files/2013/06/f2/hdbk1103.pdf

Reference #3: Recognized Operator Training Topics

See Appendix A – Recognized Operator Training Topics within the NERC System Operator Certification Program Manual.
http://www.nerc.com/pa/Train/SysOpCert/Documents/SOC_Program_Manual_February_2012_Final.pdf

Reference #4: Definitions of Simulation and Simulators

Georgia Institute of Technology – Modeling & Simulation for Systems Engineering
http://www.pe.gatech.edu/conted/servlet/edu.gatech.conted.course.ViewCourseDetails?COURSE_ID=840

University of Central Florida – Institute for Simulation & Training
Just what is "simulation" anyway (or, Simulation 101)?
And what about "modeling"?
But what does IST do with simulations?
http://www.ist.ucf.edu/overview.htm

Implementation Plan

Project 2010-01 Operations Personnel Training

Implementation Plan for PER-005-2 – Operations Personnel Training

Approvals Required
PER-005-2 – Operations Personnel Training

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

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

System Operator: An individual at a Control Center of a Reliability Coordinator, Balancing Authority, or Transmission Operator who operates or directs the operation of the Bulk Electric System in Real-time.

Operations Support Personnel: Individuals who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms,[1] in direct support of Real-time operations of the Bulk Electric System.

Other Definitions Used within the Standard
None

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Operator

[1] Nomograms are used in the WECC Region to describe element operating limits.

- Transmission Owners that has personnel, excluding field switching personnel, who can act independently to operate or direct the operation of the Transmission Owner's Bulk Electric System transmission Facilities in Real-time
- Generator Operators that have dispatch personnel at a centrally located dispatch center who receive direction from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control. These personnel do not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions without making any modifications.

Applicable Facilities
None

Conforming Changes to Other Standards
None

Effective Dates
PER-005-2 shall become effective as follows:

> This standard shall become effective the first day of the first calendar quarter that is 24 months beyond the date that this standard is approved by an applicable governmental authority or is otherwise provided for in a jurisdiction where approval by an applicable authority is required for a standard to go into effect.
>
> Where approval by an applicable governmental authority is not required, this standard shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Actions to be Completed as of the Effective Date:
An implementation period provides time for an entity to become compliant with the standard prior to the standard becoming enforceable. This section describes the requirements that an entity must be compliant with as of the enforceable date of PER-005-2. This section does not address evidence of compliance; see measures, compliance input and RSAWs for further information regarding possible evidence.

<u>Requirement R1:</u>
Reliability Coordinators, Balancing Authorities, and Transmission Operators must have completed the requirements for PER-005-2 Requirement R1 as of the enforceable date of the standard as provided below. Note that these entities are subject to PER-005-1.

R1: Entities must have developed and implemented a training program for its System Operators using a systematic approach.

1.1: Entities must have defined and documented its methodology for creating a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks, and must have a list of these tasks.

1.1.1: Entities must have conducted a review of its tasks list once in the calendar year that this standard becomes enforceable.

Note: this review may be conducted either under the existing standard PER-005-1 or under PER-005-2 after it becomes enforceable, as long as the entity conducts one review during the calendar year.

1.2: An entity must have completed the design and development of training materials as necessary under its training program as of the enforceable date of PER-005-2. An entity is not obligated to have designed and developed training materials for all future training.

1.3: Entities must have delivered training in accordance with their training program as of the enforceable date of PER-005-2.

1.4: Entities must have conducted an evaluation once in the calendar year that PER-005-2 becomes enforceable.

Note: this may be conducted either under PER-005-1 or under PER-005-2 after it becomes enforceable, as long as the entity conducts one evaluation during the calendar year.

<u>Requirement R2:</u>

R2: Applicable Transmission Owners must have developed and implemented a training program for its applicable personnel using a systematic approach.

2.1: An applicable Transmission Owner must have defined and documented its methodology for creating a list of BES company-specific Real-time reliability-related tasks, and must have a list of these tasks as of the enforceable date of PER-005-2.

2.1.1: As applicable Transmission Owners were not previously subject to PER-005-1, they would not be required to have conducted a review prior to the enforceable date of the proposed standard or in the calendar year that the proposed standard becomes enforceable. The entity’s first required evaluation would occur within the first calendar year following the enforceable date of PER-005-2.

2.2: An applicable Transmission Owner must have completed the design and development of training materials according to its training program as of the enforceable date of PER-005-2. An entity is not obligated to have designed and developed training materials for all future training.

2.3: As applicable Transmission Owners were not previously subject to PER-005-1, they must begin to implement training in accordance with its training program as of the enforceable date. Under the standard, these entities are not required to have delivered training prior to the enforceable date.

2.4: As applicable Transmission Owners were not previously subject to PER-005-1, they would not be required to have conducted an evaluation prior to the enforceable date of the proposed standard or in the calendar year that the proposed standard becomes enforceable. The entity's first required evaluation would occur within the first calendar year following the enforceable date of PER-005-2.

Requirement R3:

R3: Reliability Coordinators, Balancing Authorities, Transmission Operators and Transmission Owners must have verified the capabilities of its personnel identified in Requirements R1 and R2 to perform each of its assigned BES company-specific Real-time reliability-related tasks, at least once, as of the enforceable date of PER-005-2.

3.1: Reliability Coordinators, Balancing Authorities, and Transmission Operators that are already subject to PER-005-1 are required to, within six months of a change to its task list, have verified the capabilities of its personnel identified in Requirement R1 to perform each new or modified BES company-specific Real-time reliability-related tasks identified in Requirement R1 part 1.1. These entities will continue to have the time allotted to complete the verification under PER-005-1 after the enforceable date of PER-005-2.

Because Transmission Owners were not previously subject to PER-005-1, they are not expected to have verified the capabilities of its personnel identified in Requirement R2 to perform a new or modified BES company-specific Real-time reliability-related tasks identified under Requirement R2 part 2.1 prior to the enforceable date of the standard. This requirement pertains to BES company-specific reliability-related tasks that are newly identified or modified after the enforceable date of PER-005-2.

Requirement R4:

R4: Reliability Coordinators, Balancing Authorities, Transmission Operators and Transmission Owners must be providing training using the simulation technologies described in Requirement R4 according to its training program as of the date PER-005-2 becomes enforceable.

4.1: Entities that do not meet the criteria set forth in Requirement R4 prior to the enforceable date of the standard are required to comply with Requirement R4 within 12 months of meeting the criteria.

Requirement R5:

R5: Reliability Coordinators, Balancing Authorities, and Transmission Operators must have developed training, using a systematic approach, for their Operations Support Personnel on the impact of their job function(s) to those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1 and must have implemented that training according to its systematic approach as of the enforceable date of PER-005-2.

5.1: As Operations Support Personnel were not previously subject to PER-005-1, they would not be required to have conducted an evaluation prior to the enforceable date of the proposed standard or in the calendar year that the proposed standard becomes enforceable. The entity's first required evaluation would occur within the first calendar year following the enforceable date of PER-005-2.

Requirement R6:

R6: Generator Operators must have developed training, using a systematic approach, for their applicable personnel on the impact of their job function(s) to the reliable operations of the BES during normal and emergency operations and must have implemented that training according to its systematic approach as of the enforceable date of PER-005-2.

6.1: As Generator Operators were not previously subject to PER-005-1, they would not be required to have conducted an evaluation prior to the enforceable date of the proposed standard or in the calendar year that the proposed standard becomes enforceable. The entity's first required evaluation would occur within the first calendar year following the enforceable date of PER-005-2.

Justification

The 24-month period for implementation of PER-005-2 will provide sufficient time for the applicable entities to make necessary modifications to their systematic approach to training and, for entities not yet subject to the standard, time to develop a systematic approach to training that is compliant with the proposed standard. This time frame is consistent with the 24-month implementation period FERC approved for PER-005-1 to allow for Reliability Coordinators, Balancing Authorities, and Transmission

Operators to develop a systematic approach to training. The standard drafting team concluded that the same timeframe (24-months) should be provided to the new applicable entities and for the entities currently subject to PER-001-1 to development training for their Operations Support Personnel.

Retirements

PER-005-1 – System Personnel Training should be retired at 11:59:59 pm of the day immediately prior to the enforceable date of PER-005-2 in the particular jurisdiction in which the new standard is becoming enforceable. For entities that are completing actions under Requirement R3.1 of PER-005-1, this requirement will remain in effect until the time allotted under the requirement has expired.

Attachment 1
Approved Standards Incorporating the Term "System Operator"

EOP-005-2 — System Restoration from Blackstart Resources

EOP-006-2 — System Restoration Coordination

EOP-008-1 — Loss of Control Center Functionality

IRO-002-3 — Reliability Coordination – Analysis Tools

IRO-014-1 — Procedures, Processes, or Plans to Support Coordination between Reliability Coordinators

MOD-008-1 — TRM Calculation Methodology

MOD-020-0 — Providing Interruptible Demands and DCLM Data

PER-003-1 — Operation Personnel Credentials

PRC-004-WECC-1 – Protection System and Remedial Action Scheme Maintenance and Testing

PRC-023 -2 — Transmission Relay Loadability

Implementation Plan

Project 2010-01 Operations Personnel Training

Implementation Plan for PER-005-2 – Operations Personnel Training

Approvals Required

PER-005-2 – Operations Personnel Training

Prerequisite Approvals

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

Revisions to Glossary Terms

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

System Operator: An individual at a Control Center of a Reliability Coordinator, Balancing Authority, or Transmission Operator who operates or directs the operation of the Bulk Electric System in Real-time.

Operations Support Personnel: Individuals who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms,[1] in direct support of Real-time operations of the Bulk Electric System.

Other Definitions Used within the Standard

None

Applicable Entities

- Reliability Coordinator
- Balancing Authority
- Transmission Operator

[1] Nomograms are used in the WECC Region to describe element operating limits.

- Transmission Owners that has personnel, excluding field switching personnel, who can act independently to operate or direct the operation of the Transmission Owner's Bulk Electric System transmission Facilities in Real-time
- Generator Operators that have dispatch personnel at a centrally located dispatch center who receive direction from the Generator Operator's Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control. These personnel do not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions without making any modifications.

Applicable Facilities
None

Conforming Changes to Other Standards
None

Effective Dates
PER-005-2 shall become effective as follows:

> This standard shall become effective the first day of the first calendar quarter that is 24 months beyond the date that this standard is approved by an applicable governmental authority or is otherwise provided for in a jurisdiction where approval by an applicable authority is required for a standard to go into effect.
>
> Where approval by an applicable governmental authority is not required, this standard shall become effective on the first day of the first calendar quarter that is 24 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Actions to be Completed as of the Effective Date:
An implementation period provides time for an entity to become compliant with the standard prior to the standard becoming enforceable. This section describes the requirements that an entity must be compliant with as of the enforceable date of PER-005-2. This section does not address evidence of compliance; see measures, compliance input and RSAWs for further information regarding possible evidence.

<u>Requirement R1:</u>
Reliability Coordinators, Balancing Authorities, and Transmission Operators must have completed the requirements for PER-005-2 Requirement R1 as of the enforceable date of the standard as provided below. Note that these entities are subject to PER-005-1.

R1: Entities must have developed and implemented a training program for its System Operators using a systematic approach.

1.1: Entities must have defined and documented its methodology for creating a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks, and must have a list of these tasks.

1.1.1: Entities must have conducted a review of its tasks list once in the calendar year that this standard becomes enforceable.

Note: this review may be conducted either under the existing standard PER-005-1 or under PER-005-2 after it becomes enforceable, as long as the entity conducts one review during the calendar year.

1.2: An entity must have completed the design and development of training materials as necessary under its training program as of the enforceable date of PER-005-2. An entity is not obligated to have designed and developed training materials for all future training.

1.3: Entities must have delivered training in accordance with their training program as of the enforceable date of PER-005-2.

1.4: Entities must have conducted an evaluation once in the calendar year that PER-005-2 becomes enforceable.

Note: this may be conducted either under PER-005-1 or under PER-005-2 after it becomes enforceable, as long as the entity conducts one evaluation during the calendar year.

<u>Requirement R2:</u>

R2: Applicable Transmission Owners must have developed and implemented a training program for its applicable personnel using a systematic approach.

2.1: An applicable Transmission Owner must have defined and documented its methodology for creating a list of BES company-specific Real-time reliability-related tasks, and must have a list of these tasks as of the enforceable date of PER-005-2.

2.1.1: As applicable Transmission Owners were not previously subject to PER-005-1, they would not be required to have conducted a review prior to the enforceable date of the proposed standard or in the calendar year that the proposed standard becomes enforceable. The entity's first required evaluation would occur within the first calendar year following the enforceable date of PER-005-2.

2.2: An applicable Transmission Owner must have completed the design and development of training materials according to its training program as of the enforceable date of PER-005-2. An entity is not obligated to have designed and developed training materials for all future training.

2.3: As applicable Transmission Owners were not previously subject to PER-005-1, they must begin to implement training in accordance with its training program as of the enforceable date. Under the standard, these entities are not required to have delivered training prior to the enforceable date.

2.4: As applicable Transmission Owners were not previously subject to PER-005-1, they would not be required to have conducted an evaluation prior to the enforceable date of the proposed standard or in the calendar year that the proposed standard becomes enforceable. The entity's first required evaluation would occur within the first calendar year following the enforceable date of PER-005-2.

Requirement R3:

R3: Reliability Coordinators, Balancing Authorities, Transmission Operators and Transmission Owners must have verified the capabilities of its personnel identified in Requirements R1 and R2 to perform each of its assigned BES company-specific Real-time reliability-related tasks, at least once, as of the enforceable date of PER-005-2.

3.1: Reliability Coordinators, Balancing Authorities, and Transmission Operators that are already subject to PER-005-1 are required to, within six months of a change to its task list, have verified the capabilities of its personnel identified in Requirement R1 to perform each new or modified BES company-specific Real-time reliability-related tasks identified in Requirement R1 part 1.1. These entities will continue to have the time allotted to complete the verification under PER-005-1 after the enforceable date of PER-005-2.

Because Transmission Owners were not previously subject to PER-005-1, they are not expected to have verified the capabilities of its personnel identified in Requirement R2 to perform a new or modified BES company-specific Real-time reliability-related tasks identified under Requirement R2 part 2.1 prior to the enforceable date of the standard. This requirement pertains to BES company-specific reliability-related tasks that are newly identified or modified after the enforceable date of PER-005-2.

Requirement R4:

R4: Reliability Coordinators, Balancing Authorities, Transmission Operators and Transmission Owners must be providing training using the simulation technologies described in Requirement R4 according to its training program as of the date PER-005-2 becomes enforceable.

4.1: Entities that do not meet the criteria set forth in Requirement R4 prior to the enforceable date of the standard are required to comply with Requirement R4 within 12 months of meeting the criteria.

Requirement R5:

R5: Reliability Coordinators, Balancing Authorities, and Transmission Operators must have developed training, using a systematic approach, for their Operations Support Personnel on the impact of their job function(s) to those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1 and must have implemented that training according to its systematic approach as of the enforceable date of PER-005-2.

5.1: As Operations Support Personnel were not previously subject to PER-005-1, they would not be required to have conducted an evaluation prior to the enforceable date of the proposed standard or in the calendar year that the proposed standard becomes enforceable. The entity's first required evaluation would occur within the first calendar year following the enforceable date of PER-005-2.

Requirement R6:

R6: Generator Operators must have developed training, using a systematic approach, for their applicable personnel on the impact of their job function(s) to the reliable operations of the BES during normal and emergency operations and must have implemented that training according to its systematic approach as of the enforceable date of PER-005-2.

6.1: As Generator Operators were not previously subject to PER-005-1, they would not be required to have conducted an evaluation prior to the enforceable date of the proposed standard or in the calendar year that the proposed standard becomes enforceable. The entity's first required evaluation would occur within the first calendar year following the enforceable date of PER-005-2.

Justification

The 24-month period for implementation of PER-005-2 will provide sufficient time for the applicable entities to make necessary modifications to their systematic approach to training and, for entities not yet subject to the standard, time to develop a systematic approach to training that is compliant with the proposed standard. This time frame is consistent with the 24-month implementation period FERC approved for PER-005-1 to allow for Reliability Coordinators, Balancing Authorities, and Transmission

Operators to develop a systematic approach to training. The standard drafting team concluded that the same timeframe (24-months) should be provided to the new applicable entities and for the entities currently subject to PER-001-1 to development training for their Operations Support Personnel.

Retirements

PER-005-1 – System Personnel Training should be retired at 11:59:59 pm of the day immediately prior to the enforceable date of PER-005-2 in the particular jurisdiction in which the new standard is becoming enforceable. For entities that are completing actions under Requirement R3.1 of PER-005-1, this requirement will remain in effect until the time allotted under the requirement has expired.

Attachment 1
Approved Standards Incorporating the Term "System Operator"

EOP-005-2 — System Restoration from Blackstart Resources

EOP-006-2 — System Restoration Coordination

EOP-008-1 — Loss of Control Center Functionality

IRO-002-3 — Reliability Coordination – Analysis Tools

IRO-014-1 — Procedures, Processes, or Plans to Support Coordination between Reliability Coordinators

MOD-008-1 — TRM Calculation Methodology

MOD-020-0 — Providing Interruptible Demands and DCLM Data

PER-003-1 — Operation Personnel Credentials

PRC-004-WECC-1 – Protection System and Remedial Action Scheme Maintenance and Testing

PRC-023 -2 — Transmission Relay Loadability

NERC
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Item 2d-Att 2

Standards Authorization Request Form

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

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

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Operations Personnel Training		
Date Submitted:	Revised: September 25, 2013 Original: July 18, 2013		
SAR Requester Information			
Name:	Jordan Mallory		
Organization:	NERC		
Telephone:	404-446-9733	E-mail:	Jordan.mallory@nerc.net
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
Address outstanding FERC directives, modify System Operator definition (project 2010-16), and incorporate ERO initiatives, including drafting results-based or performance-based standards that are consistent with Paragraph 81 criteria.

SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):
• Modify System Operator Definition (Project 2010-16). • Define applicable entities to address outstanding FERC Directives from Order No. 693 and Order No. 742. • Modify existing PER-005-1 requirements for additional applicable entities and personnel. • Remove the requirement to provide at least 32 hours of emergency operations training from Requirement R3 of PER-005-1 as it no longer meets criteria set forth in the standard for utilizing a systematic approach to training. The appropriate amount of such training should be determined by the applicable entities through the analysis phase of a systematic approach to training and outlined in a continuous education section of their training program. Any additional hours may be duplicative or repetitive for the entity in providing training to their personnel.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
This project will address the following FERC directives. In addition, the project will review the present standard to eliminate ambiguity within the standard. 1. This SAR is needed to address outstanding FERC Directives from Order No. 693 and Order No. 742. The following is a summary of the FERC Directives to the ERO: ▪ "Develop specific Requirements addressing the scope, content and duration appropriate for generator operator personnel." Order No. 693 at P 1363. A new requirement has been suggested to address Generator Operator personnel at a centrally located dispatch center who receive direction from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control. Personnel at a centrally located dispatch center who relay dispatch instructions, without making any modifications, are excluded. ▪ "Include [operations support personnel] who carry out outage coordination and assessments in accordance with IRO-004-1 and TOP-002-2 and determine SOLs and IROLs or operating nomograms in accordance with IRO-005-1 and TOP-004-0." Order No. 693 at P 1372. A new requirement has been suggested to address operation support and support staff personnel for training. The term Operations Support Personnel has been defined solely for the revised PER-005-1 standard. ▪ Consider whether personnel responsible for ensuring that critical reliability applications

SAR Information
of the EMS, such as state estimator, contingency analysis and alarm processing packages are available, up-to-date in terms of system data and produce useable results should be included in a mandatory training standard. Order No. 693 at P 1373. The team considered whether there is technical justification for including EMS personnel in the standard. ▪ Consider the necessity of developing a similar implementation plan with respect to PER-005-1, Requirement R3.1 addressing simulation technology. Order No. 693 at P 1390-1391 and Order No. 742 at P 55. ▪ Expand the applicability of PER-005 to include training requirements for local transmission control center" operator personnel and define the term "local transmission control center." Order No. 693 at P 1343; Order No. 742 at P 64. The team thought it would be a better path to define local transmission control center through extending the applicability to Transmission Owners versus creating a new term for the NERC Glossary. Transmission Owner in the PER standard is defined as "Personnel at a facility, excluding field switching personnel, who act independently to carry out tasks that require Real-time operation of the Bulk Electric System including protecting assets, protecting personnel safety, adhering to regulatory requirements and establishing stable islands during system restoration ." Transmission Owner has been added to all the requirements of the suggested revised PER-005-1 standard. 2. Revise definition of System Operator in glossary of terms to address industry concerns for clarity based on Project 2010-16. 3. Implement Paragraph 81 criteria by identifying Reliability Standards requirements that either: (a) provide little protection to the BES; (b) are unnecessary or (c) are redundant.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Detailed description of this project can be found in the Technical White Paper included with the initial SAR posting.

Reliability Functions

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

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

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

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

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

Related Standards	
Standard No.	Explanation

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
ERCOT	None
FRCC	None
MRO	None
NPCC	None
RFC	None
SERC	None

Regional Variances	
SPP	None
WECC	None

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Item 2d-Att 1

Standards Authorization Request Form

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

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

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Operations Personnel Training		
Date Submitted:	Revised: September 25, 2013 Original: July 18, 2013		
SAR Requester Information			
Name:	Jordan Mallory		
Organization:	NERC		
Telephone:	404-446-9733	E-mail:	Jordan.mallory@nerc.net
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
~~Resolve~~Address outstanding FERC directives, modify System Operator definition (project 2010-16), and ~~to~~ incorporate ERO initiatives~~ such as~~, including drafting results-based~~,~~ or performance-based~~,~~ standards that are consistent with Paragraph 81~~, etc~~ criteria.

SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):

- Modify System Operator Definition (Project 2010-16).
- Define applicable entities to address outstanding FERC Directives from Order No. 693 and Order No. 742.
- Modify existing PER-005-1 requirements for additional applicable entities and personnel.
- ~~Remove existing PER-005-1 R3 prescriptive 32 hours of emergency operations as it is covered under the Systematic Approach to Training and thus is repetitive. In Paragraph 81 of the March 15, 2012 Order (link), FERC provided an opportunity for the ERO to remove requirements that did little to protect to the BPS pursuant to specific criteria. The requirement for 32 hours of training meets the Paragraph 81 criteria for redundancy. It further is not a results-based requirement, as it is unnecessarily prescriptive.~~Remove the requirement to provide at least 32 hours of emergency operations training from Requirement R3 of PER-005-1 as it no longer meets criteria set forth in the standard for utilizing a systematic approach to training. The appropriate amount of such training should be determined by the applicable entities through the analysis phase of a systematic approach to training and outlined in a continuous education section of their training program. Any additional hours may be duplicative or repetitive for the entity in providing training to their personnel.

Brief Description (Provide a paragraph that describes the scope of this standard action.)

This project will ~~be addressing~~address the following FERC directives. In addition, the project will ~~be reviewing~~review the present standard to eliminate ~~in~~ ambiguity within the standard.

1. This SAR is needed to address outstanding FERC Directives from Order No. 693 and Order No. 742. The following is a summary of the FERC Directives to the ERO:

   - "Develop specific Requirements addressing the scope, content and duration appropriate for generator operator personnel~~.~~." Order No. 693 at P 1363.

     A new requirement ~~R5~~ has been suggested ~~as an addition~~ to ~~a revised PER-005-1 capturing~~address Generator ~~Operators Personnel~~Operator personnel at a centrally located dispatch center who receive direction from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control. Personnel at a centrally located dispatch center who relay dispatch instructions, without making any modifications, are excluded.

   - "Include [operations support personnel] who carry out outage coordination and assessments in accordance with IRO-004-1 and TOP-002-2 and determine SOLs and IROLs or operating nomograms in accordance with IRO-005-1 and TOP-004-0~~.~~." Order No. 693

SAR Information
at P 1372. A new requirement ~~R4~~ has been suggested ~~as an addition~~ to ~~a revised PER-005-1 capturing~~address operation support and support staff personnel for training. The term Operations Support Personnel has been ~~created with a definition~~defined solely for the revised PER-005-1 standard. ▪ Consider whether personnel responsible for ensuring that critical reliability applications of the EMS, such as state estimator, contingency analysis and alarm processing packages are available, up-to-date in terms of system data and produce useable results should be included in a mandatory training standard. ~~(Technical Justification)~~ Order No. 693 at P 1373. The team considered whether there is technical justification for including EMS personnel in the standard. ▪ Consider the necessity of developing a similar implementation plan with respect to PER-005-1, Requirement R3.1~~. (~~ addressing simulation technology~~)~~. Order No. 693 at P 1390-1391 and Order No. 742 at P 55. ▪ ~~Develop a definition~~Expand the applicability of ~~"local transmission control center" for developing the~~PER-005 to include training requirements for local transmission control center" operator personnel~~.~~ and define the term "local transmission control center." Order No. 693 at P 1343; Order No. 742 at P 64. The ~~group~~team thought it would be a better path to define local transmission control center through extending the applicability to Transmission Owners versus creating a new term for the NERC Glossary. Transmission Owner in the PER standard is defined as "Personnel ~~in a transmission control center who operate a portion of the Bulk Electric System at the direction of its Transmission Operator."~~at a facility, excluding field switching personnel, who act independently to carry out tasks that require Real-time operation of the Bulk Electric System including protecting assets, protecting personnel safety, adhering to regulatory requirements and establishing stable islands during system restoration ." Transmission Owner has been added to all the requirements of the suggested revised PER-005-1 standard. 2. Revise definition of System Operator in glossary of terms to address industry concerns for clarity based on Project 2010-16. 3. Implement Paragraph 81 criteria by identifying Reliability Standards requirements that either: (a) provide little protection to the ~~BPS~~BES; (b) are unnecessary or (c) are redundant.

SAR Information
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Reliability Functions		
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☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma

Reliability Functions		
		tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
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☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
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☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☒	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.

Reliability and Market Interface Principles	
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

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

Related Standards	
Standard No.	Explanation

Related SARs	
SAR ID	Explanation

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	None
FRCC	None
MRO	None
NPCC	None
RFC	None
SERC	None
SPP	None
WECC	None

Project 2010-01 Operations Personnel Training
PER-005-2 Mapping Document

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
R1. Reliability Coordinator, Balancing Authority and Transmission Operator shall use a systematic approach to training to establish a training program for the BES company-specific reliability-related tasks performed by its System Operators and shall implement the program. **1.1.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall create a list of BES company-specific reliability-related tasks performed by its System Operators. **1.1.1.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall update its list of BES company-specific reliability-related tasks performed by its System Operators each calendar year to	Requirement R1 parts 1.1.1., 1.1., 1.2., 1.3., and 1.4.	**R1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement a training program for its System Operators as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **1.1** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology. **1.1.2** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 1.1 each calendar year.

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
identify new or modified tasks for inclusion in training. **1.2.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall design and develop learning objectives and training materials based on the task list created in R1.1. **1.3.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall deliver the training established in R1.2. **1.4**. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall conduct an annual evaluation of the training program established in R1, to identify any needed changes to the training program and shall implement the changes identified.		**1.2** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 1.1. **1.3** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall deliver training to its System Operators according to its training program. **1.4** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall implement the changes identified.
R2. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator's capabilities to perform each assigned task identified in R1.1 at least one time.	The old Requirement R2 is now Requirement R3.	**R3.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
2.1. Within six months of a modification of the BES company-specific reliability-related tasks, each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator's capabilities to perform the new or modified tasks.		Requirement R1 part 1.1 or Requirement R2 part 2.1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]* **3.1** Within six months of a modification or addition of a BES company-specific Real-time reliability-related task, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its personnel identified in Requirement R1 or Requirement R2 to perform the new or modified BES company-specific Real-time reliability-related tasks identified in Requirement R1 part 1.1 or Requirement R2 part 2.1.
R3. At least every 12 months each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each of its System Operators with at least 32 hours of emergency operations training applicable to its organization that reflects emergency operations topics, which includes system	This Requirement has been updated with deleting R3 and moving 3.1 from the approved standard to be the new R4. Part 4.1 in the proposed standard it	**R4.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1 or

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
restoration using drills, exercises or other training required to maintain qualified personnel. **3.1.** Each Reliability Coordinator, Balancing Authority and Transmission Operator that has operational authority or control over Facilities with established IROLs or has established operating guides or protection systems to mitigate IROL violations shall provide each System Operator with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES during normal and emergency conditions.	addresses the implementation of simulation technology.	Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **4.1.** A Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not previously meet the criteria of Requirement R4, shall comply with Requirement R4 within 12 months of meeting the criteria.
	This requirement is new to PER-005-2.	**R2.** Each Transmission Owner shall use a systematic approach to develop and implement a training program for its personnel identified in Applicability Section 4.1.4.1 of this standard as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
		2.1 Each Transmission Owner shall create a list of BES company-specific Real-time reliability-related tasks based on a defined and documented methodology. **1.1.2** Each Transmission Owner shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 2.1 each calendar year. **2.2** Each Transmission Owner shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 2.1. **2.3** Each Transmission Owner shall deliver training to its personnel identified in Applicability Section 4.1.4.1 of this standard according to its training program. **2.4** Each Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement R2 to identify any needed changes to the training program and shall implement the changes identified.

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
	This requirement is new to PER-005-2.	**R5.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **5.1** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training.

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
	This requirement is new to PER-005-2.	**6.** Each Generator Operator shall use a systematic approach to develop and implement training to its personnel identified in Applicability Section 4.1.5.1 of this standard, on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **6.1.** Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R6 to identify and implement changes to the training.

Project 2010-01 Operations Personnel Training
PER-005-2 Mapping Document

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
R1. Reliability Coordinator, Balancing Authority and Transmission Operator shall use a systematic approach to training to establish a training program for the BES company-specific reliability-related tasks performed by its System Operators and shall implement the program. **1.1.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall create a list of BES company-specific reliability-related tasks performed by its System Operators. **1.1.1.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall update its list of BES company-specific reliability-related tasks performed by its System Operators each calendar year to	Requirement R1 parts 1.1.1., 1.1., 1.2., 1.3., and 1.4.	**R1.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement a training program for its System Operators as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **1.1** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology. **1.1.2** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 1.1 each calendar year.

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
identify new or modified tasks for inclusion in training. **1.2.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall design and develop learning objectives and training materials based on the task list created in R1.1. **1.3.** Each Reliability Coordinator, Balancing Authority and Transmission Operator shall deliver the training established in R1.2. **1.4**. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall conduct an annual evaluation of the training program established in R1, to identify any needed changes to the training program and shall implement the changes identified.		**1.2** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 1.1. **1.3** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall deliver training to its System Operators according to its training program. **1.4** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall implement the changes identified.
R2. Each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator's capabilities to perform each assigned task identified in R1.1 at least one time.	The old Requirement R2 is now Requirement R3.	**R3.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
2.1. Within six months of a modification of the BES company-specific reliability-related tasks, each Reliability Coordinator, Balancing Authority and Transmission Operator shall verify each of its System Operator's capabilities to perform the new or modified tasks.		Requirement R1 part 1.1 or Requirement R2 part 2.1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]* **3.1** Within six months of a modification or addition of a BES company-specific Real-time reliability-related task, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its personnel identified in Requirement R1 or Requirement R2 to perform the new or modified BES company-specific Real-time reliability-related tasks identified in Requirement R1 part 1.1 or Requirement R2 part 2.1.
R3. At least every 12 months each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each of its System Operators with at least 32 hours of emergency operations training applicable to its organization that reflects emergency operations topics, which includes system	This Requirement has been updated with deleting R3 and moving 3.1 from the approved standard to be the new R4. Part 4.1 in the proposed standard it	**R4.** Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs), or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1 or

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 **NERC Board Approved**	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
restoration using drills, exercises or other training required to maintain qualified personnel. **3.1.** Each Reliability Coordinator, Balancing Authority and Transmission Operator that has operational authority or control over Facilities with established IROLs or has established operating guides or protection systems to mitigate IROL violations shall provide each System Operator with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES during normal and emergency conditions.	addresses the implementation of simulation technology.	Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **4.1.** A Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not previously meet the criteria of Requirement R4, shall comply with Requirement R4 within 12 months of meeting the criteria.
	This requirement is new to PER-005-2.	**R2.** Each Transmission Owner shall use a systematic approach to develop and implement a training program for its personnel identified in Applicability Section 4.1.4.1 of this standard as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
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Standard PER-005-1 NERC Board Approved	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
	This requirement is new to PER-005-2.	**R5.** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **5.1** Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training.

PER-005-1 Mapping to Proposed NERC Reliability Standard PER-005-2		
Standard PER-005-1 **NERC Board Approved**	**Transitions to the below Requirement in New Standard or Other Action**	**Proposed Standard PER-005-2**
	This requirement is new to PER-005-2.	**6.** Each Generator Operator shall use a systematic approach to develop and implement training to its personnel identified in Applicability Section 4.1.5.1 of this standard, on how their job function(s) impact the reliable operations of the BES during normal and emergency operations. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **6.1.** Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R6 to identify and implement changes to the training.

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Compliance Operations

Draft Reliability Standard Compliance Guidance for PER-005-2
October 1, 2013

Introduction
The NERC Compliance department (Compliance) worked with the PER-005 standard drafting team (SDT) to review the proposed standard PER-005-2. The purpose of the review was to discuss the requirements of the proposed standard to obtain an understanding of its intended purpose and the evidence necessary to support compliance. The purpose of this document is to address specific questions posed by the PER SDT in order to aid in the drafting of the requirements and provide a level of understanding regarding evidentiary support necessary to demonstrate compliance.

While all compliance evaluations require levels of auditor judgment, participating in these reviews allows Compliance to develop training and approaches to support a high level of consistency in audits conducted by the Regional Entities. The following questions and answers are intended to assist the SDT in further refining the standard and to serve as a resource in the development of training for auditors.

PER-005-2 Questions

Question 1
For Requirement R1, what criteria would an auditor use to determine if a registered entity uses a systematic approach to training for developing its training program?

Compliance Response to Question 1
A systematic approach to training is a concept or methodology. This version of the standard retains flexibility for the entity to determine how it will apply the principles of this concept to develop and implement its training program. There are different models of systematic approaches to training, and the standard does not specify a certain model that should be used.

Consistent with FERC orders[1] and current Electric Reliability Organization's practices, to determine whether the entity used a systematic approach to training, an auditor will evaluate whether the entity's training program follows the principles below:

- Assess training needs (analysis)
- Conduct the training activity (design, develop and implement)
- Evaluate the training activity (evaluate the effectiveness of the training)

[1] See FERC Order No. 742 at P 25 and Order No. 693 at P 1380, 1382.

Further, as provided in the Application Guidelines attached to the standard, an auditor will assess whether the entity's training program, using a systematic approach to training:

1. determined the skills and knowledge needed to perform Real-time reliability-related tasks;
2. determined what training is needed to achieve those skills and knowledge;
3. determined if the trainee can perform the Real-time reliability-related task(s) acceptably in either a training or on-the-job environment; and
4. determined if the training is effective, and makes adjustments as necessary.

Question 2
In Requirement R3, does an entity that has one or more IROLs have 12 months to conduct simulation technology training when it obtains another IROL?

Compliance Response to Question 2
No, if an entity currently has one or more IROLs, it has the ability to conduct simulation technology. The 12 months applies only to an entity that did not have any IROLs but obtains an IROL for the first time.

Question 3
Is an auditor to assess a registered entity based on a systematic approach to training for the Operations Support Personnel referenced in Requirement R4?

Compliance Response to Question 3
Yes. An auditor will evaluate the entity's systematic approach to training with regard to the <u>impact of the Operations Support Personnel's job function</u> on the Real-time reliability-related tasks, <u>NOT on the Operations Support Personnel's ability to conduct these tasks</u>.

Operations Support Personnel are required to receive training only on how their job functions impact the Real-time reliability-related tasks. Therefore, modifying the assessment outlined above in Question #1, rather than:

- determined the skills and knowledge needed to perform Real-time reliability-related tasks;

the auditor will determine if the entity's systematic approach to training:

- determined the skills and knowledge needed to understand the impact of the job function(s) on the Real-time reliability-related tasks.

Question 4
Since Requirement R5 does not include the same parts as Requirement R1 to define a systematic approach to training, do entities have to adhere to the Requirement R1 parts for Requirement R5?

Compliance Response to Question 4
No. However, an auditor would verify that an entity followed a systematic approach to training. An auditor will evaluate this systematic approach to training with regard to the impact of the Generator Operator's (GOP's) job function(s) on the reliable operations of the BES during normal and emergency operations.

Consistent with FERC orders[2] and current Electric Reliability Organization's practices, to determine whether the entity used a systematic approach to training, an auditor will evaluate whether the entity's training program follows the principles below:

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1. determined the skills and knowledge needed to understand the impact of the Generator Operator's job function(s) on the reliable operations of the BES during normal and emergency operations.
2. determined what training is needed to achieve those skills and knowledge;
3. determined if the trainee can support the reliable operation of the BES during normal and emergency operations acceptably in either a training or on-the-job environment; and
4. determined if the training is effective, and makes adjustments as necessary.

Conclusion
Following final approval of the Reliability Standard, Compliance will develop the final Reliability Standards Auditor Worksheet (RSAW) and associated training. Attachment A represents the version of the proposed standard requirements referenced in this document.

[2] See FERC Order No. 742 at P 25 and Order No. 693 at P 1380, 1382.

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[2] See FERC Order No. 742 at P 25 and Order No. 693 at P 1380, 1382.

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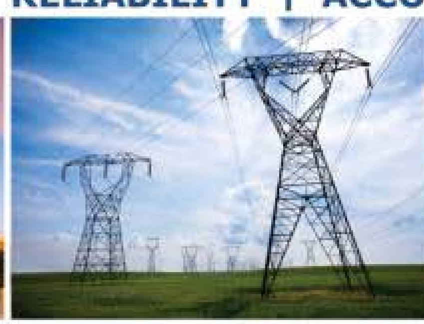
PER-005 Standards White Paper

July 18, 2013

RELIABILITY | ACCOUNTABILITY



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Executive Summary

A Personnel, Performance, Training, and Qualifications (PER) ad hoc group was formed to work with industry stakeholders to address five outstanding Federal Energy Regulatory Commission (FERC) directives.

The five outstanding FERC directives are as follows:

1. The Commission directs the Electric Reliability Organization (ERO) to develop specific requirements addressing the scope, content, and duration appropriate for Generator Operator (GOP) personnel (Order No. 693, P. 1363).
2. The Commission directs the ERO to develop a modification to PER-002-0 to require training of operations planning and operations support staff of Transmission Operators (TOPs) and Balancing Authorities (BAs) who have a direct impact on the reliable operation of the Bulk-Power System (BPS) (Order No. 693, P. 1372).
3. The Commission directs the ERO to consider personnel responsible for ensuring that critical reliability applications of the EMS, such as state estimator, contingency analysis and alarm processing packages, are available, up to date in terms of system data and produce useable results that can also have an impact on the reliable operation of the BPS (Order No. 693, P. 1373).
4. The Commission directs the ERO to consider the necessity of developing a similar implementation plan with respect to PER-005-1, Requirement R3.1 (Order No. 742, P. 24).
5. The Commission directs the ERO to develop through a separate reliability standards development project formal training requirements for local transmission control center operator personnel, and to develop a definition of "local transmission control center" in the standards development project (Order No. 742, P. 64).

The ERO is required to comply with FERC directives unless there is an equally effective and efficient method of addressing the reliability concern, or if there is evidence that the directive has been overcome by events or is no longer needed. These five directives were challenging due to the variance of industry opinion.

The PER informal development project reviewed the FERC directives, conducted outreach to industry stakeholders, and developed the pro forma standard. There were differing opinions from industry; some stated that the directives should be complied with while others stated there was sufficient justification as to why the directives were no longer needed. Although persuasive, the majority of the arguments as to why the directives were no longer needed had been addressed by FERC in prior orders as outlined in Appendix A. The discussion for each of the above directives are summarized as follows.

First, discussions were held regarding GOP dispatchers at a local control center. Through industry feedback, it became apparent that stakeholders needed a better understanding of the types of GOPs FERC was including in the directive. Initially it appeared that the directive would apply only to those GOPs that make independent decisions; however, FERC had addressed that narrow reading in FERC Order 693 P. 1359. The group's final determination was that even though GOPs at a local control center receive direction from their BA or TOP, those that take direction and then develop dispatch instructions for their plant operators are the specific GOPs the FERC Orders are attempting to capture. Therefore, the pro forma standard expanded the applicability in PER-005 to include these specific types of GOPs.

Second, the ad hoc group received strong feedback from industry that operations planning and operations support staff should not be included in the PER standard. Some of the reasons presented were: the System Operator is the one who impacts the Bulk Electric System (BES) and not the support personnel; support personnel do not make any Real-time decisions on BES operations; mandating training would distract training staff from the more critical functions of training System Operators; and this would create an administrative burden and would be too costly of a task on industry for the reliability protection it offers. Through further research it was determined that these were the same arguments previously presented and responded to by FERC in Orders 693 and 742 (see Appendix A). Therefore, as the informal development effort was not able to provide an argument that had not previously been rejected by FERC, the ad hoc group continued with the inclusion of support personnel in PER-005.

The third major discussion was in regard to the directive for the ERO to consider including personnel responsible for ensuring that critical reliability applications of the EMS, such as state estimator, contingency analysus and alarm processing packages, are available, up-to-date in terms of system data and produce useable results can also have an impact on the reliable operation of the BPS. Similar to the previously described discussions, many of the arguments had been addressed by FERC, but there was new evidence in this area. The argument for not including EMS personnel in the training standard at this time is based on a report provided by the Event Analysis Subcommittee (EAS). The EAS worked with the NERC Event Analysis (EA) staff to review the events that have been cause-coded since October 2010. The database has over 263 events; 208 of them were cause-coded to allow for trending and cluster analysis. The EAS and NERC EA staff queried the 208 events and looked in particular for cause codes that pertain to human errors and training that were less than adequate. The query produced 44 events that had the possibility for human errors or training being a contributing factor in the event. An analysis of those 44 events indicated that only 10 had human error or training as a contributing factor. Six of those 10 events were related to the loss of EMS or SCADA. Out of the six events, only two were deemed to be a training issue. Therefore, based on the information, the EAS and PER ad hoc group do not believe it is necessary at this time to require EMS support personnel to receive the level of training required of a BA, Reliability Coordinator (RC), and TOP by NERC standard PER-005.

Fourth, the ad hoc group and industry stakeholders agreed with the Commission on developing an implementation plan with respect to the simulation technology requirement. The ad hoc group determined that six months would suffice for an entity to become compliant with the simulation technology requirement in PER-005. No feedback has been received thus far from industry regarding this suggested change.

Last, the group addressed the local transmission control center directive by expanding the PER-005 applicability section to Transmission Owners (TO) and creating a standard-only definition. The group defined “local transmission control center” in the standard as *personnel in a transmission control center who operate a portion of the Bulk Electric System at the direction of its Transmission Operator.* This term will not become a part of the NERC Glossary of Terms used in NERC Reliability Standards at this time.

In summary, the PER ad hoc group created a pro forma standard (PER-005-2) extending the applicability to certain GOPs, support personnel, and TOs, excluding EMS support personnel. The 32-hour requirement has been removed as it is inherent to the systematic approach to training that training hours should be left up to each entity. The requirement for 32 hours of training meets the Paragraph 81 criteria for redundancy and was further not a results-based requirement and considered unnecessarily prescriptive. A new requirement R3.1 was created to develop the implementation of the simulation technology requirement.

The pro forma standard was drafted to provide maximum flexibility to industry while addressing the reliability concerns in the FERC directives. Under the pro forma standard, each entity has the ability to identify its reliability-related tasks, determine which of its personnel conduct those tasks, and determine the appropriate training and level of training for each employee. The ad hoc group understood the concerns from industry regarding the systematic approach to training, and each requirement has been left up to the entity to decide which approach should be used.

Purpose

The purpose of the PER-005 white paper is to provide the issues, rationale, and support for the revisions to the PER-005 standard. This white paper provides an explanation of how each of the FERC directives was addressed, including the issues that were raised during informal development and the rationale for proceeding or not proceeding with each. This paper will also provide technical justification and support for the revisions to the standard. The contents in this paper will provide the standard drafting team with the basis for the pro forma standard so they can begin the formal standard development process.

History of the PER-005 Informal Development

In February 2012, the North American Electric Reliability Corporation (NERC) Board of Trustees (Board) formed the Standards Process Input Group (SPIG) to address the widespread frustration with the duration of the standards development process.[1] In May 2012, SPIG submitted a report to the NERC Board recommending improving both the timeliness and quality of the standards. The process manual changes were approved by the Board in February 2013.[2] Since then, the Board issued a resolution requesting SPIG, the Members Representative Committee (MRC), NERC staff, and industry stakeholders to reform their standards development paradigm. Changes were integrated into the 2013–15 Reliability Standards Development Plan (RSDP) and Standards Committee (SC) Strategic Plan.[3]

The evolving standards process includes an informal development period in which NERC Standards developers work with an ad hoc group to gather information up front from industry regarding the FERC directives or other standards development project. There are three approaches to consider when addressing FERC directives: comply with the FERC directive, present an equally and effective alternative, or provide technical justification as to why the directive is no longer needed.

A PER ad hoc group was formed in January of 2013 to work with industry stakeholders to address five outstanding FERC directives. The ad hoc group addressed each directive through informal development, with the goal of filing a revised standard with FERC by December 31, 2013.

The PER ad hoc group held its first informal development meeting February 25–27, 2013, in Atlanta, Georgia. A small ad hoc group of industry subject matter experts (SMEs) representing RCs', BAs', GOPs', TOPs', and TOs' participated in discussions about the FERC directives and possible resolutions to address them. The ad hoc group created the first draft of a pro forma standard to address each directive. The ad hoc group conducted conference calls, workshops, and, to reach additional industry participants, two webinars: a March 15 informational webinar and an April 4 industry feedback webinar requesting feedback from industry regarding the PER ad hoc group suggestions. Multiple conference calls were held with the ad hoc group to keep all members aware of feedback received.

A second informal meeting was held April 22–23, 2013, at NERC's Atlanta office. The meeting was a continuation of the efforts of the first meeting with the addition of discussion on the information received through the outreach efforts. The ad hoc group discussed issues raised by industry and revised the pro forma standard based on that information. The group presented the revised pro forma standard to industry at the May 31 industry feedback webinar and other conference calls. During the webinar, polling questions were presented to participants, and 147 out of 323 people participated in the polling. The purpose of this polling was to gauge industry's support of the suggested PER-005 standard.

The last informal development meeting was held June 20–21, 2013 to develop the materials necessary to move into the formal process. This will entail submitting a Standard Authorization Request (SAR), the pro forma standard, input to a reliability standards audit worksheet (RSAW), an implementation plan, a mapping document, and a technical white paper to the NERC Standards Committee (SC).

A complete list of entities that participated during the informal development can be located in Appendix B.

[1] May 9, 2012 NERC Board minutes: http://www.nerc.com/gov/bot/Agenda%20Minutes%20and%20Highlights%20DL/2012/BOT_050912m_complete.pdf
[2] August 16, 2012 NERC Board minutes: http://www.nerc.com/gov/bot/Agenda%20Minutes%20and%20Highlights%20DL/2012/0-BOT08-12a-complete.pdf
[3] 2013–15 Reliability Standards Development Plan: http://www.nerc.com/pa/Stand/Standards%20Development%20Plan%20Library/2013-2015_RSDP_BOT_Approved_12-19-12.pdf

Outstanding FERC Directives and Technical Discussions

There are five outstanding FERC directives from Order 693[4] and Order 742.[5] Each directive was discussed in detail during the informal development stage, and below are the summaries of the discussions.

Applicability of the PER Standard to GOP Dispatchers

FERC Order 693 ¶ 1360-1361, 1363

P. 1360. We agree with FirstEnergy and others that some clarification is required regarding which generator operator personnel should be subject to formal training under the Reliability Standard. As noted above, a generator operator typically receives instructions from a balancing authority. Some generator operators are structured in such a way that they have a centrally-located dispatch center that receives direction and then develops specific dispatch instructions for plant operators under their control. For example, a balancing authority may direct a centrally-located dispatch center to deliver 300 MW to the grid, and the dispatch center would determine the best way to deliver that generation from its portfolio of units. In this type of structure, it is the personnel of the centrally located dispatch center that must receive formal training in accordance with the Reliability Standard. Plant operators located at the generator plant site also need to be trained but the responsibility for this training is outside the scope of the Reliability Standard.

P. 1361. Other generator operators may be structured in such a way that the dispatch center and the single generation plant are at the same site. In this structure as well, some personnel will perform dispatch activities while others are designated as plant operators. Again, it is the dispatch personnel that must receive formal training in accordance with the Reliability Standard. Plant operators also need to be trained but the responsibility for this training is outside the scope of the Reliability Standard.

P. 1363. Further, the Commission agrees with MidAmerican, SDG&E and others that the experience and knowledge required by transmission operators about Bulk-Power System operations goes well beyond what is needed by generation operators; therefore, training for generator operators need not be as extensive as that required for transmission operators. Accordingly, the training requirements developed by the ERO should be tailored in their scope, content and duration so as to be appropriate to generation operations personnel and the objective of promoting system reliability. Thus, in addition to modifying the Reliability Standard to identify generator operators as applicable entities, we direct the ERO to develop specific Requirements addressing the scope, content and duration appropriate for generator operator personnel.

FERC Order 742 ¶ 83-84

P. 83. EPSA requests clarification of several statements in the NOPR regarding the Order No. 693 directive related to expanding the applicability of the system operator training Reliability Standard to include certain generator operators. First, EPSA expresses concern that the NOPR discussion broadly addresses generator operator personnel in a way that could be construed as subjecting all generator operator personnel, regardless of the disposition of the generating unit and how it fits into the grid and the topology of the grid, to the system operator training requirements. Therefore EPSA seeks clarification that the Commission did not intend for the NOPR to expand the Order No. 693 directives. We confirm that we have not modified the scope of applicability of the Order No. 693 directive regarding generator operator training. As described in Order No. 693, the directive applies to generator operator personnel at a centrally-located dispatch center who receive direction and then develop specific dispatch instructions for plant operators under their control. Those generator operator personnel must receive formal training of the nature provided to system operators under PER-005-1. As clarified in Order No. 693, this group of personnel would include a generator operator's dispatch personnel where a single generator and dispatch center are located at the same site.

P. 84. EPSA also seeks clarification regarding the statement in the NOPR that: "[I]n the event communication is lost, the generator operator personnel must have had sufficient training to take appropriate action to ensure reliability of the Bulk-Power System." EPSA expresses concern that this statement suggests that if communication is lost with the grid operator, the generator operator must take unilateral action for which it requires training. EPSA notes that generator operators do not take such unilateral action nor do they have access to information to make such decisions. Therefore, EPSA asks the Id. Commission to make clear that while communication should be addressed in training requirements for centrally located generator operator dispatch employees, the Commission is not extending related responsibilities or training requirements to generator operator employees. We grant the requested clarification, and affirm that we are not modifying the Order No.

[4] *Mandatory Reliability Standards for the Bulk-Power System*, 118 FERC ¶ 61,218, FERC Stats. & Regs. ¶ 31,242 (Order No. 693), *order on reh'g, Mandatory Reliability Standards for the Bulk-Power System*, 120 FERC ¶ 61,053 (Order No. 693-A) (2007).

[5] FERC Order 742 PP 83-84

693 directive regarding training for certain generator operator dispatch personnel, nor are we expanding a generator operator's responsibilities.

Consideration of Directive

The PER ad hoc group considered all options (such as complying with the FERC directive, presenting an equally and effective alternative, or providing technical justification as to why the directive is no longer needed) when addressing GOPs at a centrally located dispatcher center who receive direction and then develop specific dispatch instructions for plant operators under their control.[6] The ad hoc group suggested a revised PER-005-1 standard that expands the applicability section to these specific GOPs, leaving it up to the entity to identify the reliability-related tasks its GOP personnel should be trained on. The group attempted to draw a bright line of GOPs that make independent decisions. Through subsequent discussions with FERC's OER staff, the group learned that this bright line, per the FERC orders, would not address the FERC directive. It appears that the intent of the FERC order is for GOPs at a control center who receive direction from their BAs or TOPs to develop specific dispatch instructions (not just that make an independent decision) for their plant operator. These are the people who should be captured under the standard. The group considered and suggested a revised PER-005 that extends applicability to these specific GOPs. The standard language allows the entity to decide which systematic approach to training should be used when training GOPs and includes coordination on training topics with the entity's RC, BA, TOP, and TO.

Technical Discussions

Many technical discussions were held regarding increasing the applicability of the PER standard to GOP dispatchers. The feedback provided in the list below are the reasons provided by industry as to why this directive was no longer needed for GOP dispatchers.

- All decisions that GOPs make that impact the reliability of the BES must be approved by the BA, TOP, or RC. Even in the case of an emergency situation, the GOP will not make any decisions until approved by the BA, TOP, or RC. It was further explained that there are GOPs that do not develop dispatch instruction and simply take the information received from the BA, TOP, or RC and relayed information directly to the plant operator.
- FERC limited emergency shutdowns of generation to occur at the plant level, not the dispatch level; at this time, the FERC order does not require plant operators to be trained.
- The NERC Functional Model was stated many times as a reason to show that GOP dispatchers follow the direction of the BA or TOP. The NERC Functional Model for GOPs states that GOPs in Real time:
  - Provide Real-time operating information to the Transmission Operators and the required Balancing Authority.
  - Adjust real and reactive power as directed by the Balancing Authority and Transmission Operators.[7]
- When a GOP would be making decisions that impact reliability, they are also registered as the BA or TOP.

Entities that agreed with GOPs being added to the standard made the following comments:

- Consider including some criteria regarding various sizes of generation like in CIP Version 5.
- Consider creating a new standard addressing GOP dispatchers.
- PPL Electric Utilities Corp., Louisville Gas and Electric Co., and PPL Generation LLC stated that the TOP or BA should prepare the GOP training modules since the goal is to ensure that dispatchers do what the TOP or BA wants in emergency situations.

The arguments provided above constitutes the same arguments that FERC rejected in Order Nos 693 and 742 (see Appendix A).

[6] FERC Order 742 P 83.
[7] NERC functional model: http://www.nerc.com/pa/Stand/Resources/Documents/FunctionalModelTechnicalDocumentV5Clean2009Dec1.pdf

FERC Order 693 P. 1393 clearly states that GOP dispatchers need to be trained using the systematic approach to training methodology.

> 1393. Accordingly, the Commission approves Reliability Standard PER-002-0. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, the Commission directs the ERO to develop a modification to PER-002-0 through the Reliability Standards development process that: (1) identifies the expectations of the training for each job function; (2) develops training programs tailored to each job function with consideration of the individual training needs of the personnel; (3) expands the Applicability section to include (a) reliability coordinators, (b) local transmission control center operator personnel (as specified in the above discussion), **(c) generator operators centrally-located at a generation control center with a direct impact on the reliable operation of the Bulk-Power System and** (d) operations planning and operations support staff who carry out outage planning and assessments and those who develop SOLs, IROLs or operating nomograms for Real-time operations; **(4) uses the Systematic Approach to Training (SAT) methodology in its development of new training programs** and (5) includes the use of simulators by reliability coordinators, transmission operators and balancing authorities that have operational control over a significant portion of load and generation.[8]

The pro forma standard is written to require the use of a Systematic Approach to Training, but provides the entity the ability to determine the reliability-related tasks GOP dispatchers need to be trained on and the method of how the GOP dispatchers are trained.

There were discussions regarding whether training for GOPs should be in a separate standard, however the current PER-005 is a systematic approach to training based standard and thus it is logical to include the GOP dispatchers within the current standard.

Because the ad hoc group received the same feedback that was provided in FERC Order Nos. 693 and 742; the ad hoc group suggested expanding the applicability section in PER-005 to capture these certain GOP dispatchers using the systematic approach to training, which is left up to the entity.

Applicability of the PER Standard to Operations Planning and Operations Support Staff

FERC Order 693 ¶ 1366

P. 1366. As mentioned above, the Commission proposed in the NOPR to direct the ERO to develop a modification to PER-002-0 to require training of operations planning and operations support staff of transmission operators and balancing authorities who have a direct impact on the reliable operation of the Bulk-Power System.[9]

FERC Order 742 ¶ 82

P. 82. Associated Electric expressed concern that the NOPR definition of the “operations planning and operations support staff” who should receive training pursuant to the Order No. 693 directive is “broad and will encompass operations planning and operation support staff who engage in tasks that do not directly affect the reliable operation of the bulk electric system.” The Commission clarifies that the scope of the Reliability Standard or modification to a Reliability Standard to address training for “operations planning and operations support staff” is limited by the qualifications stated in Order No. 693. Specifically, in Order No. 693, the Commission directed the ERO to develop a modification to PER-002-0 that extends applicability of the training requirements to the operations planning and operations support staff of transmission operators and balancing authorities. The Commission further clarified that such directive applies only to operations planning and operations support personnel who: “carry out outage coordination and assessments in accordance with Reliability Standards IRO-004-1 and TOP-002-2, and those who determine SOLs and IROLs or operating nomograms in accordance with Reliability Standards IRO-005-1 and TOP-004-0.” The NOPR did not expand or alter the scope of this directive as set forth in Order No. 693.[10]

[8] FERC Order 693 P 1363.
[9] FERC Order 693 P 1366.
[10] FERC Order 742 P 82.

Consideration of Directive

The PER ad hoc group held multiple discussions regarding the impact that operations planning and operations support staff have on the BES. The feedback received from industry regarding this topic was deemed to be the same arguments provided in the NOPR and rejected in FERC Orders 693 and 742 (see Appendix A). Therefore, the ad hoc group group revised PER-005-1 to incorporate operations planning and support personnel in the standard.

Technical Discussions

Industry provided the following information regarding operations planning and operations support staff about why training is not needed for support personnel:

- Training will provide no reliability benefit because of the administrative burden on entities and costly burden on industry with uncertain benefits.
- Training will provide no reliability impact because System Operators make the final decision, and support personnel do not make Real-time decisions.
- Operations planning and planning support staff is ambiguous and should be clarified.
- Entities appear to already train their support personnel; therefore, it should not be a mandatory requirement.

Again, the feedback received was deemed to be the same arguments provided on FERC Orders 693 and 742; therefore, the ad hoc group revised PER-005-1 to incorporate operations planning and support personnel in the standard.

Applicability of the PER Standard to EMS Personnel FERC Order 693 ¶ 1373

1373. In addition, the Commission is aware that the personnel responsible for ensuring that critical reliability applications of the EMS, such as state estimator, contingency analysis and alarm processing packages, are available, up-to-date in terms of system data and produce useable results can also have an impact on the Reliable Operation of the Bulk-Power System. Because these employees' impact on Reliable Operation is not as clear, we direct the ERO to consider, through the Reliability Standards development process, whether personnel that perform these additional functions should be included in mandatory training pursuant to PER-002-0.[11]

Consideration of Directive

Through discussion with industry, the ad hoc group determined that the report provided by the Event Analysis Subcommittee (EAS) serves as rationale for why EMS personnel should not be included in the PER standard at this time. The technical discussion section below provides more in-depth information regarding this determination.

Technical Discussions

As background, in Orders 693 and 742, the Commission directed NERC to consider whether there is a need to include EMS personnel in the training standard. In contrast to the directive for GOPs and operations support personnel, FERC did not conclude that it was necessary to include EMS personnel in the standard; rather, it directed the ERO to consider EMS personnel inclusion. The ad hoc group discussed the issue with industry stakeholders and concluded that the data does not support a need to include EMS personnel in the standard at this time.

Based on the information in the EMS report on cause-coded events, the EAS and PER ad hoc group do not believe it is necessary at this time to require EMS support personnel to receive the level of training required of a BA, Reliability Coordinator (RC), and TOP by NERC Reliability Standard PER-005.

Lastly, the EMS events will continue to be monitored, and if EMS events begin to indicate that training is a root or contributing cause, NERC will readdress inclusion of EMS personnel to PER-005. A request will be submitted to the Operating Committee (OC) to produce an EMS guideline for training EMS personnel.

[11] FERC Order 693 P 1373.

New Simulation Technology Implementation Plan
FERC Order 742 ¶ 24

With respect to EEI's comment regarding the effective date for entities that may become subject to the simulator training requirement in PER-005-1 R3.1, the Commission believes that this issue should be considered by the ERO. We note that, with respect to the Critical Infrastructure Protection (CIP) Reliability Standards, NERC has developed a separate implementation plan that essentially gives responsible entities some lead time before newly acquired assets must be in compliance with the effective CIP Reliability Standards. **We direct NERC to consider the necessity of developing a similar implementation plan with respect to PER-005-1, Requirement R3.1.**[12]

Consideration of Directive

The PER ad hoc group was in agreement that a new subrequirement 3.1 should be developed in the PER-005 standard to address entities that may become subject to simulator training in the future. Further discussion was held regarding the best time frame for entities to become compliant, and the general consensus was that six months is a reasonable timeframe. This information was presented at webinars, conferences, and face-to-face meetings, and no feedback was received regarding the implementation plan of simulator training for entities.

Technical Discussions

The ad hoc group did not receive feedback regarding the implementation plan for simulation technology.

Applicability of the PER Standard to Local Transmission Control Center
FERC Order 742 ¶ 64

Accordingly, we adopt our NOPR proposal and direct the ERO to develop through a separate Reliability Standards development project formal training requirements for local transmission control center operator personnel. Finally, given the numerous comments stating that term "local transmission control center" should be defined, we direct NERC to develop a definition of "local transmission control center" in the standards development project for developing the training requirements for local transmission control center operator personnel. We will not evaluate Associated Electric's proposed definition but, rather, leave it to the ERO to develop an appropriate definition that reflects the scope of local transmission control centers. The Commission will not opine on the appropriate definition of local transmission control center, as this definition can be addressed first using NERC's Reliability Standards Development Procedures.

Consideration of Directive

The ad hoc group considered whether to define local transmission control center in the NERC Glossary of Terms or create a standard-only definition. The group defined "local transmission control center" by extending the PER standard applicability to TOs and developing a definition that only applies to the PER standard. The suggested TO standard-only definition is *personnel in a transmission control center who operate a portion of the BES at the direction of its Transmission Operator*.

Technical Discussions

The group did not receive many comments regarding expanding formal training for local transmission control center operator personnel and defining local transmission control center. The group suggested a revision to PER-005-1 and created a standard-only definition of "local transmission control center."

Other Issues

Inconsistent usage of "each calendar year," "annual," and "at least every twelve months"

The PER ad hoc group changed all terms (such as "annual" and "at least every twelve months") to "each calendar year" due to "each calendar year" being better defined than the other two terms.

Definitions

System Operator

A SAR was submitted for GOPs to be removed from the System Operator definition. The ad hoc group removed the term and suggested a revised definition. The suggested definition is as follows: *An individual at a ~~c~~Control ~~c~~Center ~~(Balancing~~*

[12] FERC Order 742 P 64

~~Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control~~ who operates or directs the operation of the Bulk ~~e~~Electric ~~s~~System in Real time.

System Personnel

The term "System Personnel" was created as a standard-only definition for PER-005. The purpose of this definition is to capture certain applicable entities within the requirement instead of having to type each one out individually, multiple times, in a requirement. The suggested definition is as follows: *System Operators of a Reliability Coordinator, Transmission Operator, or Balancing Authority, and the Transmission Owner personnel described in the Applicability Section of this standard.*

Support Personnel

The term "System Personnel" was created as a standard-only definition for PER-005. The purpose of this definition is to capture certain applicable personnel within the requirement as a group for clarity. The suggested definition is as follows: *Individuals who carry out outage coordination and assessments, or determine SOLs, IROLs, or operating nomograms for Real-time operations.*

Conclusion

The informal development initiative provided key discussions regarding the outstanding PER FERC directives. This white paper encapsulates all of the components of what is needed for the Standards Committee to act on, discuss, and ultimately authorize the PER Standard Authorization Request.

Appendix A: Industry Arguments and FERC Responses

The below table shows initial arguments received from industry regarding FERC Orders 693 and 742. Also shown below are the arguments received from industry to-date that are deemed to be the same arguments found in both orders.

EXTENDING APPLICABILITY TO GOPS				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comment**
<u>Clarification of Applicable GOPs</u> Many commenters requested clarification as to which GOPs needed to be trained: 1) FirstEnergy supported GOP training but noted there was some confusion over the GOP classification, which is sometimes used to refer to dispatch personnel (or fleet operators at a control center) and other times used to refer to a plant or unit operator. FirstEnergy requested that the Commission direct NERC to recognize this distinction. 2) California PUC, Nevada Companies, Reliant, Dynegy, MISO, and Wisconsin Electric all presented various arguments as to why training should not be extended to plant operators. These entities did not argue against application of the training standard to dispatch personnel.	Order No. 693 at PP. 1350, 1352-54	FERC clarified that the directive to train GOPs only applies to GOPs located at a dispatch center that receives direction and then develops specific dispatch instructions for plant operators under their control. FERC clarified that plant operators need not be trained under the standard.	Order No. 693 at PP. 1360-61 See also Order No. 742 at P. 83.	

EXTENDING APPLICABILITY TO GOPS				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comment**
Decision-Making Arguments A number of commenters, including Xcel, argued that GOPs need not be trained because they do not make independent decision. They argued that GOPs simply take their direction from Transmission Operators, Balancing Authorities, and Reliability Coordinators, which limits their ability to exercise independent action impacting the reliability of the Bulk-Power System.	Order No. 693 at PP. 1351; 1354	FERC rejected this argument, stating: "Xcel and others oppose extending the applicability of PER-002-0 to generator operators, because they take directions from balancing authorities and others, which limits their ability to impact reliability. Although a generator may be given direction from the balancing authority, it is essential that generator operator personnel have appropriate training to understand those instructions, particularly in an emergency situation in which instructions may be succinct and require immediate action. Further, if communication is lost, the generator operator personnel should have had sufficient training to take appropriate action to ensure reliability of the Bulk-Power System. Thus, we direct the ERO to develop a modification to make PER-002-0 applicable to generator operators.	Order No. 693 at P. 1359	Decision-Making Arguments A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that all decisions that GOPs make that impact the BES must be approved by BA, TOP, or RC have the final say in the decisions being made.

EXTENDING APPLICABILITY TO GOPS				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comment**
No Reliability Benefit Argument Entergy, Xcel and Nevada companies further argued that generator operator training will provide limited benefit. Entergy further stated that that expanding the applicability to generator operators would provide little benefit to those personnel in the performance of their own functions, and could distract them from those functions.	Order No. 693 at P. 1351; 1357	FERC disagreed, stating that with the limitation of training to dispatch personnel, "the benefits to the Bulk-Power System will be maximized and the cost of formal training limited."	Order No. 693 at P. 1362	No Reliability Benefit Argument Creating training for GOPs will be costly and provide no benefit.
Scarcity of Resources and Cost Argument Entergy argued that training would be extremely costly and would divert necessary resources from more important reliability objectives. TAPS also opposed the expanded applicability, especially in the case of small systems, because it believes that the requirement would be costly with no benefits to reliability.	Order No. 693 at P. 1351; 1357	See above. FERC rejected these arguments, stating that the limitation to dispatch personnel would limit the cost of training.	Order No. 693 at P. 1362	Scarcity of Resources and Cost Argument A number of commenters, through verbal conversations and the chat feature during PER webinars stated that it will be costly to train GOPs. Smaller entities state it will be a costly to provide training to their GOPs and no major benefits will appear.
Scope of Training Arguments Many commenters discussed the scope of training for GOPs, arguing that the scope, content, and duration needs to be limited and tailored to their functions.	Order No. 693 at P. 1356	FERC agreed, stating that training for Generator Operators need not be as extensive as that required for Transmission Operators, and the training requirements developed by the ERO should be tailored in their scope, content, and duration so as to be appropriate to Generation Operations personnel and the objective of promoting system reliability.	Order No. 693 at P. 1363	Scope of Training Arguments Concerns about GOPs that do not develop dispatch instructions will be captured regardless.

EXTENDING APPLICABILITY TO GOPS				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comment**
Size Limitation Arguments APPA, TAPS, and the Process Electricity Committee requested a size limitation, arguing that while a generator plays an important role in the reliable operations of the Bulk Electric System, the Generator Operator takes commands from the Rransmission Operator, Balancing Authority, or Reliability Coordinator. Without a size limitation, the standard would require many small generators to enroll in a training program.	Order No. 693 at P. 1357	FERC responded that concerns regarding the need for a size limitation on Generator Operators should be satisfied by FERC's determination that the applicability of particular entities should be determined based on the ERO compliance registry criteria.	Order No. 693 at P. 1357	Size Limitation Arguments Comments received stated that a size limitation needs to be captured like CIP V5.
In response to the Order No. 742 NOPR, a number of commenters challenged the need for the directive.	Order No. 742 at P. 79	FERC rejected these arguments as beyond the scope of Order No. 742 and as collateral attacks on the ruling in Order No. 693 and refused to address the arguments again.	Order No. 742 at PP. 79, 81	

EXTENDING APPLICABILITY TO GOPS				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comment**
EPSA Clarification EPSA sought clarification regarding the statement in the NOPR, "[I]n the event communication is lost, the generator operator personnel must have had sufficient training to take appropriate action to ensure reliability of the Bulk-Power System." EPSA expressed concern that this statement suggests that if communication is lost with the grid operator, the Generator Operator must take unilateral action for which it requires training. EPSA notes that Generator Operators do not take such unilateral action, nor do they have access to information to make such decisions. EPSA asks the Commission to make clear that while communication should be addressed in training requirements for centrally located Generator Operator dispatch employees, the Commission is not extending related responsibilities or training requirements to Generator Operator employees.	Order No. 742 at P. 84	FERC granted the requested clarification and affirmed that it did not modify the Order No. 693 directive regarding training for certain Generator Operator dispatch personnel, nor expand a Generator Operator's responsibilities.	Order No. 742 at P. 84	

EXTENDING APPLICABILITY TO SUPPORT PERSONNEL				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comments**
No Reliability Benefit EEI states that the extension of the applicability to "operations support personnel" could result in a dramatic expansion of industry training requirements with uncertain benefits to system reliability.	Order No. 693 at P. 1368	FERC stated that because it is limiting training of support personnel to those who carry out outage coordination and assessments and those who determine SOLs and IROLs or operating nomograms, the directive is limited to those with a direct impact on reliability.	Order No. 693 at P. 1374	No Reliability Benefit A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that expanding PER-005 applicability to support personnel will capture a variety of people who do not impact the BES.
TOP makes decision Entergy argued that it is unnecessary to require all staff supporting the Transmission Operator to be trained in the Transmission Operator's Reliability Standards responsibilities, because as long as the supporting personnel work under the direction of a NERC-certified Transmission Operator, there is no need for duplicative training for supporting personnel.	Order No. 693 at P. 1370	FERC stated that because it is limiting training of support personnel to those who carry out outage coordination and assessments and those who determine SOLs and IROLs or operating nomograms, the directive is limited to those with a direct impact on reliability.	Order No. 693 at P. 1374	TOP makes decision A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that decisions are made by the NERC-Certified System Operators.
Administrative Burden APPA expressed concern about expanding the applicability to operations planning and operations support staff, especially if the Commission adopts its proposed interpretation of the Bulk Electric System, because this would become quite onerous for small utilities.	Order No. 693 at P. 1368	FERC limited the scope of what support personnel must be trained and clarified that training for support personnel should be tailored to the functions they perform and need not be trained to the same extent as Transmission Operators.	Order No. 693 at P 1375	Administrative Burden A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that this would be a huge administrative burden regarding the SAT process.

EXTENDING APPLICABILITY TO SUPPORT PERSONNEL				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comments**
<u>Directive is Ambiguous</u> Wisconsin Electric argued that the Commission's proposal does not address how to identify the operations planning and operations support personnel who would be subject to the Reliability Standard and how to develop compliance measures for them. It contended that the proposed modification is ambiguous and should not be implemented. Northern Indiana also argued that the terms "operations planning" and "operations support staff" should be clarified.	Order No. 693 at P. 1368	FERC clarified that the support personnel who need to be trained are those who carry out outage coordination and assessments in accordance with Reliability Standards IRO-004-1 and TOP-002-2, and those who determine SOLs and IROLs or operating nomograms in accordance with Reliability Standards IRO-005-1 and TOP-004-0. FERC said that because the reliability impact of EMS personnel are unclear, it directed NERC to consider whether such personnel need to be trained.	Order No. 693 at P. 1372	<u>Directive is Ambiguous</u> A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that "operations planning" and "operations support" are too broad.
<u>Scope of Training</u> Entergy commented that if training is required, it should focus on the functions operations planning and operations support staff must perform, not on the functions that others perform.	Order No. 693 at P. 1370	FERC clarified that training for support personnel should be tailored to the functions they perform and need not be trained to the same extent as transmission operators.		<u>Scope of Training</u>

EXTENDING APPLICABILITY TO SUPPORT PERSONNEL				
Industry Comment	**Order Cite**	**FERC Response**	**Order Cite**	**Phase 2 Industry Comments**
No Reliability Benefit In response to the Order No. 742 NOPR, a number of commenters challenged the need for the directive. For example, Associated Electric urged the Commission to direct NERC to adopt a definition of "operations planning" and "operations support staff" that more narrowly identifies those personnel who will be subject to the training standard. Associated Electric stated that the directive in Order No. 693 is broad and will encompass operations planning and operation support staff who engage in tasks that do not directly affect the reliable operation of the Bulk Electric System. GSOC and GTC do not support expanding the applicability of the PER-005-1 training requirements to any other personnel and argue that time spent expanding training requirements to other personnel will take away from their job of supporting their operating personnel—a use of time and resources that could actually decrease reliability.	Order No. 742 at P. 80	FERC rejected these arguments as beyond the scope of Order No. 742 and as collateral attacks on the ruling in Order No. 693 and refused to address the arguments again.	Order No. 742 at PP. 79, 81	No Reliability Benefit A number of commenters, through verbal conversations and the chat feature during PER webinars, stated that tasks performed by support personnel do not directly affect the BES. Support personnel may guide, but do not operate.

Appendix B: Entity Participants

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

Table 2: Entity Participation in PER Informal Development				
ACES Power	CPS Energy	IESO	NV Energy	Southern Co.
AECI	CSU	IMPA	OGE	STEC
AEP	CWLP	Integry Group	OMU	Sunflower
AES	DC PUD	IREA	ORU	Sycamore
ALCOA	Detroit Renewable	ISO-NE	OUC	TID
Alliant Energy	Direct Energy	ITC	OXY	Tri-State G&T
Ameren	Dominion	KCPL	PacifiCorp	TVA
AMP Partners	DTE Energy	KUA	PEPCO	
APS	Duke Energy	LCEC	PGE	
ATC	Dynegy	LCRA	PGN	**Regional Entities**
Austin Energy	Energy GRP	LES	PJM	FRCC
Blackhills Corp	Entergy	LGE-KU	PNM	MRO
BPA	EP Electric	Luminant	PNM Resources	NPCC
Brazos Electric	ERCOT	MGE	PPL	RFC
Brownsville PUD	Essential Power LLC	MidAmerican	Seattle Power & Light	SERC
CAISO	Exelon Corp	Minnkota Power	Sempra Utilities	SPP
CB Power	FMTN	MISO Energy	Sharyland	TRE
Center Point Energy	FPL	NaturEner	SMEPA	WECC
Chelan PUD	GASOC	NIPSCO	SMMPA	
City of Tacoma	GC Pud	Northwestern	SMUD	
City Utilities	Hydro Manitoba	NRECA	Snohomish PUD	
Cleco Corporation	Hydro-Quebec	NU	South Westgen	

Table 3: Presentations and Events	
NERC Operating Committee	FRCC Compliance Workshop
NERC EAS	WECC Operations Training Subcommittee
NERC Standards and Compliance Workshop	WECC Standing Committees
NERC News	TRE Standards Discussion Forum

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

DRAFT Reliability Standard Audit Worksheet[1]

PER-005-2 – Operations Personnel Training

This section to be completed by the Compliance Enforcement Authority.

Audit ID: Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity: Registered name of entity being audited
NCR Number: NCRnnnnn
Compliance Enforcement Authority: Region or NERC performing audit
Compliance Assessment Date(s)[2]: Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method: Audit
Names of Auditors: Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1	X								X			X[3]			
R2												X[3]			
R3	X								X			X[3]	X		
R4	X								X			X[3]	X		
R5	X								X			X[3]			
R6				X[4]											

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.
[3] Applicable to Transmission Owner that has personnel, excluding field switching personnel, who can act independently to operate or direct the operation of its Bulk Electric System transmission facilities in Real-time.
[4] Applicable to Generator Operator that has dispatch personnel at a centrally located dispatch center who receive directions from their Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner and may develop specific dispatch instructions for plant operators under their control. These personnel do not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions, without making any modifications.

Subject Matter Experts

Identify Subject Matter Expert(s) responsible for this Reliability Standard. (Insert additional rows if necessary)

Registered Entity Response (Required):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

R1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement a training program for its System Operators as follows:

1.1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall create a list of Bulk Electric System (BES) company-specific Real-time reliability-related tasks based on a defined and documented methodology.

1.1.1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 1.1 each calendar year.

1.2. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 1.1.

1.3. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall deliver training to its System Operator according to its training program.

1.4. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training program established in Requirement R1 to identify any needed changes to the training program and shall implement the changes identified.

M1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence of using a systematic approach to develop and implement a training program, as specified in Requirement R1.

M1.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection its methodology and its BES company-specific Real-time reliability-related task list, with the date of the last review, as specified in Requirement R1 part 1.1 and part 1.1.1.

M1.2 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection training materials, as specified in Requirement R1 part 1.2.

M1.3 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection System Operator training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R1 part 1.3.

M1.4 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation of its training program each calendar year, as specified in Requirement R1 part 1.4.

Definition of System Operator

An individual at a Control Center of a Balancing Authority, Transmission Operator, or Reliability Coordinator, who operates or directs the operation of the Bulk Electric System in Real-Time.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[5]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
(part 1.1) List of BES company-specific Real-time reliability-related tasks and documented methodology for developing task list.
(part 1.1.1) Evidence, such as a memo, meeting minutes, or dated task list, of review of the task list each calendar year.
(part 1.2) Samples of training materials as requested by the auditor.
(part 1.3) An organization chart or other list identifying all System Operator and the BES company-specific Real-time reliability-related tasks they perform. List of training delivered and attendance logs for a sample of training sessions requested by the auditor.
(part 1.4) Evidence, such as a memo, meeting minutes, or other information as specified in M1.4 demonstrating that the review of the training program occurred every calendar year and a list of needed changes to the training program based on the review.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

[5] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Compliance Assessment Approach Specific to PER-005-2, R1

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process.
	(part 1.1) and (part 1.1.1) Verify entity's list of BES company-specific Real-time reliability-related tasks, related methodology, and evidence of review each calendar year. Ensure list of BES company-specific Real-time reliability-related tasks was created pursuant to their methodology.
	(part 1.2) Review sample of training materials provided to determine if they support the BES company-specific Real-time reliability-related task list.
	(part 1.3) Agree specific System Operators, as selected by the auditor from the organization chart, back to attendance logs for training that was delivered related to the BES company-specific Real-time reliability-related tasks they perform pursuant to its program.
	(part 1.4) Review evidence that the review of the training program occurred every calendar year. Review list of changes to the training program based on the review and examine training materials, or other documents, to gain reasonable assurance that changes identified were implemented into the training program.

Note to Auditor: The training staff do not have to be internal staff of the entity.

Auditors are not to assess an entity's use of a systematic approach to training against any specific framework such as the ADDIE model. Rather, t~~While t~~he sub-requirements for Requirement R1 address the elements of a systematic approach consistent with FERC orders No.742 at P25 and No. 693 at P1380 and P1382~~,~~. ~~a~~An auditor will evaluate whether the entity's overall training program follows the principles below:

- Assess training needs (analysis)
- Conduct the training activity (design, develop and implement)
- Evaluate the training activity (evaluate the effectiveness of the training)

Auditors are to interpret a calendar year as January 1 to December 31.

Changes such as simply rewording for clarification, that do not affect the task performance or knowledge requirements, are not considered a modified task.

It is acceptable to group tasks under a job position, and then identify the System Operators that perform that job position, in lieu of assigning tasks to each individual System Operator.

~~The nature and extent of audit procedures applied related to this requirement will vary depending on certain risk factors to the Bulk Electric System. In general, more extensive audit procedures will be applied where risks to the Bulk Electric System are higher based on compliance with this requirement.~~

~~Based on the assessment of risk, as described above, specific audit procedures applied for this requirement may range from exclusion of this requirement from audit scope to the auditor reviewing training records for an entity's entire population of System Operators.~~

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each Transmission Owner shall use a systematic approach to develop and implement a training program for its personnel identified in Applicability Section 4.1.4.1 of this standard as follows: ~~[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]~~

2.1. Each Transmission Owner shall create a list of BES company-specific Real-time reliability-related tasks based on a defined and documented methodology.

2.1.1. Each Transmission Owner shall review, and update if necessary, its list of BES company-specific Real-time reliability-related tasks identified in part 2.1 each calendar year.

2.2. Each Transmission Owner shall design and develop training materials according to its training program, based on the BES company-specific Real-time reliability-related task list created in part 2.1.

2.3. Each Transmission Owner shall deliver training to its personnel identified in Applicability Section 4.1.4.1 of this standard according to its training program.

2.4. Each Transmission Owner shall conduct an evaluation each calendar year of the training program established in Requirement R2 to identify any needed changes to the training program and shall implement the changes identified.

M2. Each Transmission Owner shall have available for inspection evidence of using a systematic approach to training to develop and implement a training program for its applicable personnel, as specified in Requirement R2.

M2.1 Each Transmission Owner shall have available for inspection its methodology and its BES company-specific Real-time reliability-related task list, with the date of the last review, as specified in Requirement R2 part 2.1.

M2.2 Each Transmission Owner shall have available for inspection training materials, as specified in Requirement R2 part 2.2.

M2.3 Each Transmission Owner shall have available for inspection training records showing the names of the people trained, the title of the training delivered, and the dates of delivery to show that it delivered the training, as specified in Requirement R2 part 2.3.

M2.4 Each Transmission Owner shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation of its training program each calendar year, as specified in Requirement R2 part 2.4.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the

appropriate page, are recommended.

Evidence Requested[6]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
(part 2.1) List of BES company-specific Real-time reliability-related tasks and documented methodology for developing task list.
(part 2.1.1) Evidence, such as a memo, meeting minutes, or dated task list, of review of the task list each calendar year.
(part 2.2) Samples of training materials as requested by the auditor.
(part 2.3) An organization chart or other list identifying all personnel applicable to Requirement R2 and the tasks they perform. List of training delivered and attendance logs for a sample of training sessions requested by the auditor.
(part 2.4) Evidence, such as a memo, meeting minutes, or other information as specified in M2.4 demonstrating that the review of the training program occurred every calendar year and a list of needed changes to the training program based on the review.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PER-005-2, R2

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process.
	(part 2.1) and (part 2.1.1) Verify entity's list of BES company-specific Real-time reliability-related tasks, related methodology, and evidence of review each calendar year. Ensure list of BES company-specific

[6] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

	Real-time reliability-related tasks was created pursuant to their methodology.
	(part 2.2) Review sample of training materials provided to determine if they support the BES company-specific Real-time reliability-related task list.
	(part 2.3) Agree specific System Operator, as selected by the auditor from the organization chart, back to attendance logs for training that was delivered related to the BES company-specific Real-time reliability-related tasks they perform pursuant to its program.
	(part 1.4) Review evidence that the review of the training program occurred every calendar year. Review list of changes to the training program based on the review and examine training materials, or other documents, to gain reasonable assurance that changes identified were implemented into the training program.

Note to Auditor: The training staff do not have to be internal staff of the entity.

Auditors are not to assess an entity's use of a systematic approach against any specific framework such as the ADDIE model. Rather, consistent with FERC orders No.742 at P25 and No. 693 at P1380 and P1382.~~, a~~An auditor will evaluate whether the entity's overall training program follows the principles below:

- Assess training needs (analysis)
- Conduct the training activity (design, develop and implement)
- Evaluate the training activity (evaluate the effectiveness of the training)

~~While the sub-requirements for Requirement R2 address the elements of a systematic approach consistent with FERC orders No.742 at P25 and No. 693 at P1380 and P1382, an auditor will evaluate whether the entity's overall training program follows the principles below:~~

- ~~Assess training needs (analysis)~~
- ~~Conduct the training activity (design, develop and implement)~~
- ~~Evaluate the training activity (evaluate the effectiveness of the training)~~

Auditors are to interpret a calendar year as January 1 to December 31.

Changes such as simply rewording for clarification, that do not affect the task performance or knowledge requirements, are not considered a modified task.

It is acceptable to group tasks under a job position, and then identify the personnel that perform that job position, in lieu of assigning tasks to each individual.

~~The nature and extent of audit procedures applied related to this requirement will vary depending on certain risk factors to the Bulk Electric System and the auditor's assessment of management practices specific to this requirement. In general, more extensive audit procedures will be applied where risks to the Bulk Electric System are higher and management practices are determined to be less effective.~~

~~Based on the assessment of risk and internal controls, as described above, specific audit procedures applied for this requirement may range from exclusion of this requirement from audit scope to the auditor reviewing training records for an entity's entire population of applicable personnel.~~

Auditor Notes:

R3 Supporting Evidence and Documentation

R3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify, at least once, the capabilities of its personnel, identified in Requirement R1 or Requirement R2, assigned to perform each of the BES company-specific Real-time reliability-related tasks identified under Requirement R1 part 1.1 or Requirement R2 part 2.1

3.1. Within six months of a modification or addition of a BES company-specific Real-time reliability-related task, each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall verify the capabilities of each of its personnel identified in Requirement R1 or Requirement R2 to perform the new or modified BES company-specific Real-time reliability-related tasks identified in Requirement R1 part 1.1 and Requirement R2 part 2.1.

M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection evidence to show that it verified the capabilities of each of its personnel identified in Requirement R1 and Requirement R2 assigned to perform each of the BES company-specific Real-time reliability-related task identified under Requirement R1 part 1.1 or Requirement R2 part 2.1. This evidence may be documents such as records showing capability to perform BES company-specific Real-time reliability-related tasks with the employee name and date; supervisor check sheets showing the employee name, date, and BES company-specific Real-time reliability-related task completed; or the results of learning assessments.

M3.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner shall have available for inspection evidence that it verified the capabilities of applicable personnel to perform new or modified BES company-specific Real-time reliability-related tasks within 6 months of a modification or addition of a BES company specific Real-time reliability-related task.

Registered Entity Response (Required):
Question: Has entity modified or added a Real-time reliability-related task, since the Requirement R1 part 1.1 or Requirement R2 part 2.1 task lists were initially developed? ☐ Yes ☐ No

If so, when was task added, or what task was modified and when?

Include additional information regarding the Question in gray area below, including the type of response and format of the response requested, as appropriate.
Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[7]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
(R3) Documentation, such as provided in M3, evidencing selected personnel's capabilities to perform the BES company-specific Real-time reliability-related tasks selected by the auditor based on tasks identified under Requirements R1 part 1.1 and R2 part 2.1.
(part 3.1) A list of modifications or additions to BES company-specific Real-time reliability-related tasks. Entity's previous list of BES company-specific Real-time reliability-related tasks. Documentation, such as provided in M3, evidencing selected personnel's capability to perform modified or new tasks, as selected by the auditor.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PER-005-2, R3
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R3) For a sample of personnel and BES company-specific Real-time reliability-related tasks, review documentation verifying the personnel's capabilities to perform the task at least one time.
	(part 3.1) Determine if entity added any BES company-specific Real-time reliability-related tasks, which can be gleaned from auditor's knowledge of the entity's history and operations based on experience and specific facts discovered during the audit scoping process as confirmed with the entity, the entity's own assertions, a comparison of the current task list with a previous task list (also see parts 1.4 and 2.4), or any combination thereof. For a sample of additions, examine dated documentation to verify each of its

[7] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

	personnel's capabilities occurred within six months of the modification or addition.

Note to Auditor: Note entity's response to above Questions.

~~The nature and extent of audit procedures applied related to this requirement will vary depending on certain risk factors to the Bulk Electric System. In general, more extensive audit procedures will be applied where risks to the Bulk Electric System are higher based on compliance with this requirement.~~

~~Based on the assessment of risk, as described above, specific audit procedures applied for this requirement may range from exclusion of this requirement from audit scope to the auditor reviewing training records for an entity's entire population of applicable personnel.~~

Auditor Notes:

R4 Supporting Evidence and Documentation

R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner that (1) has operational authority or control over Facilities with established Interconnection Reliability Operating Limits (IROLs) or (2) has established protection systems or operating guides to mitigate IROL violations, shall provide its personnel identified in Requirement R1 and Requirement R2 with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES.

4.1. A Reliability Coordinator, Balancing Authority, Transmission Operator, or Transmission Owner that did not previously meet the criteria of Requirement R4 shall comply with Requirement R4 within 12 months of meeting the criteria.

M4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that personnel identified in Requirement R1 and Requirement R2completed training that includes the use of simulation technology, as specified in Requirement R4.

M4.1 Each Reliability Coordinator, Balancing Authority, Transmission Operator, and Transmission Owner shall have available for inspection training records that provide evidence that personnel identified in Requirement R1 and Requirement R2 completed training that included the use of simulation technology, as specified in Requirement R4, within 12 months of meeting the criteria of Requirement R4.

Registered Entity Response (Required):
Question: Has entity gone from a situation of not having previously met the criteria of Requirement R4 to having to comply with it? ☐ Yes ☐ No

Include additional information regarding the Question in gray area below, including the type of response and format of the response requested, as appropriate.
Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[8]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
(R4) Documentation such as training materials and attendance logs, evidencing emergency operations training using simulation technology replicating the operational behavior of the BES, for a sample of applicable personnel selected by the auditor.
(part 4.1) A dated list of IROLs acquired in accordance with Requirement R4.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PER-005-2, R4
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R4) Review training materials and interview entity personnel to verify that the entity trained applicable personnel using simulation technology that replicated the operational behavior of the BES. Agree specific applicable personnel, as selected by the auditor from the organization chart (evidence for parts 1.3 and

[8] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

	2.3), back to attendance logs for training using simulation technology.
	(part 4.1) Determine if entity obtained an IROL as outlined in Requirement R4, which can be gleaned from auditor's knowledge of the entity's history and operations based on experience and specific facts discovered during the audit scoping process as confirmed with the entity, the entity's own operating records and assertions, or any combination thereof. For a sample of applicable personnel, examine dated training materials and attendance records to verify training occurred within 12 months.

Note to Auditor: Note entity's response to above Questions.

Only applicable to entities that have operational authority or control over Facilities with IROLs, or protection systems or operating guides to mitigate IROL violations.

12 month window to execute simulation training only applies to entities newly acquiring IROLs (per above), since entities with existing IROLs should already have access to simulation technology.

~~The nature and extent of audit procedures applied related to this requirement will vary depending on certain risk factors to the Bulk Electric System. In general, more extensive audit procedures will be applied where risks to the Bulk Electric System are higher based on compliance with this requirement.~~

~~Based on the assessment of risk, as described above, specific audit procedures applied for this requirement may range from exclusion of this requirement from audit scope to the auditor reviewing training records for an entity's entire population of applicable personnel.~~

Auditor Notes:

R5 Supporting Evidence and Documentation

R5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall use a systematic approach to develop and implement training for its identified Operations Support Personnel on how their job function(s) impact on those BES company-specific Real-time reliability-related tasks identified by the entity pursuant to Requirement R1 part 1.1.

5.1. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall conduct an evaluation each calendar year of the training established in Requirement R5 to identify and implement changes to the training.

M5. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence that Operations Support Personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training. Documentation of training shall include employee name and date of training.

M5.1 Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation each calendar year, as specified in Requirement R5 part 5.1.

Definition of Operations Support Personnel
Individuals, who perform current day or next day outage coordination or assessments, or who determine SOLs, IROLs, or operating nomograms, in direct support of Real-time, operations of the Bulk Electric System.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[9]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
(R5) A list of the entity's Operations Support Personnel with a description of their role within the organization along with the BES company-specific Real-time reliability-related tasks they impact. Evidence that that training was developed using a systematic approach, and a list of training that has been delivered for Operations Support Personnel along with attendance logs for a sample of training sessions requested by the auditor.
(part 5.1) Evidence, such as a memo, meeting minutes, or other information as specified in M5 demonstrating the review of the training occurred every calendar year and a list of needed changes to the training program based on the review.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

[9] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Compliance Assessment Approach Specific to PER-005-2, R5

This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R5) Interview entity to understand their process for determining training requirements for Operations Support Personnel. Select a sample of Operations Support Personnel and training materials for training specific to Operations Support Personnel. Vouch a sample of personnel back to attendance logs and review the sample of training materials.
	(part 5.1) Review evidence that the review of the training occurred every calendar year. Review list of changes to the training based on the review and examine training materials, or other documents, to gain reasonable assurance that changes identified were implemented into the training.

Note to Auditor: An auditor will evaluate the entity's systematic approach with regard to the impact of the Operations Support Personnel's job function on the BES company-specific Real-time reliability-related tasks.

Operations Support Personnel are required to receive training only on how their job functions impact the Real-time reliability-related tasks, not on the Operations Support Personnel's ability to conduct these tasks. Therefore, the auditor will only determine if the entity's systematic approach determined the skills and knowledge needed to understand the impact of the job function(s) on the BES company-specific Real-time reliability-related tasks.

Auditors are not to assess an entity's use of a systematic approach against any specific framework such as the ADDIE model. Rather, consistent with FERC orders No.742 at P25 and No. 693 at P1380 and P1382.~~, a~~An auditor will evaluate whether the entity's overall training program follows the principles below:

- Assess training needs (analysis)
- Conduct the training activity (design, develop and implement)
- Evaluate the training activity (evaluate the effectiveness of the training)

~~Consistent with FERC orders No.742 at P25 and No. 693 at P1380 and P1382 and current Electric Reliability Organization's practices, to determine whether the entity used a systematic approach, an auditor will evaluate whether the entity's training program follows the principles below:~~

- ~~Assess training needs (analysis)~~
- ~~Conduct the training activity (design, develop and implement)~~
- ~~Evaluate the training activity (evaluate the effectiveness of the training)~~

Auditors are to interpret a calendar year as January 1 to December 31.

~~The nature and extent of audit procedures applied related to this requirement will vary depending on certain risk factors to the Bulk Electric System. In general, more extensive audit procedures will be applied where risks to the Bulk Electric System are higher based on compliance with this requirement.~~

~~Based on the assessment of risk, as described above, specific audit procedures applied for this requirement may range from exclusion of this requirement from audit scope to the auditor reviewing training records for~~

~~an entity's entire population of Operations Support Personnel~~.

Auditor Notes:

R6 Supporting Evidence and Documentation

R6. Each Generator Operator shall use a systematic approach to develop and implement training to its personnel identified in Applicability Section 4.1.5 of this standard, on how their job function(s) impact the reliable operations of the BES during normal and emergency operations.

6.1 Each Generator Operator shall conduct an evaluation each calendar year of the training established in Requirement R6 to identify and implement changes to the training.

M6. Each Generator Operator shall have available for inspection evidence that its applicable personnel completed training in accordance with its systematic approach. This evidence may be documents such as training records showing successful completion of training. Documentation of training shall include employee name and date of training.

M6.1 Each Generator Operator shall have available for inspection evidence (such as instructor observations, trainee feedback, supervisor feedback, course evaluations, learning assessments, or internal audit results) that it performed an evaluation each calendar year, as specified in Requirement R6 part 6.1.

Registered Entity Response to General Compliance with this Requirement (Required):
Describe, in narrative form, how you meet compliance with this Requirement. Provide a brief explanation, in your own words, of how you meet compliance with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested[10]:

Provide the following evidence, or other evidence to demonstrate compliance. If the provisioning of this evidence is burdensome or otherwise unreasonable, contact your CEA to arrange for sampling or other means of reduction of the quantity of evidence submitted.
(R6) A list of personnel in accordance with Applicability Section 4.1.5 and 4.1.5.1 of this Reliability Standard with a description of their role and position within the organization. Evidence that training was developed using a systematic approach, and a list of training delivered for such personnel along with attendance logs for a sample of training sessions requested by the auditor.
(part 6.1) Evidence, such as a memo, meeting minutes, or other information as specified in M6.1 demonstrating the review of the training occurred every calendar year and a list of needed changes to the training program based on the review.

[10] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Registered Entity Evidence (Required):

The following information is recommended for all evidence submitted: File Name, Document Title, Revision, Date, Page(s), Section(s), Section Title(s), Description Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to PER-005-2, R6
This section to be completed by the Compliance Enforcement Authority

	The RSAW Developer will complete this section with a set of detailed steps for the audit process. See the RSAW Developer's Guide for more information.
	(R6) Interview entity to understand their process for determining training requirements for applicable personnel. Select a sample of personnel and training materials for training specific to their impact on the reliable operations of the BES during normal and emergency operations. Agree a sample of personnel to attendance logs and review the sample of training materials.
	(part 6.1) Review evidence that the review of the training occurred every calendar year. Review list of changes to the training based on the review and examine training materials, or other documents, to gain reasonable assurance that changes identified were implemented into the training.

Note to Auditor: An auditor will evaluate the systematic approach with regard to the impact of the Generator Operator's job function(s) on the reliable operations of the BES during normal and emergency operations.

Auditors are not to assess an entity's use of a systematic approach against any specific framework such as the ADDIE model. Rather, consistent with FERC orders No.742 at P25 and No. 693 at P1380 and P1382~~,. a~~An auditor will evaluate whether the entity's overall training program follows the principles below:

- Assess training needs (analysis)
- Conduct the training activity (design, develop and implement)
- Evaluate the training activity (evaluate the effectiveness of the training)

~~Consistent with FERC orders No.742 at P25 and No. 693 at P1380 and P1382 and current Electric Reliability Organization's practices, to determine whether the entity used a systematic approach, an auditor will evaluate whether the entity's training program follows the principles below:~~

- ~~Assess training needs (analysis)~~
- ~~Conduct the training activity (design, develop and implement)~~
- ~~Evaluate the training activity (evaluate the effectiveness of the training~~)

A calendar year is January 1 through December 31.

~~The nature and extent of audit procedures applied related to this requirement will vary depending on certain risk factors to the Bulk Electric System. In general, more extensive audit procedures will be applied where risks to the Bulk Electric System are higher based on compliance with this requirement.~~

~~Based on the assessment of risk, as described above, specific audit procedures applied for this requirement may range from exclusion of this requirement from audit scope to the auditor reviewing training records for an entity's entire population of Generator Operators.~~

Auditor Notes:

Revision History

Version	Date	Reviewers	Revision Description
1	12/17/2013	NERC Compliance, Standards	New Document
2	1/27/2014	NERC Compliance, Standards	Revisions based on RSAW feedback received during comment period for PER-005-2.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Justifications

PER-005-2 – Operations Personnel Training

This document provides the Standard Drafting Team's (SDT) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in PER-005-2 – Operations Personnel Training. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project. To review the VRFs and VSLs for PER-005-2, please go to the standards webpage (PER-005-2 Standard Webpage link).

NERC Criteria - Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

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

Lower Risk Requirement

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

FERC Violation Risk Factor Guidelines

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

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

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

• Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

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

Guideline (3) – Consistency among Reliability Standards

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

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

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

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

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

NERC Criteria - Violation Severity Levels

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

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

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

FERC Order of Violation Severity Levels

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

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

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

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

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

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

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

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

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justification – PER-005-2 Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is consistent with the NERC VRF definition. Requirement R1 requires that Reliability Coordinators (RCs), Balancing Authorities (Bas) and Transmission Operators (TOPs) train their System Operators and prescribes that they use a systematic approach when developing a training program for their System Operators. While a violation of this requirement is unlikely to directly lead to Bulk Electric System instability, separation, or a cascading sequence of failures, a failure to adequately train System Operators could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. Additionally, the Medium VRF is consistent with the prior version of Requirement R1 in the currently effective version of the standard, PER-005-1. PER-005-1 will be retired upon the effective date of PER-005-2.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: While the Blackout report identified training for operator personnel to have a severe VRF, it is unlikely that failure to use a systematic approach to develop and implement training for System Operators would directly lead to bulk power system instability, separation or cascading failures or hinder restoration to a normal condition. Therefore, the Medium VRF assignment is appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The Medium VRF is applicable to all parts of Requirement R1 and is consistent with other requirements in the Reliability Standard.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with the prior version of Requirement R1 in the currently effective version of the standard, PER-005-1. PER-005-1 will be retired upon the effective date of PER-005-2.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs:

	The VRF is consistent with the NERC definition because developing a training program for System Operators could be conducted without the use of a systematic approach. Therefore, a violation of this requirement is unlikely to lead to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This VRF has one objective – to develop and implement training using a systematic approach - and thus does not co-mingle multiple objectives. It appropriately has one VRF for its single objective.

VSL Justification – PER-005-2 Requirement R1	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines, the VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered by the proposed Medium VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirements.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justification – PER-005-2 Requirement R2	
Proposed VRF	**Medium**

NERC VRF Discussion	A VRF of Medium is consistent with the NERC VRF definition. Requirement R2 prescribes a certain process for Transmission Owners to use when developing a training program for its local control center operator personnel, and training could be conducted without the use of a systematic approach. Therefore, a violation of this requirement is unlikely to lead to BES instability, separation, or a cascading sequence of failures. While a failure to adequately train Transmission Owners could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES, the requirement for applicable entities to use a systematic approach to develop and implement a training program requires that each applicable entity: • Assess training needs (analysis) • Conduct the training activity (design, develop and implement) • Evaluate the training activity (evaluate the effectiveness of the training) Thus, failure to adequately train System Operators would be a failure to use a systematic approach to training.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: While the Blackout report identified training for operator personnel to have a severe VRF, in this case it is not probable that failure to use a systematic approach to develop and implement training for Transmission Owners would lead to bulk power system instability, separation or cascading failures or hinder restoration to a normal condition. Therefore, the Medium VRF assignment was appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The VRF is applicable for all of the parts within Requirement R2 and thus are consistent with one another. Requirement R2 contains the similar requirements as Requirement R1, Requirement R5 and Requirement R6, but applies to Transmission Owners. Therefore, to be consistent within the Reliability Standard, the VRF for Requirement R2 reflects the VRFs of Requirement R1, Requirement R4, Requirement R5 and Requirement R6. Further, the Medium VRF is consistent with Requirement R1 of the FERC approved prior version of the standard, PER-005-1. PER-005-1 will be retired upon the effective date of PER-005-2.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with Requirement R1 of the FERC approved prior version of the standard, PER-005-1. PER-005-1 will be retired upon the effective date of PER-005-2. Although this is a new requirement to PER-005-2, it requires the same actions for a different functional entity.

FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition because developing a training program for Transmission Owners could be conducted without the use of a systematic approach. Therefore, a violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This VRF has one objective – to develop and implement training for local control center operators using a systematic approach - and thus does not co-mingle multiple objectives. It appropriately has one VRF for its single objective.

VSL Justification – PER-005-2 Requirement R2	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines, the VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary.

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

VRF Justification – PER-005-2 Requirement R3	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of high is consistent with the NERC VRF definition. Requirement R3 requires Reliability Coordinators, Balancing Authorities, Transmission Operators and Transmission Owners to verify the capabilities of their System Operators or local control center operators. If such personnel are not able to complete their tasks, the

	situation could lead to BES instability, separation or cascading failures or hinder restoration to a normal condition. Additionally, the High VRF is consistent with the requirement in the currently effective version of the standard, PER-005-1, addressing verification of System Operator personnel capabilities. PER-005-1 will be retired upon the effective date of PER-005-2.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: The High VRF is consistent with the Blackout Report listing of operator personnel training as a critical impact area. The Blackout report listed training as a mechanism to have competent personnel in operator positions; Requirement R3 mandates that applicable entities verify the capabilities of its personnel identified in Requirement R1 and Requirement R2 to perform assigned tasks. Failure for personnel to perform assigned reliability-related tasks could lead to bulk power system instability, separation or cascading failures or hinder restoration to a normal condition.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The VRF for all of the parts within Requirement R3 are consistent with one another.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The High VRF is consistent with other requirements containing actions identified in the Blackout report.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition because it is important that personnel are capable of performing each of the BES company-specific Real-time reliability-related tasks. A violation of this Requirement could lead to BES instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This VRF has one objective – to verify the capabilities of an entity's applicable personnel to perform reliability-related tasks – and thus does not co-mingle multiple objectives. It appropriately has one VRF for its single objective.

VSL Justification – PER-005-2 Requirement R3	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines, the VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The current level of compliance is not lowered with the proposed VSL.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the	The VSL level is consistent with the requirement.

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

VRF Justification – PER-005-2 Requirement R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is consistent with the NERC VRF definition. The need to conduct emergency operations training is inherent under Requirement R1 and Requirement R4 requires that entities use simulation technology to conduct such training. It is unlikely that failure to provide training using simulation technology would lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition. Specifically, if an entity did not provide emergency operations using a simulator an entity is still required to conduct other forms of operations training under Requirement R1 and Requirement R2, as emergency operations would be considered a Real-time reliability-related task.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: While the Blackout report identified training for operator personnel to have a severe VRF, in this case it is difficult to argue that a failure to use a simulator, virtual technology, or other technology that replicates the operational behavior of the BES will directly lead to instability, separation, or Cascading. NERC staff believes that the Medium VRF assignment was appropriate.

FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: All of the parts within Requirement R4 are consistent with one another and are commensurate with Requirements R1 and Requirement R2.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with Requirement R4 of the FERC approved prior version of the standard, PER-005-1. PER-005-1 will be retired upon the effective date of PER-005-2.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition because it is important to provide emergency operations training using simulation technology. A violation of this Requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This VRF has one objective – to provide emergency operations training using technology that replicates the operational behavior of the BES – and thus does not co-mingle multiple objectives. It appropriately has one VRF for its single objective.

VSL Justification – PER-005-2 Requirement R4	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines, the VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering	The current level of compliance is not lowered with the proposed VSL.

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

Not on A Cumulative Number of Violations	

VRF Justification – PER-005-2 Requirement R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is consistent with the NERC VRF definition. Requirement R5 prescribes a certain process for applicable entities to use when developing training for its Operations Support Personnel A violation of this requirement is unlikely to lead BES instability, separation, or a cascading sequence of failures. However, a failure to adequately train Operations Support Personnel on the impact of their job functions on Real-time reliability-related tasks could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System.
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: While the Blackout report identified training for operator personnel to have a severe VRF, it is unlikely that failure to use a systematic approach to develop and implement training for Operations Support Personnel would lead to bulk power system instability, separation or cascading failures or hinder restoration to a normal condition. Therefore, the Medium VRF assignment was appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The VRF is applicable to all of the parts within Requirement R5 and thus are consistent with one another. Requirement R5 contains the similar requirements as Requirement R1, Requirement R2, and Requirement R6, but applies to Operations Support Personnel. Therefore, to be consistent within the Reliability Standard, the VRF for Requirement R5 should reflect the VRFs of Requirement R1, Requirement R2 and Requirement R6. Further, the Medium VRF is consistent with Requirement R1 of the FERC approved prior version of the standard, PER-005-1. PER-005-1 will be retired upon the effective date of PER-005-2.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards:

	The Medium VRF is consistent with Requirement R1 of the FERC approved prior version of the standard, PER-005-1 to use a systematic approach to training. PER-005-1 will be retired upon the effective date of PER-005-2. Although this is a new requirement to PER-005-2, it requires the similar actions for a different functional entity.
FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition because developing a training program for Operations Support Personnel could be conducted without the use of a systematic approach. Therefore, a violation is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This VRF has one objective – to develop and implement training for its Operations Support Personnel using a systematic approach – and thus does not co-mingle multiple objectives. It appropriately has one VRF for its single objective.

VSL Justification – PER-005-2 Requirement R5	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines, the VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.

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

VRF Justification – PER-005-2 Requirement R6	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is consistent with the NERC VRF definition. Requirement R6 prescribes a certain process for Generator Operators to use when developing training for certain dispatch personnel. A violation of this requirement is unlikely to lead to BES instability, separation, or a cascading sequence of failures. However, a Generator Operator's failure to adequately train its applicable personnel on the impact of their job functions on the reliable operations of the BES could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES
FERC VRF G1 Discussion	Guideline 1 – Consistency with Blackout Report: While the Blackout report identified training for operator personnel to have a severe VRF, it is unlikely that failure to use a systematic approach to develop and implement training for applicable Generator Operator personnel would lead to bulk power system instability, separation or cascading failures or hinder restoration to a normal condition. Therefore, the Medium VRF assignment was appropriate.
FERC VRF G2 Discussion	Guideline 2 – Consistency within a Reliability Standard: The VRF is applicable for all of the parts within Requirement R6 and thus are consistent with one another. Requirement R6 contains the similar requirements as Requirement R1, Requirement R2, and Requirement R5, but applies to Generator Operator applicable personnel. Therefore, to be consistent within the Reliability Standard, the VRF for Requirement R6 should reflect the VRFs of Requirement R1, Requirement R2, and Requirement R5. Further, the Medium VRF is consistent with Requirement R1 of the FERC approved prior version of the standard, PER-005-1 to use a systematic approach to training. PER-005-1 will be retired upon the effective date of PER-005-2. Although this is a new requirement to PER-005-2, it requires the similar actions for a different functional entity.
FERC VRF G3 Discussion	Guideline 3 – Consistency among Reliability Standards: The Medium VRF is consistent with Requirement R1 of the FERC approved prior version of the standard, PER-005-1. PER-005-1 will be retired upon the effective date of PER-005-2.Guideline 5 – There is no co-mingling factors. Therefore the standard is not watered down.

FERC VRF G4 Discussion	Guideline 4 – Consistency with NERC Definitions of VRFs: The VRF is consistent with the NERC definition because developing a training program for Generator Operators could be conducted without the use of a systematic approach. Therefore, a violation is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.
FERC VRF G5 Discussion	Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation: This VRF has one objective – to develop and implement training for applicable Generator Operator personnel using a systematic approach – and thus does not co-mingle multiple objectives. It appropriately has one VRF for its single objective.

VSL Justification – PER-005-2 Requirement R6	
NERC VSL Guidelines	Consistent with NERC's VSL Guidelines, the VSL describes degrees of noncompliant performance in an incremental manner.
FERC VSL G1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
FERC VSL G2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency	The proposed VSL is written to ensure uniformity and consistency in the determination of penalties. Guideline 2a: The proposed VSL is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

in the Determination of Penalties Guideline 2a: The single VSL assignment category for "Binary" Requirements is not consistent Guideline 2b: VSL Assignments that contain ambiguous language	
FERC VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The VSL level is consistent with the requirement.
FERC VSL G4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on cumulative number of violations.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2010-01 Training (PER)
PER-005-2

A Final Ballot is now open through February 5, 2014

Now Available

A final ballot for **PER-005-2 – Operations Personnel Training** is open through **8 p.m. Eastern on Wednesday, February 5, 2014.**

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

Instructions

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the final ballot window. If a ballot pool member does not participate in the final ballot, that member's vote cast in the previous ballot will be carried over as that member's vote in the final ballot.

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

Next Steps

Voting results for the standard will be posted and announced after the ballot window closes. If approved, the standard will be submitted to the Board of Trustees for adoption.

Standards Development Process

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

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

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

Standards Announcement

Project 2010-01 Training (PER-005-2)

Final Ballot Results

Now Available

A final ballot for **PER-005-2 – Operations Personnel Training** concluded at **8 p.m. Eastern on Wednesday, February 5, 2014.**

The standard achieved a quorum and sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Ballot Results
Quorum: 84.02%
Approval: 77.06%

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

Next Steps

The NERC Board of Trustees adopted the standard on February 6, 2014. The standard will be filed with applicable regulatory authorities.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

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

North American Electric Reliability Corporation
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Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results	
Ballot Name:	Project 2010-01 Training PER-005-2
Ballot Period:	1/27/2014 - 2/5/2014
Ballot Type:	**Final Ballot**
Total # Votes:	326
Total Ballot Pool:	388
Quorum:	**84.02 % The Quorum has been reached**
Weighted Segment Vote:	77.06 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	105	1	67	0.753	22	0.247	0	1	15
2 - Segment 2	9	0.8	6	0.6	2	0.2	0	1	0
3 - Segment 3	86	1	57	0.792	15	0.208	0	1	13
4 - Segment 4	31	1	18	0.72	7	0.28	0	0	6
5 - Segment 5	89	1	50	0.746	17	0.254	0	3	19
6 - Segment 6	52	1	36	0.783	10	0.217	0	1	5
7 - Segment 7	0	0	0	0	0	0	0	0	0
8 - Segment 8	5	0.2	2	0.2	0	0	0	0	3
9 - Segment 9	2	0.1	1	0.1	0	0	0	0	1

10 - Segment 10	9	0.9	7	0.7	2	0.2	0	0	0
Totals	**388**	**7**	**244**	**5.394**	**75**	**1.606**	**0**	**7**	**62**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton		
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Negative	COMMENT RECEIVED
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.	Negative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Negative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Pablo Onate		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg		
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Affirmative	
1	Kansas City Power & Light Co.	Jennifer Flandermeyer		
1	Lakeland Electric	Larry E Watt	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Negative	

1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Negative	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	SUPPORTS THIRD PARTY COMMENTS
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Negative	COMMENT RECEIVED
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	COMMENT RECEIVED
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey		
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	
1	Omaha Public Power District	Doug Peterchuck	Negative	
1	Oncor Electric Delivery	Jen Fiegel	Negative	COMMENT RECEIVED
1	Orange and Rockland Utilities, Inc.	Edward Bedder	Negative	
1	Orlando Utilities Commission	Brad Chase		
1	Otter Tail Power Company	Daryl Hanson		
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Negative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Negative	SUPPORTS THIRD PARTY COMMENTS
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Texas Municipal Power Agency	Brent J Hebert		
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Negative	COMMENT RECEIVED
1	United Illuminating Co.	Jonathan Appelbaum	Negative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	

2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	American Public Power Association	Nathan Mitchell	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blue Ridge Electric	James L Layton	Negative	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	COMMENT RECEIVED
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	City of Anaheim Public Utilities Department	Dennis M Schmidt		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse		
3	City of Clewiston	Lynne Mila		
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Garland	Ronnie C Hoeinghaus		
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Negative	
3	City Water, Light & Power of Springfield	Roger Powers	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	COMMENT RECEIVED
3	Consumers Energy Company	Gerald G Farringer	Negative	
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre	Affirmative	
3	Florida Power Corporation	Lee Schuster		
3	Georgia System Operations Corporation	Scott McGough	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	National Grid USA	Brian E Shanahan	Negative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	

3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	SUPPORTS THIRD PARTY COMMENTS
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Ocala Electric Utility	David Anderson		
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy Company	Tracy Goble	Negative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	COMMENT RECEIVED
4	Fort Pierce Utilities Authority	Cairo Vanegas	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Negative	COMMENT RECEIVED
4	Integrys Energy Group, Inc.	Christopher Plante		
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	North Carolina Electric Membership Corp.	John Lemire	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	

4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Negative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
4	WPPI Energy	Todd Komplin		
5	AEP Service Corp.	Brock Ondayko		
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Arkansas Electric Cooperative Corporation	Brent R Carr		
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Negative	COMMENT RECEIVED
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Calpine Corporation	Hamid Zakery		
5	City and County of San Francisco	Daniel Mason	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	COMMENT RECEIVED
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman	Negative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	COMMENT RECEIVED
5	Consumers Energy Company	David C Greyerbiehl	Negative	
5	CPS Energy	Robert Stevens		
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	El Paso Electric Company	Gustavo Estrada		
5	Electric Power Supply Association	John R Cashin		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Essential Power, LLC	Patrick Brown		
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer	Negative	SUPPORTS THIRD

				PARTY COMMENTS
5	Luminant Generation Company LLC	Rick Terrill	Negative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	NiSource	Huston Ferguson		
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Affirmative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Orlando Utilities Commission	Richard K Kinas	Affirmative	
5	PacifiCorp	Ryan Millard		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Raven Power	Scott A Etnoyer		
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Feather Power Project	Kathryn Zancanella		
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot	Negative	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Alabama Electric Coop. Inc.	Ron Graham		
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	

6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Negative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Affirmative	
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Washburn	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brenda Hampton	Negative	COMMENT RECEIVED
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall		
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Oklahoma Gas & Electric Services	Jerry Nottnagel	Negative	
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	John Volz	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina		
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Edward C Stein		
8		Merle Ashton		
8		Roger C Zaklukiewicz		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney		
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	

10	New York State Reliability Council	Alan Adamson	Negative	COMMENT RECEIVED
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Account Log-In/Register

Exhibit G

Standard Drafting Team

PER Standards Drafting Team BIOs

February 7, 2014

	Name	Company	Functions	Region(s)
1	Charles Abell*	Ameren	BA, DP, LSE, RP, TO, TOP, TP	SERC
2	Sam Austin*	Tennessee Valley Authority	BA, DP, GO, GOP, IA, LSE, PA, PSA, RC, RP, TO, TOP, TP, TSP	SERC
3	JimBowles*	ERCOT	BA, IA, PA, RC, RP, TOP, TSP	TRE
4	Jeff Gooding*	Glorido Power & Light Co.	BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, TSP	FRCC
5	Mark Grear*	Constellation	DP, GO, GOP, LSE, PSE, TO	FRCC, MRO, NPCC, RFC, SERC, SPP, TRE WECC
6	Venona Greaff*	OXY	GO, GOP	TRE
7	Lauri Jones*	PG&E	DP, GO, GOP, LSE, PSE, RP, TO, TOP, TP	WECC
8	Patti Metro*	NRECA	N/A	N/A
9	John M. Rymer	MISO	RTO, ISO	MRO, RFC, SERC
10	Stanley Winbush	American Electric Power	TO	ERCOT, RFC, SPP

Biographies of Recommended Candidates for the Project 2010-01 PER SDT

1. **Charles Abell,** Ameren

Bio: Charles is the Supervising Engineer of Technical Support for Transmission Operations at Ameren Services in Saint Louis, MO with over 29 years of experience in his field. In this capacity he is responsible to supervise personnel in the support, maintenance, upgrade & expansion of the EMS/SCADA system and related systems and applications associated with Transmission Operations as well as monitor, review and approve processes & procedures for achieving and maintaining NERC CIP Standards compliance for the Transmission Operations control center. Charles currently serves as the Chair of the NERC Critical Infrastructure Protection Committee (CIPC) and as a member of the Electricity Sub-sector Coordinating Council. He is a core team member on the NATF Security Practices (CIP) Group and served as the former Chair of the SERC CIPC and Chair of the Alstom Grid Users Group.
Drafting team experience: Yes, vice chair of the Project 2009-02 SARDT for Real-time Reliability Monitoring and Analysis Capabilities and a member of 2010-15 Urgent Action SARDT for CIP-005.

2. **Sam Austin,** Tennessee Valley Authority

Bio: Sam currently manages System Operator Training for TVA which is responsible for meeting NERC requirements for System Operator Certification, Continuing Education and other regulatory required training (i.e PER-005 etc). Sam has been certified as a Reliability Operator since February 2001 and worked as a Balancing Authority System Operator for 9 years. He has worked in the utility industry for 27 years which also included licensed duties as a Reactor Operator in one of TVA's nuclear plants. He currently is the Vice Chair of the SERC System Operator Sub-committee, which among other things, delivers System Operator Conferences for the SERC region annually.
Drafting team experience: Sam has not participated in a formal drafting team, but has provided input on draft standards pertaining to system operations for several years. He did participate in the informal development process as an ad hoc member for PER-005.

3. **Jim Bowles**, ERCOT

Bio: Jim is currently responsible for supervising a group of 4 trainers at ERCOT, responsible for system operator training and the Operations Training Simulator. He is also facilitating a task force for the ERCOT Operations Working Group that is tasked with updating the ERCOT Fundamentals Manual and the ERCOT Certification Program.
Drafting team experience: Yes, member of the PER-005-1 Drafting Team and the PER-005-2 Ad Hoc Group.

4. **Jeff Gooding**, Florida Power and Light

Bio: Jeff is currently responsible for managing Transmission Operations for Florida Power and Light (FPL). He has over twenty five years of operational experience and more recently as the Manager of Training and Certification. In that role, he was responsible for developing and implementing a sustainable PER-005 compliant training program for System Operations. Jeff is also a member of the NERC Personnel Subcommittee and an active participant in the North American Transmission Forum (NATF) training group.
Drafting team experience: Yes, member of the Project 2007-04, PER-003-1- Operating Personnel Credentials Standard Drafting Team.

5. **Mark Grear**, Constellastion

Bio: Mark is currently the Manager of NERC and ISO Compliance, providing oversight to a team that consists of Compliance Analysts, Generation Liaisons, Trainers, and Generation Dispatchers. His team's goal is to insure compliance in the eight Regional Reliability Organizations within the United States and Canada and with the individual ISO requirements. His team also handles Generation outages, testing, and training to maintain compliance within the areas we do business. Mark is NERC Certified as a Reliability Coordinator for the last 11 years, and is PJM Generation and Transmission certified. He currently participates on the following teams: PJM System Operator Subcommittee, PJM Dispatcher Training Subcommittee, PJM eDart User's Group, ERCOT Operations Working Group, ERCOT Working Group of Trainers, NERC PER Ad Hoc Group, and IEEE Working Group of Trainers. Mark's past experience consisted of working at a Generating Station that could produce 1520 Mw's via two once through super critical units, two drum boilers, and four combustion turbines. While at the Generating Station he trained 64 operators from helper to lead operator. Next Mark went to System Operations as a Transmission Dispatcher. From there he went to the Outage Planning Branch where he ran studies, did new build projects, and continued to train incoming employees. While at System Operations he trained 25+ Dispatchers on the tagout process. With the split of Transmission and Generation, Mark became a Generation Dispatcher. He was then promoted to Senior Generation Dispatcher where he trained 40+ Generation Dispatchers. Before his current position he held the position of Senior Operations and Training Liaison. All of the above mentioned experience has been obtained during his 33+ years at Exelon.
Drafting team experience: Yes, member of the PER ad Hoc Group

6. **Venona Greaff**, Occidental Energy Ventures Corp.

Bio: Venona is the lead on Occidental's NERC compliance team and is responsible for working directly with Oxy's NERC registered entities to ensure compliance with the Reliability Standards as well as the CIP Standards. This includes developing and delivering all NERC related training.

Drafting team experience: No drafting team experience. Venona did participate as a member of the NERC Ad Hoc group for PER.

7. **Lauri Jones**, PG&E

Bio: Lauri has been with Pacific Gas and Electric Company for 28 years, the past 16 of which have been in the Electric Operations. She joined the Electric Operations in 1992, becoming a Journeyman System Operator, transferring to their Transmission Operations Center in 1997 and becoming a System Dispatcher, attaining NERC/WECC certification in 1999 as a Reliability Coordinator and a Shift Supervisor over PG&E's Electric Transmission System. She is currently a Sr. Supervisor over the Transmission System Operations - Training team involved in designing and coordinating the development of their System Dispatcher and Transmission System Operator training programs. Lauri is the current chairperson of the WECC Operations Training Subcommittee and the North American Transmission Forum Operator Training group; past chairperson and member of the California Electric Training Advisory Committee (CETAC) which provides emergency training to the System Dispatchers/System Operators of California; incoming Vice chair of the NERC Personnel Subcommittee, as well as a member of the Continuing Education Review Program. She graduated in 1984 with a B.S. in Education from Arizona State University.

Drafting team experience: Yes, member on PER-005 and PER-003 and a member of the NERC Ad Hoc group for PER.

8. **Patti Metro**, NRECA

Bio: Patti has over 25 years of extensive utility experience in compliance, customer service, engineering, operations, project management and training. Her responsibilities include being the NRECA principal technical expert on Federal Energy Regulatory Commission (FERC) approved mandatory reliability standards, and compliance and enforcement requirements of the North American Electric Reliability Corporation (NERC). Patti also coordinates review of draft reliability standards and assigned transmission and system operation-related activities of the NRECA Transmission and Distribution Engineering Committee (T&DEC) and subcommittees. Prior to working at NRECA, Patti provided consulting services regarding preparation for NERC audits, managed the Florida Reliability Coordinating Council Compliance program, and various work in industry project management, bulk power operations, and planning, design and operations. Patti has a Bachelor of Science degree in Electrical Engineering from Clemson University and is a Certified NERC Reliability Operator and Dale Carnegie Graduate.

Drafting team experience: Yes, Chair of the PER-005-1 Standard Drafting Team and member of the Project 2007-04 Certifying System Operators Standard Drafting Team.

9. **John Rymer**, MISO

Bio: John has 26 years of experience in Transmission operations, substation operations. He has been a technical trainer for Duke Energy for 6 years and served as Principal Technical Trainer for 4.5 years at MISO. John is now the Manager of the Technical Training group with responsibility for 100+ operators and support personnel's training and maintaining NERC certification. He has been in his present position as manager for 9 months. During that time the department has revised the training program documentation to implement and maintain compliance with the current PER-005 SAT requirement.

Drafting team experience: No prior drafting team experience.

10. **Stanley Winbush**, American Electric Power

Bio: Stanley works for American Electric Power (6-years): Manager for curriculum design, development and delivery for Transmission Operations system operators across RFC/PJM, SPP and ERCOT. Management of trainers and simulator engineer to ensure our operating personnel are competent to staff the real-time desk. He works with internal and external organizations to learn, grow and meet our training requirements. Stanley manages the AEP Transmission Operations training program which includes over 100 operating personnel. Stanley also ensures that the training staff knowledge, skills and abilities meet the challenges of a changing work environment. AT&T (12-years): Curriculum and instructional design, development, implementation, technical support and delivery of training for AT&T transmission systems (PDH, SDH, and SONET), Element Management Systems (EMS), and Network Management Systems (NMS) in the US and International locations. Honeywell-Sensotec (2-years): Design, development and delivery of procedures/work instructions, internal audits, implementing corrective action, continuous improvement, and management of 10 auditors to meet the ISO 9001:2000 quality management objectives.

Drafting team experience: No prior drafting team experience.