NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Agenda
Technical Conference on Interpretations of Standards

November 4, 2009 | 11 a.m. EDT
Dial-In: 800-940-2599

Introductions

Antitrust Compliance Guidelines

1. **PRC-005-1 for the Compliance Monitoring Processes Working Group (20 min.)**
2. **TOP-005-1 — Operational Reliability Information Requirement R3 and IRO-005-1 — Reliability Coordination — Current Day Operations Requirement R12 for Manitoba Hydro (15 min.)**
3. **MOD-001-1 and MOD-029-1 for NYISO (10 min.)**
4. **CIP-007-1, Requirement R2 for WECC (5 min.)**
5. **TPL-002-0, Requirement R1.3.10 for PacifiCorp (5 min.)**

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Reliability Standards

Action Required

Approve or remand reliability standards, interpretations, procedures, and plans as follows:

a. Interpretation of PRC-005-1 for the Compliance Monitoring Processes Working Group — **Remand and Address Staff Opinion**

b. Interpretation of TOP-005-1 — Operational Reliability Information Requirement R3 and IRO-005-1 — Reliability Coordination — Current Day Operations Requirement R12 for Manitoba Hydro — **Remand and Address Staff Opinion**

c. Interpretation of CIP-007-1, Requirement R2 for WECC — **Approve and Direct Standard Changes**

d. Interpretation of TPL-002-0, Requirement R1.3.10 for Pacificorp — **Approve**

e. Interpretation of MOD-001-1 and MOD-029-1 for NYISO — **Approve**

f. Reliability Standards Development Procedure — Version 7 — **Approve**

g. Reliability Standards Development Plan: 2010-2012 — **Approve**

h. Project 2009-18 — Withdrawal of MISO Waivers — **Approve**

i. Errata Change — FAC-010-2: WECC Regional Difference — **Approve**

j. Status of Standards Development — **Information Only**

Information

NERC's Reliability Standards Program works through the Standards Committee (SC) to develop and maintain continent-wide reliability standards, utilizing NERC's Reliability Standards Development Procedure. NERC also is responsible for the review of proposed regional entity standards. The program also has primary responsibility for managing NERC's relationship with the North American Energy Standards Board, which develops business practice standards and communications protocols for electric and gas wholesale and retail market participants. The standards program depends on the active involvement of industry subject matter experts to both recommend and develop reliability standards.

Since the issuance of Rick Sergel's letter of September 30, 2009 describing the board's process for considering requests for interpretation, NERC has received two formal appeals regarding Project 2008-7 – EOP-002-2, Requirement R6.3 and R7.1 (Brookfield Power). NERC, in accordance with a SC recommendation, has elected to remove this item from board consideration at its November 5, 2009 meeting pending resolution of the appeals. NERC will forward input on the Brookfield Power interpretation to the team that developed the response for their consideration should they determine that a revision is necessary to address the issues raised in the appeals.

a. Interpretation of PRC-005-1, Requirement R1 for the Compliance Monitoring Processes Working Group

Action

Remand Interpretation of Requirement R1 of PRC-005-1 for the Regional Entity Compliance Monitoring Processes Working Group and direct interpretation team to address staff concerns noted in the discussion.

Introduction

In his September 30, 2009 letter to stakeholders, Rick Sergel outlined the manner in which the board will consider requests for interpretation of NERC Reliability Standards at future meetings. This process invites input from any interested party and expressly from NERC staff. The materials that follow include the record of development for each interpretation as has been customarily provided, followed by NERC staff discussion on each interpretation in support of the board's request for input. This information will be paired with all input received and presented to the board for consideration in advance of its November 4, 2009 technical conference on interpretations and the November 5, 2009 board meeting.

Background on Interpretation of PRC-005-1, Requirement R1

On January 30, 2009, the Regional Entities Compliance Monitoring Processes Working Group (CMPWG) submitted a request for formal interpretation of PRC-005-1 — Transmission and Generation Protection System Maintenance and Testing, Requirement R1. The focus of the request was on the definition of Protection System. The purpose of PRC-005-1 is to ensure all transmission and generation Protection Systems affecting the reliability of the Bulk Electric System (BES) are maintained and tested.

Requirement R1 states:

> **R1**. Each Transmission Owner and any Distribution Provider that owns a transmission Protection System and each Generator Owner that owns a generation Protection System shall have a Protection System maintenance and testing program for Protection Systems that affect the reliability of the BES. The program shall include:
>
> **R1.1.** Maintenance and testing intervals and their basis.
>
> **R1.2.** Summary of maintenance and testing procedures.

The term "Protection System" is defined in NERC's Glossary of Terms as follows:

Protection System: Protective relays, associated communication systems, voltage and current sensing devices, station batteries, and DC control circuitry.

In its request, the CPMWG asked the following questions to which the Project 2007-17 (Protection System Maintenance and Testing) standard drafting team provided the responses.

- **Does R1 require a maintenance and testing program for the battery chargers for the "station batteries" that are considered part of the Protection System?**

  Response: *While battery chargers are vital for ensuring "station batteries" are available to support Protection System functions, they are not identified within the definition of "Protection System." Therefore, PRC-005-1 does not require maintenance and testing of battery chargers.*

- **Does R1 require a maintenance and testing program for auxiliary relays and sensing devices? If so, what types of auxiliary relays and sensing devices? (i.e., transformer sudden pressure relays)**

  Response: *The existing definition of "Protection System" does not include auxiliary relays; therefore, maintenance and testing of such devices is not explicitly required. Maintenance and testing of such devices is addressed to the degree that an entity's maintenance and testing program for DC control circuits involves maintenance and testing of imbedded auxiliary relays. Maintenance and testing of devices that respond to quantities other than electrical quantities (for example, sudden pressure relays) are not included within Requirement R1.*

- **Does R1 require maintenance and testing of transmission line re-closing relays?**

  Response: *No. "Protective Relays" refer to devices that detect and take action for abnormal conditions. Automatic restoration of transmission lines is not a "protective" function.*

- **Does R1 require a maintenance and testing program for the DC circuitry that is just the circuitry with relays and devices that control actions on breakers, etc., or does R1 require a program for the entire circuit from the battery charger to the relays to circuit breakers and all associated wiring?**

  Response: *PRC-005-1 requires that entities 1) address DC control circuitry within their program, 2) have a basis for the way they address this item, and 3) execute the program. PRC-005-1 does not establish specific additional requirements relative to the scope and/or methods included within the program.*

- **For R1, what are examples of "associated communications systems" that are part of "Protection System" that require a maintenance and testing program?**

  Response: *"Associated communication systems" refer to communication systems used to convey essential Protection System tripping logic, sometimes referred to as pilot relaying or teleprotection.*

  Examples include the following:

  - *Communications equipment involved in power-line-carrier relaying*
  - *Communications equipment involved in various types of permissive protection system applications*
  - *Direct transfer-trip systems*
  - *Digital communication systems (which would include the protection system communications functions of standard IEC 618501 as well as various proprietary systems)*

NERC presented the interpretation response for pre-ballot review on March 9, 2009 followed by a ten-day initial ballot that commenced on April 8, 2009. The initial ballot achieved a 92.70 percent quorum with a weighted segment approval of 92.71 percent. There were eight negative ballots submitted for the initial ballot, and five of those ballots included a comment. Some balloters listed more than one reason for their negative ballot.

The reasons cited for the negative ballots included the following:

- One balloter disagreed with the response to question 5, specifically relating to digital communications systems, stating that the continuously monitored digital communications systems are not maintained and tested because the functions are embedded within the relays.

- Three balloters indicated the answers given to the question on examples of “associated communications systems” were not sufficient.
- Three balloters indicated support for including station battery chargers under PRC-005-1, stating that battery charger failure could lead to other problems.
- One balloter indicated the drafting team did not provide sufficient clarification regarding DC control circuitry in question 4.
- Two balloters indicated disagreement with the last portion of the response to question 2: “devices that respond to quantities other electrical quantities (for example, sudden pressure relays) are not included in R1.” The balloters stated that relays/devices, such as sudden pressure relays in a major transformer and some protective relays for transformers tapped off a Bulk Electric System (BES) line should be considered as part of the protection system, as they are important for ensuring reliability.
- Three balloters indicated the team interpreted the language of the standard too strictly and should have considered the intent of the original standard. One balloter stated the proper approach would be to assume the "but not limited to" language was never removed from the definition when the Version 0 standards were developed. Two balloters stated the strict interpretation runs counter to the purpose of the standards, *i.e.*, ensuring reliability.
- One balloter commented that the interpretation should not redefine the meaning of the standard.

The recirculation ballot was conducted from July 24, 2009 – August 6, 2009 and achieved a quorum of 95.26 percent with a weighted affirmative approval of 95.62 percent.

Additional Information

The System Protection and Control Task Force (SPCTF), now Subcommittee, issued an assessment of the PRC-005-1 standard in March, 2007. In the assessment the SPCTF concluded, among other items, that:

- The listed requirements do not provide clear and sufficient guidance concerning the maintenance and testing of the Protection System to achieve the commonly stated purpose which is “To ensure all transmission and generation Protection Systems affecting the reliability of the BES are maintained and tested.”
- The standards should clearly state which power system elements are being addressed.

The SPCTF assessment led to the submission of a SAR in May, 2007 to revise the PRC-005-1 standard. Because of the concerns identified with the current definition of “Protection System,” the team determined it necessary to revise the definition to add needed clarity to the issue that is the subject of the interpretation and in accord with the assessment findings. The Project 2007-17 (Protection System Maintenance and Testing) standard drafting team posted the first draft of a revised PRC-005-2 standard for a 45-day industry comment period that concluded on September 8, 2009. In the draft, the team has proposed a revised definition for Protection System to:

- More precisely define the applicable communication systems;
- More precisely define the involved voltage and current sensing inputs;
- Expand the existing definition to include the entire station DC supply; and to

- More expansively and precisely define the applicable DC control circuitry.

The proposed definition is:

> **Protection System** — Protective relays, associated communication systems necessary for correct operation of protective devices, voltage and current sensing inputs to protective relays, station DC supply, and DC control circuitry from the station DC supply through the trip coil(s) of the circuit breakers or other interrupting devices.

In addition, the team provides comprehensive expectations with regard to maintenance and testing requirements through the standard and through the following supplemental references:

- PRC-005-2 Protection System Maintenance Supplementary Reference — July 2009
- NERC Protection System Maintenance Standard PRC-005-2 Frequently Asked Questions — Practical Compliance and Implementation Draft 1.0 — June 2009
- PRC-005-2 Protection System Maintenance Supplementary Reference Draft 1— July 2009
- PRC-005-2 - Protection System Maintenance Frequently Asked Questions — Practical Compliance and Implementation Draft 1 — July 2009
- Assessment of Impact of Proposed Modification to the Definition of "Protection System"

The proposed standard includes the maximum allowable testing and maintenance activities for unmonitored, for partially monitored, and fully monitored protection systems. This is presented in chart format based on the type of component and includes requirements for auxiliary relays. In addition, regarding the topics included in the request for interpretation, the proposed revision does not address devices that sense non-electrical conditions, such as thermal or transformer sudden pressure relays, nor are line reclosing relays included unless they are part of a special protection system. Line reclosing relays are viewed as a control action, not a protective action.

The team is projected to complete its development activity in the third quarter 2010 and present for Board approval thereafter, although the team is contemplating advancing the definition of Protection System as soon as consensus is reached.

PRC-005 History

The source of the Version 0 standard regarding transmission and generation protection system maintenance and testing was the NERC Planning Standard III.A.S4 and associated compliance template III.A.M4, approved by the NERC board on April 2, 2004. The standard, applicable to the transmission protection system owner, required that "[t]ransmission protection system maintenance and testing programs shall be developed and implemented." The associated measure added the following specificity:

Transmission protection system owners shall have a system maintenance and testing program(s) in place. The program shall include:

a. Transmission Protection system identification shall include but are not limited to:
    - Relays
    - Instrument transformers
    - Communications systems, where appropriate
    - Batteries
b. Documentation of maintenance and testing intervals and their basis
c. Summary of testing procedure

d. Schedule for system testing

e. Schedule for system maintenance

f. Date last tested/maintained

This planning standard was converted to a Version 0 standard, PRC-005-0, that the NERC board approved in February, 2005, effective April 1, 2005. This standard contained the following similar requirement:

R1. The Transmission Owner, Generator Owner and Distribution Provider that owns a transmission protection system shall have a transmission protection system maintenance and testing program in place. The program(s) shall include:

- **R1.1** Transmission protection system identification shall include but are not limited to:
  - **R1.1.1** Relays
  - **R1.1.2** Instrument transformers
  - **R1.1.3** Communications systems, where appropriate
  - **R1.1.4** Batteries
- **R1.2** Documentation of maintenance and testing intervals and their basis
- **R1.3** Summary of testing procedure
- **R1.4** Schedule for system testing
- **R1.5** Schedule for system maintenance
- **R1.6** Date last tested/maintained

At the time the Version 0 standards were drafted and approved, a number of additional standards were being developed as Version 1 standards, including PRC-002-1 regarding Disturbance Monitoring and Reporting. In the course of developing PRC-002-1, the drafting team determined the need to specify the definition of "Protection System" that resulted in conforming changes to PRC-005-0. The term "Protection System" was defined as follows:

> **Protection System:** Protective relays, associated communication systems, voltage and current sensing devices, station batteries, and DC control circuitry.

Of importance, the phrase existing in PRC-005-0, "include but are not limited to" was removed. PRC-005-1 was amended accordingly and this requirement language became the source of the interpretation request. PRC-005-1 was approved by the NERC board on February 7, 2006, and became effective on May 1, 2006.

NERC Staff Opinion
NERC staff has three issues with this interpretation:

- The definition of "Protection System" is deficient and the drafting team should have developed a SAR to modify the term Protection System to include battery chargers and auxiliary relays as these components are necessary for correct and reliable operation of a Protection System. An appropriate definition change is already underway under Project 2007-17 – Protection System Maintenance and Testing, which is in the process of revising PRC-005.
- NERC staff disagrees with the interpretation classifying a sudden pressure relay as an auxiliary relay on the basis it does not respond to electrical quantities. Sudden pressure relays are protective relays and maintenance and testing of such relays should be covered by PRC-005. This confusion suggests that a definition for Protective Relay should be

added to the NERC Glossary. The interpretation also appears to be inconsistent with the current IEEE definition of "protective relay."

- NERC staff does not believe the interpretation is responsive to the fourth question in the request for interpretation. The question requests clarification as to what DC control circuitry is covered by the standard and no direction is provided in the interpretation. However, this clarification is included in the proposed modified definition of Protection System.

  The following discussion details the NERC staff assessment of each interpretation question.

- Does R1 require a maintenance and testing program for the battery chargers for the "station batteries" that are considered part of the Protection System?

  NERC staff agrees with the response to this question. The term "Protection System" as defined in the NERC Glossary does not include battery chargers. Therefore the interpretation is correct that a maintenance and testing program for battery chargers is not required by PRC-005-1. To interpret otherwise would create a conflict with the definition of "Protection System" and expand the scope of the subject standard. However, battery chargers should be included in the list of required elements in a relay maintenance and testing program.

- Does R1 require a maintenance and testing program for auxiliary relays and sensing devices? If so, what types of auxiliary relays and sensing devices? (i.e., transformer sudden pressure relays)

  The term "Protection System" as defined in the NERC Glossary does not include auxiliary relays. However, the definition does include current and voltage sensing devices.

  - The response is correct that PRC-005-1 does not require maintenance and testing program for auxiliary relays as the standard is silent on the issue. To interpret otherwise would create a conflict with the definition of "Protection System" and expand the scope of the subject standard. That being said, auxiliary relays that contribute to the proper functioning of a Protection System should be included in the list of required elements in a relay maintenance and testing program.

    However, staff does have a concern with the response to this question because the response incorrectly classifies a sudden pressure relay as an auxiliary relay. A sudden pressure relay is installed on a transformer or shunt reactor to detect fault conditions and initiate tripping to protect the element. A fault pressure relay is therefore a protective relay, not an auxiliary relay, and maintenance and testing of fault pressure relays is covered by the standard. The response incorrectly concludes that fault pressure relays are not covered by the standard because they do not respond to "electrical quantities."

    The current IEEE definition of "protective relay" also supports NERC staff's concern. IEEE defines a "protective relay" to be "a relay whose function is to detect defective lines or apparatus or other power system conditions of an abnormal or dangerous nature and to initiate appropriate control circuit action." The definition also notes that "a protective relay may be classified according to its input quantities, operating principle, or performance characteristics."

    - The response offers no guidance on the second part of this question relative to sensing devices. The term "Protection System" does include current and voltage sensing devices, thus PRC-005-1 does require maintenance and testing for such devices. To the extent other sensing devices exist, the standard would not apply to other types of sensing devices not explicitly included in the definition of a "Protection System."

- Does R1 require a maintenance and testing program for transmission line re-closing relays?

  NERC staff agrees with the response to this question. The term "Protection System" as defined in the NERC Glossary does not include reclosing relays, and reclosing relays are not considered to be protective relays. Therefore the interpretation is correct that a maintenance and testing program for reclosing relays is not required by PRC-005. To interpret otherwise would create a conflict with the definition of "Protection System" and expand the scope of the subject standard. Further, reclosing relays should be considered to be system controls since they take control action rather than trip elements to clear faults.

- Does R1 require a maintenance and testing program for the DC circuitry that is just the circuitry with relays and devices that control actions on breakers, etc., or does R1 require a program for the entire circuit from the battery charger to the relays to circuit breakers and all associated wiring?

  The question inquires as to what DC control circuitry is covered by the standard and the response does not answer this question. The response only restates Requirement R1. A correct interpretation is that a maintenance and testing program is required for any DC control circuitry that is required for operation of the Protection System, which would require DC control circuitry between the station battery, the protective relay, and the circuit breaker trip coil. However, it should be noted that the DC control circuitry that controls actions on breakers other than tripping by protective relays (e.g., wiring from the circuit breaker control handle or supervisory control of the breaker) would not be covered by the PRC-005.

  The revision to the definition of Protection System proposed by the Project 2007-17 – Protection System Maintenance and Testing and outlined above will explicitly include this clarification.

- For R1, what are examples of "associated communications systems" that are part of "Protection Systems" that require a maintenance and testing program?

  NERC staff agrees with the response. The types of communication systems included in the response are the communication systems required for operation of a "Protection System."

NERC staff believes the standard, as interpreted, does not support the best interest of reliability and in fact could harm reliability by excluding essential components from the scope of required maintenance and testing. Therefore, NERC staff urges the board to remand the interpretation response in order to address the staff issues noted. Additionally, since the request for interpretation asks whether battery chargers and auxiliary relays are covered by the standard, the drafting team should have noted that while they are not covered presently, they should be covered to ensure correct and reliable operation.

b. Interpretation of TOP-005-1 — Operational Reliability Information Requirement R3 and IRO-005-1 — Reliability Coordination — Current Day Operations Requirement R12 for Manitoba Hydro

Action

Remand the Interpretation of TOP-005-1, Requirement R3 and IRO-005-1, Requirement R12 and direct interpretation team to consider staff concerns.

Background

On November 25, 2008, Manitoba Hydro requested an interpretation of the meaning of the term “degraded/degradation” as used in NERC standards TOP-005-1 and IRO-005-1 and specifically, whether a Special Protection System (“SPS”) that is operating with only one communication channel in service would be considered “degraded” for the purposes of these standards.

The stated purpose of the three standards (including PRC-012) under consideration and the associated requirement language is as follows:

TOP-005-1 — To ensure reliability entities have the operating data needed to monitor system conditions within their areas.

R3. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.

The above-referenced **Attachment 1 — TOP-005-0** specifies the following data as item 2.6:

2.6. New or degraded special protection systems.

IRO-005-1 — The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor BES parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.

R12. Whenever a SPS that may have an inter-Balancing Authority, or inter-Transmission Operator impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the Reliability Coordinators shall be aware of the impact of the operation of that SPS on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the SPS including any degradation or potential failure to operate as expected.

PRC-012-0 — To ensure that all SPS are properly designed, meet performance requirements, and are coordinated with other protection systems. To ensure that maintenance and testing programs are developed and misoperations are analyzed and corrected.

R1. Each Regional Reliability Organization with a Transmission Owner, Generator Owner, or Distribution Providers that uses or is planning to use an SPS shall have a documented Regional Reliability Organization SPS review procedure to ensure that SPSs comply with Regional criteria and NERC Reliability Standards. The Regional SPS review procedure shall include:

R1.3. Requirements to demonstrate that the SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined in Reliability Standards TPL-001-0, TPL-002-0, and TPL-003-0.

The interpretation provided the following clarifications:

- TOP-005-1 does not provide, nor does it require, a definition for the term "degraded."
- The IRO-005-1 (R12) standard implies that degraded is a condition that will result in a failure of an SPS to operate as designed; thus if the loss of a communication channel results in the failure of an SPS to operate as designed, then the Transmission Operator is required to report that information. On the other hand, if the loss of a communication channel will not result in the failure of the SPS to operate as designed, then such a condition can be, but is not mandated to be, reported.

NERC presented the interpretation response for pre-ballot review on February 18, 2009 followed by an initial ballot that began on March 19, 2009. The interpretation achieved 92.62 percent weighted segment approval with 89.78 percent quorum participating. There were 14 negative ballots submitted for the initial ballot, and nine of those ballots included a comment. Some balloters listed more than one reason for their negative ballot.

The reasons cited for the negative ballots included the following:

- Three balloters indicated a need for a definition of degraded so an entity can be evaluated on a known measurable basis. The balloters stated that since SPSs are designed so that no one component failure will prevent the SPS to operate as designed, there would be no requirement for the SPS unit to be reported for a single failure. The balloters state, however, that when an SPS alone is not operating as designed (*i.e.*, degraded), the SPS is not functional and should be removed from the BES.
- Two balloters disagreed with the drafting team's description of degradation. The balloters view degradation as an indication of the existence of a problem but not the state of failure; the balloters interpreted the drafting team's description of degradation as the state of failure.
- Two balloters indicated any off-nominal SPS operating states should be appropriately reported, regardless of how degradation is defined.
- One balloter indicated the interpretation extends to requirements associated but not included in the request, resulting in too broad an application of the interpretation process.
- One balloter agreed with the conclusion for IRO-005-1 but disagreed that a definition for degraded is not needed for TOP-005-1. The balloter suggested the Transmission Operator and Balancing Authority are obligated to provide information on new or degraded special protections systems to the Reliability Coordinator upon request, and a definition of degraded is necessary for specifying systems that would need to be reported.

In response to these comments, the team responded that an interpretation does not permit the creation of requirements or definitions. Absent this ability to define "degraded", the team provided its subjective view of the intent of the word. In its view, the term "any degradation or potential failure to operate as expected" was interpreted to mean "any actual or any forecasted conditions that would result in the SPS not operating as expected."

The recirculation ballot was conducted from April 17–27, 2009 and achieved a quorum of 95.56 percent with a weighted affirmative approval of 92.81 percent.

NERC Staff Opinion

NERC staff believes that the interpretation does not support the stated purpose of IRO-005-1: "The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor BES parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas."

Given that Requirement R12 pre-supposes that the SPS is armed to address inter-Balancing Authority or inter-Transmission Operator impacts (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation), the argument not discussed in the interpretation is that the SPS itself with one communication channel in service can be viewed for advance planning or reliability assessment purposes as a single contingency (loss of the communication channel). The question asked by the requestor indicates that the operation of the SPS on a single channel is known ahead of the timeframe for which the SPS may be armed and that the condition was not first identified when the SPS was called to operate.

In this regard, the Reliability Coordinator must be aware of the less dependable state of the SPS in order to properly assess the impact and plan for the next single contingency that it conceivably could experience. In this case, the Reliability Coordinator may wish to consider the loss of an armed SPS when performing its reliability assessments. While the Reliability Coordinator may not elect to proactively position the system to withstand the loss of the SPS that is operating on a single communication channel, the Reliability Coordinator may elect to develop a contingency plan in the event the SPS does fail to operate as designed or if the remaining communication channel is lost. The importance of the SPS relative to current or anticipated system conditions would be considerations for the Reliability Coordinator. This consideration only becomes possible if the Transmission Operator notifies the Reliability Coordinator that the SPS is operating on a single communication channel. Therefore, Transmission Operator notification to the Reliability Coordinator of this condition raises the Reliability Coordinator's situational awareness that may influence current or future operating conditions or decisions in a preventive rather than reactive manner. NERC staff does agree that the SPS is still mission capable with only one communication channel in service, but degraded in terms of its dependability due to the unavailability of redundant communications channels. The fact that a second communications channel was part of the original design of the SPS suggests that both channels were important to the dependability of the system, and that the unavailability of either channel causes some degradation in the overall dependability of the SPS.

Additionally, the team equated "any degradation" with "potential failure to operate as expected" in IRO-005. The use of the term "or" connecting these two phrases in the standard indicates these were not intended to be equivalent. Therefore, NERC staff believes the conclusion reached by the team that the two terms are synonymous is incorrect.

Further, the specific circumstances contemplated in the interpretation request are not likely to occur often and the additional burden to Transmission Operators to notify the Reliability Coordinator is de minimis when compared to the improved situational awareness that would result.

On this basis, NERC staff believes the interpretation is not serving the best interests of reliability and should be remanded to the team for further consideration of the NERC staff opinion.

c. Interpretation of CIP-007-1, Requirement R2 for WECC

Action
Approve interpretation of Requirement R2 to CIP-007-1 for WECC and direct staff to file the interpretation with FERC and applicable governmental authorities in Canada. Also direct standards drafting team to address staff concerns regarding physical ports.

Background
On March 9, 2009, WECC requested an interpretation of CIP-007-1 — Systems Security Management, Requirement R2. Standard CIP-007 requires Responsible Entities to define methods, processes, and procedures for securing those systems determined to be Critical Cyber Assets, as well as the non-critical Cyber Assets within the Electronic Security Perimeter(s). Standard CIP-007 should be read as part of a group of standards numbered Standards CIP-002 through CIP-009.

Specifically, Requirement R2 states:

R2: Ports and Services — The Responsible Entity shall establish and document a process to ensure that only those ports and services required for normal and emergency operations are enabled.

> **R2.1:** The Responsible Entity shall enable only those ports and services required for normal and emergency operations.
>
> **R2.2:** The Responsible Entity shall disable other ports and services, including those used for testing purposes, prior to production use of all Cyber Assets inside the Electronic Security Perimeter(s).
>
> **R2.3:** In the case where unused ports and services cannot be disabled due to technical limitations, the Responsible Entity shall document compensating measure(s) applied to mitigate risk exposure or an acceptance of risk.

WECC asked if the term "port" means a physical (hardware) or a logical (software) connection to a computer. In its request, WECC included the following supporting information:

> The de facto view of the term "port" as used within the standard and within the FAQ has led most organizations to reach the conclusion that "port" is a logical (software) connection to a computer in accordance with most of the application, network and security lexica. For example see the IANA port list at http://www.iana.org/assignments/port-numbers. As such, most organizations have implemented their CIP compliance programs accordingly. If, on the other hand, the view should have been that the term "port" is meant to indicate a physical (hardware) connection to a computer, there may be a very significant effort by many organizations to manually review all physical (hardware). This effort may not be achievable by the respective deadlines within the CIP Implementation Plan resulting in a potential state of noncompliance for a significant segment of the industry, most notably Table 1 and 2 entities that arguably have the largest number, diversity and geographic range of Critical Cyber Assets.

The Cyber Security Order 706 standard drafting team provided the response that the term "ports" as used as part of the phrase "ports and services" refers to logical ports, e.g., Transmission Control Protocol (TCP) ports, where interface with communication services occurs.

NERC presented the response for pre-ballot review on August 7, 2009 and conducted a ten-day initial ballot that began on September 10, 2009. The initial ballot achieved a quorum of 85.31 percent with a weighted affirmative approval of 100 percent. Since there was no negative ballot that included a comment, these results are final and no recirculation ballot was necessary.

NERC Staff Opinion

NERC staff subject matter experts offer the following views on the interpretation response for CIP-007-1, Requirement R2:

The term "port" can refer to either physical or logical connection points to a computing device. Physical network ports allow cables or devices to connect with a computer; examples of physical ports include Ethernet ports, USB ports, and serial ports to name a few. Logical ports are associated with TCP/IP services running on a computer. Logical ports allow software applications to use hardware resources without conflicting with each other.

The purpose of CIP-007-1 requires Responsible Entities to define methods, processes, and procedures for securing those systems determined to be Critical Cyber Assets, as well as the non-critical Cyber Assets within the Electronic Security Perimeter(s).

The greatest amount of protection, and therefore the most beneficial to reliability, is to interpret "ports" to constitute both physical and logical ports on Critical Cyber Assets. The interpretation adopts a limited definition of "port" to exclusively refer to a logical port. The complete definition to include physical and logical ports would add protection requirements that support a "defense-in-depth" strategy to protect Critical Cyber Assets from both network based attacks and physical attempts to compromise a device.

If the standard is implemented as interpreted it would remove an additional protection or layer to prevent physical attempts to compromise Critical Cyber Assets. This results in a single layer of protection (established by CIP-006-1 R1 which requires Critical Cyber Assets to reside within an identified Physical Security Perimeter) from physical attempts to attack a Critical Cyber Asset. The interpretation as approved results in no NERC standards or requirements governing the security (logical or otherwise) of physical ports on Critical Cyber Assets. This represents a potential for cyber intrusion into a Critical Cyber Asset if any Physical Security Perimeter protections are breached or defeated. With that said, if entities have only considered "logical ports", then there would be a significant effort required to establish and document a process to ensure that only those ports and services required for normal and emergency operations are enabled.

While NERC staff recommends the board approve this interpretation, it recommends that it consider instructing the existing CIP Standard drafting team working on Version 4 of the standard to address a "defense-in-depth" approach to appropriately protect Critical Cyber Assets from physical attempts to compromise the asset.

d. Interpretation of TPL-002-0, Requirement R1.3.10 for PacifiCorp — Approve

Action
Approve the Interpretation of TPL-002-0, Requirement R1.3.10 for PacifiCorp and direct staff to file the interpretation with FERC and applicable governmental authorities in Canada.

Background
On January 12, 2009, PacifiCorp requested an interpretation of TPL-002-0a — System Performance Following Loss of a Single Bulk Electric System Element (Category B), Requirement R1.3.10. The purpose of standard TPL-002-0a is as follows:

> System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

Specifically, Requirement R1.3.10 states:

R1: The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.3: Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.10: Include the effects of existing and planned protection systems, including any backup or redundant systems.

Category B of Table 1 refers to events that result in the loss of a single element. Events to be assessed include single line to ground or three-phase faults with normal clearing on generator, transmission circuit, or transformers or the loss of an element without a fault. In footnote (e) to Table 1, normal clearing is defined to be when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to the failure of any protection system component such as a relay, circuit breaker[1], or current transformer, and not because of an intentional design delay.

[1] Inclusion of "circuit breaker" in the list of protection system components is inconsistent with the definition of "Protection System" in the NERC Glossary. Project 2006-02: Assess Future Transmission Needs will correct this issue. In addition, the term "Normal Clearing" in Category B of Table 1 should include footnote (e), which was an oversight.

PacifiCorp requested clarification for the following items and a subset of the Project 2006-02: Assess Future Transmission Needs standard drafting team provided the responses:

- **Does TPL-002-0 R1.3.10 require that all elements that are expected to be removed from service through normal operation of the protection systems be removed in simulations?**

  Response: *TPL-002-0 requires that System studies or simulations be made to assess the impact of single Contingency operation with Normal Clearing. TPL-002-0a R1.3.10 does require that all elements expected to be removed from service through normal operations of the Protection Systems be removed in simulations.*

- **Is a Category B disturbance limited to faults with normal clearing where the protection system operates as designed in the time expected with proper functioning of the protection system(s) or do Category B disturbances extend to protection system misoperations and failures?**

  Response: *This standard does not require an assessment of the Transmission System performance due to a Protection System failure or Protection System misoperation. Protection System failure or Protection System misoperation is addressed in TPL-003-0 — System Performance following Loss of Two or More Bulk Electric System Elements (Category C) and TPL-004-0 — System Performance Following Extreme Events Resulting in the Loss of Two or More Bulk Electric System Elements (Category D).*

- **Does TPL-002-0 R1.3.10 require that planning for Category B contingencies assume a contingency that results in something other than a normal clearing event even though the TPL-002-0 Table I — Category B matrix uses the phrase "SLG or 3-Phase Fault, with Normal Clearing"?**

  Response: *TPL-002-0a R1.3.10 does not require simulating anything other than Normal Clearing when assessing the impact of a Single Line Ground (SLG) or 3-Phase (3Ø) Fault on the performance of the Transmission System.*

NERC presented the response for pre-ballot review on April 30, 2009 and conducted a ten-day initial ballot that began on June 1, 2009. The ballot achieved 87.10 percent quorum and a 95.71 percent weighted approval. There were four negative ballots submitted for the initial ballot, and one of those ballots included a comment. Commenters generally agreed with the drafting team's interpretation and were merely suggesting the addition of explanatory text to the interpretation statements. The reason cited for the negative ballot referenced support for the comments of Duke Energy, which voted affirmative but offered suggestions for further guidance related to "Normal Clearing." Duke references support for the standards authorization request (SAR) for Project 2009-07: Reliability of Protection Systems. The SAR for this project proposes a standard requiring facility owners to have protection system equipment installed such that, if there were a failure to a specified component of that protection system, the failure would not prevent meeting the bulk electric system performance identified in the TPL standards. The SAR for this project has been posted for industry comment once and the SAR drafting team is assisting the requester in responding to comments.

NERC held a recirculation ballot of the interpretation response from July 24, 2009–August 6, 2009 and achieved a quorum of 95.26 percent with a weighted affirmative approval of 95.62 percent.

NERC Staff Opinion

NERC staff agrees with the interpretation response as accurately interpreting the language in the current standard and that the current language supports the interests of reliability. Taken collectively, Requirement R1.3.10, the list of Category B contingencies in Table 1, and the defined term "Normal Clearing," require that simulations model the effects of Normal Clearing initiated by planned and existing protection systems, which includes removing from service all elements expected to be removed from service through normal operation of the protection system. The clause in R1.3.10, "including backup or redundant protection systems," seems to be unnecessary and could be a source of confusion. NERC staff also recognizes that additional efforts by the drafting team regarding redundancy of protection systems are necessary in support of the System Protection Initiative and that the SAR for Project 2009-07 adequately addresses the scope of the issue.

e. Interpretation of MOD-001-1 and MOD-029-1 for NYISO

Action
Approve Interpretation of MOD-001-1 and MOD-029-1 for NYISO and direct staff to file the interpretation with FERC and applicable governmental authorities in Canada.

Background
On February 17, 2009, the NYISO requested an interpretation of MOD-001-1 — Available Transmission System Capability, Requirements R2 and R8, and MOD-029-1 — Rated System Path Methodology, Requirements R5 and R6. Because NYISO raised individual questions relating to each standard, each will be presented separately. In each case, the ATC standard drafting team provided the response to the interpretation request.

MOD-001-1
The purpose of standard MOD-001-1 is "to ensure that calculations are performed by Transmission Service Providers to maintain awareness of available transmission system capability and future flows on their own systems as well as those of their neighbors."

Specifically, Requirements R2 and R8 state:

R2. Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s):

- **R2.1** Hourly values for at least the next 48 hours.
- **R2.2** Daily values for at least the next 31 calendar days.
- **R2.3** Monthly values for at least the next 12 months (months 2-13).

R8. Each Transmission Service Provider that calculates ATC shall recalculate ATC at a minimum on the following frequency, unless none of the calculated values identified in the ATC equation have changed:

- **R8.1** Hourly values, once per hour. Transmission Service Providers are allowed up to 175 hours per calendar year during which calculations are not required to be performed, despite a change in a calculated value identified in the ATC equation.
- **R8.2** Daily values, once per day.
- **R8.3** Monthly values, once per week.

NYISO requested clarification of whether the "advisory ATC" used under the NYISO tariff is subject to the ATC calculation and recalculation requirements in MOD-001-1, Requirements R2 and R8? If not, is it necessary to document the frequency of "advisory" calculations in the responsible entity's Available Transfer Capability Implementation Document?

Response: *Requirements R2 and R8 of MOD-001-1 are both related to Requirement R1, which defines that ATC methodologies are to be applied to specific "ATC Paths." The NERC definition of ATC Path is "Any combination of Point of Receipt and Point of Delivery for which ATC is calculated; and any Posted Path." Based on a review of the language included in this request, the NYISO Open Access Transmission Tariff, and other information posted on the NYISO Web site, it appears that the NYISO does indeed have multiple ATC Paths, which are subject to the calculation and recalculation requirements in Requirements R2 and R8. It* *appears from reviewing this information that ATC is defined in the NYISO tariff in the same manner in which NERC defines it, making it difficult to conclude that NYISO's "advisory ATC" is not the same as ATC. In addition, it appears that pre-scheduling is permitted on certain external paths, making the calculation of ATC prior to day ahead necessary on those paths. The second part of NYISO's question is only applicable if the first part was answered in the negative and therefore will not be addressed.*

MOD-029-1

The purpose of MOD-029-1 is "to increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations."

Specifically, Requirements R5 and R6 state:

R5. When calculating ETC for firm Existing Transmission Commitments (ETC_F) for a specified period for an ATC Path, the Transmission Service Provider shall use the algorithm below:

$$ETC_F = NL_F + NITS_F + GF_F + PTP_F + ROR_F + OS_F$$

Where:

$\mathbf{NL_F}$ is the firm capacity set aside to serve peak Native Load forecast commitments for the time period being calculated, to include losses, and Native Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{NITS_F}$ is the firm capacity reserved for Network Integration Transmission Service serving Load, to include losses, and Load growth, not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

$\mathbf{GF_F}$ is the firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

$\mathbf{PTP_F}$ is the firm capacity reserved for confirmed Point-to-Point Transmission Service.

$\mathbf{ROR_F}$ is the firm capacity reserved for Roll-over rights for contracts granting Transmission Customers the right of first refusal to take or continue to take Transmission Service when the Transmission Customer's Transmission Service contract expires or is eligible for renewal.

$\mathbf{OS_F}$ is the firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using Firm Transmission Service as specified in the ATCID.

R6. When calculating ETC for non-firm Existing Transmission Commitments (ETCNF) for all time horizons for an ATC Path the Transmission Service Provider shall use the following algorithm:

$$ETC_{NF} = NITS_{NF} + GF_{NF} + PTP_{NF} + OS_{NF}$$

Where:

$NITS_{NF}$ is the non-firm capacity set aside for Network Integration Transmission Service serving Load (i.e., secondary service), to include losses, and load growth not otherwise included in Transmission Reliability Margin or Capacity Benefit Margin.

GF_{NF} is the non-firm capacity set aside for grandfathered Transmission Service and contracts for energy and/or Transmission Service, where executed prior to the effective date of a Transmission Service Provider's Open Access Transmission Tariff or "safe harbor tariff."

PTP_{NF} is non-firm capacity reserved for confirmed Point-to-Point Transmission Service.

OS_{NF} is the non-firm capacity reserved for any other service(s), contract(s), or agreement(s) not specified above using non-firm transmission service as specified in the ATCID.

NYISO asks if OS_F in MOD-029-1 Requirement R5 and OS_{NF} in MOD-029-1 Requirement R6 be calculated using Transmission Flow Utilization in the determination of ATC?

Response: *This request for interpretation and the NYISO Open Access Transmission Tariff describe the NYISO's concept of "Transmission Flow Utilization;" however, it is unclear whether or not Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6 are incorporated into "Transmission Flow Utilization." Provided that "Transmission Flow Utilization" does not include Native Load, Point-to-Point Transmission Service, Network Integration Transmission Service, or any of the other components explicitly defined in Requirements R5 and R6, it is appropriate to be included within the "Other Services" term. However, if "Transmission Flow Utilization" does incorporate those components, then simply including "Transmission Flow Utilization" in "Other Service" would be inappropriate.*

NERC presented the response for pre-ballot review on April 30, 2009 and conducted a ten-day initial ballot that began on June 1, 2009. The ballot achieved 85.13 percent quorum and 82.10 percent weighted segment approval. There were 24 negative ballots submitted for the initial ballot, and 15 of those ballots included a comment. Some balloters listed more than one reason for their negative ballot.

The reasons cited for the negative ballots included the following:

- All 15 balloters who submitted a negative vote with an associated comment suggested the issue should be addressed using a method or process other than the interpretation process.
  - Six balloters indicated no opposition to the content of the interpretation but did not believe it was appropriate to append the interpretation to a continent-wide standard, since it is narrowly applied to a specific region.
  - Four balloters stated the interpretation process is being used to verify if a responsible entity process is compliant, not to clarify or correct issues with a standard.
  - Six balloters stated it would be more appropriate to deal with this type of request through a regional variance or a waiver.
  - Four balloters indicated NYISO should ask for a letter of no action from FERC on this issue. The balloters stated that FERC, as the entity that allowed the market design, should determine whether the "advisory" ATC calculations are actual ATC

calculations. And, if not, FERC should advise the NYISO if it should perform ATC calculations.

- Three balloters indicated the interpretation of MOD-029-1 appears to be in conflict with the NYISO's tariff.

NERC held a recirculation ballot of the interpretation response from July 8–17, 2009 and achieved a quorum of 90.26 percent with a weighted affirmative approval of 82.25 percent.

NERC Staff Opinion

NERC staff believes the interpretation carefully responds to the questions raised by NYISO in a manner consistent with the requirements in the standards. The interpretation does not change the requirement or standard. It simply reviews the definitions in the standard, in the FERC pro-forma Open Access Transmission Tariff, and the NYISO tariff, and explains the manner in which the standard applies to NYISO's transmission system. NERC staff believes the interpretation is clear and unambiguous. The interpretation addresses the intent of the requirement and supports reliability without adversely affecting market operations. In hindsight, NERC staff agrees with the majority of commenters that indicates the NYISO request is one of application of the standard, not an interpretation.

f. Reliability Standards Development Procedure — Version 7

Action

Approve Reliability Standards Development Procedure — Version 7

Direct staff to file the revised procedure as a NERC Rules of Procedure (RoP) change with FERC and applicable governmental authorities in Canada.

Background

In February 2008 the board acted to dissolve the Joint Interface Committee (JIC). In October 2008, as recommended by the Corporate Governance and Human Resources Committee (CGHR) in its Standards mandate assignment, the board directed the SC to modify the standards development process to address standards developed in response to national security emergency situations. Similarly, in February 2009 the board directed the SC to modify the standards development process to change the way Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are developed and approved, which modifications were proposed by the CGHR after posting its proposal for stakeholder comment.

The SC addressed these directed modifications by proposing Version 7 of the Reliability Standards Development Procedure. The modified procedure was posted for a 45-day industry review period that concluded on April 29, 2009. NERC received 18 sets of comments, including comments from more than 65 different people from approximately 40 organizations representing seven of the ten Industry Segments.

- Several stakeholder comments suggested alternatives to those in the board's directives. The SC did not consider those alternatives because the CGHR solicited stakeholder comments and gave due consideration to alternatives similar to those submitted in comments to Version 7 before it directed the SC to "implement" its proposed policy processes.
- Some stakeholder comments indicated that the SC's proposed language did not accurately reflect the Board's directives, and the SC did modify language in these instances.
- Some comments suggested that the proposed language indicating that VRFs and VSLs would be posted "at least once" may not provide stakeholders with sufficient opportunity to provide feedback to drafting teams and staff. The SC modified this language as follows:

  ~~At least one posting must include proposed violation risk factors, and violation severity levels.~~ The posting of draft VRFs and VSLs for stakeholder comment can be deferred until a second or later posting of the draft standard as determined by the standard drafting team; however, it is recommended that the VRFs and VSLs be posted for comment with the entire draft Reliability Standard as early in the standard development process as possible.

- One commenter recommended the following sentence that appeared on page 10 of the revised process be added to the language in Step 9 of the balloting process to confirm that VRFs and VSLs may be modified after the non-binding poll, based on stakeholder comments. The SC adopted this modification:

If stakeholder comments submitted with the non-binding poll indicate specific improvements that would improve consensus, then the SDT, working with NERC staff, will revise the VRFs and VSLs to reflect stakeholder comments.

- Another commenter suggested that more definitions should be added to describe what will be presented to the board when the board is asked to approve a set of VRFs or VSLs. To address this concern, the SC modified the language as shown below:

  Separately, the board shall consider approval of the VRFs and VSLs associated with a reliability standard. In making its determination, the board shall consider the following: ~~results of the non-binding poll as well as the recommendation of NERC staff~~.

  The Standards Committee shall present the results of the non-binding poll conducted and a summary of industry comments received on the final posting of the proposed VRFs and VSLs.

  - *NERC staff shall present a set of recommended VRFs and VSLs that considers the views of the standard drafting team, stakeholder comments received on the draft VRFs and VSLs during the posting for comment process, the non-binding poll results, appropriate governmental agency rules and directives, and VRF and VSL assignments for other Reliability Standards to ensure consistency and relevance across the entire spectrum of Reliability Standards.*

- One commenter suggested that the opening paragraph of the "Special Procedure" section of the manual seemed to expand on the board's process by omitting the phrase "national emergency." It was not the intent of the SC to expand on the scope of scenarios applicable for use with Special Procedures, and modified the opening paragraph of the "Special Procedures" section of the manual to replace the phrase, "critical issue" with "national security emergency situation" to clarify the intent.

- Another commenter indicated that the board's meeting minutes included a step to indicate that a standard developed to address a confidential issue would be presented to the board during a closed session. This was added to the manual as follows:

  If a standard is approved by its ballot pool, the team will present the proposed standard to the NERC board for approval in a special closed session, either in person or by conference call. (The closed session will allow the team to present not only the standard, but also the confidential information supporting its need.)

The initial ballot was conducted from July 10, 2009–20, 2009 and failed to reach quorum. A re-ballot was conducted from July 27, 2009–August 14, 2009 and achieved a quorum of 84.65 percent with a weighted affirmative approval of 74.79 percent. There were 50 negative ballots submitted for the initial ballot, and 34 of those ballots included a comment, which initiated the need for a recirculation ballot. The recirculation ballot was conducted from September 2–14, 2009 and achieved a quorum of 86.31 percent with a weighted affirmative approval of 76.09 percent. There were 52 negative ballots submitted for the recirculation ballot, and 33 of those ballots included a comment.

The comments were very similar to those submitted during the public comment period. No changes were made based on the comments submitted during the initial ballot.

- Most objections are related to the use of a “non-binding” poll to replace the existing balloting process, which included VRFs and VSLs as part of the standard.
- Some commenters expressed a view that VRFs and/or VSLs are technical aspects of the standard and should not be separated from the associated requirements.
- Some commenters suggested that the “Special Procedures” section of the manual is not clear and proposed modifications for improved clarity, but did not identify anything that is “incorrect.”
- Some commenters wanted more details about the administrative processes that are needed to support the “Special Procedures” section of the manual. These detailed procedures are not yet available, but the concerns identified will be submitted to NERC staff working on those procedures.

g. Reliability Standards Development Plan: 2010-2012

Action
Approve Reliability Standards Development Plan: 2010-2012.

Direct staff to file the updated development plan with FERC and applicable governmental authorities in Canada for information only.

Background
NERC developed an initial version of the plan for standards development, *Reliability Standards Development Plan: 2007-2009,* in 2006 and revised it annually thereafter. The plan serves as the management tool that guides, prioritizes, and coordinates revision or retirement of existing reliability standards and the development of new reliability standards for the immediate three-year time horizon. The plan also serves as a communications tool for coordinating standards development work with applicable governmental agencies in the United States and Canada, and for engaging stakeholders in standards development. The plan further provides a basis for developing annual work plans and budgets for the standards program. The *Reliability Standards Development Plan: 2010-2012* is the fourth installment of the plan and was approved by the SC on October 7, 2009.

The plan demonstrates NERC's comprehensive, proactive program to improving the standards and NERC's commitment to the timely development of other new high priority reliability standards. The plan also fulfills NERC's commitment to address the "fill-in-the-blank" regional standards, as promised in NERC's April 2006 application to be certified as the electric reliability organization. The revisions of the plan continue to demonstrate NERC's commitment to develop Reliability Standards that are technically accurate, clear, enforceable, and provide an Adequate Level of Reliability for the North American bulk power system.

The plan contains three volumes. Volume I provides an overview of the plan and the modifications made to the plan as compared to the previous plan. Volume II provides project descriptions for current and planned standards development projects. Volume III summarizes the regional reliability standards development activity anticipated over the next three years.

Stakeholder Comments
As part of the process employed in 2009 for revising the *Reliability Standards Development Plan,* NERC staff twice reached out to industry stakeholders and asked for input on the plan, initially in May 2009 to seek input for updating the plan, and a second time in August once the revised plan had been drafted. The stakeholder comments and NERC's response to these comments are provided in Appendix A to Volume I of the revised plan. Several stakeholders indicated a concern that too many projects are under concurrent development, which is stretching the available industry resources. They recommended that the plan focus industry resources on the projects having the greatest impact on reliability in the near-term, while deferring those of less immediate reliability benefit. This message is consistent with that identified in NERC's Three-year ERO Performance Assessment. In the Assessment, several stakeholders recommended that NERC focus existing reliability standards and reliability standards development on areas that will lead to the greatest improvement in bulk power system reliability. Suggestions included: (1) focus the development of new reliability standards on those that will lead to the greatest improvement in reliability; i.e., address the greatest risks of wide-area cascading outages; (2) reduce the number of existing reliability standards to just those that have a critical impact on reliability of the bulk power system and

convert the remaining reliability standards to guidelines; and (3) develop a more systematic process for prioritizing new reliability standards development projects based on risks to the bulk power system.

In response to this significant concern, the proposed plan establishes a new project (Project 2010-06 Results-based Reliability Standards) aimed at focusing NERC Reliability Standards on reliability performance. This effort is being largely shaped by an ad hoc industry group whose approach and recommendations have been formally supported by the SC.

Significant Work Plan Revisions
This revised *Reliability Standards Development Plan: 2010-2012* identifies a total of 37 continent-wide standards development projects, which is two less projects that appeared in the 2009-2011 version of the plan:

- The following seven projects identified in the 2009-2011 plan have been completed and removed from this revised plan:

  Projects initiated in 2006:
  2006-01 System Personnel Training
  2006-03 System Restoration and Blackstart
  2006-07 Transfer Capabilities: ATC, TTC, CBM, and TRM
  2006-09 Facility Ratings

  Projects initiated in 2007:
  2007-14 Permanent Changes to CI Timing Table
  2007-23 Violation Severity Levels

  Projects initiated in 2008:
  2008-08 EOP Violation Severity Levels Revisions

- Project 2008-05 Credible Multiple Element Contingencies, which was identified in the 2009-2011 plan, was removed from this revised plan as the requester of the Standard Authorization Request (SAR) withdrew the SAR.

- The following six projects are new to the 2010-2012 plan:

  Projects not anticipated but newly initiated in 2009:
  2009-06 Facility Ratings
  2009-07 Reliability of Protection Systems
  2009-18 Withdrawal of Three Midwest ISO Waivers

  Projects anticipated to commence in 2010:
  2010-06 Results-based Reliability Standards
  2010-07 Generator Requirements at the Transmission Interface

  Projects anticipated to commence in 2012:
  2012-02 Physical Protection

The proposed plan also moves one project, Project 2012-01 Equipment Monitoring and Diagnostic Devices, from 2011 to 2012 in order to ensure NERC and industry resources are available to devote the needed level of expertise to Project 2010-06 Results-based Reliability Standards. There are no other projects planned for initiation in 2011 as a result.

Other Considerations

In addition, in conjunction with this year's project to revise the plan, NERC staff reviewed the items in what is termed the "NERC Standards Issues Database (Issues Database)." The Issues Database is used by the NERC Standards program staff to track the issues and concerns identified with a particular standard. These "issues" are then used to populate the "Issues to be Considered by the Standard Drafting Team" tables that are prepared for each project in Volume II of the plan.

The update to this year's plan also includes more detailed project schedules. The revised project schedules include a more detailed list of tasks needed to be undertaken as part of the standards development project and has been modified based on "lessons learned" from prior projects. In doing so, the timeline for the majority of projects has been extended, but at the same time provides a better estimate for the completion of each of the projects.

The proposed plan also incorporates standards development projects that support NERC's broad-based reliability initiatives. In 2009, NERC initiated the System Protection Initiative, designed to focus efforts to improve system protection and control practices and approaches that have led or contributed to a significant number of system disturbance events. This effort served as the basis for Project 2010-05 System Protection and a number of other ongoing standards development projects in the area of system protection and control. This ongoing collaborative effort between the Event Analysis program and Standards development will continue to be used to identify specific changes to reliability standards to ensure an Adequate Level of Reliability of the North American bulk power system.

h. Project 2009-18 — Withdrawal of MISO Waivers

Action

Approve INT-003-3 — Interchange Transaction Implementation
Approve BAL-006-2 — Inadvertent Interchange

Direct staff to file the standards with FERC and applicable governmental authorities in Canada.

Background

Three waivers to NERC standard requirements, the “Scheduling Agent Waiver” and the “Enhanced Scheduling Agent Waiver” from INT-003-2, and “RTO Inadvertent Interchange Accounting Waiver” associated with BAL-006-1, were necessary to accommodate the operation of the Midwest ISO market in a multi-Balancing Authority environment. These waivers were first approved by the NERC Operating Committee in 2002, 2003, and 2004, respectively and were carried forward into the Reliability Standards. Now that the Midwest ISO is a Balancing Authority, these waivers are no longer needed. On April 15, 2009, the SC accepted the SAR to withdraw these three waivers, and the proposal was submitted for a 45-day comment period that began on April 22, 2009. There were 16 sets of comments, including comments from approximately 60 different people from more than 30 organizations representing nine of the 10 Industry Segments. Most indicated support for the changes, and one commenter suggested that an additional waiver in INT-003-2, the “MISO Energy Flow Information Waiver” be considered for withdrawal. The Midwest ISO believes this waiver to still be appropriate. As a result, no changes were made.

The initial ballot was conducted from August 27, 2009–September 8, 2009 and achieved a quorum of 85.28 percent with a weighted affirmative approval of 99.62 percent. There was one negative ballot submitted for the initial ballot. Since the negative vote did not include a comment, the results are final and no recirculation ballot is required.

Since no changes are proposed for any of the requirements in the two standards proposed for approval, VSLs and VRFs are carried forward intact in this proposal.

i. Errata Change – FAC-010-2: WECC Regional Difference

Action

Approve FAC-010-2.1 — System Operating Limits Methodology for the Planning Horizon and direct staff to file the standard with FERC and applicable governmental authorities in Canada.

Background

On October 8, 2009, WECC notified NERC of an Errata change needed in FAC-010-2, section E1.1 pertaining to the Regional Difference for WECC. When FAC-010-1 was modified, requirement R2.3.3 was renumbered to R2.4. As a result of this change, requirements R2.4 and R2.5 of FAC-010-1 were renumbered to R2.5 and R2.6 in FAC-010-2. No changes were made to the content of these two requirements when they were renumbered. However, conforming changes were not made to reflect the renumbering in the regional difference portion of the standard. Therefore, FAC-010-2 should be modified to reflect the renumbering of requirements R2.4 and R2.5 from FAC-010-1 to R2.5 and R2.6 in FAC-010-2. Specifically, Section E1.1 should now read:

> *As governed by the requirements of R2.5 ~~R2.4~~ and R2.6 ~~R2.5~~, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:*

WECC, a Regional Entity organized on an Interconnection basis, has a rebuttable presumption of validity for regional standards it proposes, including for regional differences to NERC continent-wide standards. Therefore, this requested activity is not subject to SC processes for errata changes and specific board action is required to correct the erroneous references.

j. Status of Standards Development

Action
Information Only

Regulatory Status
In the United States, NERC has received approval for 95 continent-wide reliability standards and nine WECC regional standards. An additional twenty-four standards ("fill-in-the-blank") are still held as pending further information per Order No. 693.

Since the August NERC board meeting, FERC issued the following standards-related actions:

- Order Approving Violation Risk Factors for CIP Reliability Standards
- Order Approving Version of CIP Cyber Security Standards

Also since the last board meeting, the following standards regulatory filings have been made:

- System Personnel Training
- Informational Filing on the Status of Field Trial to Modify Certain Resource and Demand Balancing Reliability Standards
- Compliance Filing and Petition for Approval of an Implementation Plan for CIP Reliability Standards for U.S. Nuclear Power Plants
- Motion for Extension of Time to File Violation Severity Levels
- Second Quarter 2009 Compliance Filing in Response to Order No 693 for Standards Ballots
- Compliance Filing in Response to Order No. 723 — Violation Risk Factors for WECC Automatic Time Error Correction Regional Standard
- Comments to FERC NOPR on PRC-023-1 — Transmission Relay Loadability
- Compliance Filing in Response to Order No. 716 and Petition for Approval of NUC-001-2 Reliability Standard
- Petition for Approval of Errata Changes to Three Reliability Standards
- Informational Filing Regarding the Assignment of Violation Risk Factors and Violation Severity Levels

Standards Under Development
Key standards under development are:

- Project 2008-06 — Cyber Security Order 706: On September 30, 2009, FERC approved Version 2 CIP standards that NERC filed in May, 2009. In the order approving the standards, FERC directed NERC to submit a compliance filing within 90 days to address deficiencies with the standards regarding visitor control programs and to add clarity to the implementation plans. The drafting team addressed the directives and posted a draft Version 3 of the CIP standards for industry comment on October 13, 2009.

- With Version 2 changes complete and Version 3 changes available for comment, the drafting team is focusing on how to structure its approach to the substantive work on the standards. At its meeting in July, the drafting team reached a pivotal step in its Phase II activities when it approved a concept paper that outlines a methodology that categorizes BES subsystems and cyber systems according to their impacts on reliability functions. This framework is expected to be used to rewrite CIP-002-2 through CIP-009-2. The team expects to present the methodology for identifying critical cyber assets per CIP-002-2 by year end for industry review.
- Project 2006-02 — Assess Transmission Future Needs and Develop Transmission Plans: The fourth posting of the proposed standards concluded on October 16, 2009. The team will respond to these comments and determine whether a subsequent posting is necessary before proceeding to the ballot phase. The current schedule calls for project completion date in early 2010.
- Project 2006-04 — Backup Facilities: The proposed standard completed an initial ballot on September 28, 2009, achieving a 72.86 percent weighted segment approval. The team is preparing responses to comments and will determine whether to proceed to recirculation ballot or to modify the standard further in response to comments. The project is targeted for completion in 2009 pending resolution of any outstanding comments.

NERC Interpretations

Comments of Edison Electric Institute

October 21, 2009

On behalf of our member companies, Edison Electric Institute (EEI) provides the following comments in response to the September 30 letter announcing a technical review by the NERC Board of Trustees (BOT) on several proposed interpretations of Reliability Standards.

While the short notice does not provide time sufficient for thorough technical comments on potential limitations of the existing Standards relevant to the proposed interpretations, EEI offers some process observations and recommendations on each of five interpretations being presented to the BOT for approval. A sixth interpretation, EOP-002, was recently appealed by EEI.

The interpretations process has a very narrow scope, providing Registered Entities an opportunity to ask 'what do the words of this Requirement mean' or 'do the words of the Requirement mean this or that?' It should not be a forum for 'backdoor' changes to Reliability Standards, nor should it be a forum for seeking non-binding compliance opinions. The appropriate forum for reviewing the technical limitations, and making changes to address any such limits, is the standards development process.

CIP-007-1 / WECC

WECC seeks an interpretation of CIP-007-1, asking whether the term 'port' used in R2 means a physical hardware connection or a logical software connection. The approved interpretation states that the term 'ports' refers to logical ports, where interface with communications services occurs.

The ballot body supported the interpretation unanimously by a vote of 191-0. EEI believes that the interpretation will not change the industry's behavior for complying with the Standard and will, therefore, have no impact on BPS reliability if the Standard is applied and enforced as interpreted. EEI recommends approval of the interpretation.

EEI also believes that physical security protection is covered by CIP-006, where physical security issues are addressed. Adding provisions for physical security under CIP-007 will add potential confusion and unnecessary redundancy, where companies are already challenged in setting their initial compliance strategies under the CIP Standards.

TOP-005-1, IRO-005-1, PRC-012-0 / Manitoba Hydro

Manitoba Hydro seeks an interpretation of TOP-005-1 and IRO-005-1, asking whether use of the term ‘degraded’ should be interpreted to mean a Special Protection System (SPS) that operates with only one communication channel in service. Manitoba Hydro references the IEEE definition of ‘a failure that is gradual, or partial or both….’ Manitoba Hydro also notes PRC-012, which contains documentation requirements, including ‘requirements to demonstrate that the SPS will be designed so that a single SPS component failure … does not prevent … the interconnected system from meeting performance requirements’ in various TPL –class planning Reliability Standards.

The approved interpretation states that the Reliability Standards in question do not provide a definition of the term ‘degraded,’ and none is needed. The interpretation goes on to state that IRO-005-1 implies a meaning of degradation as ‘a condition that will result in a failure of an SPS to operate as designed.’

The ballot body approved the interpretation with a 190-14 vote. EEI believes that the interpretation will not change the industry’s behavior for complying with the Standard and will, therefore, have no impact on BPS reliability if the Standard is applied and enforced as interpreted. EEI recommends approval of the interpretation.

EEI also believes that while the term ‘degradation’ may need clarification for purposes of this Standard, there is another Standard, IRO-005-2 that specifically requires a Transmission Operator to report SPS status, including any degradation or potential failure.

PRC-005-1 / Compliance Monitoring Processes Working Group (CMPWG)

CMPWG seeks interpretation of PRC-005, asking several questions pertaining to maintenance and testing programs. The approved interpretation states:

- Maintenance and testing of battery chargers is not required.
- Maintenance and testing of auxiliary relays is not explicitly required, however, such testing is required to the extent that DC control circuits involve embedded auxiliary relays.
- Maintenance and testing of transmission line reclosing relays is not required, since automatic restoration of transmission lines is not a protective function.
- PRC-005 requires a program to address DC control circuitry and the execution of the program, it does not prescribe specific methods to address DC control circuitry.
- Examples of ‘associated communications systems’ used to convey tripping logic for protection systems includes equipment involved in power line carrier relaying

or various types of permissive protection system applications, direct transfer trip systems, and digital communications systems).

The ballot body approved the interpretation 244-8. EEI believes that the interpretation will not change the industry's behavior for complying with the Standard and will, therefore, have no impact on BPS reliability if applied and enforced as interpreted. EEI recommends approval of the interpretation.

EEI also recognizes that CMPWG raises several potentially important technical issues related to maintenance and testing. Therefore, EEI also recommends that BOT request review of PRC-005 by the NERC Operating Committee, including review of the Standard for any technical issues with a timely followup report to the BOT, which could include recommendations for changes to the Standard.

MOD-001-1, MOD-029-1 / New York ISO

New York ISO (NYISO) seeks interpretation of MOD-001-1 and MOD-029-1. For MOD-001-1, NYISO asks whether the ISO's 'advisory ATC' calculation performed under its tariff is subject to the requirements of the Reliability Standard. For MOD-029-1, NYISO asks whether the calculation of 'other firm service,' a variable in calculating existing Transmission Commitments (ETC) could be determined by using NYISO transmission flow utilization calculations.

NYISO explains that customers' abilities to schedule transactions are not limited by a pre-defined amount of Available Transmission Capacity (ATC). Rather, under FERC-approved tariffs, ATC values are viewed as 'advisory projections,' where FERC has granted various waivers of OASIS posting requirements. In addition, NYISO points out that its 'advisory ATC' does not extend beyond day-ahead, where MOD-001-1 seems to presume that ATC values are calculated for longer time periods.

The approved interpretation states that MOD-001-1 defines ATC methods to be applied to "ATC paths."   Based on review of various documents, including NYISO Open Access Transmission Tariff (OATT), the interpretation team states that NYISO must meet the requirements of since NYISO has "ATC Paths."

The ballot body approved the interpretation 99-24.'

Stakeholder comments on the proposed interpretation suggested that:

- NYISO made inappropriate use of the interpretation process
- NYISO was seeking a determination of compliance from NERC and not an interpretation of the Reliability Standard

- NYISO should have asked for a waiver from compliance requirements
- NYISO should have approached FERC, and not NERC, to clarify various issues.

These comments correctly suggest concern that the NYISO request is an appropriate use of the interpretations process. While not the primary focus of the Board's present technical review, the NYISO request for interpretation appears to focus more on applicability issues in light of NYISO circumstances and not what the standard actually requires. The 'answer' provided by the interpretation has much more the appearance of a compliance opinion, rather than an interpretation of the requirements on their own.

EEI believes that the Board of Trustees would create a troublesome procedural precedent by approving this interpretation. EEI does not believe that registered Entities should be presenting a set of facts and circumstances and obtain a compliance-related opinion as part of the interpretations process. While EEI has recommended many times that parties should have an ability to seek non-binding opinions on compliance matters, the interpretations process should not become such a tool.

TPL-002 / Pacificorp

Pacificorp seeks interpretation of TPL-002, asking several questions on the scope of various requirements, for example, whether TPL-002 requires planning for contingencies to assume failure or misoperation of protection systems. Pacificorp indicates concern that aggressive interpretations of these requirements could result in significant transmission investments without corresponding reliability benefits.

The balloted interpretation states that failure or misoperation of protection systems is within scope of TPL-003 and not TPL-002.

The ballot body approved the interpretation 181-4. EEI believes that the interpretation will not change the industry's behavior for complying with the Standard and will, therefore, have no effect on BPS reliability if applied and enforced as interpreted. EEI recommends approval of the interpretation.

While this interpretation appears to be straightforward, EEI recognizes that the questions raised here have potentially broader implications. Stakeholders have been engaged in the revision of the TPL class of Standards for over two years, covering a broad range of issues, which includes consideration on the issue raised in this interpretation.

Manitoba Hydro

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October 21, 2009

The North American Electric Reliability Corporation
116 - 390 Village Boulevard
PRINCETON, New Jersey
U.S.A. 08540

ATTENTION: **Ms. Courtney Camburn**

Dear Ms. Camburn:

RE: COMMENTS ON INTERPRETATION OF TOP-005-1 AND IRO-005-1 (PROJECT 2008-18)

By letter dated September 30, 2009, Mr. R. Sergel notified stakeholders of a new "board process" for the approval of interpretations of reliability standards, inviting written comments on several interpretations which have already successfully concluded the stakeholder ballot process and which will be before the NERC board for approval on November 5th. By separate letter to Mr. Sergel, Manitoba Hydro has voiced its objections to such a process as: (1) being an indirect revision to the NERC Rules of Procedure without due process; and (2) inappropriately attempting to assess the reliability impact of an interpretation, independent from the reliability impact of the standard. Notwithstanding these objections, Manitoba Hydro provides the following comments on the interpretation of Project 2008-18.

Manitoba Hydro supports the adoption of the interpretation of IRO-005-1 and TOP-005-1 that was approved by the ballot body. Manitoba Hydro believes that the approved interpretation is a reasonable one based on the current wording of the standard, the IEEE definition of "degraded", and the function of a special protection system defined by the NERC glossary of terms. As noted in Manitoba Hydro's request for interpretation dated November 25, 2008, a special protection system with one communication channel out of service will still operate as required to protect for the next N-1 condition.

However, Manitoba Hydro also recognizes that the standards at issue only address the data exchange requirements related to certain facilities, such as special protection systems and that an additional standard is needed to address the actions that a transmission operator must take in the event that there is a loss of a communication channel in a special protection system. This deficiency should be addressed through the development of a new reliability standard rather than through an unreasonable interpretation of the standards which essentially adds elements to the standards which cannot be supported by their plain wording. The standards interpretation process should not be used as a means of indirectly amending a standard.

Yours truly,

MANITOBA HYDRO LAW DEPARTMENT
Per:
"K. Jennifer Moroz"

K. JENNIFER MOROZ
Barrister & Solicitor

KJM/sc

cc: L. Midford
M. Rheault
B. Poff
Kasia Mihalchuk

NEW YORK INDEPENDENT SYSTEM OPERATOR

10 Krey Boulevard ♦ Rensselaer, NY 12144

October 21, 2009

Via Electronic Mail

Dear Ms. Camburn:

In response to NERC's September 30, 2009 letter regarding the *NERC Board of Trustees Process for Consideration of Interpretation of Standards,* the New York Independent System Operator, Inc. ("NYISO") submits its input regarding *Project 2009-15 -- MOD-001-1, Requirements R2 and R8, and MOD-029-1, Requirements R5 and R6 (New York Independent System Operator)* (the "Interpretations"). The NYISO requested the Interpretations and respectfully renews its request that they be approved by the Board of Trustees ("BOT").

First and foremost, accepting the Interpretations would have no negative impact on reliability. The Interpretations would not substantively change the MOD requirements at issue or affect the way in which other Registered Entities would comply with them. Rather, the Interpretations would confirm the NYISO's understanding that its continued use of a FERC-approved "financial reservation" based transmission model is compatible with the new MOD standards. FERC has repeatedly found the NYISO's financial model to be consistent with or superior to the "physical reservation based" transmission model contemplated under FERC's *pro forma* OATT.

Available Transfer Capability ("ATC") has a different meaning, and is calculated differently, under the NYISO's model than under the *pro forma* system. With certain narrow exceptions, ATC in New York performs an "advisory" function, by signaling the presence of congestion, and does not determine a customer's ability to obtain transmission service. (*See Request for Interpretation* at 1-2). FERC's ATC-related reliability concerns, namely the potential for the transmission system to be over- or undersubscribed and the need for consistent approaches to deciding which transmission reservations could be supported, are therefore generally inapplicable to the NYISO. Nevertheless, the NYISO believes that its existing methodology for calculating ATC can be accommodated under the MOD standards as currently drafted.

No commenter took issue with the substance of the Interpretations, although some suggested that the NYISO's concerns might have been better addressed via a request for waivers or regional variances. The NYISO considered these procedural alternatives, and discussed them informally with NERC staff, before requesting interpretations. The NYISO ultimately concluded, with no objection from NERC staff, that seeking interpretations would be the best approach.

Specifically, a waiver request would have conflicted with FERC Order No. 890's directive that ISOs/RTOs work through the NERC stakeholder process[1] to try to ensure that the MOD

[1] Prior to requesting the interpretations the NYISO attempted to have language included in the MOD standards through the stakeholder process that would have more expressly accommodated the NYISO's model.

Standards accommodated their transmission models rather than seeking waivers in the first instance. Seeking a variance likewise seemed inconsistent with Order No. 890's requirement that NERC develop a single set of standards for all transmission providers. The NYISO also saw no reason to seek a waiver, or to try to create a NYISO variance, because it believed that its existing ATC calculation methodology was compatible with the MOD standards as drafted. At the same time, it was appropriate to request interpretations given the different nature of ATC and related differences in terminology under the NYISO system.

The NYISO has nothing further to add to its previous comments on Question Two, regarding the compatibility of MOD-029 with the NYISO's use of a unique market-based "transmission flow utilization" variable in its ATC calculations. With respect to Question One, the NYISO wishes to inform the BOT that it intends to seek the approval of its stakeholders to revise its OATT to clarify its definition of "ATC." The existing definition is a *pro forma* OATT vestige that does not accurately describe the nature of ATC in New York. Its survival in the NYISO OATT, however, appears to have caused some confusion that it would be best to eliminate. In addition, the NYISO will soon file a request with FERC to expand its existing waivers of FERC's ATC posting regulations to better reflect the nature of ATC in the NYISO system.

In conclusion, the NYISO respectfully asks that the BOT vote to approve the Interpretations on the grounds that the "standard as interpreted maintains reliability" at its November 5 meeting.

Respectfully submitted,

/s/Ricardo Gonzales

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October 21, 2009

Dear NERC Trustees,

In his September 30, 2009 letter to NERC stakeholders, NERC President and CEO Rick Sergel outlined a new process the Board of Trustees will use to consider pending Interpretations of NERC Reliability Standards and requested related input by no later than October 21, 2009. The Standards Committee appreciates the opportunity to submit these comments, which focus on standards policy and process considerations.

The Interpretation Process is an evolving but integral component of NERC's mandate to develop and enforce clear and unambiguous Reliability Standards. While NERC's Reliability Standards Development Procedure has been utilized for several years, its Interpretation Process has had very little use until recently. The Interpretation Process is in its infancy and by its nature has opportunity for improvements. For example, when the current Interpretation Process was developed, the authors had little, if any, idea that the interpretation outcomes would be subject to intense regulatory authority review.

It should come as no surprise that the number of Interpretation requests is increasing. The fact that NERC's Version 0 Standards are sufficient but not perfect was clearly documented during NERC's evolution to the Electric Reliability Organization in the United States. As ambiguities and imperfections are identified by registered entities, NERC, and regional entities responsible for standards compliance and enforcement, the need to seek clarification is increasing. The Interpretations Process exists to provide the opportunity for stakeholders to gain clarity on the intent of an existing Reliability Standard while not expanding the scope and requirements of the existing Reliability Standard.

As part of its ongoing efforts to improve the standards development process, the Standards Committee recognized the need to provide for an industry pre-ballot comment period during the development and approval of a proposed Interpretation. A comment period might build greater industry consensus in support of interpretations and help ensure a more robust record to support regulatory approval. Alternatively, if a proposed Interpretation is inconsistent with or otherwise departs from the specific scope and requirements of the existing Reliability Standard, such concerns are more likely to be developed early in the Interpretation process, and in all but rare circumstances, before the Interpretation is presented to the Board of Trustees for its approval. Upon request of the Standards Committee, the NERC Board of Trustees at its February 2009 meeting endorsed a field trial for use of this new process and directed staff to make informational filings with the applicable governmental authorities. Unfortunately, the field trial and informational filing have not been pursued at the recommendation of NERC legal staff. It was recommended that NERC pursue formal Rules of Procedure changes first. The Standards Committee is currently developing the necessary changes to the Reliability Standards Development Procedure to submit to the Registered Ballot Body for approval, which then can be submitted for regulatory authority approval.

While the Standards Committee acknowledges that the current Interpretation Process, which does not permit a reasonable comment period, may not produce the justification necessary to be accepted by regulatory authorities, the Standards Committee is committed to making the necessary Interpretation process improvements that will both ensure greater industry consensus and produce adequate information for regulatory review. With confidence that we will achieve that objective, the Standards Committee believes that the Board's use of a technical conference process to review Interpretations that have been presented to the Board for approval will not be needed in the future, after the Interpretation process improvements outlined above have been approved.

As the Board considers the action to be taken on the pending Interpretations, the Standards Committee respectfully reminds the Board that an Interpretation is intended simply to explain the intent of an existing Reliability Standard. To the extent that an existing Reliability Standard is imperfect or otherwise doesn't deliver the performance desired, the existing Reliability Standard should be modified through submittal of a Standards Authorization Request. The Interpretation Process is not designed to be the method to modify the content or scope of an existing Reliability Standard. To address the concern that Interpretations of existing Reliability Standards may leave or even create reliability gaps, the Standards Committee wishes to advise the Board that an effort is already underway to assess mechanisms that might be used to initiate expeditious Reliability Standard changes in parallel with formulation of Interpretations, if a reliability concern is identified in the early stage of assessing the Interpretation request.

The Standards Committee also urges the Board to exercise caution in remanding Interpretations as this action leaves the standard unclear for an extended period until a revised Interpretation is worked out and/or a Reliability Standard change is approved. The Standards Committee also urges the Board to consider that there are process alternatives to remanding an Interpretation that, as described in Mr. Sergel's letter, may "result in a 'less reliable' implementation of the standard because of a limitation in the wording of the standard itself." We suggest that the Board may wish to consider whether to accept the Interpretation, but direct the Standards Committee to either consider revisions to the Interpretation or to initiate a Reliability Standards change to address any reliability concerns. This has the effect of providing immediate clarification to the Requestor, while quickly addressing broader policy considerations.

Finally, the September 30, 2009 letter lists six Interpretations to be considered by the Board of Trustees at its November 5th meeting. The Standards Committee notes that an appeal has been filed on one of the Interpretations. As a policy matter, the Standards Committee believes that it is premature for the Board to consider approval of an Interpretation for which a known appeal exists.

The Standards Committee greatly appreciates the interest the Board of Trustees has shown in the standards program area. We take seriously our responsibility to be the stewards of the process we believe will produce Reliability Standards that assure operational excellence. We thank you for your continued support as we fulfill those responsibilities.

Sincerely,

R. Scott Henry
Chairman, NERC Standards Committee