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January 3, 2007

VIA ELECTRONIC FILING

The Honorable Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

**Re: Mandatory Reliability Standards for the Bulk-Power System;
Docket No. RM06-16-000**

Dear Secretary Salas:

Transmitted electronically for filing in the referenced docket are the Comments of ISO New England Inc.

If there are any questions concerning this filing, please call me at (202) 661-2212.

Very truly yours,

/s/ Daniel R. Simon

Daniel R. Simon
Counsel for
ISO New England Inc.

Enclosure

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

**Mandatory Reliability Standards for
the Bulk-Power System**

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Docket No. RM06-16-000

COMMENTS OF ISO NEW ENGLAND INC.

ISO New England Inc. (“ISO-NE”) submits these comments on the Notice of Proposed Rulemaking issued by the Federal Energy Regulatory Commission (“Commission”) regarding Mandatory Reliability Standards for the Bulk-Power System, 117 FERC ¶ 61,084 (2006), 71 Fed. Reg. 64,770 (Nov. 3, 2006) (“NOPR”). ISO-NE submits these comments to supplement comments submitted jointly through the ISO-RTO Council (“IRC”).

I. EXECUTIVE SUMMARY

ISO-NE generally supports the approach the Commission follows in the NOPR, which proposes to approve approximately 83 Reliability Standards and to direct the North American Electric Reliability Council (“NERC”) to modify certain Standards as mandatory and enforceable requirements to be followed by users, owners and operators of the Bulk-Power System pursuant to Section 215 of the Federal Power Act (“FPA”). ISO-NE provides these comments to explain five general issues of concern, to raise concerns regarding specific individual standards as either proposed by NERC or as the NOPR proposes to have NERC modify, and to provide comments in response to specific requests raised in the NOPR.

ISO-NE’s comments are organized as follows:

- Section II provides a brief description of ISO-NE.
- Section III discusses five primary issues of concern for ISO-NE.
- Section IV provides specific exceptions to individual NERC Standards proposed for approval by the Commission and to certain modifications proposed by the Commission for NERC to undertake.
- Section V includes any ISO-NE comments it provides in response to specific Commission requests in the NOPR.

Below, ISO-NE summarizes its primary issues of concern, which are addressed at length in Section III.

- *Although ISO-NE does not oppose the NOPR's interpretation of "Bulk-Power System," ISO-NE recommends delay of civil penalty enforcement until January 1, 2008.*

ISO-NE does not oppose the NOPR's approach on how to interpret "Bulk-Power System" as used in Section 215 of the FPA. The Commission's proposed interpretation appears to be in accord with ISO-NE's governing documents (*e.g.*, its Transmission Operating Agreements), which require ISO-NE to operate transmission facilities in compliance with NERC Standards. Nevertheless, it is appropriate for the Commission to delay the date the NERC Standards are enforced through civil penalties. Because the final definition employed by the Commission will not be known until later in the first quarter of this year, and because it will require some "case by case" review (as recognized by the Commission¹), ISO-NE respectfully submits that civil penalties should not commence until January 1, 2008 in order to provide additional time to ensure compliance with whatever definition the Commission ultimately promulgates. Such an approach will avoid any potential disruption that might arise due to the

¹ See NOPR at P 68 ("If there is a question concerning which underlying transmission system limits or supplements the operation of the higher voltage transmission system, the Commission proposed that the ERO would provide the final determination on a case by case basis.").

fact that Bulk-Power System users, owners and operators have traditionally interpreted the reach of the NERC Standards more narrowly than the Commission.

- ***The Commission should direct NERC not to refer to “Local Control Centers.” To the extent the Commission directs that NERC review the performance of such entities in carrying out reliability-related functions, the Commission should specify the NERC’s review be done in accordance with the responsibilities of such entities as laid out in Commission-approved ISO/RTO operating agreements.***

The Commission must clarify its intent, as expressed in paragraph 237 of the NOPR, that NERC should hold entities that are responsible for implementing an ISO’s or RTO’s directives (i.e., Local Control Centers) in a manner that respects the current hierarchical authority exercised by the ISO or RTO today. In accordance with Order No. 2000, the Commission’s subsequent approval of individual RTO operating agreements, and the Commission’s April 19, 2004 Policy Statement,² if an RTO exercises authority over another entity’s performance of a delegated task, then that RTO must be held ultimately responsible for the reliable performance of the task. Such an approach will promote an operating philosophy of their being only “one set of hands on the wheel” during real-time system conditions.

- ***The Commission should direct NERC to resolve ambiguities in the Interconnection Reliability Operating Limit (“IROL”) definition.***

The Commission has appropriately recognized the need to allow ISOs and RTOs the flexibility to rely on redispatch, as opposed to Transmission Loading Relief, as a means to manage Interconnection Reliability Operating Limits. There remains, however, the issue identified in the Commission Staff Assessment about the ambiguity allowing for multiple

² *Policy Statement on Matters Related to Bulk Power System Reliability*, 107 FERC ¶ 61,052 (Apr. 19, 2004) (“April 19, 2004 Policy Statement”), *clarified*, 108 FERC ¶ 61,288 (2004), *supplemented*, 110 FERC ¶ 61,096 (2005).

interpretations in defining the requirement to mitigate IROL violations under normal pre-contingency conditions. Due to the critical importance to reliability of how to respond to IROL violations (*i.e.*, TOP-007-0 and TOP-008-1), and the fact that multiple interpretations should be avoided, the Commission should direct NERC to address the ambiguities in the current definition for IROL.

- ***The Commission should refrain from approving NERC Standards that rely on “fill-in-the-blank” Standards.***

If the Commission carries out its proposal to take no action on those “fill-in-the-blank” NERC Standards that impose requirements that must be developed by Regional Reliability Organizations, then the Commission should also refrain from taking action on those NERC Standards that rely on or make reference to such “fill-in-the-blank” NERC Standards.

- ***Some provisions of NERC Standards, and some Commission recommended modifications, are too prescriptive and thereby can frustrate the administration of wholesale electricity markets.***

NERC Standards should focus on clearly articulating what reliability objectives should be achieved by the industry, as opposed to mandating overly prescriptive approaches to attaining reliability. A number of the NERC Standards are drafted such that they preclude or frustrate market-based approaches to power system operations and design. In this regard, ISO-NE supports the Commission’s proposal that NERC must modify its Standards referring to Transmission Loading Relief (“TLR”) (*see* NOPR at 562) so as to provide flexibility for ISOs and RTOs to rely on re-dispatch (as is provided for in their Market Rules) as a means to mitigate an IROL violation. Likewise, the Commission should not approve or modify other NERC standards in a manner that suggests that reliance on wholesale electric markets is inappropriate.

II. DESCRIPTION OF ISO-NE

ISO-NE is a private, not-for-profit entity that serves as the regional transmission organization (“RTO”) for New England.³ ISO-NE administers the New England energy markets and operates the New England Bulk-Power System pursuant to ISO New England Inc. Transmission, Markets and Services Tariff (“ISO-NE Tariff”)⁴ and the Transmission Operating Agreements with the New England transmission owners.⁵ In its capacity as the RTO for New England, ISO-NE has the responsibility to protect the short-term reliability of the Balancing Area as well as to provide oversight and fair administration of the New England markets.

III. GENERAL ISSUES OF CONCERN

A. ISO-NE Does Not Oppose the NOPR’s Interpretation of “Bulk-Power System,” But Requests Additional Time to Prepare for Compliance With the Commission’s Broad Definition Before Instituting Civil Penalties

ISO-NE does not oppose the NOPR’s approach on how to interpret “Bulk-Power System” as used in Section 215 of the FPA. As the following section explains, ISO-NE appears well-positioned to comply with the Commission’s proposed interpretation – an interpretation that is broader than the jurisdictional scope that NERC and the regional reliability councils have traditionally followed for implementing the voluntary standards they used before the

³ The Commission authorized the establishment of ISO-NE as an RTO in a series of orders. *See ISO New England, Inc.*, 106 FERC ¶ 61,280, *order on reh'g and compliance*, 109 FERC ¶ 61,147 (2004), *order on reh'g and compliance*, 110 FERC ¶ 61,111, *order on reh'g and compliance*, 110 FERC ¶ 61,335, *order on reh'g*, 111 FERC ¶ 61,344 (2005).

⁴ The ISO-NE Tariff is available at <http://www.iso-ne.com/regulatory/tariff/index.html>.

⁵ ISO-NE operates pursuant to three separate TOAs: (i) the primary TOA (an agreement among ISO-NE and the majority of Participating Transmission Owners) formed to first establish ISO-NE’s RTO operations (“ISO-NE TOA”); plus (ii) a separate similar agreement with Maine Electric Power Company regarding its intertie with New Brunswick Power (“MEPCO TOA”); and (iii) a similar agreement regarding the Phase I/II HVDC (high voltage, direct current) Transmission Facilities (“HVDC TOA”). All three TOAs are available at <http://www.iso-ne.com/regulatory/toa/index.html>.

establishment of an Electric Reliability Organization (“ERO”). Nevertheless, it is appropriate for the Commission to delay the date civil penalties take effect from June 1, 2007 until January 1, 2008. Such a delay will provide the industry sufficient time to review the Commission’s final rule; to adjust to the Commission’s proposal to expand the jurisdictional scope NERC, the regional reliability councils, and certain users, owners, and operators traditionally have followed; and to allow parties to perform prudent regulatory compliance review in advance of any case-by-case review of covered facilities that would be required by the Commission’s final rule.

1. In New England, NERC Standards Have Been Applied to a Broader Class of Transmission Facilities Than Only Those Falling Within NERC’s and NPCC’s Traditional Definitions

In the New England Balancing Area, transmission facilities in the six New England states⁶ and the transmission interties with neighboring Balancing Authorities,⁷ have been operated in accordance with NERC’s current standards, as well as the Northeast Power Coordinating Council’s (“NPCC”) regional reliability criteria. By virtue of commencing operations as an RTO, under its TOAs, ISO-NE is obligated to operate transmission facilities in New England in this manner. The Commission reaffirmed this requirement in a general policy statement.⁸ Consequently, as an RTO, ISO-NE has performed its operational functions with an

⁶ ISO-NE’s operation of transmission facilities in accordance with NERC Standards and NPCC Criteria includes transmission facilities serving a broad range of areas of New England, including load pockets within New England, such as Southwest Connecticut, Boston, Cape Cod, and Vermont.

⁷ For ISO-NE, such interties include not only “AC” Ties with New York, but also the Cross-Sound Cable (an HVDC underwater cable between Connecticut and Long Island, New York), the Maine Electric Power Company’s 345 kV transmission facilities connecting to New Brunswick Power, and the Hydro-Quebec Phase I/II HVDC facilities.

⁸ In its April 19, 2004 Policy Statement (at P 24), the Commission restated that under Order No. 2000, it “expect[ed] ISOs and RTOs to perform their functions consistent with NERC reliability
(continued...)”

outlook that a wide range of transmission facilities in New England (*i.e.*, not only those transmission facilities that can impact *inter*-regional operations) are to be operated in accordance with NERC Standards, as well as any more stringent regional reliability criteria. As a result, as an RTO, ISO-NE's governing documents put ISO-NE in a position that may perhaps be unique, as compared with non-ISO/RTO regions, in preparing for the new mandatory NERC Standards.

2. Because the NOPR Proposes to Expand NERC's and the Regional Reliability Councils' Traditional Interpretation of "Bulk Electric System," In Order to Avoid Any Resulting Disruption, the Commission Should Allow for Greater Lead Time Before Civil Penalties Commence

Although ISO-NE currently applies NERC Standards to transmission facilities that appear to be in accord with the NOPR's proposed scope of application for Bulk-Power System, the Commission should nevertheless recognize that the Commission's proposed interpretation covers a broader range of facilities than traditionally followed by NERC, regional reliability councils, and certain users, owners and operators. As a result, the yet-to-be issued final rulemaking might not provide many regulated entities sufficient time to ensure that such additional facilities will be operated and maintained in accordance with the Commission's newly proposed interpretation by June 1, 2007. Therefore, the Commission should delay the date civil penalties may be imposed until January 1, 2008.

The Commission's interpretation of the Bulk-Power System covers more transmission and generating facilities than have traditionally been covered in the Northeast by the NPCC.⁹

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standards (or with regional variations that are no less stringent than, and not inconsistent with, NERC standards) and the findings and recommendations of NERC audits."

⁹ By way of background, the term "bulk electric system" has evolved over decades in NERC. The term has long been used in the industry, and is a technical term describing those facilities that
(continued...)

For example, the NPCC's interpretation has traditionally not explicitly included low voltage transmission that serves cities and radial transmission serving generation.¹⁰ In addition, NPCC's definition has traditionally not included *all* of the ≥ 100 kV transmission systems unless a performance-based analysis demonstrated the need to include such systems (without regard to voltage levels above or below 100 kV).¹¹ Lastly, NPCC's definition has traditionally not included any underlying transmission system that could limit or supplement the operation of the higher voltage transmission system.¹² NERC's bulk electric system would include such underlying transmission systems in NPCC's region if, and only if, based on the performance-based methodology, a faulted element on the system would cause a significant adverse impact outside the local area.

In light of the Commission's proposed expanded interpretation, it appears that there is the potential for disruption associated with entities trying to bring their facilities within this new interpretation. First, if facilities never covered by NERC Standards are now encompassed by those standards by virtue of the Commission's interpretation, there may be a need for entities to

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must be included in planning models, system studies, operating assessments and reliability analyses that impact the reliability and operability of the interconnected transmission system. Moreover, existing transmission systems have been designed and installed based on this long-standing terminology. Furthermore, NERC's policies and standards were not developed to protect sub-transmission, distribution systems, or large load centers.

¹⁰ For over 35 years, NPCC has followed a functional, reliability impact approach to determining elements of the Bulk Power System that has not explicitly included low voltage transmission. Northeast Power Coordinating Council, NPCC Document A-2, *Criteria for Design and Operation of Interconnected Power Systems*, available at <https://www.npcc.org/publicFiles/reliability/criteriaGuidesProcedures/new/A-02.pdf>; *see also* NPCC's comments submitted in response to the NOPR.

¹¹ *Id.*

¹² *Id.*

implement new operating protocols because of the need to respect facilities not previously treated “on par” with facilities that have inter-area impacts. Disruptions related to such changes in instituting new operating protocols could then negatively impact New England. Second, with any Commission change or clarification in the scope of applicability of the NERC Standards, users, owners and operators (including ISO-NE) will need to conduct their regulatory compliance review to ensure that all such facilities are being operated in compliance with NERC Standards as ultimately approved by the Commission. ISO-NE respectfully submits that, in order to ensure an orderly transition in any operations or maintenance practices, the Commission should allow more than one Calendar Quarter (assuming Commission-promulgation of this NOPR by March 31, 2007) for this to occur. A January 1, 2008 commencement date for imposition of civil penalties would appear appropriate.

B. The Commission’s Proposal Regarding Local Control Centers Should Be Clarified to Respect an ISO’s or RTO’s Operational Authority, Pursuant to Order No. 2000 and Commission-Approved Transmission Operating Agreements

In the context of discussing Communications standards, the NOPR proposes in Paragraph

237

that all control centers and organizations that are necessary for the actual implementation of the decisions or are needed for operation and maintenance made by the ISO or RTO or the pooled resource organizations are part of the transmission or generation operator function in the functional model. All of the requirements for telecommunication would apply to all of these entities as appropriate to their respective functions within the transmission or generation operation functional model. Further, we note that this proposed definition of responsibility within a function would apply to other Reliability Standards that address such activities as training, operator certification, transmission operations, and cyber and physical security.

As discussed in more detail below, ISO-NE agrees with the Commission that if the ISO/RTO delegates a task related to the performance of a NERC Standard requirement, NERC should be assured that the entity performing the task is doing so reliably. However, the Commission's proposal to include the tasks performed by a Local Control Center needs to be clarified to respect the specific operating agreements approved by the Commission for ISOs and RTOs.

As an initial matter, the Commission should note that the term Local Control Center is not a Functional Model-defined term, and may, in fact, mean different things in different ISO/RTO regions. For example, for the Midwest ISO,¹³ there are over twenty-five (25) Balancing Areas, and the term "Local Control Center" may refer to the entities performing Balancing Authority functions. In New England, however, Local Control Centers do not perform Balancing Authority functions. Rather, they implement *tasks* on behalf of ISO-NE, in accord with the ISO-NE TOA, relating to operations of the transmission facilities.

In this regard, the proposal to merge the functions of a "Local Control Center" into the functions of the Transmission Operator could be viewed as inconsistent with the single authority concept established in the hierarchical control structure for entities within an RTO as set forth in Order No. 2000,¹⁴ as well as NERC's own Rules of Procedure.¹⁵ Without clarification, the

¹³ Midwest ISO filed the comments to which the NOPR (at P 237) responds.

¹⁴ By approving the ISO-NE TOA, which transferred to ISO-NE the day-to-day control over the transmission owners' facilities, the Commission acknowledged the hierarchical relationship between ISO-NE and the Local Control Centers. *See, e.g., ISO New England, Inc.*, 106 FERC ¶ 61,280 at P 100 ("The Filing Parties state that under Section 3.06 of the ISO-NE TOA, the Transmission Owners would be required to physically operate their respective transmission facilities through existing Local Control Centers and would be required to perform various functions in accordance with RTO-NE's directions.").

Commission’s proposal could create confusion about the ultimate authority over the control of the Bulk-Power System. It could also lead to unnecessary disputes between system operators and transmission owners. Consequently, the Commission’s proposal should be clarified with respect to the concerns discussed below.

1. Having “One Set of Hands on the Wheel” For Conducting System Operations is Critical to Running a Reliable Bulk-Power System

ISO-NE has long been a proponent of an operating philosophy that only one entity should be responsible and have the authority for providing directions on how to operate a defined set of facilities within a defined footprint (*i.e.*, “one set of hands on the wheel”).¹⁶ Decentralized control of core reliability functions (*i.e.*, “multiple hands on the wheel”) increases the risk of ineffective coordination over the defined set of facilities during real-time system operations, which can frustrate the goal of achieving a reliable Bulk-Power System.¹⁷

Based on this operating philosophy, in New England, ISO-NE acts as the Reliability Coordinator, Balancing Authority and Transmission Operator for all transmission facilities above

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¹⁵ See NERC Rule of Procedure, 501.4. NERC’s Committees are also considering memorializing such a rule in its Functional Model. Consistent with the Commission’s direction at Paragraph 48 of the NOPR, ISO-NE supports the Commission requiring NERC to submit any such change to the Functional Model to the Commission for approval.

¹⁶ See Attachment 1 (Memo from Steve Whitley, ISO-NE Senior Vice-President and Chief Operating Officer to NPCC Executive Committee, dated November 3, 2003; Letter from NPCC to NERC, dated November 9, 2003).

¹⁷ See, *e.g.*, U.S.-Canada Power System Outage Task Force, *Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendation* (2004) (*hereinafter* referred to as *2003 Blackout Report*) at p. 146 (“Some observers believe that some U.S. regions have too many control areas.... The resulting institutional fragmentation and decentralization of control leads to a higher number of operating contacts and seams, complex coordination requirements, misalignment of control areas with other electrical boundaries and/or operating hierarchies, inconsistent practices and tools, and increased compliance monitoring requirements. *These consequences hamper the efficiency and reliability of grid operations.*”).

100 kV, as well as lower voltage transmission facilities for which an outage can cause a violation of reliability criteria. The benefit of having “one set of hands on the wheel” for system operations is that there will be no disagreement among users, owners and operators of the Bulk-Power System during real-time operating conditions. In short, there will not be multiple entities giving duplicate or inconsistent instructions on how to operate any given facility, and there will not be any facility for which no one is giving instructions.

2. If Tasks are Delegated *Appropriately*, Then One Entity Can Oversee Transmission Operations on Multiple Facilities

Currently, the ISO-NE TOA specifies that ISO-NE either directly operates the transmission facilities, provides a specific directive to an entity (*i.e.*, a “Local Control Center”) to implement an operating task, approves the operating procedures that govern an implementing entity’s performance of a task, or is able to audit an entity’s performance of a task. At the end of the day, ISO-NE is responsible for how the transmission system is operated in New England.¹⁸

¹⁸ Section 3.02 of the ISO-NE TOA defines ISO-NE’s Operating Authority as “those functions set forth in Sections 3.02, 3.03, and 3.08 and those responsibilities set forth in Section 3.05.” The long list of functions in these sections constitutes ISO-NE’s direct control over the Bulk-Power System. To make clear that ISO-NE is to have such direct control over day-to-day operating decisions, Section 3.02(e) of the ISO-NE TOA provides that, where operating decisions are *not* spelled out in Operating Procedures, and when there is a disagreement between the transmission owner and ISO-NE about how to operate the system during real-time system conditions, ISO-NE’s position on real-time operating decisions prevails. Although a transmission owner may seek redress through dispute resolution, ISO-NE’s judgment at the time prevails in the interim.

a. The Commission’s Order No. 2000 Anticipated That an RTO May Delegate Tasks to an Implementing Entity, But May Not Delegate the Responsibility to Ensure That the Task is Being Performed Reliably

Order No. 2000 specifically addressed the question of whether an RTO may “delegate” authority to a “satellite control center” in a “hierarchical” relationship. In pertinent part, the Commission explained:

We conclude that those designing the RTO should have flexibility to decide how it would exercise its operational control authority. The RTO [may] operate the transmission system through direct physical operation by RTO employees, contractual agreements with other entities (e.g., transmission owners and control area operators) or implement a hierarchical control structure involving a combination of direct and functional control. Under these arrangements, the personnel of existing control centers might become employees of the RTO or remain as employees of the control center owner, while being supervised by RTO personnel. We will leave it to the discretion of the region to decide on the combination of direct and functional control that works best for its circumstances. . . .

However, regardless of the method of control chosen, the RTO must have clear authority to direct all actions that affect the facilities under its control, including the decisions and actions taken at any satellite control centers. The system of operational control chosen must ensure reliable operation of the grid and non-discriminatory access to the grid by all market participants. In addition, to ensure that the RTO does not become locked into an operational system that is unsatisfactory, the Commission will require the RTO to prepare a public report that assesses the efficacy of its operational arrangements no later than two years after it begins operations.¹⁹

¹⁹ *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 at 31,091-92 (1999), *order on reh’g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (Mar. 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff’d sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001) (internal footnotes omitted) (emphasis added).

The Commission's view in Order No. 2000 is that, while delegation of functional authority is acceptable, a split of direct authority over the control of the Bulk-Power System is not. In fact, as discussed below, the very model of combined direct and functional authority, under one Responsible Entity, is exactly what the Commission approved through the ISO-NE TOA structure as part of the New England RTO.

b. NERC's Single Transmission Operator Concept, Which Allows Delegation Of Individual Tasks, Is Consistent With Order No. 2000

The responsibility for operations, as described above, is consistent with NERC's Rule of Procedure § 501.4. The Rule states that

For all geographical or electrical areas of the bulk power system, the registration process shall ensure that (1) no areas are lacking any entities to perform the duties and tasks identified in and required by the reliability standards to the fullest extent practical, and (2) there is no duplication of such coverage or of required oversight of such coverage. In particular the process shall:

[e]nsure that all transmission elements of the bulk power system are the responsibility and under the control of one and only one transmission planner, planning authority, and transmission operator.²⁰

NERC's Functional Model Working Group recently reaffirmed and strengthened this position in its Reliability Functional Model, Version 3. Specifically, it discusses the *Guiding Principles of the Functional Model* ("Principles") as applying to all aspects of the Functional Model – not simply those functions listed in NERC's Rules of Procedure. One of these Principles states that "[a]n organization who registers with NERC as performing a function is considered a Responsible Entity and must ensure that all tasks are performed." The Functional

²⁰ NERC Rules of Procedure, Section 500 ("Organization Registration and Certification") at § 501.4 (emphasis added).

Model, Version 3 also provides that, “while the organization may agree to split or delegate Tasks of the Function, NERC will require that one, and only one, organization be the Responsible Entity, ensuring all of the Tasks of the Function are performed.”²¹

In conclusion, it is clear from NERC’s Rules of Procedure that that there should be only one entity responsible for the transmission operation of any transmission element of the Bulk-Power System, although individual tasks related to the performance of a function may be delegated to another entity. This philosophy is consistent with Order No. 2000 and should be promoted by the Commission as it reviews operating arrangements around the country.

3. The Commission’s Proposal Should Therefore Be Clarified to Make Clear That the Commission Does Not Intend to Frustrate Commission-Approved Hierarchies

ISO-NE agrees with the Commission that NERC Standards cover all tasks necessary for accomplishing the function in the Standard. If an RTO has delegated a task under that Standard to another entity, then regardless of who performs the task, the task must be accomplished in a manner consistent with the Reliability Standard. However, this flexibility in relying on entities to implement a task identified in a NERC Standard should not conflict with the principle of “one set of hands on the wheel.” If an entity is carrying out a task because an RTO has delegated performance of that task, then the entity must follow the RTO’s instruction. Concomitantly, NERC should hold the RTO as the “Responsible Entity,” because the RTO exercises ultimate oversight responsibility for the successful implementation of the task.

²¹ While the NERC Operating Committee recently failed to recommend NERC Board approval of this version of the Functional Model, ISO-NE hopes that, in line with the *2003 Blackout Report’s* concerns about decentralized control over the Bulk-Power System, *see supra* note 17, the NERC Board will address this matter in calendar year 2007.

C. The Commission Should Direct NERC to Resolve Ambiguities in the IROL Definition

Although ISO-NE generally supports TOP-007-0 and TOP-008-0, the Commission should direct NERC to address the ambiguities in the current definition for IROL. Prompt action is important because addressing IROL violations is critically important to maintaining reliability.²²

Requirement R2 of TOP-007-0, *Reporting SOL and IROL Violations*, states that “[f]ollowing a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.” The Commission notes that the Staff Preliminary Assessment of this requirement identified that the phrase “or other event” is open to interpretation. The Commission stated the interpretations as follows:

One interpretation is that it allows IROLs to be exceeded under normal precontingency conditions, provided the system can be returned to a secure state within 30 minutes. Another, more conservative, interpretation is that the Requirement does not allow IROLs to be exceeded under normal pre-contingency conditions, and that after a contingency occurs the system must be returned to a secure condition as soon as possible and no later than 30 minutes.²³

²² In the NOPR, the Commission proposes leaving these Standards “as is,” noting, in part, that the ISO-NE Council (“IRC”) asked the Commission to approve these NERC Standards in their present form. ISO-NE’s view is that the IRC’s comments stood for the proposition that NERC’s traditional approach of relying on TLRs for mitigating IROLs is inappropriate in regions that rely on re-dispatch – a finding supported by the Commission in this NOPR. Notwithstanding this view, ISO-NE respectfully submits that reliable system operations in North America would be enhanced by a review of the reasons why operators interpret the IROL differently. At a minimum, having clarity as to *how* system operators are interpreting IROLs will help ensure that one Balancing Area is not adversely impacted by another Area’s methodology for mitigating IROLs.

²³ NOPR at P 1020.

ISO-NE strongly agrees with the Staff Preliminary Assessment. However, allowing the standard to be approved “as is” without prompt action to address the ambiguities would be inconsistent with the *2003 Blackout Report* findings. A key finding in the *2003 Blackout Report* was that operators lacked sufficient awareness about whether operating limit violations existed after the trip of a transmission line. The *2003 Blackout Report* concluded that that it would have been difficult or impossible for operators to adjust the system within 30 minutes to prepare for the next critical contingency, as required by NERC Operating Policy A.2, because in real-time, operators would have to calculate operating limits and prepare to use the last resort of manually shedding large blocks of load before the advent of a second contingency.

In New England, ISO-NE operators are required by procedure to consider a double contingency.²⁴ This approach is the most prudent one, is consistent with the lessons learned from the *2003 Blackout Report*, and provides a conservative means of managing reliability risk. But, to ensure that this approach is consistent with TOP-007-0 and TOP-008-0, the Commission must direct NERC to resolve the ambiguities.

As suggested above, the timing for resolving this issue is important, and the Commission should make this a high priority effort. However, the timeline for addressing such issues is unclear. Even issues formally designated as having a “high priority” could apparently take up to

²⁴ See, e.g., ISO-NE’s system operating procedures SOP-RTMKTS.0060.0020 (Monitor System Security) and SOP- RTMKTS.0120.0030 (Implement Transmission Remedial Action). ISO-NE’s system operating procedures governing operations of the real-time markets are available at http://www.iso-ne.com/rules_proceeds/operating/sysop/rt_mkts/index.html.

one year after the Final Rule is issued to be addressed.²⁵ ISO-NE respectfully submits that this issue should be addressed much sooner due to the critical importance of these Standards.

D. The Commission Should Refrain from Approving Any Standards That Rely on “Fill-in-the-Blank” Standards

The NOPR proposes to request additional information with regard to 24 proposed NERC Standards that “would not be approved or remanded by the Commission until further action is taken by the ERO,” including “NERC’s so-called ‘fill-in-the-blank’ standards that require regional reliability organizations to develop – and users, owners, or operators to comply with – regional criteria.”²⁶ The NOPR explains that the Commission will not approve or remand such Standards until “the Commission receives this supplemental information to fill in the ‘blanks’ and assurances that the processes to fill in the blanks satisfy our procedural requirements. ...”²⁷ Although these standards will not be enforceable under Section 215 of the FPA, “compliance with these Reliability Standards would be expected as a matter of good utility practice.”²⁸ ISO-NE agrees with the Commission that these NERC Standards are important and should continue to be followed (as ISO-NE must under its governing documents, *see supra* Section III.A), but respectfully submits that if the Commission withholds approval of these 24 NERC Standards, the Commission should also withhold approval of those NERC Standards that rely, by reference, on such “fill-in-the-blank” standards.

²⁵ NOPR at P 85 (explaining that the NERC Standards included on the High Priority List are those that would “have the largest impact on near term Bulk-Power System reliability” and would be resolved “within 1 year of the effective date of the Final Rule”).

²⁶ *Id.* at P 10 (footnote omitted).

²⁷ *Id.* (footnote omitted).

²⁸ *Id.* at P 11.

ISO-NE views the following NERC Standards that the NOPR proposes to approve as dependent upon “fill-in-the-blank” NERC Standards, and as such, the Commission should refrain from approving and making them enforceable at this time: FAC-013-1, MOD-010-0, MOD-012-0, MOD-016-1, MOD-017-0, MOD-018-0, MOD-019-0, MOD-021-0, PRC-004-1, PRC-007-0, PRC-008-0, PRC-009-0, PRC-015-0, PRC-016-0, PRC-018-1, and PRC-021-0.²⁹ These Standards appear to fall within the list NERC identified as the third category of “fill-in-the-blank” Standards.³⁰ As the NOPR explains, this category involves NERC Standards “that require users, owners, and operators to follow criteria or procedures developed by the regional reliability organization, but did not (in the same Reliability Standard) require the development of such criteria or procedures.”³¹

ISO-NE submits that these Standards share the same difficulties as those the Commission found it could not approve until the missing information is provided. The NOPR itself recognizes that, where NERC determines that regional differences are warranted, the regional “fill-in-the-blank” proposal “must be developed in accordance with the NERC’s ANSI-approved process, or through an alternative process approved by the ERO, and must be submitted to the ERO and the Commission for approval.”³² As the Commission correctly acknowledges, “[w]here important information has not been provided to us to enable us to complete our review,

²⁹ ISO-NE provides comments on each of these Reliability Standards individually in Section IV, below.

³⁰ See NOPR at P 116 (discussing NERC’s three categories of “fill-in-the-blank” Standards).

³¹ *Id.*

³² *Id.* at P 122.

we are not in a position to approve those Reliability Standards.”³³ The same rationale should apply to the “fill-in-the-blank” Standards identified by ISO-NE that the NOPR proposes to approve. Furthermore, until the missing information has been provided in the cross-referenced Standards, it will be impossible for the applicable entities to determine exactly what criteria they are expected to satisfy.

E. Some Provisions of NERC Standards, and Some Commission Recommended Modifications, Are Too Prescriptive and Thereby Can Frustrate Administration of Wholesale Electricity Markets

ISO-NE is concerned that provisions of some proposed NERC Standards – or even some Commission-required modifications – are too prescriptive by dictating specific actions. The Commission has agreed in principle with this concern while acknowledging that, under certain circumstances, a Reliability Standard might be “inextricably linked” to “how” a Responsible Entity must respond to certain situations:

For some Reliability Standards, leaving out implementation features could: (1) sacrifice necessary uniformity in implementation of the Reliability Standard; (2) create uncertainty for the entity that has to follow the Reliability Standard; (3) make enforcement difficult; and (4) increase the complexity of the Commission's oversight and review process. Accordingly, we leave it to the ERO to develop proposed Reliability Standards that appropriately balance reliability principles and implementation features.³⁴

³³ *Id.* at P 123.

³⁴ *Rules Concerning Certification of the Electric Reliability Organization; Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards*, Order No. 672, 71 Fed. Reg. 8662 (February 17, 2006), FERC Stats. & Regs. ¶ 31,204 at P 260 (2006), *order on reh'g*, Order No. 672-A, 71 Fed. Reg. 19814 (April 18, 2006), FERC Stats. & Regs. ¶ 31,212 (2006) (“While we are sympathetic to ISO/RTO Council's suggestion that, in general, a Reliability Standard should address the ‘what’ and not the ‘how’ of reliability and that the actual implementation of a Reliability Standard should be left to entities such as control area operators and system planners, in certain limited situations there may be a good reason to leave

(continued...)

Despite the Commission’s philosophy here, some of the NERC Standards and/or the NOPR’s proposed modifications to the NERC Standards are too prescriptive in places where such requirements are not “inextricably linked to the Reliability Standards.” Generally speaking, ISO-NE identifies below three categories of standards that are too prescriptive in how they seek to mandate reliable practices.³⁵

First, and as the Commission appropriately recognizes in its NOPR, those Standards that seek to mandate reliance on TLRs in ISO/RTO environments, instead of allowing ISOs/RTOs to rely on re-dispatch (as defined in their market rules), could be detrimental to reliability. For example, in IRO-006-3 (Transmission Loading Relief), the NOPR agrees with the IRC’s concerns that the TLR method is inappropriate for addressing actual emergencies.³⁶ The NOPR also agrees with the IRC that the NERC Standards should provide flexibility for ISOs and RTOs to rely on re-dispatch (as is provided for in their Market Rules), as opposed to TLRs, as a means to mitigate an IROL violation.³⁷ The Commission is correct to conclude that the NERC Standards need to account for those regions that administer competitive markets. This concern is

(...continued)

implementation practices out of a Reliability Standard. In other situations, however, the ‘how’ may be inextricably linked to the Reliability Standard and may need to be specified by the ERO to ensure the enforcement of the Reliability Standard.”).

³⁵ While ISO-NE has attempted to be comprehensive in its identification of potential conflicts between the NERC Standards and the administration of wholesale electric markets, some of the conflicts may not be “clear-cut” on their face and may become apparent only through enforcement and interpretation. Nonetheless, ISO-NE intends to continue to review actively the NERC Standards for any potential conflicts with its filed documents and Market Rules specifically. As specified in 18 C.F.R. § 39.6, ISO-NE will notify the Commission, ERO and applicable Regional Entity if it observes any conflicts.

³⁶ NOPR at P 560.

³⁷ *Id.* at P 562.

particularly important here because the TLR procedure, if primarily relied upon in ISO/RTO regions, could be detrimental to reliability. ISO-NE strongly supports the Commission's recommendations to NERC to fix the Standards relying on TLRs, in order to recognize this difference in ISO/RTO regions.

Second, certain Standards appear to be written for regions in which transmission service is provided by vertically-integrated utilities, as opposed to independent entities that administer markets and do not participate in resource acquisition. For example, in EOP-001, Requirement R7.4, NERC would require the "Transmission Operator and Balancing Authority" to "arrange deliveries of . . . fuel from remote systems." This language suggests that NERC expects that the Transmission Operator/Balancing Authority to contract for fuel from other areas. That interpretation would be inappropriate when an independent entity such as ISO-NE acts as the Transmission Operator and/or the Balancing Authority for a region. While ISO-NE has taken assertive steps to ensure that natural gas-fired generators are available during "cold snap" emergency conditions,³⁸ ISO-NE does not participate in the market, nor may it contract for the supply of fuel. As such, while "arrange deliveries of... fuel" might be susceptible to multiple interpretations, the most natural interpretation suggests that ISO-NE should be contracting for such fuel. This requirement is too prescriptive in that it directs a region as to how it should ensure that resources are available for emergencies.

³⁸ See ISO-NE Tariff, Section III (Market Rule 1), Appendix H (Operations During Cold Weather Conditions). The Commission accepted the most recent version of Appendix H as jointly filed by ISO-NE and NEPOOL in *ISO New England Inc and New England Power Pool Participants Committee*, 117 FERC ¶ 61,082 (2006).

A third category involves “resource-specific” NERC Standards. “Resource specific” Standards can conflict with the notion that administration of wholesale electric markets will determine which resources are most appropriate for the efficient and reliable operation of Bulk-Power System operations. MOD-019 provides an example. This Standard requires Planning Authorities (which includes ISO-NE) to forecast interruptible demand and Direct Control Load Management (“DCLM”) for at least five years, and up to ten years into the future as requested. This requirement is different than load forecasting (something ISO-NE does do up to 10 years in advance); rather, it appears to require forecasting of the *specific types* of resources that will be available. This Standard’s inclusion of a fixed time period for forecasting the availability of a *specific type of resource* is too prescriptive. In New England, for example, under the new Forward Capacity Market (“FCM”) Rules,³⁹ ISO-NE will rely only on those resources that clear in the FCM Auction (resources that may or may not include interruptible demand or DCLM) as being an available resource. Under the Commission-approved concept, these FCM Auctions seek new resources for a *three-year* window. Therefore, ISO-NE does not intend to forecast the availability of *specific types of resources* past the three years covered by the FCM Auction, because only those resources that respond to the FCM Auction can be considered reliably available.⁴⁰

Another example of this type of conflict can be found in those NERC Standards for which the NOPR proposes to direct NERC to add resources. In a number of BAL Standards, the

³⁹ The FCM Rules are being developed pursuant to a settlement agreement approved in *Devon Power LLC*, 115 FERC ¶ 61,340, *order on reh’g and clarification*, 117 FERC ¶ 61,133 (2006).

⁴⁰ The new FCM Rules, however, also “grant[] new capacity the option to lock-in capacity prices for up to five years.” *Devon Power LLC*, 115 FERC ¶ 61,340 at P 16.

Commission observed that the NERC Standard precluded reliance on demand side resources as being counted on for contingency reserves. Putting aside any technical questions about whether demand side resources can be responsive to act as contingency reserves, the guiding principle should be that, so long as NERC is prescriptive as to what reliable system operations require, the standard itself should be silent on the types of resources that can meet the NERC Standard.

IV. INDIVIDUAL RELIABILITY STANDARDS

In this section, ISO-NE provides exceptions to individual NERC Standards proposed for approval by the Commission and to certain modifications proposed by the Commission for NERC to undertake.

A. BAL: Resource and Demand Balancing

1. BAL-002-0: Disturbance Control Performance

ISO-NE supports Commission approval of BAL-002-0 as filed by NERC. The ISO, however, opposes two Commission-proposed modifications.

First, ISO-NE opposes the Commission's proposed modification to require NERC to include a Requirement that explicitly allows demand side management to act as a resource for contingency reserves. Requiring NERC to explicitly allow specific resources to provide a service sets a bad precedent by being too prescriptive as to how a Balancing Authority must achieve this Reliability Standard's requirements. In general, the NERC Standards should not confine or require an entity to achieve a NERC Standard in a particular manner. Specifically for this standard, ISO-NE does not believe that it can rely on demand side management resources to meet the 15-minute recovery listed in Requirement R4.2 because demand side resources cannot be counted on to respond in real-time to such a need without real-time metering. Although ISO-

NE has access to multiple demand side resources through its Load Response Programs, these resources generally have not been installed on a real-time basis. ISO-NE's demand side resources respond on a capacity basis, but may not effectively respond to relieve a contingency situation. Only a limited number of pumped storage, dispatchable load resources have real-time information available.

Second, ISO-NE opposes the Commission's proposed modification to require NERC to include a Requirement that measures response for any event or contingency that causes a frequency deviation. Requirement R3.1 for BAL-002-0 as proposed by NERC requires the Balancing Authority or Reserve Sharing Group to, *inter alia*, "carry at least enough Contingency Reserves to cover the most sever single contingency." This provisions is unambiguous and reasonable. The NOPR, however, proposes that NERC modify this requirement to include enough contingency reserve to cover any event or single contingency that results in *a significant deviation in frequency* from the loss or mismatch of supply either from local generation or imports.⁴¹ This proposed modification is ambiguous and unnecessary because (i) it is not possible to plan for all such events that may cause a frequency deviation and (ii) it is unclear what would constitute a "significant deviation."

⁴¹ NOPR at P 153.

2. BAL-005-0: Automatic Generation Control

ISO-NE supports Commission approval of BAL-005-0 without the NOPR's proposed modification that NERC include demand side management ("DSM") and Direct Control Load Management ("DCLM") as part of contingency reserves.⁴²

It appears that the proposed modification is based on a technically misguided view. Specifically, the Commission expresses concern that this Standard, as filed by NERC, "implies that only generators can participate in regulation control portion of contingency reserves."⁴³ ISO-NE, however, is unaware of any load-based resources that can closely follow its automatic generation control signals sent every four seconds. As such, demand side resources cannot satisfy BAL-005-0 Requirement R2, which provides that "[e]ach Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard." Although responsive load can effectively mitigate capacity shortages, and may someday be effective for contingencies, it has not demonstrated the load following capability necessary to provide regulation.⁴⁴

Rather than direct NERC to modify BAL-005-0 to include demand-based resources, a better approach would be for the NERC Standard to define the reliability purpose or objective, and then be "resource neutral." If the NERC Standard refrains from "locking in" the *specific types of resources* that must be relied upon to meet a reliability objective, then the NERC Standard will: (a) avoid the risk of specifying a resource that cannot fulfill the objective; (b)

⁴² *Id.* at P 197.

⁴³ *Id.* at P 191.

⁴⁴ Although ISO-NE is aware of available technologies currently testing such responsive capabilities, their capabilities have yet to be proven successful.

avoid the need to require review of the Standards to ensure that resources (including emerging technologies) are being discriminated against; and (c) allow markets to determine the most efficient means of providing resources to address reliability objectives.

B. COM: Communications

1. COM-001-1: Telecommunications

ISO-NE generally supports Commission approval of COM-001-1, but suggests that the Commission propose one modification for NERC to implement. Compliance 1.1 of this Standard currently provides that “NERC shall be responsible for compliance monitoring of the Regional Reliability Organizations,” and “Regional Reliability Organizations shall be responsible for compliance monitoring of all other entities.” COM-001-1, however, is not applicable to Regional Reliability Organizations. Furthermore, because NERC designed and created the monitoring software at issue here (*i.e.*, NERCNet), NERC should be responsible for maintaining the software and ensuring the using organizations are compliant. Therefore, ISO-NE recommends that the Commission direct NERC to modify Compliance 1.1 to provide that “NERC shall be responsible for compliance monitoring of the NERCNet User Organizations.”

2. COM-002-2: Communications and Coordination

ISO-NE supports Commission approval of COM-002-2 as filed by NERC. ISO-NE opposes the Commission’s proposal to modify this Standard to include “a Requirement for the reliability coordinator to assess and approve actions that have impacts beyond the area views of transmission operators or balancing authorities.”⁴⁵

⁴⁵ NOPR at P 262.

The NOPR correctly acknowledges that transmission operators “can take actions that place others at risk because they do not have a wide area view.”⁴⁶ As such, prudent transmission operators often times should check with their reliability coordinators before taking drastic actions. ISO-NE is concerned, however, that the Commission’s proposed modification goes too far and will prevent capable transmission operators from quickly addressing reliability problems that may arise. The window of time a transmission operator may have to effectively mitigate a reliability problem may not be long enough for it to inform the reliability coordinator, who must then “assess and approve” the proposed action. Under such a requirement, transmission operators may doubt themselves and delay necessary action.

Practically speaking, in the New England Balancing Area and (generally speaking) in the NPCC region, the Commission’s proposed requirement should not create any reliability problems, because ISO-NE serves as the New England Reliability Coordinator, Balancing Authority, and Transmission Operator.

C. EOP: Emergency Preparedness and Operations

1. EOP-001-0: Emergency Operations Planning

ISO-NE does not support adoption of this standard by the Commission for several reasons. Alternatively, ISO-NE respectfully requests the Commission to direct NERC to make improvements to the Standards in line with the following concerns.

First, as discussed at length in Section III.E of these Comments, Requirement R7.4 of EOP-001-0 requires Transmission Operators and Balancing Authorities to take emergency action

⁴⁶ *Id.* at P 258.

that would include coordination of fuel conservation and arranging for fuel deliveries.

Specifically, the Requirement states:

R7.4. The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

These types of activities are outside of the functions that *independent* Transmission Operators and Balancing Authorities (such as ISOs/RTOs) perform and, thus, should be eliminated from this NERC Standard. To the extent that such functions are critical to the reliability of the Bulk-Power System, they should be contained as requirements for other entities who typically perform such functions, such as Generator Owners or Operators.

Second, Requirement R5 states that “[e]ach Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-0 when developing an emergency plan.” Compliance Section 1.2 states that the “Regional Reliability Organization shall review and evaluate emergency plans every three years to ensure that the plans consider the applicable elements of Attachment 1-EOP-001-0.” The fifteen elements identified in the Attachment are for “consideration” and are, appropriately, not mandated. Thus, the actual emergency plan elements should be the only basis for compliance and this should be clarified in the standard.

Third, the Commission also proposes to require NERC to modify EOP-001-0 to include definitions of system states to be used by the operators (*e.g.*, “normal,” “alert,” and “emergency”) in order to provide criteria for entering into these states, and to identify the authority that will declare these states. The Commission’s proposal stems from a *2003 Blackout Report* recommendation, and ISO-NE concurs with the importance of this recommendation.

ISO-NE respectfully submits that the Commission should not direct NERC to implement this improvement before the June 1, 2007 effective date for enforceable NERC Standards for two reasons. First, without conducting a pilot program to “field-test” how the terms will actually be administered, there is a severe risk that operating entities would interpret the terms *differently*, thereby creating confusion in communications across Balancing Areas. Second, once the pilot is complete, ISO-NE (and other operators) will not only need to make changes to policies, procedures and potentially implement software changes, but also train operations staffs to ensure that the new operating practices will be administered in a secure and well-understood fashion. ISO-NE respectfully submits that such essential steps cannot be accomplished by Summer 2007.

2. EOP-002-1: Capacity and Energy Emergencies

ISO-NE does not support the Commission-proposed modifications to EOP-002-1 for several reasons. ISO-NE recommends that the Commission suggest other improvements to NERC, as discussed further below.

First, the Commission proposes that the ERO make the following modifications to this standard: (1) include in Requirement R6 “use of demand side management as one of the possible remedies;”⁴⁷ and (2) include “a clear warning that the TLR procedure is an inappropriate and ineffective tool to mitigate IROL violations or for use in emergency situations.”⁴⁸ The proposed modifications effectively dictate a specific means to solve the underlying problems. ISO-NE respectfully submits that NERC Standards should be neutral with regard to “how” an entity achieves the reliability objective that is specified by NERC. For example, the Commission is

⁴⁷ *Id.* at P 285.

⁴⁸ *Id.* at P 286; *see also id.* at P 287 (same).

correct to note that Requirement R6 is written too prescriptively to favor a resource. ISO-NE suggests that a proper recommendation would be for NERC to make the Requirement “resource neutral.” Likewise, while ISO-NE strongly supports the Commission’s conclusion on how reliance on TLR procedure can be inappropriate, *see supra* Section III.E, ISO-NE recommends that the NERC Standard would be improved if it did not specify the operating method that is required to achieve compliance. In both cases, the Commission is correct that there are alternative means to achieving reliability goals specified by NERC. ISO-NE believes that the Commission should go further in directing NERC to allow the Responsible Entity flexibility in the method by which they achieve compliance with the NERC Standard.

Second, Requirement R2 essentially requires the same actions as covered by ISO New England Operating Procedure No. 4, *Action During A Capacity Deficiency*. Compliance Section 2.4.1 states that a separate Level 4 non-compliance may occur where “[o]ne or more of the actions of the Capacity and Energy Emergency Plans were not implemented as appropriate. (R2).” The Commission should suggest that NERC improve this Standard by directing NERC to make clear that a system operator has discretion *not* to implement *every action* specified in its Capacity and Energy Emergency Plans, in light of other appropriate actions.

For example, Step 6 of ISO-NE Operating Procedure No. 4 (“OP-4”) provides that ISO-NE can allow its 30-minute reserves to diminish. Because ISO-NE also maintains 10-minute reserves, depending on the forecast of system conditions, it may be possible to simply implement Step 1 (Implement Power Caution and ADVISE GENERATORS TO PREPARE TO PROVIDE EMERGENCY ENERGY) and Step 6 for a short period of time (say, two to three hours) to maintain reliability and not implement all Steps 1-6. Alternatively, in instances where there are capacity deficiencies in specific areas within New England (perhaps due to facilities forced out

of service unexpectedly), it may be more prudent to implement steps OTHER than Step 6 because this is typically more helpful with system-wide shortages. An overly prescriptive approach to auditing compliance with this NERC Standard might result in a Regional Entity determining that ISO-NE was in violation because it skipped implementing steps that are listed in its procedure.

In short, under ISO-NE Operating Procedure No. 4, ISO-NE's operators have the flexibility to skip steps or not implement certain steps if the situation warrants. Additionally, ISO-NE's operators will cancel the steps of OP-4 based on system condition, which will also very likely be different than the order of initiation. ISO-NE has been utilizing OP-4 successfully for twenty-plus years. This procedure has proven reliable and dependable for New England operations during tight system conditions. It is also a useful tool in assisting other areas, when requested, as per the procedure.

As a final note, in the first line of Requirement R7, the reference to "R7" should instead be a reference to R6.

3. EOP-003-1: Load Shedding Plans

ISO-NE does not support the Commission's proposed modification for the following reason.

The Commission proposes that the standard be modified so that it "specifies the minimum load-shedding capability that should be provided and the maximum amount of delay before load shedding can be implemented."⁴⁹ This proposed modification requires greater

⁴⁹ *Id.* at P 299.

clarity. For example, there is no indication whether the modification would apply to automatic or manual actions, or both. In addition, because of different system characteristics within Balancing Areas, there may be difficulties with establishing a national standard. ISO-NE respectfully submits that the Commission should direct NERC to consider establishing coordinated trip settings within and among Balancing Areas for each Interconnection.

4. EOP-005-1: System Restoration Plans

ISO-NE does not support adoption of this standard by the Commission for the following reason. Alternatively, ISO-NE respectfully requests the Commission to direct NERC to improve EOP-005-1 in line with the following concern.

Similar to the remarks concerning EOP-001-0 above, this standard also references elements for consideration in an attachment. Specifically, Requirement R1 provides that “[e]ach Transmission Operator shall include the applicable elements listed in Attachment 1-EOP-005 in developing a restoration plan.” Furthermore, Compliance Section 2.4.1 provides that “[p]lan exists but does not address two or more of the requirements in Attachment 1– EOP-005.” Requirement R1 seems to indicate that the nine elements of Attachment 1 are only to be included in an emergency plan to the extent they are “applicable.” Thus, the actual emergency plan elements should be the only basis for compliance and this should be clarified in the standard.

D. Facilities Design, Connection, Maintenance, and Transfer Capabilities

1. FAC-013-1: Establish and Communicate Transfer Capabilities

ISO-NE does not support adoption of this standard by the Commission for the following reason.

Applicability Section 4.1 and 4.2 of the standard states that Reliability Coordinators and Planning Authorities are “required by its Regional Reliability Organization to establish inter-regional and intra-regional Transfer Capabilities.” Requirement R1 of the standard requires these same entities to “establish a set of inter-regional and intra-regional Transfer Capabilities.” However, NPCC, which will certainly become the registered Regional Reliability Organization for the New England Balancing Area, has not yet established requirements for development of inter-regional transfer capabilities. Consequently, ISO-NE is unclear how, as a Responsible Entity, it can currently comply with this standard. Therefore, in line with the Commission’s concerns about “fill-in-the-blank” standards, the Commission should not approve FAC-013-1 until such time as the Regional Reliability Organization has specified requirements for inter-regional transfer capabilities which are approved by the Commission.

E. INT: Interchange Scheduling and Coordination

1. ISO-NE Opposes Commission Approval of Any Standards That References the “Interchange Authority” Until That Term Is Clearly Defined (INT-001-2, INT-003-2, INT-005-1, INT-006-1, INT-007-1, INT-008-1, and INT-009-1)

Several of the INT standards would either require an Interchange Authority to take certain actions or would require other applicable entities – including ISO-NE as a Balancing Authority – to provide certain information or services to (or receive from) an Interchange Authority. *See* INT-001-2, INT-003-2, INT-005-1, INT-006-1, INT-007-1, INT-008-1, and INT-009-1. The proposed NERC Standards, however, fail to provide a clear definition for Interchange Authority, and it is not clear who the Interchange Authority should be.⁵⁰ NERC has

⁵⁰ NERC’s glossary defines “interchange authority” as “[t]he responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes.”

not yet fully defined how the tasks of an Interchange Authority could be performed operationally and how the Interchange Authority function interrelates with other reliability (and market) functions. Also, NERC has not yet fully implemented the concept of an Interchange Authority into its Functional Model construct. The problem, in fact, extends beyond the unclear definition, because NERC has not provided a means for an entity *to register* as an Interchange Authority under the Functional Model. Once the definition is clarified, NERC must still create a process to allow the appropriate entities to register as Interchange Authorities, so that their status is clear to all applicable entities.

The Commission raised similar concerns when commenting specifically on INT-005-1, INT-00701, and INT-008-1.⁵¹ ISO-NE submits that the same concern applies equally to the additional INT NERC Standards listed above that also rely on interactions with an Interchange Authority. It would be arbitrary and capricious for the Commission to make any of the standards relying on an Interchange Authority enforceable while simultaneously acknowledging that it is not clear who the Interchange Authority is.

Until the definition for Interchange Authority is clarified and NERC provides a mechanism for Interchange Authority registration, the Commission should withhold approval of these NERC Standards.

⁵¹ Specifically, the NOPR explained (at P 469):

It is not clear from NERC's definition whether an interchange authority is a user, owner or operator of the Bulk-Power System, or what types of entities would be eligible to perform such a function. Therefore, the Commission requests that NERC provide additional information regarding the role of the interchange authority so that the Commission can determine whether it is a user, owner or operator of the Bulk-Power System that is required to comply with mandatory Reliability Standards.

2. INT-004-1

ISO-NE generally supports approval of INT-004-1. ISO-NE nevertheless recommends that the Commission direct NERC to modify Requirement R1 to ensure that all relevant Balancing Authorities obtain necessary information. Specifically, Requirement R1 in INT-004-1 provides the following:

At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority.

ISO-NE recommends that this provision be clarified to provide that the entity that initiated the curtailment shall communicate the release of the limit to the Sink *and Source* Balancing Authority. ISO-NE recommends this modification because it is important that both the supplier (source) and the receiver (sink) be informed about any changes to transmission limits that can affect transaction flows.

ISO-NE also supports the NOPR's proposal to direct NERC to submit a modification to INT-004-1 that includes Levels of Non-Compliance.

3. INT-010-1

ISO-NE supports Commission approval of INT-010-1 as filed by NERC. ISO-NE does not share the Commission's concerns regarding the initiation or modification of Interchange schedules to address SOL or IROL violations.⁵² Interchange schedules can provide, in certain circumstances, an additional effective tool to help prevent an SOL or IROL violation. ISO-NE

⁵² *Id.* at P 494.

recognizes that other tools may, in certain circumstances, be more effective, but that neither diminishes the value nor precludes the use of the tools contained in INT-010-1.

ISO-NE also notes that Section 2.4, which provides the Level 4 non-compliance, should be edited to provide that “[t]here shall be a level ~~three~~four non-compliance”

F. IRO: Interconnection Reliability Operations and Coordination

1. IRO-005-1: Reliability Coordination — Current Day Operations

ISO-NE generally supports IRO-005-1 but asks the Commission to direct NERC to clarify its Requirement R14, which states:

Each Reliability Coordinator shall make known to Transmission Service Providers within its Reliability Coordinator Area, SOLs or IROLs within its wide-area view. The Transmission Service Providers shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.

The phraseology indicating that the Transmission Service Provider (“TSP”) “shall respect” the SOLs and IROLs suggests an action that is more operational in nature than what would generally be thought of as a TSP function. Therefore, to make clear that a TSP is not expected to exercise some form of operational action, the Standard should be appropriately modified to hold the Transmission Operator responsible for such action.

2. IRO-006-3: Reliability Coordination — Transmission Loading Relief

As discussed in Sections III.E of these comments, although ISO-NE strongly supports the Commission’s conclusions with regard to reliance on TLRs, ISO-NE respectfully submits a more appropriate recommendation to NERC would be to go further and have the Standard be silent on

the specific methodology that a system operator should or should not use to fulfill the reliability objective.

G. MOD: Modeling, Data, and Analysis

1. MOD-010-0: Steady-State Data for Transmission System Modeling and Simulation

ISO-NE does not support adoption of this standard by the Commission for the following reason.

The MOD-010-0 Requirements refer several times to the “data requirements and reporting procedures of MOD-011-0,” which has been identified by the Commission as a “fill-in-the-blank” standard. Demonstrating compliance with MOD-010-0 is dependent on an unapproved standard. Moreover, the unapproved standard lacks the requisite criteria or procedures developed by the Regional Reliability Organization. Consequently, MOD-010-0 cannot be effectively implemented, and Responsible Entities should therefore not be subject to compliance with an incomplete standard.

2. MOD-012-0: Dynamics Data for Transmission System Modeling and Simulation

ISO-NE does not support adoption of this standard by the Commission for the following reason.

The MOD-012-0 Requirements refer several times to the “data requirements and reporting procedures of MOD-013-0,” which has been identified by the Commission as a “fill-in-the-blank” standard. Demonstrating compliance with MOD-012-0 is dependent on an unapproved standard. Moreover, the unapproved standard lacks the requisite criteria or procedures developed by the Regional Reliability Organization. Consequently, MOD-012-0

cannot be effectively implemented, and Responsible Entities should therefore not be subject to compliance with an incomplete standard.

3. MOD-016-0: Actual and Forecast Demands, Net Energy for Load, Controllable DSM

ISO-NE does not support adoption of this standard by the Commission for the following reason.

MOD-016-0 Requirement R1.1 states that the

aggregated and dispersed data submittal requirements shall ensure that consistent data is supplied for Reliability Standards TPL-005, TPL-006, MOD-010, MOD-011, MOD-012, MOD-013, MOD-014, MOD-015, MOD-016, MOD-017, MOD-018, MOD-019, MOD-020, and MOD-021.

Of the identified standards, TPL-005, TPL-006, MOD-011, MOD-013, MOD-014 and MOD-015 are pending approval by the Commission based on their characterization as applying only to Regional Reliability Organizations or because they have been categorized as “fill-in-the-blank” standards. Consequently, MOD-016-0 cannot be effectively implemented, and Responsible Entities should therefore not be subject to compliance with an incomplete standard.

4. MOD-017-0: Aggregated Actual and Forecast Demands and Net Energy for Load

ISO-NE does not support adoption of this standard by the Commission for the following reason.

Requirement R1 of MOD-017-0 states that

[t]he Load-Serving Entity, Planning Authority and Resource Planner shall each provide the following information annually on an aggregated Regional, subregional, Power Pool, individual system, or Load-Serving Entity basis to NERC, the Regional

Reliability Organizations, and any other entities specified by the documentation in Standard MOD-016-0_R1.

As pointed out above, MOD-016-0 is dependent on various unapproved standards.

MOD-017-0, in turn, depends on MOD-016-0. This creates a co-dependency of MOD-017-0 on the same unapproved standards. Consequently, MOD-017-0 cannot be effectively implemented, and Responsible Entities should therefore not be subject to compliance with an incomplete standard.

5. MOD-018-0: Reports of Actual and Forecast Demand Data

ISO-NE does not support adoption of this standard by the Commission for the following reason.

Requirement R1.3 of the standard states that “Items (MOD-018-0_R1.1) and (MOD-018-0_R1.2) shall be addressed as described in the reporting procedures developed for Standard MOD-016-0_R1.” As pointed out above, MOD-016-0 is dependent on various unapproved standards. This creates a co-dependency of MOD-018-0 on the same unapproved standards. Consequently, MOD-018-0 cannot be effectively implemented, and Responsible Entities should therefore not be subject to compliance with an incomplete standard.

6. MOD-019-0: Forecasts of Interruptible Demands and DCLM Data

ISO-NE does not support adoption of this standard by the Commission for the following reason.

Requirement R1 of the standard states

The Load-Serving Entity, Planning Authority, Transmission Planner, and Resource Planner shall each provide annually its forecasts of interruptible demands and Direct Control Load Management (DCLM) data for at least five years and up to ten

years into the future, as requested, for summer and winter peak system conditions to NERC, the Regional Reliability Organizations, and other entities (Load-Serving Entities, Planning Authorities, and Resource Planners) as specified by the documentation in Reliability Standard MOD-016-0_R1.

As pointed out above, MOD-016-0 is dependent on various unapproved standards. This creates a co-dependency of MOD-019-0 on the same unapproved standards. Consequently, MOD-019-0 cannot be effectively implemented, and Responsible Entities should therefore not be subject to compliance with an incomplete standard.

7. MOD-021-0: Forecasts

ISO-NE does not support adoption of this standard by the Commission for the following reason.

The Load-Serving Entity, Transmission Planner and Resource Planner shall each include information detailing how Demand-Side Management measures are addressed in the forecasts of its Peak Demand and annual Net Energy for Load in the data reporting procedures of Standard MOD-016-0_R1.

As pointed out above, MOD-016-0 is dependent on various unapproved standards. This creates a co-dependency of MOD-021-0 on the same unapproved standards. Consequently, MOD-021-0 cannot be effectively implemented, and Responsible Entities should therefore not be subject to compliance with an incomplete standard.

H. PER: Personnel Performance, Training and Qualifications

1. PER-001-0: Operating Personnel Responsibility and Authority

ISO-NE can support the adoption of this standard *if* the Commission does not mandate that the tasks performed by Local Control Centers be included in the definition of Transmission

Operator. As explained above,⁵³ to do so would be to suggest that a Local Control Center has independent autonomy in operating the Bulk Power System, which conflicts with the “one set of hands on the wheel” philosophy supported by Order No. 2000 and the operating agreements approved by the Commission to establish ISO-NE as New England’s RTO.

2. PER-002-0: Operator Personnel Training

ISO-NE can support the adoption of this standard on the following conditions. First, as with the discussion regarding PER-001-0 above, Local Control Center personnel in New England implement tasks delegated to them by ISO-NE for operation of designated transmission facilities. Therefore, ISO-NE respectfully submits that the scope of the Standard need not be expanded.⁵⁴ In any event, such training could not be practically accomplished by June 1, 2007, given the number of personnel in North America that work for entities that implement tasks delegated to them by ISOs and RTOs. Second, the Commission’s proposal to require the incorporation of SAT methodology into PER-001-0⁵⁵ should not be mandated. Responsible Entities under this standard should be allowed the flexibility of using the most appropriate training methodology available, rather than requiring one particular methodology. In this regard, ISO-NE notes that the Staff’s Preliminary Assessment only recommended that “some of the elements of the SAT methodology” be incorporated.⁵⁶

⁵³ See *supra* Section III.B.

⁵⁴ ISO-NE makes this point solely to distinguish Transmission Operator training from other programs. ISO-NE does not suggest that some other form of training would not be appropriate for Local Control Center operators.

⁵⁵ NOPR at P 780.

⁵⁶ *Id.* at P 760.

I. PRC: Protection and Control

1. To Be Consistent within the PRC Category, Several PRC Standards Should Be Modified to Apply to Load-Serving Entities

ISO-NE asks the Commission to direct NERC to modify the following PRC NERC Standards to make them applicable to Load-Serving Entities: PRC-004-1, PRC-005-1, PRC-008-0, PRC-011-0, PRC-015-0, PRC-016-0, PRC-017-0, and PRC-021-1. All of these standards provide requirements regarding either Protection Systems in general or Underfrequency Load Shedding (“UFLS”), Undervoltage Load Shedding (“UVLS”), or Special Protection Systems (“SPS”) specifically. Based on current practice, the operation and/or ownership of any or all types of protection schemes in the New England Balancing Area is not limited to a specific Transmission Operator, Transmission Owner, Load-Serving Entity, and/or Distribution Provider; rather, any of these entities may individually own, operate, or own and operate, a general protection program, a UFLS program, a UVLS program, or an SPS. Based on that practice, all four entities should be included in the above-cited examples.

2. The Commission Should Direct NERC to Combine the Four PRC Maintenance Standards

Four of the PRC Standards concern maintenance issues: PRC-005-1 (Transmission and Generation Protection System Maintenance Testing); PRC-008-0 (Underfrequency Load Shedding Equipment Maintenance Programs); PRC-011-0 (UVLS System Maintenance and Testing); and PRC-017-0 (Special Protection System Maintenance and Testing). As four separate Standards, the maintenance requirements are directed at different Registered Entities in an inconsistent fashion. Also, the Requirements contain varying degrees of specificity and detail, such that some Standards allow more latitude, while others provide more prescriptive definitions. In order to correct this inconsistency, ISO-NE suggests that the Commission direct

NERC to draft one all-encompassing maintenance Standard, which could include necessary elements from the four currently-separate NERC Standards.

3. PRC-004-1: Analysis and Mitigation of Transmission and Generation Protection System Misoperations

ISO-NE opposes Commission approval of PRC-004-1 at this time, primarily because it relies on a separate “fill-in-the-blank” Standard. The purpose of PRC-004-1 is to “[e]nsure all transmission and generation Protection System Misoperations affecting the reliability of the Bulk Electric System (BES) are analyzed and mitigated.” All three requirements included in PRC-004-1 rely directly on PRC-003-1 (Regional Requirements for Analysis of Misoperations of Transmission and Generation Protection Systems). Specifically, the requirements of PRC-004-1 provide that each applicable entity must develop and implement a Corrective Action Plan, as well as provide it to the appropriate Regional Reliability Organization, all according to the procedures developed by the Regional Reliability Organization pursuant to PRC-003 Requirement R1. The Commission, however, identified PRC-003 as a “fill-in-the-blank” Standard because the Regional Reliability Organizations have not yet developed such procedures.⁵⁷ Until the requirements of the separate standard relied on are presented, it will be impossible for an applicable entity to comply with PRC-004-1. Furthermore, until the underlying “fill-in-the-blank” standard has been completed, it is impossible for the Commission to determine whether PRC-004-1 is just and reasonable.

⁵⁷ *Id.* at P 832.

4. PRC-007-0: Assuring Consistency with Regional UFLS Program Requirements

ISO-NE opposes approval of PRC-007-0 because its Levels of Non-Compliance rely on PRC-006-0, R1, a separate “fill-in-the-blank” Standard as identified by the Commission. Requirement R1 of PRC-007-0 also requires the applicable entities to ensure that their UFLS programs are consistent with the Regional Reliability Organization’s UFLS program requirements, which must be developed in accordance with PRC-006-0. The NOPR correctly identifies PRC-006-0 as a “fill-in-the-blank” Standard “[b]ecause the regional procedures have not been submitted to the Commission,”⁵⁸ and Regional Reliability Organizations have yet to establish such requirements. Consequently, in line with the Commission’s concerns about “fill-in-the-blank” Standards, PRC-007-0 cannot be effectively implemented, and Responsible Entities should therefore not be subject to compliance with an incomplete standard.

5. PRC-008-0: Underfrequency Load Shedding Equipment Maintenance Programs

ISO-NE opposes approval of PRC-008-0 because its requirements involve the operation of a UFLS program, but the Regional Reliability Organizations have yet to establish the requirements for such programs. The NOPR recognizes this problem by identifying PRC-006-0 (the Reliability Standard requiring Regional Reliability Organizations to develop UFLS programs) as a “fill-in-the-blank” Standard. Consequently, in line with this concern, PRC-008-0 also cannot be effectively implemented, and Responsible Entities should therefore not be subject to compliance with an incomplete standard.

⁵⁸ *Id.* at P 855.

6. PRC-009-0: UFLS Performance Following an Underfrequency Event

ISO-NE opposes approval of PRC-009-0 because Requirement R1 provides that the Responsible Entities must operate a UFLS program as required by their Regional Reliability Organizations, but the Regional Reliability Organizations have yet to establish the requirements for such programs. The NOPR recognizes this problem by identifying PRC-006-0 (the Reliability Standard requiring Regional Reliability Organizations to develop UFLS programs) as a “fill-in-the-blank” Standard. Consequently, in line with this concern, PRC-009-0 also cannot be effectively implemented, and Responsible Entities should therefore not be subject to compliance with an incomplete standard.

7. PRC-010-0: Assessment of the Design and Effectiveness of UVLS Program

ISO-NE generally supports approval of PRC-010-0, but opposes the Commission’s proposal to direct NERC to modify this standard to include an integrated and coordinated approach in all protection systems on the Bulk-Power System, particularly for UVLS and UFLS programs, because such integration cannot be technologically accomplished.⁵⁹

UVLS and UFLS operate on different planes, independent from one another. Whereas UVLS is a local problem that requires study and mediation for various system configurations, UFLS is a system or island problem that is not contingency specific. The two problems simply do not occur in synch or at the same time. As a technical matter, the two schemes simply cannot

⁵⁹ *Id.* at P 892.

be integrated. As the purpose of PRC-010-0 involves the implementation of UVLS programs,⁶⁰ it should not address additional unrelated operational issues.

8. PRC-015-0: Special Protection System Data and Documentation

ISO-NE opposes Commission approval of PRC-015-0 at this time, primarily because it relies on two separate “fill-in-the-blank” standards. Two requirements included in PRC-015-0 rely directly on PRC-013-0_R1 or PRC-012-0_R1. Specifically, PRC-015-0 R1 states that the Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall maintain a list and provide data for existing and proposed SPSs as specified in Reliability Standard PRC-013-0_R1. Similarly, PRC-015-0 R2 states that the Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall have evidence it reviewed new or functionally modified SPSs in accordance with the Regional Reliability Organization’s procedures as defined in Reliability Standard PRC-012-0_R1 prior to being placed in service.

9. PRC-016-0: Special Protection System Misoperations

ISO-NE opposes Commission approval of PRC-016-0 at this time, primarily because it relies on a separate “fill-in-the-blank” standard. Requirement R1 relies directly on PRC-012-0 (Special Protection System Review Procedure). Specifically, the requirements of PRC-016-0 R1 states that the Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall analyze its SPS operations and maintain a record of all misoperations in accordance with the Regional SPS review procedure specified in Reliability Standard PRC-012-0_R1. Until the requirements of the separate standard relied on are presented, it will be impossible for an

⁶⁰ The purpose of PRC-010-0 is to “[p]rovide System preservation measures in an attempt to prevent system voltage collapse or voltage instability by implementing an Undervoltage Load Shedding (UVLS) program.”

applicable entity to comply with PRC-016-0. Furthermore, until the underlying “fill-in-the-blank” standard has been completed, it is impossible for the Commission to determine whether PRC-016-0 is just and reasonable.

ISO-NE also notes that the Commission proposes to direct NERC to make the same modification to both PRC-016-0 and PRC-017-0. Specifically, the Commission proposes to require NERC to include a requirement that maintenance and testing of special protection systems be carried out within a maximum allowable interval appropriate for the type of relaying used and the impact of these special system protection programs on Bulk-Power System reliability.⁶¹ This proposed modification is more appropriate for PRC-017-0,⁶² which provides for “Special Protection System Maintenance and Testing.” ISO-NE therefore recommends that the Commission not require NERC to make this same modification to PRC-016-0 as well.

10. PRC-018-1: Disturbance Monitoring Equipment Installation and Data Reporting

ISO-NE opposes Commission approval of PRC-018-1 at this time because it relies on “fill-in-the-blank” Standard PRC-002-1. The Requirements for PRC-018-1 provide that Transmission and Generation Owners must install Disturbance Monitoring Equipment (“DME”) in accordance with requirements created by their Regional Reliability Organizations pursuant to PRC-002. The NOPR does not propose to approve PRC-002-1 at this time in part because the Regional Reliability Organizations have yet to establish the DME installation requirements, thus treating PRC-002-1 as a “fill-in-the-blank” standard. Until the Regional Reliability

⁶¹ NOPR at P 926.

⁶² *Id.* at P 931.

Organizations develop such standards, and the Commission can thereby approve PRC-002-1, it is impossible for Transmission and Generation Owners to comply with PRC-018-1. Furthermore, until the underlying “fill-in-the-blank” standard has been completed, it is impossible for the Commission to determine whether PRC-018-1 is just and reasonable.

11. PRC-021-1: Under-Voltage Load Shedding Program Data

ISO-NE opposes approval of PRC-021-1 because its Requirements provide that Responsible Entities must operate a UVLS program as required by their Regional Reliability Organizations, but the Regional Reliability Organizations have yet to establish the requirements for such programs. The NOPR recognizes this problem by identifying PRC-020-1 (the Reliability Standard requiring Regional Reliability Organizations to develop UVLS programs) as a “fill-in-the-blank” Standard. Consequently, in line with this concern, PRC-021-1 cannot be effectively implemented, and Responsible Entities should therefore not be subject to compliance with an incomplete standard.

J. TOP: Transmission Operations

1. TOP-002-2: Normal Operations Planning

ISO-NE generally supports Commission approval of TOP-002-2, but recommends a modification to Requirement R12 of TOP-002-2. Requirement 12 currently provides that “[t]he *Transmission Service Provider* shall include known SOLs and IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs, and or regional Total Transfer Capability and Available Transfer Capability calculation processes.” (emphasis added) Requirement R12 should be modified to provide that the Transmission Operator and/or the Transmission Owner shall include known SOLs and IROLs when determining transfer capabilities.

The purpose of TOP-002-2 provides: “Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events.” The NOPR summarizes TOP-002-1 as requiring “transmission operators and balancing authorities to look ahead to the next hour, day and season, and have operating plans ready to meet any unscheduled changes in system configuration and generation dispatch.”⁶³ The Transmission Operator is “[t]he entity responsible for the reliability of its ‘local’ transmission system, and that operates or directs the operations of the transmission facilities.” As NERC’s Functional Model indicates, Transmission Operations is a Planning and Operations function. In other words, Transmission Operations standards in general, and TOP-002-2 specifically, involve planning and operations functions often performed by Transmission Operators. It is not surprising, therefore, that the list of requirements in TOP-002-2 imposes numerous obligations on Transmission Operators.

As the entity that “maintains transmission facilities,” Transmission Owners also perform certain Planning and Operations functions. As such, they may need SOL and IROL data as well.

In contrast, the Transmission Service Provider is “[t]he entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.”⁶⁴ In performing this function, the Transmission Service Provider provides a business service that entails executing contractual agreements with its customers to provide open access transmission service. SOLs and IROLs should not translate into Transmission Service Provider functions. Transmission Service Providers do not need to

⁶³ *Id.* at P 962.

⁶⁴ *See* NERC Glossary.

have the data listed in Requirement R12 to provide its service reliably, and it is misplaced to impose Requirement R12 on such entities.

2. TOP-005-1: Operational Reliability Information

ISO-NE generally supports Commission approval of TOP-005-1, but recommends a modification to Requirement 4. Requirement 4 provides that “[e]ach Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.” NERC’s Glossary defines the Purchasing-Selling Entity simply as “[t]he entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operation services.” Many entities can fall within this category (*e.g.*, commodity traders such as financial/power marketers) but may possess little or none of the operational or reliability data the host Balancing Authority and Transmission Operator need to conduct such reliability assessments. ISO-NE recommends that Requirement 4 be modified to replace Purchasing-Selling Entity with Generation Owner, Transmission Owner and Load-Serving Entity as the entities likely to possess the necessary data.

V. NOPR REQUESTS FOR COMMENTS

ISO-NE provides the following discussion in response to the NOPR’s specific requests for comments or other specific proposals.

A. Whether NERC Should File Changes to the Functional Model

The Commission proposes in the NOPR (at P 48) to require NERC to submit future modifications to the Functional Model that may affect the applicability of Standards to the commission for approval, because such changes are so closely linked to the Standards. ISO-NE

generally agrees with the Commission. As an example, and as discussed in Section III.B, recent work undertaken by the NERC Functional Model Working Group to Version 3 of the *Functional Model* is responsive to concerns expressed in the *2003 Blackout Report* regarding the risks to reliability associated with decentralized operating control. As the Commission is also concerned with this matter, Commission review and approval of such changes would be valuable to supporting improvements to the reliable operation of the Bulk-Power System.

B. Whether the Proposed Retention Time Periods Are Sufficient to Foster Effective Enforcement

The Commission seeks comments in the NOPR (at P 107) “on whether the retention time periods specified in various Standards proposed by NERC are sufficient to foster effective enforcement.” In response, ISO-NE submits that any data retention policy established by the ERO should be in line with the five year civil penalty statute of limitations for violations of NERC Standards.⁶⁵

C. WECC Automatic Time Error Correction Procedure

In its discussion of BAL-004-0, the NOPR requests comments at P 182 as to whether NERC should “adopt Requirements similar to those in the WECC automatic time error correction procedure.” In response, ISO-NE submits that Inadvertent Interchange is not, in and of itself, a reliability problem; it is simply an accounting of who “owes” MWhs to the Interconnection and to whom MWhs are “owed” from the Interconnection. Inadvertent Interchange instead can serve as an indicator of poor control. Therefore, ISO-NE recommends that such a requirement not be adopted.

⁶⁵ NOPR at P 107 n.83 (noting that the civil penalty statute of limitations for Reliability Standard violations will be five years) (citing Order No. 672 at P 487).

D. Regarding BAL-005-0, Whether Balancing Authorities Experience or Predict Any Difficulty in Obtaining Sufficient Automatic Generation Control

The NOPR requests (at P 192) information regarding difficulty in obtaining sufficient automatic generation control.⁶⁶ ISO-NE is not currently experiencing or predicting any difficulty in obtaining sufficient automatic generation control.

E. Whether COM-001 Should Provide Requirements That Consider the Relative Role of Applicable Entities

In the context of considering whether specific or minimum requirements for telecommunications adequacy, redundancy and/or diverse routing should be incorporated into COM-001-0, Telecommunications, the NOPR seeks comment (at P 248) on whether such requirements would vary depending upon the “relative role” of a Responsible Entity.⁶⁷ ISO-NE submits that the requirements should be reflective of a Responsible Entity’s relative role and functions. For example, a single generator operator would not need the level of redundancy and diverse routing that a Reliability Coordinator would need because of the “relatively” small communications for the generator as compared to that of a Reliability Coordinator.

F. Regarding MOD-013-1, Whether It Is Reasonable to Permit Entities to Estimate Dynamics Data If They Are Unable to Obtain Unit Specific Data

In discussing MOD-013-1, the NOPR expresses concern regarding Requirement R1.1.1, which allows for the use of estimated or typical manufacturer’s data on pre-1990 generating units to model dynamic behavior when unit-specific data is unavailable. Regarding this concern, the

⁶⁶ *Id.* at P 192 (“Recognizing that insufficient automatic generation control would constitute a violation of this Reliability Standard, the Commission is interested in understanding if any balancing authority is experiencing or is predicting any difficulty in obtaining sufficient automatic generation control.”).

⁶⁷ COM-001-0 has been replaced with COM-001-1. *See* Notice Granting in Part Motions for Extension of Time to File Comments and Announcing Rulemaking Proceeding (Nov. 27, 2006).

NOPR (at P 685) “seeks comment whether it is reasonable to permit entities to estimate dynamics data if they are unable to obtain unit specific data for any reason.” ISO-NE submits that new generation or transmission should not interconnect until facility-specific data has been provided.

Sections I.3.9 and I.3.10 of the ISO-NE Tariff require ISO-NE to evaluate if new projects or material changes to existing supply and demand-side resources or transmission facilities (rated at 69 kV or above) will have a “significant adverse effect.”⁶⁸ In the case of a new project, if ISO-NE determines that there will be such an effect, the proposing party may not proceed unless it constructs at its expense such facilities as ISO-NE determines are reasonably necessary to avoid the adverse effect.

When a new project is proposed, ISO-NE’s evaluation process includes a system impact study (“SIS”). While estimated or typical dynamics data can be used for the SIS and, thus, a decision on whether to approve the project, actual, facility-specific data should always be required before allowing final approval of interconnection to the grid. Such a policy will prevent unknown conditions from presenting themselves in real-time after the operation of the facility commences.

G. Regarding PER-002-0, Whether Simulators Should Be Required for System Emergency Training

In discussing PER-002-0, the NOPR (at P 778) “solicits comments on the benefits and appropriateness of required ‘hands-on’ training using simulators in dealing with system emergencies as identified in the training related recommendations made in studies of major

⁶⁸ These provisions also cover any changes by Market Participant that may have a significant effect on stability, reliability or operating characteristics of the Bulk-Power System

outages.” In response, ISO-NE notes that it has a fully-functioning simulator and has used different simulation devices in restoration and other emergency training. ISO-NE has found the use of such simulators beneficial. Nevertheless, NERC Standards should not require simulator usage, because other effective ways to achieve the desired state of readiness training exist than just through the use of a simulator. For example, ISO-NE is aware that Hydro-Quebec has used a computer-based training module that appears to provide much of the same level of training that a simulator provides. While ISO-NE supports simulator-based training, the Responsible Entity should be accorded greater flexibility to choose the training approach(es) most suited to its needs.

H. Whether TOP-007 and TOP-008 Overlap

In response to the Commission’s request for comments in P 1029 “on potential overlapping matters addressed in NERC Standards TOP-007-0 and TOP-008-0,” ISO-NE notes that it agrees with the NOPR’s observation that the two Standards overlap regarding how to respond to transmission limit violations. Although TOP-008-0 has been replaced with TOP-008-1, this overlap still exists. The two standards should be modified such that the reporting requirements remain in TOP-007 and that only TOP-008 should include the requirements for how to respond to such violations.

I. Planning For Cybersecurity Incidents and Where It Should Be Addressed

The NOPR (at P 1051) seeks comments on planning for Cybersecurity incidents and whether planning for it “should be addressed in the planning standards or in the CIP standards.” In response, ISO-NE states that planning for Cybersecurity incidents should be included in the Cybersecurity standards, because Cybersecurity issues are unique and inextricably linked with each other.

J. Regarding TPL-001-0, Whether ISO-NE Can Obtain and Validate Resource Information on New Generation and Retirements for Assessments Over Ten Year Planning Horizon

In discussing TLP-001-0, the NOPR (at P 1060) requests comments “on whether transmission planners and planning authorities are currently able to obtain and validate resource information on new generation and retirements for assessments over the ten year planning horizon.” ISO-NE provides the following responsive comments.

ISO-NE, as the Planning Authority, obtains resource plans for additions, capacity changes, deactivations, and retirements for a ten-year planning horizon. Although these plans cannot be expected to occur exactly as projected, they serve as useful tools in projected needs for additional resources, be it assistance from neighbors, demand-side resources, new or upgraded transmission facilities, or proposed new resource siting.

So, while ISO-NE actually obtains applications from asset owners with regard to new generation projects, as well as for generator retirements,⁶⁹ ISO-NE, as an *independent* Planning Authority, cannot validate the information in the same manner that a vertically-integrated public utility might, because ISO-NE does not own the resource. Therefore, while an asset owner might plan to retire a unit, ISO-NE cannot predict, for example, whether the asset owner would sell the unit so that it can be re-powered. As the administrator of wholesale electric markets, ISO-NE relies on its market rules, and developing improvements to those rules as may be needed, to bring new resources to address system needs. For example, the Commission recently approved New

⁶⁹ See ISO-NE Tariff § I.3.9.

England's Forward Capacity Market ("FCM").⁷⁰ It will require ISO-NE to oversee a three-year auction window, in which new resources can come to market to address forecasted needs.⁷¹ If the wholesale market does not spur the addition of new resources to address system needs, then ISO-NE is obligated under its tariff to ensure that planned transmission upgrades are in place to address the region's reliability and economic needs.⁷²

The fact that the region does not rely on a single entity to plan how investments should be allocated among specific resources by no means suggests that there is anything lacking in the ISO-NE planning process. In fact, ISO-NE has recently taken steps to provide greater signals about what the system's needs are and how different resources could contribute to addressing those system needs. However, it is through the development of robust market rules – such as the FCM – as accompanied by a regulated transmission planning process that assists ISO-NE in trying to achieve its goal of encouraging the availability of sufficient resources. Planning for the introduction and retirement of specific resources ten years in advance not only is unnecessary, it is inconsistent with relying on markets to determine the most efficient allocation of resources to

⁷⁰ The FCM is being developed pursuant to a settlement agreement approved in *Devon Power LLC*, 115 FERC ¶ 61,340, *order on reh'g and clarification*, 117 FERC ¶ 61,133 (2006).

⁷¹ The new FCM Rules, however, also “grant[] new capacity the option to lock-in capacity prices for up to five years.” *Devon Power LLC*, 115 FERC ¶ 61,340 at P 16, *order on reh'g and clarification*, 117 FERC ¶ 61,133 (2006).

⁷² Pursuant to its Open Access Transmission Tariff (*i.e.*, Section II of the ISO-NE Tariff), ISO-NE completes a Regional System Plan (“RSP”). “The purpose of the RSP is to identify system reliability and market efficiency needs and types of resources that may satisfy such needs so that Market Participants may provide efficient market solutions (*e.g.*, demand-side projects, distributed generation and/or merchant transmission) to identified needs.” ISO-NE Tariff § II.48.1. The RSP must identify a list of proposed Transmission Upgrades deemed appropriate by ISO-NE and “needed to maintain system reliability and operation of efficient markets under a set of planning assumptions.” *Id.* at § II.48.3(c). If the market develops credible alternative projects, ISO-NE may remove a Transmission Upgrade from the RSP. *Id.* at § II.48.3(d).

meet system needs. ISO-NE, in a variety of forums, has repeatedly explained the benefits and successes of its planning process.⁷³ In fact, ISO-NE's planning process has been recognized as one of the best in the country.⁷⁴

VI. CONCLUSION

ISO-NE requests that the Commission accept these comments and provide the relief requested herein.

Respectfully submitted,

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⁷³ Comments of ISO New England Inc. and the New England Power Pool at 8-9, Docket No. RM05-25-000 (filed Nov. 22, 2005).

⁷⁴ See Eric Hirst, Consulting in Electric Industry Restructuring, *U.S. Transmission Capacity Present Status and Future Prospects* (June 2004), prepared for Energy Delivery Group, Edison Electric Institute and Office of Electric Transmission and Distribution, U.S. Department of Energy.

Attachment 1



Stephen G. Whitley
Senior Vice President & Chief Operating Officer

TO: NPCC Executive Committee
Edward Schwerdt
Charley Durkin
NPCC TFCO

FROM: Stephen Whitley

DATE: November 3, 2003

SUBJECT: NERC Functional Model

On behalf of ISO New England, I would like to share with you some of our concerns with the recent NERC initiative to create a Functional Model. This model will serve as the foundation for the development of NERC Standards.

As NERC has stated, there is no longer a “standard” reliability organization, and the effort to create a framework for the certification of performance of core reliability functions for a variety of organizations going forward is critical to continued reliable operation of the bulk electric system. We are not confident that the current approach reflected in the model will provide for reliable operation of the bulk electric system. As currently drafted, the model promotes decentralized control, multiple “hands on the wheel” operation, complex accountability, and an “anything goes” approach to core real-time operations functions. **The August 14 blackout clearly demonstrated that this approach is not good for reliability.** My purpose here is not to stop or slow down the development of the functional model. Instead, it is to get it correct at the outset. While developing these comments, I have had discussions with numerous operations staffs in the Northeast and Southeast. I am asking for your support in developing these extremely important revisions before the model is approved.

Problem Statement

The current draft of the Functional Model breaks down the core reliability functions in a manner that will potentially allow any entity to opt to perform all or a portion of them. The intent of this breakdown appears to ensure that the model will work for any and all organizations and organizational structures, without regard to reliability.

The primary concern with the current model draft is that by breaking apart the core reliability functions and allowing more organizations to take on limited roles in the operation of the interconnection, there is increased reliability risk in effective coordination of core functions essential to bulk electric system operation. There are no clear lines of authority described in the functional model. We strongly believe in having “one set of hands on the wheel” with respect to core reliability functions, and are convinced that the model as proposed would open the door for an increase in unreliable approaches to assignment of core reliability functions (i.e. the “Swiss cheese” approach, generator-only control areas, and unacceptable levels of complexity). As we have all seen from the August 14 blackout, unclear operational authority, overlapping levels of accountability, and too many “sets of hands on the wheel” can and will lead to catastrophic results.

How To Improve the Document

As you know, the NPCC Reliability Coordinators and many of the Reliability Coordinators across the country perform the core/high level functions defined in the draft Functional Model without unnecessarily delegating them to subordinate levels. In these cases, the Reliability Coordinator tasks performed are synonymous with the definitions in the draft Functional Model for the Reliability Authority (RA), Balancing Authority (BA), Interchange Authority (IA), Market Operator (MO), and Transmission Provider (TP) functions. This model works. However, not all Reliability Coordinators are set up correctly, and the currently drafted NERC Functional Model opens the door to almost any decentralized combination of core responsibilities. Our specific concerns are addressed below, along with associated recommendations:

1. The core functions in the model as currently defined should “roll-up” under the RA function, in essence the RA should be the Operational Authority for its region with all core functions under its direct control.

It is essential that any entity performing the RA function have assigned to it the ultimate authority over **all core functions** to ensure that action to meet reliability requirements and bulk power system conditions can be performed efficiently and effectively. The recent events of August 14 have reaffirmed these beliefs, and we are confident that the authority and responsibility provided for in the combination of tasks assigned to the areas within NPCC allowed for effective and efficient response to the problems seen in the region on that day.

2. Understanding our view as stated in item 1 above that the RA be the ultimate authority, it is our opinion that the **RA must have a contiguous electrical boundary/footprint**.

There is a lack of clear reference to constraints on geographical/electrical boundaries within the draft functional definitions. In the model, the definition for the RA function states that it “Ensures the real-time operating reliability of the interconnected bulk electric transmission systems within a Reliability Authority Area”. We would interpret that statement to infer that the geographical/electrical footprint or boundary of an entity performing the RA function would be **contiguous**, with operational control over **all** of the transmission and generation facilities within its footprint. The establishment of a RA function within which certain facilities are controlled by other entities (e.g. other ISOs/RTOs or Control Areas) dramatically increases the complexity of operations and poses an unacceptable risk to reliability.

3. The RA system **size needs to be manageable**. An RA area can be too large to be manageable and too small to be effective.

We believe there is a finite limit to the effective size of the RA boundary/footprint based on the ability of human operators to be able to operate the system with confidence. Computer systems are important aids to decision-making, but they can still experience failures, in which case operators must take action to protect reliability based on their knowledge, experience and familiarity with the system they are operating. Therefore the RA geographical boundary **can become too large** to be managed reliably. The current definition of “wide area” may prove problematic and needs further refinement. This issue cannot be pushed off to be addressed in the certification process. It needs to be addressed up front in the model definitions.

On the other hand, the electrical boundary of a Reliability Authority can become **too small to be effective** (e.g., proliferation of small control areas in the Midwest). This results in too many hands on the wheel, poor accountability, and unclear operational authority.

4. There should be a **single entity with responsibility** for the core reliability functions. Those core functions include security analysis, transmission and generation dispatch, security unit commitment, Control Area operations, AGC, interchange scheduling and curtailment, maintenance coordination, emergency operations and system restoration (most of these are described under the RA, BA, IA, and MO functions in the draft model). The model, as proposed, would open the door for an increase in the decentralized approach to assignments of core reliability functions.

The TFCO recently raised this issue with NERC. The response was – “we want to be sure to accommodate everything that is out there today”. This current approach has allowed for too many control areas, some of which are generator-only control areas, to exist under a single RC entity in a less reliable form. The model should ensure that this approach is not allowed.

5. There **should be no overlap in RA responsibilities**. That is not clear in the model at this time.

To minimize confusion and ensure reliable operation, multiple RA’s should not have control over common facilities.

6. The **BA function as written is loosely defined** and may lead to the proliferation of entities opting to perform BA functions.

The BA function as drafted will promote small BA boundaries/footprints, such as generator only BA’s, and if allowed will degrade reliability.

7. The RA function can only be reliably achieved if the responsible BA(s) is/are within the RA footprint; BA(s) larger or external to the RA footprint represent a reliability risk. There is no clear reference that a **BA should fall under the authority of a single RA**.

The model fails to reinforce that understanding, and infers that an entity performing the Balancing Authority function in one geographical region could opt to fall under the purview of an entity performing the Reliability Authority function in another remote geographical area of the interconnection. This promotes the idea of core functions being scattered all over the country...mixed and matched... resulting in poorly defined operational authorities and unacceptable risks to reliability..

8. There should be a **single IA for each RA footprint**. The RA function can only be reliably achieved if it coordinates with a single IA operating within its footprint. Multiple IA(s) reporting to a single RA represents a reliability risk. This relationship is not clearly defined in the model.

9. **The process for approving the Functional Model is off track**. We would have expected NERC to request a review and approval of the current draft by its technical subject matter experts such as the RCWG, ORS, IS, etc. prior to seeking approval by the standing committees. As we understand the situation at this time, none of the technical subject matter experts have completed a thorough review of version #2 of the Functional Model and none have “officially” approved the model. It has been brought to our attention that there are still issues within the general NERC technical community. We believe a more formal review of the entire model is appropriate prior to rendering any opinion on the model – especially subsequent to the August 14 blackout. The technical subject matter experts provide critical feedback to the standing committees on reliability issues, and with the Functional Model providing the framework for defining how entities will perform those tasks critical to reliable operation, it would seem appropriate to have those committees review the drafts prior to any standing committee approval.

Summary

NERC staff and those close to the drafting of the model may argue that the Certification Process will address these issues and that an entity opting to perform any of the functions must clearly describe how it can meet the objectives in a reliable manner. We simply cannot take this risk or assume that will happen. Instead, we need the correct model as the first step.

The NERC Functional Model as presently proposed has serious flaws. We recommend the concerns above be addressed to make the Functional Model a better starting point. It is time to get back to sound fundamentals in system operations and at NERC. Setting out with a model that fails to address the issues raised, moving forward with standards based on this incomplete model, and then relying on the certification process to address all of these issues is inappropriate and could ultimately result in a degradation of reliability in North America. NERC needs to:

- a) Address these concerns and correct the model;
- b) Present this revised draft to their technical committees for review and approval prior to review and approval by the standing committees; and,
- c) Build on that foundation with the development of sound standards and a sound certification process.

I would appreciate your support in getting the above-defined revisions in the NERC Functional Model before it is approved. If you have any questions, please contact Don Gates or me at (413-535-4350).



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November 9, 2003

Mr. James Byrd
Chairman
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ONCOR
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Subject: **NERC Reliability Functional Model**

Dear Jim,

The NPCC Executive Committee reviewed Version 2 of the NERC Reliability Functional Model at a recent meeting. Following discussion, they agreed to support this draft revision with the conditions that the uncertainties and deficiencies identified below are resolved in a subsequent version and reflected in the implementation plan for the model for consideration at the March Standing Committee meetings. NPCC supports allowing the standards development process to move forward during this period, rather than delaying approval until the issues outlined are addressed in March.

Significant strides have been made in the last months in defining and clarifying the individual reliability functions and you and the rest of the FMRTG are to be congratulated. However, much work still needs to be done to develop a blueprint describing how to integrate these basic building blocks into a reliable structure.

The integration of core real-time operations reliability functions needs to be addressed in those sections of the Functional Model dealing with the relationship between the functions and explicitly required in the implementation plan. These core functions include security analysis, transmission and generation dispatch, security unit commitment, AGC, interchange scheduling and curtailment, maintenance coordination, emergency operations and system restoration. The Board of Trustees' imperative contained in their post-blackout Near-Term Actions letter emphasizing that, "*systems are operated within their design criteria and within conditions known to be reliable through analytic study*", make this integration more than a secondary technical specification. In addition, an unambiguous definition of contiguous electrical and physical operating area boundaries must be established.

Specific issues include the following:

1. Clarity of authority of entities performing the RA function over all core real-time operations reliability functions within their electrical boundary and geographic footprint.

2. Requirement for entities performing the RA function to have a contiguous electrical boundary/geographic footprint.
3. Clarify that the RA entity's system size needs to be consistent with the computational tools and communication capabilities available, and reliably manageable by operators should those tools and capabilities fail.
4. The model needs to clearly indicate that there should be no overlap in RA responsibilities and to preclude the possibility of multiple RA entities having control over common facilities.
5. Clarify that the boundary/footprint requirements for entities performing the BA function should be identified and should preclude generator-only BA areas.
6. Clarify that a BA entity should fall under the authority of a single RA entity and should be within the RA footprint.
7. Clarify that there should be a single IA entity within each RA footprint.

In conclusion, NPCC offers to continue to work with the FMRTG to address the concerns expressed. NPCC also recommends that other technical subject matter experts, such as the RCWG, ORS, and the IS be engaged to help move the development of the implementation of the Functional Model forward. These technical subject matter experts provide critical feedback to the Standing Committees on reliability issues, and their direct support of this effort could prove invaluable.

Thank you for your consideration these matters.

Sincerely yours,

Ed Schwerdt

Edward A. Schwerdt
Executive Director

EAS:jm
cc: NPCC Executive Committee