December 14, 2009

VIA ELECTRONIC FILING

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

Re: ***North American Electric Reliability Corporation***
Docket No. RM10-___-000

Dear Ms. Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits this petition in accordance with Section 215(d) (1) of the Federal Power Act ("FPA") and Part 39.5 of the Federal Energy Regulatory Commission's ("FERC") regulations seeking approval of proposed Regional Reliability Standard BAL-502-RFC-02 — Planning Resource Adequacy Analysis, Assessment and Documentation, and four associated new definitions included below and set forth in **Exhibit A** to this petition:

> **Resource Adequacy** — the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses).
>
> **Net Internal Demand** — Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Load Management and Interruptible Demand.
>
> **Peak Period** — A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur.
>
> **Year One** — The planning year that begins with the upcoming annual Peak Period.

These proposed terms will be added to the NERC Glossary of Terms as applicable only to entities in the Reliability*First* Corporation ("RFC") footprint.

The proposed Regional Reliability Standard and defined terms were approved by the NERC Board of Trustees during its August 5, 2009 meeting. NERC requests the standard be effective upon approval by FERC.

This petition consists of the following:

- this transmittal letter;
- a table of contents for the entire petition;
- a narrative description explaining how the proposed Regional Reliability Standard meets FERC's requirements;
- Regional Reliability Standard BAL-502-RFC-02 — Planning Resource Adequacy Analysis, Assessment and Documentation, submitted for approval (**Exhibit A**);
- the NERC Board of Trustees' Resolution approving BAL-502-RFC-02 — Planning Resource Adequacy Analysis, Assessment and Documentation and directing it be filed with FERC (**Exhibit B**);
- the complete development record of the proposed Regional Reliability Standard (**Exhibit C**);
- The Standard Drafting Team roster (**Exhibit D**); and
- the Violation Severity Level Guideline Analysis **(Exhibit E**).

Please contact the undersigned if you have any questions.

Respectfully submitted,

/s/ Holly A. Hawkins
Holly A. Hawkins
Attorney for North American Electric Reliability Corporation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	**) Docket Nos. RM10-__-000** **)**

PETITION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
FOR APPROVAL OF PROPOSED RFC REGIONAL RELIABILITY STANDARD
BAL-502-RFC-02 — PLANNING RESOURCE ADEQUACY ANALYSIS,
ASSESSMENT, AND DOCUMENTATION

David N. Cook
Vice President and General Counsel
North American Electric Reliability Corporation
116-390 Village Boulevard
Princeton, NJ 08540-5721
(609) 452-8060
(609) 452-9550 – facsimile
david.cook@nerc.net

Rebecca J. Michael
Assistant General Counsel
Holly A. Hawkins
Attorney
North American Electric Reliability Corporation
1120 G Street, N.W.
Suite 990
Washington, D.C. 20005-3801
(202) 393-3998
(202) 393-3955 – facsimile
rebecca.michael@nerc.net
holly.hawkins@nerc.net

December 14, 2009

TABLE OF CONTENTS

I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[1] hereby requests the Federal Energy Regulatory Commission ("FERC") to approve, in accordance with Section 215(d)(1) of the Federal Power Act ("FPA")[2] and Section 39.5 of FERC's regulations, 18 C.F.R. § 39.5, proposed Regional Reliability Standard, BAL-502-RFC-02 and four associated new definitions, also included in **Exhibit A**. The proposed Regional Reliability Standard includes four defined terms as follows:

Resource Adequacy — the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses).

Net Internal Demand — Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Load Management and Interruptible Demand.

Peak Period — A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur.

Year One — The planning year that begins with the upcoming annual Peak Period.

These terms do not presently appear in the NERC Glossary of Terms, and they do not conflict with existing terms.

This petition is the first request by NERC for FERC approval of this proposed Regional Reliability Standard. The Reliability Standard proposed will be in effect only for responsible entities within Reliability*First* footprint ("RFC"). NERC continent-wide Reliability Standards do not presently address the issues covered in this proposed Regional Reliability Standard, validating its consideration as a Regional Entity standard.

---

[1] NERC has been certified by FERC as the electric reliability organization ("ERO") authorized by Section 215 of the Federal Power Act. FERC certified NERC as the ERO in its order issued July 20, 2006 in Docket No. RR06-1-000. 116 FERC ¶ 61,062 (2006) ("ERO Certification Order).
[2] 16 U.S.C. 824o.

On August 5, 2009, the NERC Board of Trustees approved BAL-502-RFC-02 — Planning Resource Adequacy Analysis, Assessment and Documentation. NERC requests that FERC approve this Regional Reliability Standard and make it effective upon FERC approval. **Exhibit A** to this filing sets forth the proposed Regional Reliability Standard. **Exhibit B** is the NERC Board of Trustees' resolution to approve the proposed Regional Reliability Standard. **Exhibit C** contains the complete record of development for the proposed Regional Reliability Standard. **Exhibit D** includes the standard drafting team roster. **Exhibit E** is the Violation Severity Level guideline analysis.

II. NOTICES AND COMMUNICATIONS

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

David N. Cook*
Vice President and General Counsel
North American Electric Reliability Corporation
116-390 Village Boulevard
Princeton, NJ 08540-5721
(609) 452-8060
(609) 452-9550 – facsimile
david.cook@nerc.net

*Persons to be included on FERC's service list are indicated with an asterisk. NERC requests waiver of FERC's rules and regulations to permit the inclusion of more than two people on the service list.

Rebecca J. Michael*
Assistant General Counsel
Holly A. Hawkins*
Attorney
North American Electric Reliability Corporation
1120 G Street, N.W.
Suite 990
Washington, D.C. 20005-3801
(202) 393-3998
(202) 393-3955 – facsimile
rebecca.michael@nerc.net
holly.hawkins@nerc.net

III. <u>BACKGROUND</u>

a. Regulatory Framework

By enacting the Energy Policy Act of 2005,[3] Congress entrusted FERC with the duties of approving and enforcing rules to ensure the reliability of the Nation's Bulk Power System, and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to FERC approval. Section 215 of the FPA states that all users, owners and operators of the Bulk Power System in the United States will be subject to FERC-approved Reliability Standards.

b. Basis for Approval of Proposed Regional Reliability Standard

Section 39.5(a) of FERC's regulations requires the ERO to file with FERC for its approval each Reliability Standard that the ERO proposes to become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes to be made effective. FERC has the regulatory responsibility to approve standards that protect the reliability of the Bulk Power System. In discharging its responsibility to review, approve, and enforce mandatory Reliability Standards, FERC is authorized to approve those proposed Reliability Standards that meet the criteria detailed by Congress:

> FERC may approve, by rule or order, a proposed reliability standard or modification to a reliability standard if it determines that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[4]

When evaluating proposed Reliability Standards, FERC is expected to give "due weight" to the technical expertise of the ERO and to the technical expertise of a Regional Entity *organized on an Interconnection-wide basis* with respect to a Reliability Standard

---

[3] 16 U.S.C. § 824o.
[4] 16 U.S.C. § 824o(d)(2).

to be applicable within that Interconnection. Order No. 672 provides guidance on the factors FERC will consider when determining whether proposed Reliability Standards meet the statutory criteria.[5]

A Reliability Standard proposed by a Regional Entity must meet the same standards that NERC's Reliability Standards must meet, *i.e.*, the Regional Reliability Standard must be shown to be just, reasonable, not unduly discriminatory or preferential, and in the public interest.[6] If the Regional Reliability Standard is proposed by a Regional Entity *organized on an Interconnection-wide basis*, to be applicable on an Interconnection-wide basis, then NERC (but not FERC) must rebuttably presume that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[7] In the case of the standard proposed in this filing, the rebuttable presumption does not apply because, although RFC is a Regional Entity, it is *not* organized on an Interconnection-wide basis.

FERC's Order No. 672 establishes two additional criteria that a Regional Reliability Standard must satisfy: A regional difference from a continent-wide Reliability Standard must either be (1) more stringent than the continent-wide Reliability Standard (which includes a regional standard that addresses matters that the continent-wide Reliability Standard does not), or (2) a Regional Reliability Standard that is necessitated by a physical difference in the bulk power system.[8]

---

[5] *See Rules Concerning Certification of the Electric Reliability Organization; Procedures for the Establishment, Approval and Enforcement of Electric Reliability Standards, FERC Stats. & Regs.*, ¶ 31,204 at PP 320-338 ("Order No. 672"), *order on reh'g*, FERC Stats. & Regs. ¶ 31,212 (2006) ("Order No. 672-A").

[6] Section 215(d)(2) of the FPA and 18 C.F.R. §39.5(a).

[7] *See* Section 215(d)(3) of the FPA and 18 C.F.R. §39.5(b).

[8] Order No. 672 at P 291.

c. Progress in Improving Reliability Standards

NERC continues to develop new and revised Reliability Standards that address the issues NERC identified in its initial filing of proposed Reliability Standards in April 2006, the concerns noted in FERC Staff Report issued on May 11, 2006, and the directives FERC has included in several subsequent orders pertaining to NERC's Reliability Standards at the continent-wide and regional entity level. NERC has incorporated these activities into its *Reliability Standards Development Plan: 2009-2011* that was submitted to FERC on February 3, 2009 and in its *Reliability Standards Development Plan: 2010-2012* that was submitted to FERC on December 2, 2009.

RFC is not an "interconnection-wide" Regional Entity, and its standards are intended to apply only to that part of the Eastern Interconnection within the RFC geographical footprint. As discussed in the *ReliabilityFirst Standard Development Procedure,*[9] RFC's standards are developed according to the following principles:

- developed in a fair and open process that provides an opportunity for all interested parties to participate;
- does not have an adverse impact on commerce that is not necessary for reliability;
- provides a level of BPS reliability that is adequate to protect public health, safety, welfare, and national security and would not have a significant adverse impact on reliability; and
- based on a justifiable difference between Regions or between sub-regions within the Regional Entity geographic area.

The *ReliabilityFirst Standard Development Procedure* is consistent with the NERC *Reliability Standards Development Procedure.*[10] Proposed RFC standards are subject to approval by NERC, as the ERO, and by FERC before becoming mandatory and

[9] The *Reliability First Standard Development Procedure* is available at http://www.rfirst.org/Documents/Standards/Reliability%20Standards%20Developmental%20Procedure.pdf.
[10] The NERC *Reliability Standards Development Procedure* is available at: http://www.nerc.com/files/Appendix3A_StandardsDevelopmentProcess.pdf.

enforceable under Section 215 of the FPA. The RFC Regional Reliability Standard was developed in an open, transparent, inclusive fashion. During drafting of the standard, workshops were conducted jointly with other Regions and RFC Regional Transmission Organization members and state regulators. The proposed standard is widely supported by the RFC ballot body and regulatory agencies that see this as a meaningful and necessary step forward in solving a longstanding problem. The standard was reviewed by RFC legal counsel for consistency with the provisions and stated goals of the Energy Policy Act of 2005. RFC counsel concluded that the proposed standard is consistent with the Act because it does not require the building or acquisition of new generating capacity. As a condition of RFC membership, all RFC Members[11] agree to adhere to the NERC Reliability Standards in addition to the RFC Standards. NERC Reliability Standards and the RFC Standards are both included within the RFC Compliance Program.

As noted, RFC is a Regional Entity, but is not organized on an Interconnection-wide basis. Therefore, NERC does not rebuttably presume the proposed standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. The proposed Regional Reliability Standard was developed using the *ReliabilityFirst Standards Development Procedure* that enabled all those with an interest in the standard to participate in its development. NERC's public posting of this proposed Regional Reliability Standard did not elicit any significant technical objection. NERC determined that the proposed standard meets the criteria for consideration and approval as a Regional Reliability Standard.

[11] As defined in the RFC Corporation By-laws.

IV. JUSTIFICATION FOR APPROVAL OF PROPOSED REGIONAL RELIABILITY STANDARD

This section summarizes the development of the proposed Regional Reliability Standard BAL-502-RFC-02 — Planning Resource Adequacy Analysis, Assessment and Documentation; describes the reliability objectives to be achieved by the Regional Reliability Standard; explains the development history of the Regional Reliability Standard; and explains how the standard meets the criteria for approval set by FERC. NERC, in its analysis of the proposed Regional Reliability Standard, determined that the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

The complete development record for the proposed Regional Reliability Standard is provided in **Exhibit C** and includes the development and approval process, comments received during the industry-wide comment period NERC conducted responses to those comments, ballot information, and NERC's evaluation of the proposed standard.

a. Basis and Purpose of Standard BAL-502-RFC-02 — Planning Resource Adequacy Analysis, Assessment and Documentation

BAL-502-RFC-02 — Planning Resource Adequacy Analysis, Assessment and Documentation establishes common criteria based on the principle of "one day in ten year" loss of load expectation for the analysis, assessment and documentation of Resource Adequacy for load in the RFC footprint. The proposed standard establishes requirements for Planning Coordinators in the RFC Region regarding resource adequacy assessment, area subject matter not presently addressed in NERC's continent-wide standards, thereby satisfying the statutory criteria for approval as a regional standard.[12]

[12] NERC has a continent-wide project, Project 2009-05 – Resource Adequacy Assessments, that was created to establish a requirement for the Regions to: (1) create a metric(s) to assess resource adequacy that

The proposed Regional Reliability Standard contains two main requirements applicable to Planning Coordinators within the RFC footprint.

> **Requirement R1** The Planning Coordinators shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall:
>
> > **Requirement R1.1** Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[13] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion);
> >
> > **Requirement R1.2** Be performed or verified separately for each of the planning years as specified in Requirement R1.2.1 and Requirement R1.2.2;
> >
> > **Requirement R1.3** Include the following subject matter and documentation of its use: Requirement R1.3.1 Load Forecast characteristics, Requirement R.1.3.2 Resource characteristics, Requirement 1.3.3 Transmission limitations that prevent the delivery of generation reserves as further specified in Requirements R1.3.3.1; Requirement R1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area;
> >
> > **Requirement R1.4** Consider the following resource availability characteristics and document how and why they were included in the analysis of why they were not included, as further specified in the sub-requirement;
> >
> > **Requirement R1.5** Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included;
> >
> > **Requirement R1.6** Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis; and
> >
> > **Requirement R1.7** Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis.

---

takes into account various factors, including, but not limited to, fuel deliverability, (2) perform resource adequacy assessments, (3) make the results of the assessments available to the industry and appropriate regulatory agencies, and (4) make the assessments and associated data available to NERC for their review. This project is in the initial stages of standard development and recently finalized the Standard Authorization Request (SAR). This project is targeted for completion by third quarter 2011.

[13] The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

> **Requirement R2** The Planning Coordinators shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area indentified in the Resource Adequacy analysis in accordance with the documentation specifications contained in Requirements R2.1 through R2.3.

RFC requests that BAL-502-RFC-01 be approved on the basis that mandatory and enforceable requirements for Resource Adequacy assessments do not currently exist in NERC's continent-wide standards.

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

1. Proposed reliability standards must be designed to achieve a specified reliability goal

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

The purpose of the proposed Regional Reliability Standard is to establish common criteria, based on "one day in ten year" loss of load expectation principles, for the analysis, assessment and documentation of Resource Adequacy in the RFC Region. The proposed standard does not require the building or acquisition of new generating capacity. The proposed standard contains assessment requirements to determine generating capacity needs to ensure a reliable electric supply to customer loads in the event that some generating capacity is forced out of service due to equipment failure, taken out of service for maintenance or a combination of both. In addition, the studies need to consider the deliverability of generating capacity based on location and the probability of the aggregated customer demand being greater than expected. Experience has demonstrated that correlating generating capacity and customer load in a "loss of load" methodology with a target of "one day in 10 year" criterion has provided adequate generating capacity in real time operation (at some times in conjunction with operating measures such as voltage reduction and exercising interruptibles) to supply all customer firm loads, even under extreme conditions.

Requirement R1 requires the Planning Coordinator to annually perform and document a Resource Adequacy analysis. The various sub-requirements of Requirement R1 (R1.1 to R1.7) provide specific details on what is to be included in the system assessment and how to determine the appropriate planning reserve margin to meet the planning reserve criteria.

Requirement R2 establishes a requirement to document and publicly post the projected Load and resource capability that demonstrates over a ten-year period the sufficiency of the planning reserves for each area or transmission constrained sub-area identified in the Resource Adequacy analysis.

2. Proposed reliability standards must contain a technically sound method to achieve the goal.

> Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and

> engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

The one day in ten year loss of load probability approach defined in the proposed standard has been in practice for many years. The proposed standard requires that Planning Coordinators document how a variety of characteristics that are traditionally difficult to estimate were considered in the analysis. This includes items such as availability and deliverability of fuel, impacts of extreme weather and drought conditions affecting unit availability. Sub-requirements R1.3.1 through 1.3.4 are particularly important because they require documentation of use of items such as load forecast characteristics including load diversity, load forecast uncertainty and resource characteristics such as historic resource performance and any projected changes, modeling assumptions of intermittent and energy limits resources, and transmission limitations.

3. Proposed reliability standards must be applicable to users, owners, and operators of the bulk power system, and not others.

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

The proposed Regional Reliability Standard is applicable to Planning Coordinators in the RFC footprint.

4. Proposed reliability standards must be clear and unambiguous as to what is required and who is required to comply.

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

The proposed Regional Reliability Standard contains two main requirements applicable to Planning Coordinators within the RFC footprint. Requirement R1 requires the Planning Coordinator to annually perform and document a Resource Adequacy analysis. Sub-requirements R1.1 through R1.7 establish specific items that must be considered and documented in the analysis that is performed by the Planning Coordinator. Requirement R2 requires the Planning Coordinator to annually document the projected load and resource capability, for each area or transmission constrained sub-area identified in the Resource Adequacy analysis. Sub-requirements R2.1 through R2.3 establish the documentation specifics: the documentation must cover the timeframe Year One through year ten (R2.1); the documentation must include the planning reserve margin calculated per subrequirement R1.1 for each of the three years in the analysis (R2.2); and the documentation as specified per requirement R2.1 and R2.2 must be publicly posted no later than 30 calendar days prior to the beginning of Year One (R2.3).

5. Proposed reliability standards must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation

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

The proposed Regional Reliability Standard includes a Violation Risk Factor ("VRF") for each main requirement. In addition, the Regional Reliability Standard contains a description of Violation Severity Levels ("VSLs") that address each requirement which has a VRF. The ranges of penalties for violations will be based on the applicable VRF and VSLs and will be administered based on the sanctions table and supporting penalty determination process described in the FERC-approved NERC Sanction Guidelines, located as Appendix 4B in NERC's Rules of Procedure.

RFC developed the VSLs and VRFs proposed for assignment to BAL-RFC-502-02 following applicable NERC and FERC guidance. Requirement R1 requires the Planning Coordinator to perform and document a Resource Adequacy analysis, and the sub requirements detail what is required to be a valid analysis. The VRF is set to "Medium" which is consistent with the definition as follows: "A Medium Risk Factor requirement (a) is a requirement that, if violated, could directly affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures; or (b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system, but is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk power system instability, separation, or cascading failures, nor to hinder restoration to a normal condition." As Part b of the definition states, this requirement is in a planning time frame and if violated could affect the capability of the Bulk Power System.

Requirement R2 requires the Planning Coordinator to annually document the projected Load and resource capability for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis. The VRF is set to "Lower" which is consistent with the definition since it is a documentation requirement and considered administrative as the definition describes: “A Lower Risk Factor requirement is administrative in nature and (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system; or (b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system.”

6. Proposed reliability standards must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner.

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

Both requirements in the proposed Regional Reliability Standard are supported by a measure that clearly identifies what is required and how the requirement will be enforced. The two measures will ensure that the requirements are clearly administered for enforcement in a consistent manner and without prejudice to any party. The measures are included in Section C of the proposed Regional Reliability Standard.

Additionally, in order to aid in the compliance monitoring processes, RFC may elect to develop a Reliability Standard Audit Worksheet (“RSAW”) for this proposed Regional Reliability Standard if it includes the Regional Reliability Standard, once approved, in the list of actively monitored Regional Reliability Standards for a particular program year. The RSAWs are intended to assist an applicable entity’s understanding regarding what it is expected to provide during an audit to demonstrate compliance with the Reliability Standard.

7. Proposed reliability standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost.

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

The proposed Regional Reliability Standard helps the industry achieve the stated reliability goal effectively and efficiently by providing a common framework for Resource Adequacy analysis, assessment, and documentation. The proposed Regional Reliability Standard requires the Planning Coordinators to calculate a planning reserve margin that will result in the sum of the probabilities for loss of load for the integrated peak hour for all days of each planning year analyzed being equal to 0.1. This is comparable to a "one day in 10 year" criterion.

8. Proposed reliability standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect bulk power system reliability.

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

This proposed Regional Reliability Standard does not reflect a "lowest common denominator" approach. The standard requires Planning Coordinators within RFC to perform and document a Resource Adequacy analysis annually and to document the projected load and resource capability, for each area or transmission constrained sub-area identified in the Resource Adequacy analysis, to ensure reliability of the Bulk Power System. This proposed Regional Reliability Standard advances system reliability from the current state in which there is no mandated Resource Adequacy analysis framework or analysis against a common structure.

In developing this proposed Regional Reliability Standard, RFC conducted one category ballot as required by the *ReliabilityFirst Reliability Standards Development Procedure*. This single ballot was successful in achieving the necessary quorum of a simple majority of individuals who have joined the ballot pool, and a simple majority of affirmative category votes to demonstrate industry consensus. In this regard, the Regional Reliability Standard as proposed was not balloted previously with a more stringent set of requirements that failed to achieve the required quorum and consensus. Further, the standard drafting team prepared three successive drafts of the proposed Regional Reliability Standard, two that were published for industry comment, and the final version that was balloted.

9. Proposed reliability standards may consider costs to implement for smaller entities but not at consequence of less than excellence in operating system reliability.

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

Cost is not considered in this proposed Regional Reliability Standard as all RFC Planning Coordinators are responsible for compliance with the Reliability Standards. Furthermore, the analysis contained in the standard was in practice prior to the establishment of the regional standard by the Planning Coordinators in the RFC region.

10. Proposed reliability standards must be designed to apply throughout North America to the maximum extent achievable with a single reliability standard while not favoring one area or approach.

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

The proposed Regional Reliability Standard is designed on a regional basis and will only apply to the RFC region. It is not intended to be applied throughout North America. The objective of the Standard Authorization Request for this proposed Regional Reliability Standard was to determine whether a standard was needed to address areas not covered by the FERC-approved Reliability Standards. Because the requirements of this standard are not addressed in an existing continent-wide Reliability Standard, the standard was developed to address the objectives of the Standard Authorization Request. It is expected that the proposed Regional Reliability Standard will serve, upon approval and implementation, to inform the continent-wide standard drafting effort currently underway.

11. Proposed reliability standards should cause no undue negative effect on competition or restriction of the grid.

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

This proposed Regional Reliability Standard requires Planning Coordinators to perform and document a Resource Adequacy analysis annually and document the projected load and resource capability, for each area or transmission constrained sub-area identified in the Resource Adequacy analysis as required by Requirements R1 and R2. This proposed Regional Reliability Standard does not adversely affect competition or cause restriction of the grid because it does not require entities to secure the needed resources as an outcome of the Planning Coordinators Resource Adequacy analysis. The enforcement mechanism for planning reserve margin *obligations* (that may utilize the Planning Coordinators Resource Adequacy analysis) is not expressly permitted by the Energy Policy Act of 2005, and it is also outside the scope of the proposed standard.

12. The implementation time for the proposed reliability standards must be reasonable.

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

The implementation plan for the proposed Regional Reliability Standard states that the standard is to become effective based on the effective date listed in the proposed standard (*i.e.* upon RFC Board of Directors approval, which took place on December 4, 2008). However, the proposed standard will not become enforceable in the RFC Region until FERC approval. RFC believes this is a reasonable time frame because the proposed Regional Reliability Standard replaces a previous RFC requirement (BAL-502-RFC-01 — Resource Planning Reserve Requirements) that, although not approved by FERC and therefore not mandatory and enforceable, has been in place in the RFC Region for applicable entities. The standard proposed in this filing is proposed to become mandatory and enforceable upon approval by FERC.

13. The reliability standard development process must be open and fair.

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

RFC develops Regional Reliability Standards in accordance with Exhibit C (*Regional Standard Development Procedure*) of its Regional Delegation Agreement with NERC. The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk Power System. RFC considers the comments of all stakeholders and a vote of stakeholders and the RFC Board of Directors are both required to approve a Regional Reliability Standard for submission to NERC and FERC.

The proposed Regional Reliability Standard has been developed and approved by industry stakeholders using RFC's *Reliability Standards Development Procedure,* and was approved by the RFC Board of Directors on December 4, 2008, and subsequently presented for approval by NERC before filing with FERC. Therefore, RFC has utilized its standard development process in good faith and in a manner that is open and fair. No commenters disagreed with the open and fair implementation of the RFC process.

14. Proposed reliability standards must balance with other vital public interests.

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

Neither NERC nor RFC believes there are competing public interests with the request for approval of this proposed Regional Reliability Standard. No comments were received that indicated the proposed standard conflicts with other vital public interests.

15. Proposed reliability standards must consider any other relevant factors.

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

All comments and concerns were addressed using the *ReliabilityFirst Standards Development Procedure* which is consensus-based, technically sound, and open to the public and bordering entities that may be impacted by a regional reliability standard. No other factors were identified as necessary for consideration by the standard drafting team in the development of the proposed regional standard.

V. SUMMARY OF THE REGIONAL RELIABILITY STANDARD DEVELOPMENT PROCEEDINGS

a. Development History

RFC submitted a request to NERC for posting of a Regional Reliability Standard as the first step in the process to obtain NERC approval. RFC proposed the standard because the subject is not presently addressed by any continent-wide NERC Reliability Standard, thereby meeting the FERC criteria for approval of a Regional Reliability Standard according to Order No. 672. NERC posted the Regional Reliability Standard, in accordance with the NERC Rules of Procedure, for a 45-day public comment period from January 26, 2009 to March 12, 2009. As permitted in the NERC Rules of Procedure, RFC elected to submit its request for NERC to approve the Regional Reliability Standard, BAL-502-RFC-02 — Planning Resource Adequacy Analysis, Assessment and Documentation on February 24, 2009, prior to the closing of the required NERC 45-day posting. Upon completion of the comment period, NERC submitted the comments to RFC for review on March 16, 2009. RFC submitted its response to NERC's comments to NERC on March 17, 2009, and RFC's response was subsequently posted on the NERC website.

The majority of the commenters supported adoption of the Regional Reliability Standard. However, one commenter expressed concern that the proposed standard was not developed in coordination with the NERC Reliability Standard MOD-004-1 — Capacity Benefit Margin. Specifically, the commenter indicated that the proposed Regional Reliability Standard should include a requirement to determine import generation capability that represents the MW value of import required for an entity to meet Loss of Load Expectation ("LOLE") requirements. The entity asked that the standard be amended to include a requirement for this calculation that is required to meet the requirements of MOD-004-1. In its response to the comment, RFC stated that the proposed Regional Reliability Standard is not in conflict with the MOD-004-1 standard and that dependency on transmission to meet the LOLE requirements is addressed in other reliability standards. Further, the response indicated that the standard allows the flexibility to adopt any future transmission assessment framework.

NERC Evaluation: On February 24, 2009 RFC submitted the proposed Regional Reliability Standard for evaluation and approval to NERC. In accordance with NERC's *Rules of Procedure* and *Regional Reliability Standards Evaluation Procedure* that was approved by the Regional Reliability Standards Working Group, NERC provided its evaluation of the proposed BAL-502-RFC-02 standard to RFC on April 17, 2009, included in **Exhibit C**, after the NERC 45-day posting had concluded. In this report, NERC expressed several concerns regarding the proposed Regional Reliability Standard. These concerns are summarized as follows:

- **Missing Time Horizons —** The RFC Regional Reliability Standard does not include Time Horizons for each of the standard's main requirements. Time Horizons are used for compliance assessments as described in the NERC Sanctions Guidelines.

- **Effective Date —** The proposed Regional Reliability Standard states that the effective date is upon RFC Board approval (approved on December 4, 2008). The effective date should follow the latest language found in the standards template to meet the needs of the compliance program – that is, the first day of the first quarter after regulatory approval.

- **Complex Sub-requirements —** The proposed Regional Reliability Standard contains multiple layers of sub-requirements. It is unclear whether this is absolutely necessary or whether the requirements could be written more concisely for ease of use by the entities expected to comply with the requirements.

- **New Defined Terms —** The proposed Regional Reliability Standard is also proposing four defined terms. While these terms do not appear in the NERC Glossary of Terms and do not conflict with existing terms; it is noted that the use of terms such as "Year One" represent commonly used terms. FERC has previously[14] stated:

  > *…the Commission believes NERC, as a rule, should develop definitions that apply uniformly across the different interconnections. As a general goal, NERC should work to minimize the use of regional definitions and terminology and, assure that proposed regional definitions and terminology are as well defined as, do not conflict and are not redundant with nor redefine, NERC glossary definitions.*[15]

The proposed definitions, while applicable to entities within RFC only, may have the unintended consequence of adding confusion to users of the continent-wide NERC Reliability Standards or other Regional Entity standards that may also use these terms, albeit without having formally established definitions for them. In Order 723,[16] FERC directed NERC to develop a methodology for organizing and managing Regional

---

[14] *Western Electricity Coordinating Council Regional Reliability Standard Regarding Automatic Time Error Correction*, 127 FERC ¶ 61,176 (2009). *See* Paragraph 39:
As a general goal, NERC should work to minimize the use of regional definitions and terminology and, assure that proposed regional definitions and terminology are as well defined as, do not conflict and are not redundant with nor redefine, NERC glossary definitions. We therefore direct NERC to develop in its Rules of Procedure, a methodology for organizing and managing regional definitions and terminology consistent with the principles discussed above.
[15] *Id.*
[16] *Id.*

definitions. NERC will publish the definitions upon approval in a distinct section of the NERC Glossary of Terms noting their limited applicability to entities within *RFC.*

- **Compliance Elements —** The proposed Regional Reliability Standard contains both VRFs and VSLs. These elements are assigned to the main requirements (R1 and R2); however, the main requirements contain many sub-requirements. Consistent with NERC's August 10, 2009 Informational Filing Regarding the Assignment of VRFs and VSLs, compliance elements for this standard are assigned at the main requirement level

- **Technical Recommendations —** NERC made suggestions to improve the technical clarity of the requirements, and in particular, suggested how entities within RFC that have load and resources outside the RFC footprint account for these resources in their analysis be clarified.

On June 8, 2009 RFC submitted a response to NERC's evaluation contained in Exhibit C to this filing. RFC addressed each of NERC's concerns and recommendations:

- In response to the comments on the missing Time Horizons, RFC indicated that the existing FERC-approved *RFC Reliability Standards Development Procedure* does not include Time Horizons in the standard template, and that including them in the Regional Reliability Standard would have been a deviation. RFC contends that since the standard is focused on a "planning oriented" subject matter for one year and beyond, the appropriate time horizons are relatively straightforward.

- In response to the suggestion that the effective date should follow the streamlined language, RFC indicated that the proposed standard effective date would only be applicable to RFC members on approval by the RFC Board, and the enforcement mechanism would be as a “Term of Membership” under the RFC By-Laws with no financial penalties. Only after both NERC and FERC approval will the standard become mandatory and enforceable upon all applicable entities within the RFC footprint with the possibility of financial penalties. In addition, RFC indicated that because the requirements in the standard are currently in practice, additional implementation time is not necessary.
- In response to NERC’s comments regarding the complexity of the standard requirements, RFC replied that the extent of the organizational structure of requirements is a function of the depth and breadth of the standard target audience. This Regional Reliability Standard will be applicable to a limited number of entities, all of which were represented on the standard drafting team. RFC indicated it believes the multiple layers of sub-requirements are needed to clarify the expectations of the standard, support the standard’s objective, and enable comprehension by the entities that will use it.

- In response to NERC's concerns regarding the proliferation of regional definitions that are general in nature, RFC expressed the belief that these terms are necessary to support the proposed Regional Reliability Standard and offer a good starting point for the development of continent wide definitions. To address its concern regarding unnecessary proliferation of regional definitions, NERC will review these terms through the continent wide development process, with the goal of creating definitions applicable to all users, owners, and operators of the bulk power system. If the terms are approved, RFC will need to assess the impact on its regional standard.
- Regarding the comments on the compliance elements, RFC indicated that this standard was developed under the framework available to drafting teams at the time. In September 2009, RFC reviewed the VSLs for consistency with FERC VSL Guidelines enunciated in the June 2008 Violation Severity Level Order. The results of that review are presented in **Exhibit C** of this filing.
- In response to the technical recommendations and questions NERC provided, RFC clarified the intent of the requirements. RFC also, however, stated that the requirements will remain as approved by the RFC Board of Trustees. Additionally, on July 10, 2009 RFC submitted supporting documentation, included in **Exhibit C** of this filing, that addresses the need for this Regional Reliability Standard.

<u>Violation Risk Factors and Violation Severity Levels</u>

The proposed Regional Reliability Standard contains both VRFs and VSLs. The VRFs and VSLs are assigned to the main requirements (R1 and R2).

Violation Risk Factors

The VRFs for the proposed BAL-502-RFC-02 Regional Reliability Standard are based on the NERC VRF classifications contained in the NERC *Reliability Standards Development Procedure*. Notably, there are currently no approved FERC, NERC, or Regional Reliability Standards dealing with Resource Adequacy against which to compare the VRFs for this standard (for consistency). However, comparing the proposed standard with the Transmission Planning ("TPL") standards demonstrates that the VRF assignments are consistent. For example, TPL-001-1 — System Performance Under Normal (No Contingency) Conditions (Category A) Requirement R2 requires each Transmission Planner and Planning Authority prepare an annual Planning Assessment of its portion of the Bulk Power System. This requirement, while not redundant in content, is similar to Requirement R1 in BAL-502-RFC-02 as it requires a planning entity to perform an annual assessment for its area. Both requirements propose a "Medium" VRF as they are both within the planning time frame and if violated could impact the capability of the Bulk Power System.

BAL-502-RFC-02 Requirement R1 requires the Planning Coordinator to perform and document a Resource Adequacy analysis, and the sub requirements detail what is required to be a valid analysis. The Requirement R1 VRF is set to "Medium" based on Part b of the definition of a "Medium" VRF since this requirement is in the planning time frame and could, if violated, directly affect the capability of the Bulk Power System. The VRF guidelines provide:

> *A Medium Risk Factor requirement (a) is a requirement that, if violated, could directly affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system, but is unlikely to lead to bulk power system instability, separation,*

> *or cascading failures; or (b) is a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system, but is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk power system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.*

Considering that Requirement R1 is more than administrative in nature (VRF guideline for a "Lower" assignment) and that a violation of Requirement R1 could under emergency, abnormal, or restorative conditions anticipated by the preparations, directly affect the electrical capability of the Bulk Power System, a VRF of "Medium" is an appropriate assignment for Requirement R1. BAL-502-RFC-02 Requirement R2 is administrative in nature and requires the Planning Coordinator to annually document the projected load and resource capability for each area or transmission constrained sub-area. The VRF assigned is "Lower," which is consistent with the definition as follows:

> *A Lower Risk Factor requirement is administrative in nature and (a) is a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system; or (b) is a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system.*

Violation Severity Levels

The VSLs assigned to the requirements of this standard were developed and reviewed for consistency with NERC and FERC guidelines. **Exhibit E** of this filing presents the analysis of the VSLs following the FERC guidelines initially set out in the

VSL Order.[17] A description of the VSL assignments for the proposed requirements in BAL-502-RFC-02 follows below.

Requirement R1 Violation Severity Level Assignments

The "Lower" VSL for Requirement R1 includes failure to comply with Requirement R1.4 and Requirement R1.5. These sub-requirements require that the Planning Coordinators consider both resource availability characteristics (R1.4) and transmission characteristics (R1.5). Since the requirements simply require consideration of these characteristics, these sub-requirements are appropriately assigned a "Lower" VSL. Further, if an entity did not include consideration of these characteristics in the Resource Adequacy analysis, it would not significantly affect the intended outcome of Requirement R1.

The "Medium" VSL for Requirement R1 includes:

- Failure to express the planning reserve margin (in Requirement R1.1) as a percentage of the net median forecast peak Load according to Requirement R1.1.2 because while the entity performed the analysis they did not perform this step that ensures consistency; or
- Failure to include one of the Load forecast characteristics subcomponents under Requirement R1.3.1; or
- Failure to include one of the resource characteristics subcomponents under Requirement R1.3.2. Requirement R1.3.2 contains a list of six resource characteristics and if one is not considered it will only moderately affect the intended outcome of Requirement R1; or
- Failure to document that all the Load in the Planning Coordinator area is accounted for in the Resource Adequacy analysis according to Requirement R1.7. Failure to do so is considered of equal severity to failure to consider one resource characteristic or load forecast characteristic.

The "High" VSL for Requirement R1 includes:

[17] *Order on Violation Severity Levels Proposed by the Electric Reliability Organization*, 123 FERC ¶ 61,284 (2008).

- Failure to perform or verify the Resource Adequacy analysis separately for individual years of Year One through year ten according to Requirement R1.2; or
- Failure to perform an analysis or verification for one year in the two through five year period or one year in the six through ten year period or both according to Requirement R1.2.2. Since the analysis for Year One is very important violation of performing the analysis for Year One is considered a High VSL; or
- Failure to include two or more of the Load forecast characteristic subcomponents according to Requirement R1.3.1; or
- Failure to include two or more of the Resource characteristics subcomponents according to Requirement R1.3.2; or
- Failure to include Transmission limitations and documentation of its use in the analysis according to Requirement R1.3.3; or
- Failure to include assistance from other interconnected systems and documentation of its use according to Requirement R1.3.4 in the analysis; or
- Failure to consider three or more resource availability characteristic subcomponents in Requirement R1.4; or
- Failure to document that capacity resources are appropriately accounted for in the Resource Adequacy analysis according to Requirement R1.6. The consequence of non-compliance is potential gaps in the accounting of planning reserves.

The “Severe” VSL for Requirement R1 includes:

- Failure to annually perform and document a Resource Adequacy analysis according to Requirement R1; or
- Failure to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for each planning period being equal to 0.1 according to Requirement R1.1. The consequence of non-compliance is inconsistent analysis results as the entities implemented various methods am making the analysis invalid; or
- Failure to perform an analysis for Year One according to R1.2.1. This would result in not having a Planning Reserve set up for the upcoming planning year.

The VSLs for Requirement R1 considers all sub-requirements and assigns them to the appropriate levels.

Requirement R2 Violation Severity Level Assignments

The "Lower" VSL for Requirement R2 includes failure to publicly post the documents (described in Requirement R2.1 and Requirement R2.2) more than 30 calendar days prior to the beginning of Year One according to Requirement R2.3. The "Lower" VSL assignment was based on the determination that, while the intent of Requirement R2 was met, the results were not publicly communicated as described in Requirement R2.3.

The "Medium" VSL for Requirement R2 includes the failure to document the projected load and resource capability for each area or transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the two through ten year period according to Requirement R2.1, or failure to document the Planning Reserve margin calculated for each of the three years in the analysis according to Requirement R2.2.

The "High" VSL for Requirement R2 includes the failure to document the projected load and resource capability for each area or transmission constrained sub-area identified in the Resource Adequacy analysis for Year One of the ten year period according to Requirement R2.1, or failure to document the projected load and resource capability for each area or transmission constrained sub-area indentified in the Resource Adequacy analysis for two or more of the years in the two through ten year period according to Requirement R2.1.

The "Severe" VSL for Requirement R2 includes the failure to document the project load and resource capability for each area or transmission constrained sub-area identified in the Resource Adequacy analysis according to Requirement R2.

VI. CONCLUSION

NERC agrees that the proposed RFC Regional Reliability Standard addresses matters not currently covered in the continent-wide NERC Reliability Standards. NERC further believes, on the basis of its review and evaluation, that the proposed Regional Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest. Therefore, NERC requests that FERC approve the proposed Regional Reliability Standard BAL-502-RFC-02 — Planning Resource Adequacy Analysis, Assessment and Documentation and related definitions. The reliability of the Bulk Power System is best served by the implementation of this proposed Regional Reliability Standard by establishing a consistent framework for planning resource analysis for load within the RFC footprint. Because this action supports the improved reliability of the Bulk Power System, NERC staff recommends FERC approval of the proposed Regional Reliability Standard.

Respectfully submitted,

/s/ Holly A. Hawkins

David N. Cook
Vice President and General Counsel
North American Electric Reliability Corporation
116-390 Village Boulevard
Princeton, NJ 08540-5721
(609) 452-8060
(609) 452-9550 – facsimile
david.cook@nerc.net

Rebecca J. Michael
Assistant General Counsel
Holly A. Hawkins
Attorney
North American Electric Reliability Corporation
1120 G Street, N.W.
Suite 990
Washington, D.C. 20005-3801
(202) 393-3998
(202) 393-3955 – facsimile
rebecca.michael@nerc.net
holly.hawkins.@nerc.net

<u>CERTIFICATE OF SERVICE</u>

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

Dated at Washington, D.C. this 14th day of December, 2009.

/s/ Holly A. Hawkins
Holly A. Hawkins
Attorney for North American Electric Reliability Corporation

Exhibit A

BAL-502-RFC-02 — Planning Resource Adequacy Analysis, Assessment and Documentation Regional Reliability Standard Proposed for Approval

A. Introduction

1. Title: **Planning Resource Adequacy Analysis, Assessment and Documentation**

2. Number: **BAL-502-RFC-02**

3. Purpose:

To establish common criteria, based on "one day in ten year" loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the Reliability*First* Corporation (RFC) region

4. Applicability

4.1 Planning Coordinator

5. Effective Date:

5.1 Upon RFC Board approval

B. Requirements

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall *[Violation Risk Factor: Medium]*:

R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.

R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).

R1.2 Be performed or verified separately for each of the following planning years:

---

[1] The annual period over which the LOLE is measured, and the resulting resource requirements are established (June 1st through the following May 31st).

[2] The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50).

R1.2.1 Perform an analysis for Year One.

R1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.

R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

R1.3 Include the following subject matter and documentation of its use:

R1.3.1 Load forecast characteristics:

- Median (50:50) forecast peak Load.
- Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).
- Load diversity.
- Seasonal Load variations.
- Daily demand modeling assumptions (firm, interruptible).
- Contractual arrangements concerning curtailable/Interruptible Demand.

R1.3.2 Resource characteristics:

- Historic resource performance and any projected changes
- Seasonal resource ratings
- Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.
- Resource planned outage schedules, deratings, and retirements.
- Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.
- Criteria for including planned resource additions in the analysis

R1.3.3 Transmission limitations that prevent the delivery of generation reserves

R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis

R1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.

R1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

- Availability and deliverability of fuel.
- Common mode outages that affect resource availability
- Environmental or regulatory restrictions of resource availability.
- Any other demand (Load) response programs not included in R1.3.1.
- Sensitivity to resource outage rates.
- Impacts of extreme weather/drought conditions that affect unit availability.
- Modeling assumptions for emergency operation procedures used to make reserves available.
- Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

R1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included

R1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

R1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis

R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis *[Violation Risk Factor: Lower]*.

R2.1 This documentation shall cover each of the years in Year One through ten.

R2.2 This documentation shall include the planning reserve margin calculated per requirement R1.1 for each of the three years in the analysis.

R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

C. Measures

M1 Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1

M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor - Reliability*First* Corporation

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year

1.3. Data Retention

The Planning Coordinator shall retain information from the most current and prior two years.

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

2. Violation Severity Levels

Req. Number	VIOLATION SEVERITY LEVEL			
	LOWER	MODERATE	HIGH	SEVERE
R1	The Planning Coordinator Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under R1.4 and documentation of how and why they were included in the analysis or why they	The Planning Coordinator Resource Adequacy analysis failed to express the planning reserve margin developed from R1.1 as a percentage of the net Median forecast peak Load per R1.1.2 **OR**	The Planning Coordinator Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per R1.2 **OR**	The Planning Coordinator failed to perform and document a Resource Adequacy analysis annually per R1. **OR** The Planning Coordinator Resource

	were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per R1.5	The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under R1.3.1 and documentation of its use **OR** The Planning Coordinator Resource Adequacy analysis failed to include 1 of the Resource Characteristics subcomponents under R1.3.2 and documentation of its use **Or** The Planning Coordinator Resource Adequacy analysis failed to document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis per R1.7	The Planning Coordinator failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 though 10 year period or both per R1.2.2 **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Load forecast Characteristics subcomponents under R1.3.1 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under R1.3.2 and documentation of their use **OR** The Planning Coordinator Resource Adequacy analysis failed to include Transmission limitations and documentation of its use	Adequacy analysis failed to calculate a Planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year analyzed for each planning period being equal to 0.1 per R1.1 **OR** The Planning Coordinator failed to perform an analysis for Year One per R1.2.1

			per R1.3.3 **OR** The Planning Coordinator Resource Adequacy analysis failed to include assistance from other interconnected systems and documentation of its use per R1.3.4 **OR** The Planning Coordinator Resource Adequacy analysis failed to consider 3 or more Resource availability characteristics subcomponents under R1.4 and documentation of how and why they were included in the analysis or why they were not included **OR** The Planning Coordinator Resource Adequacy analysis failed to document that capacity resources are appropriately accounted for in its Resource Adequacy analysis per R1.6	
R2	The Planning Coordinator failed to publicly post the documents as specified	The Planning Coordinator failed to document the projected Load and resource	The Planning Coordinator failed to document the projected Load and resource	The Planning Coordinator failed to document the projected Load and resource

	per requirement R2.1 and R2.2 later than 30 calendar days prior to the beginning of Year One per R2.3	capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for one of the years in the 2 through 10 year period per R2.1. **OR** The Planning Coordinator failed to document the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis per R2.2.	capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for year 1 of the 10 year period per R2.1. **OR** The Planning Coordinator failed to document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis for two or more of the years in the 2 through 10 year period per R2.1.	capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis per R2.

Definitions:

Resource Adequacy - the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses).

Net Internal Demand - Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Load Management and Interruptible Demand.

Peak Period - A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur

Year One - The planning year that begins with the upcoming annual Peak Period.

The following definitions were extracted from the February 12th, 2008 NERC Glossary of Terms:

Direct Control Load Management – Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.

Facility - A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)

Interruptible Demand - Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.

Load - An end-use device or customer that receives power from the electric system.

Transmission - An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Version History

Version	Date	Action	Change Tracking
BAL-502-RFC-02 1st Draft	06/24/08 Through 07/23/08	Posted for 1st Comment Period	
BAL-502-RFC-02 2nd Draft	08/18/08 Through 09/16/08	Posted for 2nd Comment Period	
BAL-502-RFC-02 3rd Draft	10/16/08 Through 10/30/08	Posted for 15-Day Category Ballot	
BAL-502-RFC-02 3rd Draft	12/04/08	Reliability*First* Board Approved	
BAL-502-RFC-02	06/08/09	"Planning Reserve" changed to "planning reserve" in R2.2.	Errata

Exhibit B

The NERC Board of Trustees' Resolution on the BAL-502-RFC-02 — Planning Resource Adequacy Analysis, Assessment and Documentation Regional Reliability Standard

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Resolution of the NERC Board of Trustees

August 5, 2009
The Delta Winnipeg
350 St Mary Avenue
Winnipeg, MB R3C 3J2, Canada

RESOLVED, that the North American Electric Reliability Corporation Board of Trustees approves the following proposed Regional Reliability Standards developed by Reliability*First*:

BAL-502-RFC-01 — Planning Resource Adequacy Analysis, Assessment and Documentation to be effective within RFC and four definitions to be added to the NERC Glossary of Terms, to be effective only within RFC, as follows:

- Resource Adequacy
- Net Internal Demand
- Peak Period
- Year One

116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com

Exhibit C

Record of Development of Proposed BAL-502-RFC-02 Planning Resource Adequacy Analysis, Assessment and Documentation Reliability Standard

Planning Resource Adequacy Analysis, Assessment and Documentation

Question 1	Do you agree with the Requirements of this proposed standard? If no, provide specific suggestions that would make the requirements acceptable to you.

Answers	Frequency
Yes	0
No	12 (12 with comments)
Abstain	3 (1 with comments)

ID	Commenter	Answer	Comment	Response
2318	HARVIE BEAVERS - PINEY CREEK LP/COLMAC	Abstain	Based on review of standard, other comments, and the implementation plan, it is unclear that a specific 'new' standard that differs from BAL-502-RFC-1 is required. If 'agreement' exists that 'honors' existing methods of resource analysis, adequacy, assessment, and documentation exist, and BAL-502-RFC-1 was 'approved' with those recognized, the only update would be addition of the severity levels. If no such agreement exists, then this standard appears to be needed, but needs some administrative correction so that the acronyms are identified similer to how Reliability First Corporation (RFC) is in the purpose section. After that the acronyms are sufficient.	The purpose of the revision is stated in the SAR and includes the following modifications: • Limit enforcement to reserve requirement analysis and assignment (remove Req. to secure resources) • Addition of significant improvements from RFC experience & MRO development • Modifications to conform to current RFC Standards Procedure, such as Violation Risk Factors, Violation Severity Levels, etc. These changes were approved by the RFC Board and RFC Standards Committee.
2299	Jeanne Kurzynowski - Consumers Energy	No	R2.3 contains redundant Load forecast characteristics. Load forecast uncertainty is defined as containing load variability due to weather, regional economic forecasts. Recommend deleting bulleted item: R2.3.1 Load forecast characteristics: ? Median (50:50) forecast peak load. ? Load forecast uncertainty. ? Load diversity. ? Seasonal load variations. ? Load variability due to weather, regional economic forecasts, etc. (should be deleted) ? Daily demand modeling assumptions	R1.3.1 (R2.3.1 in 1st draft) has been modified based on your comment.

			(firm, interruptible). ? Contractual arrangements concerning curtailable/interruptible load. R2.3 requirements R2.3.3 & R2.3.4 are not aligned with the MRO standard. Page 3 of 6 from MRO standard: Standard RES-501-MRO-01 - Planned Resource Adequacy Assessment http://www.midwestreliability.org/04_standards/approved_standards/mro_standards/RES-501-MRO-01_Final_20071229_Clean.pdf R1.3 Include, at a minimum, documentation of how and why the following were/were not included in the analysis: R1.3.3 Transmission limitations that prevent the delivery of generation reserves. R1.3.3.1 Transmission maintenance outage schedules. R1.3.3.2 Transmission forced outage rates R1.3.3.3 Transmission availability for emergency considering firm commitments Draft Standard BAL-502-RFC-02 V1 R2.3.3 Transmission limitations, including the effect of firm commitments that prevent the delivery of generation reserves (should be moved to section R2.4) R2.3.4 Assistance from other interconnected systems including multi-area assessment considering transmission limitations. (should be moved to section R2.4) R2.4 Consider the following Resource availability characteristics and document how and why they were included in the analysis or why they were not included: R2.3.3 and R2.3.4 should be moved to SECTION R2.4. Another alternative would be to work with MRO and change their standard to the more restrictive RFC	The intention is to be consistent with the intent of the MRO standard but not specifically identical. The SDT took the MRO standard and enhanced it based on industry experience. The SDT believes that R1.3.3 (R2.3.3 in 1st draft) and R1.3.4 (R2.3.4 in 1st draft) must be included in the analysis. Also, in response to your comment, R1.3.3 (R2.3.3 in 1st draft) has been modified to be identical to the MRO R1.3.3.

			version. Typo in section R2.4 R2.4 Consider the following Resource availability characteristics and document how and why they were included in the analysis or why they were not included: ? Any other Demand (Load) Response Programs not included in R2.4.1. Should be: ? Any other Demand (Load) Response Programs not included in R2.3.1.	Thank you. R1.4 (R2.4 in 1st draft) has been modified based on your comment.
2300	Vincent Kaminski - Allegheny Electric Cooperative Inc.	No	The RFC standard is not necessary if the requirements are also covered in a corresponding NERC standard. Otherwise we will have duplicative reporting/standard which couls end up conflicting with each other. If it is deemed appropriate/necessary to have a RFC standard, it should be revised to clearly reflect that being a signatory to the PJM Reliability Assurance Agreement (or other similar agreement(s)) is deemed to be adequate documentation to demonstrate that the LSE has complied with the requirements of this standard. (MISO members should be able to satify the requiremets of the standard by providing the comparable MISO documentation.)	Currently, there is no corresponding NERC standard which deals with a Resource Adequacy analysis. There has been a SAR at the NERC level which has been under discussion for over three years. Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly.
2324	Thad Ness - AEP	No	The SDT has perpetuated in its draft standard the existence of the Planning Reserve Sharing Group function and pseudo-entity. This must be addressed. The PRSG is not a functional entity defined by NERC. The PRSG is assumed to be a collective set up by a group of LSEs to perform the specific functions defined in the standard, but it does not have any standing of its own for compliance purposes. The LSEs are presumed to have the ultimate responsibility for the PRSG functions. However, in general, a Load	Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly.

			Serving Entity will not have the expertise to carry out or even closely monitor the functions being delegated to the PRSG. The functions presumed to be carried out by the PRSG for the LSEs are not defined as LSE functions in NERC's functional model, either in existing version 3 or in proposed version 4. These functions belong to the Planning Coordinator under version 3 and to the Transmission Planner under version 4. Among the currently defined tasks and relationships of the Planning Coordinator are the following that are assigned to the PRSG in this standard: Ensures a plan (generally one year and beyond) is available for adequate resources within a Planning Coordinator Area. 1. Maintain and develop methodologies and tools for the analysis and development of resource adequacy plans. 2. Define information required for planning purposes, consolidate and collect or develop such information, including: b. Demand and energy forecasts, capacity resources, and demand response programs. c. Generator unit performance characteristics and capabilities. d. Long-term capacity purchases and sales. 3. Evaluate, develop, document, and report on resource - plans for the Planning Coordinator Area. Integrate the respective plans and verify that the integrated plan meets reliability standards, and, if not, report on potential - resource adequacy deficiencies and provide alternative plans to mitigate identified deficiencies. d. Monitor and evaluate - resource plan implementation. 4. Coordinate with adjoining Planning Coordinators so that system models and resource - expansion plans take into account modifications made to adjacent	

			Planning Coordinator Areas. 5. Develop and maintain - resource (demand and capacity) system models to evaluate - resource adequacy. The Planning Coordinator is responsible for assessing the longer-term reliability of its Planning Coordinator Area. 1. Coordinates and collects data for system modeling from Transmission Planner, Resource Planner, and other Planning Coordinators. 5. Collects information including: b. Demand and energy forecasts, capacity resources, and demand response programs from Load-Serving Entities, and Resource Planners. c. Generator unit performance characteristics and capabilities from Generator Owners. d. Long-term capacity purchases and sales from Transmission Service Providers. 6. Collects and reviews reports on transmission and resource plan implementation from Resource Planners and Transmission Planners. 9. Provides the coordinated plans to affected Regional Reliability Organization(s), Transmission Service Providers, Transmission Planners, Transmission Operators, and Transmission Owners. AEP recommends that the applicability of the standard to be revised to include Planning Coordinator for the appropriate functions. AEP further recommends that all references to "PRSG" be replaced with Planning Coordinator. An appropriate change will be required in the future if the functions of the Planning Coordinator are transferred to some other entity in version 4 of the functional model.	
2336	Paul Kure - ReliabilityFirst Corporation	No	Except as noted in the comments, the ReliabilityFirst Resource Assessment Subcommittee members named on the	

			group list are providing the following consensus comments on the items identified from the standard. 4. Applicability 4.1 Load Serving Entity	
			The requirement for the LSE to secure the resources needed to meet the planning reserve was removed from this standard, since it is not considered enforceable by FERC, NERC or RFC under section 215 of the Federal Power Act. The RAS questions whether the LSE is the appropriate entity for the applicability of this standard. There are other organizations that are more capable of performing the type of analyses required in this standard. Also, the PRSG is not a NERC registered entity, but a collection of LSEs grouped together for the sole purpose of satisfying the requirements of this standard. The RAS requests that the drafting team consider changing the applicability of this standard to a NERC registered entity that would be able to perform the type of analyses in this standard. (Note: This consensus comment of the RAS members above does not include Duke Energy, Midwest ISO and PJM representatives. Since this would be a material change from the original applicability of the standard, MISO and PJM wanted time to review this suggested change within their respective organizations before offering their support or opposition to this comment.)	Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly.
			R2.1 Calculate a Planning reserve margin that will result in the sum of the probabilities for loss of load for the integrated peak hour for at least all non-holiday weekdays for each planning year being equal to 0.1. (This is comparable to a 1 day in 10 year	The SDT agrees. R1.1 (R2.1 in 1st draft) has been modified based on your comment.

			criterion). The RAS believes the peak hour for all days in the planning year should be included in the analysis, but it is up to the entity performing the study to determine if days with zero loss of load probability on the peak hour need to be explicitly calculated. The RAS suggests the wording should be changed from ??integrated peak hour for at least all non-holiday weekdays for each planning year?? to ??integrated peak hour for all days of each planning year??.	
			R2.2 Be performed or verified separately for individual years of Year One through Year Ten. Year One is defined as the planning year that begins with the upcoming annual peak period. R2.2.1 Perform an analysis for Year One. R2.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period. There is some confusion with the phrase ??individual years of Year One through Year Ten.? in R2.2 and only requiring analysis or verification for one year each in the 2 through 5 year period and the 6 through 10 year period in R2.2.2. Is the annual analysis required under R2 intended to provide a reserve margin for three specific years in the study period or all ten years? The intent of the standard needs to be clarified, and other applicable references to planning years or planning reserve need to be consistent with the number of years of analysis or verification required.	R1.2 (R2.2 in 1st draft) has been modified to further clarify and address your concern.
			R2.3.3 Transmission limitations, including the effect of firm commitments that prevent the delivery of generation reserves R2.3.4 Assistance from other interconnected systems including multi-area	R1.3.3 (R2.3.3 in 1st draft) has been modified to just require Transmission limitations that prevent the delivery of generation reserves and the SDT believe this must be included in the analysis. R1.3.4 (R2.3.4 in 1st draft) has also

			assessment considering transmission limitations. As requirements under a subsection of R2.3, these items, R2.3.3 and R2.3.4, must be included in the analysis. The RAS believes inclusion of these two requirements in the analysis should be up to the discretion of the responsible entity performing the analysis. Therefore, it is more appropriate to include these items under R2.4 or R2.5 as discretionary items requiring documentation of why they were included or not included in the analysis.	been modified to further clarify transmission limitations "into the study area" and the SDT believes this must be included in the analysis as well.
2342	Eric Mortenson - Exelon	No	NO. The applicability is to the LSE (PRSG) NERC Functional Entity. The LSEs would not have access to the transmission data necessary to respond to R2.3.3 (Transmission limitations, including the effect of firm commitments that prevent delivery of generation reserves); R2.3.4 (Assistance from other interconnected systems including multi-area assessment considering transmission limitations); R2.4 (...Resource availability characteristics...);R2.5 (Transmission characteristics including transmission outage schedules); or R2.3.2 Resource characteristics. Also, the LSE may not be the best entity to determine the load forecast for the overall PRSG region. A BA or PC would be able to provide more stable forecasts coincitized over these areas. LSEs could be supplying varying loads over a 10 year period, with the ability to change responsibility on short notice. Originally the LSE would have been a more likely applicable entity when there were procurement requirements associated with this standard.	Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly
2349	Robert Mattey - Ohio Valley Electric Corp.	No	While the majority of utilities are members of larger regional entities such as MISO or	Based on industry comments and a supplemental SAR approved by the RFC

			PJM there are LSEs that are not. For those, it would seem to make sense to have a minimum load requirement (such as 200MW or less) in order for the standard to be applicable to that entity. I would also question the need for the standard at all as I would think resource adequacy would be the responsibility of the RTOs or ISOs. If the intent of the standard is to monitor if this is being done by those organizations then the need to have some type of limit on the amount of load that makes this standard applicable is even more relevant.	Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly
2355	Patrick Brown - PJM	No	No, PJM does not agree with the Requirements of this proposed standard. PJM requests the following changes: Purpose- The purpose discusses the desire to establish common criteria, based on 1 day in ten year LOLE. To be more correct, this should be one event in ten years. Description in R2 explains this sufficiently, but the purpose will read more clearly if this is stated up front. Applicability- Under the original standard, the LSE was required to provide proof that they had met the standard. The new standard simply requires the PRSG to compare ?its load and resource capability?. With the removal of the requirement to provide resources, PJM questions if it is still appropriate to hold the LSE as the sole applicable entity. PJM would request that the SDT investigate the possibility that this might now fall on more (or different) entities under the NERC Functional Model. Requirements R1 Text is awkward. Should read ?All load in the RFC footprint is included in a PRSG and each end-use customer is	The SDT further clarified the purpose by placing quotation marks around “one day in ten” to specifically indicate that this is just referring to commonly accepted terminology relative to loss of load principles. Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly R1 has been removed from the standard. A new sub-requirement R1.7 has been added to address your comment.

			included in one and only one PRSG.?	
			R1.2 Discusses the planning period, where year would be more specific. Suggested change would be to have the sentence end ?180 days prior to the first day of the planning year under review, whichever is earlier.	R1.2 has been removed from the standard.
			R2.1 Practically speaking, all of the loss of load probability occurs in the non-holiday weekdays. However, this comes as a result of the analysis that has been performed. This is not an input. Text should read ??for all days in the planning year being equal to 0.1. (This is comparable to a 1 event in 10 year criterion).	R1.1 (R2.1 in 1st draft) has been modified to address your concern.
			R2.1.1 Requirement currently requires the respondent to use Total Internal Demand. Valid analysis procedures exist that use Net Internal Demand. Text should be changed to read ?Calculation can be performed using Total Internal Demand, or Net Internal Demand. Respondent should document which is used, and why.?	R1.1.1 (R2.1.1 in 1st draft)has been modified to further clarify based on your comment.
			R2.3.3 Peak period should be changed to peak season.	R1.2.3 (R2.2.3 in 1st draft) has been removed based on your comment.
			R2.3.3 Deals with Transmission Limitations. Seems to follow more naturally under R2.5	R1.3.3 (R2.3.3 in 1st draft) has been modified to just require Transmission limitations that prevent the delivery of generation reserves and the SDT believe this must be included in the analysis.
			R2.3.4 Deals with resources from outside interconnected systems. Seems to follow more naturally under R2.4	R1.3.4 (R2.3.4 in 1st draft) has also been modified to further clarify transmission limitations “into the study area” and the SDT believes this must be included in the analysis as well.
			R2.4 Fourth bullet discusses R2.4.1. No reference found.	The reference has been modified based on your comment

			Definitions ? please add: Resource Capability ? the reliability value (MW) of the resource in meeting the Planning Resource Adequacy Standard, based on output characteristics and performance over appropriate peak demand periods. Planning Year - The annual period over which the LOLE is measured, and the resulting resource requirements are established (typically June 1st through the following May 31st).	Resource capability has been removed from the 5th bullet in R1.4 (R2.4 in 1st draft). Planning Year has been added as a footnote to address your concern
2367	Marka Shaw - Reliant Energy Mid Atlantic Power Holdin	No	Load Forecast processes and responsibility are critical elements of Resource Adequacy Assessment that need to be reconsidered. The LSE should not be the responsible entity for conducting forecasts. To ensure a more accurate forecast, the forecasts should be conducted by the EDC or BA with appropriate input from the LSEs and other entities.	Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly
2373	Scott Berry - Indiana Municipal Power Agency	No	Do not agree with R1.1.. If a PRSG is in the process of forming and this standard is approved before the PRSG can function, a LSE may not have a PRSG available to join within 90 days. MISO is scheduled to form a PRSG by June of 2009. If MISO encounters delays and this standard is approved before MISO forms the PRSG, it might take longer than 90 days for a LSE to join a PRSG.	Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly
2379	Richard Kafka - Pepco	No	The current draft says the standard applies to LSEs, but nearly all the requirements apply to the entity serving as the PSRG "administrator" - there is no NERC Functional Entity called PSRG, but within RFC, we must know the entity, such as Resource Planner or Planning Authority. Since this standard is specific to RFC, there must be some solution.	Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly

2385	Douglas Hohlbaugh - Ohio Edison Company	No	APPLICABILITYConsideration should be given to placing the requirement on an entity other than the LSE. A resource adequacy assessment is only as good as the load forecast used. It may be more appropriate to rely on load forecasts at the BA or control area level than to rely on the aggregation of LSE forecasts. It is not prudent to rely on competitive LSEs, operating in deregulated markets, to accurately predict how much load they may win out of auctions, and then sum those estimates up to use as the basis for a resource adequacy evaluation. In deregulated markets it would be much better to eliminate the error introduced by competitive LSE forecasts and replace it with more stable predictable forecasts tied to a geographic area. BA or control area forecasts would be a much better basis to use for resource adequacy assessments and the entity that provides those should be the applicable entity under this standard. We suggest showing the applicability to include LSE or a PRSG and adjust the Definition of the PRSG as shown below. The reason for this change is that as currently stated a PRSG could be defined as only one LSE. We believe it is clearer to indicate that a PRSG is defined as more than one LSE grouped together and allow provisions for meeting the standard requirements by a single LSE or a LSE through participation in a PRSG. The standard drafting team may also want to consider the roles of the Resource Planner and/or the Planning Coordinator as having a role in completing an assessment of resource adequacy. Since the standard is moving away from the need to secure resource adequacy, there is less of a real-time aspect that placed focus solely on the LSE.	Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly

			REQUIREMENTS R1 - Our suggestion is to delete R1 based on the proposed changes in Applicability above. A standard should not force a LSE into a PRSG. Also, the notifications to RFC seem more administrative and not aimed at improving reliability. R2 - Relating to our comment under "Applicability" above, requirement 2 should be broken into specific requirements applicable one or more appropriate NERC registered entities per the functional model. R2.1 - This requirement also implies that a planning reserve margin needs to be calculated for "each planning year". This should be reworded to be more clear and consistent with R2.2.1 and R2.2.2, that only a minimum of 3 years need to be analyzed or verified. R2.1.2 - The FAQ does a good job of defining what "Median (50:50)" forecast. Consideration should be given to moving the definition into the standard as follows: "Median (50:50) - A forecast developed from median economic and weather data. Median data reflects the mid-point of the scenarios used to determine a range of expected economic forecasts or scenarios of possible weather impacts. The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50) when compared to what will actually occur." R2.2	R1 has been deleted based on your comment. Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly R1.1 (R2.1 in 1st draft) has been modified to address your concern. Because the applicability has changed there is no longer a need for additional detail. A footnote has been added to R1.1.2 (R2.1.2 in 1st draft) to clarify "median".

			We suggest revising R2.2 to read "Be performed or verified separately for the annual peak period for each of the following years:" - The original sentence of this requirement may inadvertently imply that every year of the 10-yr timeframe must be analyzed. It should be reworded to clearly state that only 3 years must be analyzed as described in the subrequirements. - The second sentence of the requirement describes the definition of "Year One". This sentence should be removed from the requirement and added to the definitions section as follows "Year One - The planning year that begins with the upcoming annual peak period." -	R1.2 (R2.2 in 1st draft) has been modified to address your concern.
			R2.2.3 This requirement is not necessary because it should be assumed that the responsible entity would determine the annual peak period. "Annual peak period can be integrated into the text of R2.2 as shown above.	R2.2.3 in 1st draft has been removed from the standard based on your comment.
			R2.3.3 and R2.5 - LSE or PRSG may not be allowed access to Transmission information per the standards of conduct. If this information is needed, these requirements must be placed on another entity other than the LSE that would have unrestricted access to the information.	Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly
			R2.6 - We question how the PRSG would assure that resource capacity is not counted more than once as reserve capacity "by multiple PRSGs". We suggest each entity simply assure that it has not counted any of its reserve more than once and delete the last phrase ("by multiple PRSGs") of this	With the change to the applicability section, the Planning Coordinators are in a good position to ensure that a resource capacity is not counted more than once.

			requirement. R3: - The LOLE study is to include the consideration of transmission limitations per the sub-requirements of R2. However, R3 has no related requirement that the planning reserve margin comparison consider transmission limitations. The LOLE studies currently conducted in the Midwest ISO and PJM footprints all involve zonal analysis to address transmission limitations. If separate zones are warranted for the LOLE analysis, then separate reserve comparisons are also warranted as part of the comparison of R3. If the resources of one zone can not be fully delivered or utilized in another zone, then faulty resource adequacy assessments can result if reserve comparisons are not made on a zonal basis. Simply summing up the resources and loads in the footprint will give an overly simplistic and potentially distorted resource adequacy assessment. - The current wording implies that every year of the 10-yr period must be compared with the planning reserve margin benchmark. If the comparison is to be made for each year, but benchmarks may only exist for 3 of the 10 years, what value is to be used for the comparison for the other 7 years? Please clarify the intent. - The requirement requires documentation but does not describe what must be done with this documentation or how it is utilized. We suggest adding a subrequirement (R3.1) that requires submission to an entity upon request. DEFINITIONS 1) Planned Reserve Sharing Group (PRSG) Per our comment under "Applicability" above, we suggest revising the definition of the PRSG to read as follws:	 R2 (R3 in 1st draft) has been modified based on your comment. The definition for Planned Reserve Sharing Group (PRSG) has been removed from the standard based on the change to the applicability section.

			"Planned Reserve Sharing Group ("PRSG") - a group of Load Serving Entities ("LSEs") that agree to study their collective resources to assess the planned Resource Adequacy for the load of the PRSG as a whole. Since MISO, PJM and other RTOs currently provide administrative assistance in the required planning tasks, we ask the SDT to try to capture this aspect of the PRSG in the definition or consider the RTOs role as a Planning Coordinator as have applicability to this standard.. 2) Add the following definitions per our comments above: Year One - The planning year that begins with the upcoming annual peak period. Median (50:50) - A forecast developed from median economic and weather data. Median data reflects the mid-point of the scenarios used to determine a range of expected economic forecasts or scenarios of possible weather impacts. The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low (50:50) when compared to what will actually occur.	The definition for "Year One" has been added to the standard based on your comment. Because the applicability has changed there is no longer a need for additional detail. A footnote has been added to R1.1.2 (R2.1.2 in 1st draft) to clarify "median".
2391	Jason Shaver - American Transmission Co.	No	ATC disagrees with Requirements R2, R2.2, and R3. ? The PRSG should not be the accountable entity for R2 or R3, because it is not a defined entity in the Functional Model, is not registered NERC entity, and not listed in the Applicability section. We suggest replacing ?The PRSG shall? with ?Each LSE through its membership in one or more PRSG shall ? for its associated system?.	Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly.

			? Each LSE should identify any planned Generation and Transmission facilities they use in any Year One through Year Ten analysis. Each LSE should also have the rationale or criteria that they use for deciding which planned facilities to include in the required analyses. We suggest that two sub-requirements be added to this section ? a R2.2.4 for identifying any planned facilities that are included in the analyses and a R2.2.5 for having a rationale regarding which planned facilities are included in the analyses.	The SDT has included a bullet point under R1.3.2 (R2.3.2 in 1st draft) and a sub-requirement under R1.3.3 (R2.3.3 in 1st draft) based on your comment.

Question 2	Do you agree with the Measures of this proposed standard? If no, provide specific suggestions that would make the requirements acceptable to you.

Answers	Frequency
Yes	5 (1 with comments)
No	2 (2 with comments)
Abstain	8 (2 with comments)

ID	Commenter	Answer	Comment	Response
2325	Thad Ness - AEP	Abstain	Since AEP has concerns regarding the appropriate applicability, it would be premature to address this part of the standard at this time.	Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly
2386	Douglas Hohlbaugh - Ohio Edison Company	Abstain	Based on FE's questions on applicability and proposed requirement adjustments, we believe it is premature to address the measures at this time.	Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity

				Levels being modified accordingly
2374	Scott Berry - Indiana Municipal Power Agency	No	M2 and M3 apply to the PRSG which is not a NERC registered entity and cannot be held accountable to NERC standards. If M2 or M3 is not performed, is the individual LSE held accountable or the group of LSEs as a whole (PRSG) held accountable?	Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly
2380	Richard Kafka - Pepco	No	Since PHI feels the requirements are improperly written, the measures cannot be evaluated	The SDT has modified the Applicability section and further clarified the Requirements. Hopefully the modifications are acceptable to you.
2392	Jason Shaver - American Transmission Co.	Yes	ATC generally agrees with the Measures and has no specific suggested changes.	Thank you for your support.

Question 3	Do you agree with the Violation Risk Factors of this proposed standard? If no, provide specific suggestions that would make the requirements acceptable to you.

Answers	Frequency
Yes	3 (1 with comments)
No	1 (0 with comments)
Abstain	11 (2 with comments)

ID	Commenter	Answer	Comment	Response
2326	Thad Ness - AEP	Abstain	Since AEP has concerns regarding the appropriate applicability, it would be premature to address this part of the standard at this time.	Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly
2390	Douglas Hohlbaugh - Ohio Edison Company	Abstain	Based on FE?s questions on applicability and proposed requirement adjustments, we believe it is premature to address the VRFs at this time. However, in general the medium VRF level seems appropriate for most of the requirements since they do not have direct real-time operational impacts	Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable

				entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly
2393	Jason Shaver - American Transmission Co.	Yes	ATC generally agrees with the Violation Risk Factors and has no specific suggested changes.	Thank you for your support.

Question 4	Do you agree with the Violation Severity Levels of this proposed standard? If no, provide specific suggestions that would make the requirements acceptable to you.

Answers	Frequency
Yes	2 (0 with comments)
No	3 (2 with comments)
Abstain	10 (2 with comments)

ID	Commenter	Answer	Comment	Response
2327	Thad Ness - AEP	Abstain	Since AEP has concerns regarding the appropriate applicability, it would be premature to address this part of the standard at this time.	Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly
2388	Douglas Hohlbaugh - Ohio Edison Company	Abstain	Based on FE?s questions on applicability and proposed requirement adjustments, we believe it is premature to address the VSLs at this time	Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly
2363	Matthew Swanson - MISO	No	Many of the Violation Severity levels seem higher than would be appropriate if the assumption that only a complete lack of effort would constitute a Severe violation. In the modified severity level chart below the assumption that only a failure to perform and document a study, with special mention of year one, would constitute a severe	The SDT has considered your comments and modified the VSL’s accordingly.

			violation. Other violations have been shifted to accommodate this assumption and give a more even distribution of violations. Lower Level Violations: R2: The PRSG Resource Adequacy analysis failed to express the planning reserve developed from R2.2 as a percentage of the net Median (50:50) forecast peak load per R2.1.2 OR The PRSG failed to determine the annual peak period for Resource Adequacy analysis per R2.2.3. R3: The PRSG failed to document an assessment of its Resource Adequacy by comparing its load and resource capability for one of the years in the 2 through 10 year period per R3. Moderate Level Violations: R1: The LSE that has not reported to RFC its membership in a PRSG, as of the effective date, reported to RFC more than 90 but less than or equal to 120 calendar days of the effective date of BAL-502-RFC-02 which PRSG it belongs to per R1.1. OR The LSE either notified RFC more than 60 but less than 90 calendar days prior to a proposed PRSG membership change or more than 150 but less than 180 calendar days prior to the planning period under review, which ever is earlier per R1.2 OR The LSE either notified RFC less than 60 days prior to a proposed PRSG membership change or less than 150 calendar days prior to the planning period under review, which ever is earlier per R1.2 R2: The PRSG Resource Adequacy analysis failed to include 1 of the Load forecast Characteristics subcomponents under R2.3.1 and documentation of its use OR The PRSG Resource Adequacy	

			analysis failed to include 1 of the Resource Characteristics subcomponents under R2.3.2 and documentation of its use OR The PRSG Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under R2.4 and documentation of how and why they were included in the analysis or why they were not included OR The PRSG Resource Adequacy analysis failed to consider 1 of the Transmission characteristics subcomponents under R2.5 and documentation of how and why they were included in the analysis or why they were not included OR The PRSG Resource Adequacy analysis failed to Document that the resource capacity is not counted more than once, as reserve, by multiple PRSGs per R2.6 OR The PRSG Resource Adequacy analysis failed to include 2 or more of the Load forecast Characteristics subcomponents under R2.3.1 and documentation of their use R3: The PRSG failed to document an assessment of its Resource Adequacy by comparing its load and resource capability for two or more of the years in the 2 through 10 year period per R3. High Level Violations: R1: The LSE is a member of one or more PRSGs but the load was included more than once per R1 OR The LSE that has not reported to RFC its membership in a PRSG, as of the effective date, reported to RFC more than 120 days of the effective date of BAL-502-RFC-02 which PRSG it belongs to per R1.1. OR The LSE has failed to be a member of one or more PRSGs so that all its load in the RFC footprint is included in a PRSG per R1 R2: The PRSG Resource Adequacy analysis failed to be performed or verified separately for individual years of Year One through Year Ten per R2.2 OR The PRSG Resource Adequacy analysis failed to Calculate a Planning reserve margin that	

			will result in the sum of the probabilities for loss of load for the integrated peak hour for at least all non-holiday weekdays for each planning year being equal to 0.1 per R2.1 OR The Planning reserve margin calculation failed to be performed using the Net Internal Demand per R2.1.1 OR The PRSG failed to perform an analysis or verification for one year in the 2 through 5 year period or one year in the 6 though 10 year period or both per R2.2.2 OR If the analysis is verified per R2.2.2, the PRSG verification failed to be supported by current or past studies for the same planning year per R2.2.2.1 OR The PRSG Resource Adequacy analysis failed to include 2 or more of the Resource Characteristics subcomponents under R2.3.2 and documentation of their use OR The PRSG Resource Adequacy analysis failed to include Transmission limitations and documentation of its use per R2.3.3 OR The PRSG Resource Adequacy analysis failed to include Assistance from other interconnected systems and documentation of its use per R2.3.4 OR The PRSG Resource Adequacy analysis failed to consider all of the Resource availability characteristics subcomponents under R2.4 and documentation of how and why they were included in the analysis or why they were not included OR The PRSG Resource Adequacy analysis failed to consider all of the Transmission characteristics subcomponents under R2.5 and documentation of how and why they were included in the analysis or why they were not included R3: The PRSG failed to document an assessment of its Resource Adequacy by comparing its load and resource capability for year 1 of the 10 year period per R3. Severe Level Violations: R2: The PRSG failed to perform and document a Resource Adequacy analysis	

			annually per R2. OR The PRSG failed to perform an analysis for Year One per R2.2.1	
2394	Jason Shaver - American Transmission Co.	No	ATC generally disagrees with the Violation Severity Levels. In general, the levels are too high for simply having deficiencies in the analysis of resources adequacy. The proposed higher levels would be more appropriate for circumstances where appropriate measures were not taken to mitigate identified resource inadequacies.	Violation Severity Levels (VSL) are used to ensure consistent application in assigning the level of non-compliance over a wide range of standard requirements, after a NERC Reliability Standard non-compliance has been identified. The VSL descriptions are used in classifying and identifying the degree or level by which the entity has failed to satisfy a standard requirement. and not to classify the risk of a requirement to the reliability of the BES.which are categorized as Violation Risk Factors (VRF)

Question 5	Do you agree with the Implementation Plan of this proposed standard? If no, provide specific suggestions that would make the requirements acceptable to you.

Answers	Frequency
Yes	5 (1 with comments)
No	2 (2 with comments)
Abstain	8 (2 with comments)

ID	Commenter	Answer	Comment	Response
2322	HARVIE BEAVERS - PINEY CREEK LP/COLMAC	Abstain	Same comment as in section A.2	Please see response regarding section A2.
2328	Thad Ness - AEP	Abstain	Since AEP has concerns regarding the appropriate applicability, it would be premature to address this part of the standard at this time.	Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly
2377	Scott Berry - Indiana Municipal Power Agency	No	The implementation plan should ensure that the standard does not go into effect until every LSE in the RFC footprint has a PRSG available to join. The forming of a PRSG within MISO in the year 2009 will help with this issue.	Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the

				Requirements, Measures and Violation Severity Levels being modified accordingly
2383	Richard Kafka - Pepco	No	The standard is not at the point where an implementation plan can be determined.	Please see responses to your comments. Hopefully the modified standard is at a point where the implementation plan can be determined.
2395	Jason Shaver - American Transmission Co.	Yes	ATC generally agrees with the Implementation Plan and has no specific suggested changes.	Thank you for your support.

Question 6	Do you agree that this standard is ready for Ballot? If no, provide specific suggestions that would make it acceptable to you.

Answers	Frequency
Yes	0
No	14 (13 with comments)
Abstain	1 (0 with comments)

ID	Commenter	Answer	Comment	Response
2305	Vincent Kaminski - Allegheny Electric Cooperative Inc.	No	The RFC standard is not necessary if the requirements are also covered in a corresponding NERC standard. Otherwise we will have duplicative reporting/standard which couls end up conflicting with each other. If it is deemed appropriate/necessary to have a RFC standard, it should be revised to clearly reflect that being a signatory to the PJM Reliability Assurance Agreement (or other similar agreement(s)) is deemed to be adequate documentation to demonstrate that the LSE has complied with the requirements of this standard. (MISO members should be able to satify the requiremets of the standard by providing the comparable MISO documentation.) This clarification should be included in the standard before it is circulated for balloting.	Currently, there is no corresponding NERC standard which deals with a Resource Adequacy analysis. There has been a SAR at the NERC level which has been dormant for over three years. Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly.
2309	Jeanne Kurzynowski - Consumers Energy	No	R2.3 contains redundant Load forecast characteristics. Load forecast uncertainty is defined as containing load variability due to weather, regional economic forecasts. Recommend deleting bulleted item:	R1.3.1 (R2.3.1 in 1st draft) has been modified based on your comment.

			R2.3.1 Load forecast characteristics: ? Median (50:50) forecast peak load. ? Load forecast uncertainty. ? Load diversity. ? Seasonal load variations. ? Load variability due to weather, regional economic forecasts, etc. (should be deleted) ? Daily demand modeling assumptions (firm, interruptible). ? Contractual arrangements concerning curtailable/interruptible load. R2.3 requirements R2.3.3 & R2.3.4 are not aligned with the MRO standard. Page 3 of 6 from MRO standard: Standard RES-501-MRO-01 - Planned Resource Adequacy Assessment http://www.midwestreliability.org/04_standards/approved_standards/mro_standards/RES-501-MRO-01_Final_20071229_Clean.pdf R1.3 Include, at a minimum, documentation of how and why the following were/were not included in the analysis: R1.3.3 Transmission limitations that prevent the delivery of generation reserves. R1.3.3.1 Transmission maintenance outage schedules. R1.3.3.2 Transmission forced outage rates R1.3.3.3 Transmission availability for emergency considering firm commitments Draft Standard BAL-502-RFC-02 V1 R2.3.3 Transmission limitations, including the effect of firm commitments that prevent the delivery of generation reserves (should be moved to section R2.4) R2.3.4 Assistance from other interconnected systems including multi-area assessment considering transmission limitations. (should be moved to section R2.4)	 The intention is to be consistent with the intent of the MRO standard but not specifically identical. The SDT took the MRO standard and enhanced it based on industry experience. The SDT believes that R1.3.3 (R2.3.3 in 1st draft) and R1.3.4 (R2.3.4 in 1st draft) must be included in the analysis. Also, in response to your comment, R1.3.3 (R2.3.3 in 1st draft) has been modified to be identical to the MRO R1.3.3.

			R2.4 Consider the following Resource availability characteristics and document how and why they were included in the analysis or why they were not included: R2.3.3 and R2.3.4 should be moved to SECTION R2.4. Another alternative would be to work with MRO and change their standard to the more restrictive RFC version. Typo in section R2.4 R2.4 Consider the following Resource availability characteristics and document how and why they were included in the analysis or why they were not included: ? Any other Demand (Load) Response Programs not included in R2.4.1. Should be: ? Any other Demand (Load) Response Programs not included in R2.3.1.	 Thank you. R1.2 (R2.4 in 1st draft) has been modified based on your comment.
2316	Bob Thomas - Illinois Municipal Electric Agency	No	Planned Reserve Sharing Group should be added to the Applicability section. The proposed standard includes 21 requirements; 18 of those requirements apply to the PRSG and three apply to the LSE function. The addition of PRSG to the Applicability section would avoid confusion of responsibilities for compliance. It would be helpful to see a discussion of why this region-specific standard and region-specific PRSG function are needed; i.e., "clear and specific justification and rationale" for the need beyond reliability provisions in existing NERC standards. This may have been provided with the proposal and adoption of BAL-502-RFC-01 (in 2006), but would be helpful to see again with this proposed revision. (The SAR adequately addresses consistency with the	Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly. The original BAL-501-RFC-01 standard was developed by the RFC “Day 1” and “Day 2” standards drafting teams. The “Day 1” SDT was formed before the formation of RFC to develop a set of standards which would be in place on the first day of RFC operations. The “Day 1” SDT did not complete the initial draft and the “Day 2” SDT continued the work on this standard. Subsequently at the time of developing this standard there was no official “SAR’ associated with this standard.

			MRO Resource Adequacy standard and alignment with RTO tariffs.)	
2323	HARVIE BEAVERS - PINEY CREEK LP/COLMAC	No	Need to resolve the standardization requirement in relation to current PJM/MSO methods.	Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly
2329	Thad Ness - AEP	No	See comments to Question #1.	Please see response to Question 1.
2341	Paul Kure - ReliabilityFirst Corporation	No	The RAS does not believe the standard is ready for ballot based on the issues in question 1 above that need to be reviewed and clarified.	Please see response to Question 1.
2347	Eric Mortenson - Exelon	No	Please see Question 1.	Please see response to Question 1.
2360	Patrick Brown - PJM	No	See response to question 1.	Please see response to Question 1.
2366	Matthew Swanson - MISO	No	The present definition of PRSG makes no mention of the role RTOs currently play in the study process. Additional wording of RTO organized groups could help to clarify this section and ensure that future compliance does not require clarification of the standard. Possible addition: ?This group of LSEs could be organized under a FERC approved tariff of an RTO.?	Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section has been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). With the removal of the LSE as an Applicable entity, R1 was removed along with the Requirements, Measures and Violation Severity Levels being modified accordingly
2372	Marka Shaw - Reliant Energy Mid Atlantic Power Holdin	No	The issue identified above needs to be addressed.	Please see responses listed above.
2378	Scott Berry - Indiana Municipal Power Agency	No	See IMPA's comments for questions one, two, and five.	Please see responses to questions one, two and five.
2389	Douglas Hohlbaugh - Ohio Edison Company	No	Although this is a good starting point and we appreciate the SDT?s hard work in putting this draft together, it still needs more work based on our comments to the previous questions.	Thank you. Please see responses to your previous comments.
2396	Jason Shaver - American Transmission Co.	No	ATC disagrees that the standard is ready for Ballot and suggests that the issues with the Requirements and Violation Severity Levels be resolved before going to Ballot.	Please see response to your comments regarding the Requirements and Violation Severity Levels.

Planning Resource Adequacy Analysis, Assessment and Documentation

Question 1	Based on industry comments and a supplemental SAR approved by the RFC Standards Committee on 08/11/08, the Applicability section and subsequent Requirements have been modified to include the Planning Coordinator and remove the LSE (along with references to the PRSG). Do you agree with the change in Applicability section of this proposed standard? If no, provide specific suggestions that would make the Applicability section acceptable to you.

Answers	Frequency
Yes	4 (1 with comments)
No	1 (1 with comments)
Abstain	2 (0 with comments)

ID	Commenter	Answer	Comment	Response
2568	Howard Rulf - Wisconsin Electric Power	No	We Energies does not support the revised standard addressing the "Planning Coordinator"(PC) as the applicable entity for this Standard. It is our position that there is a potential for gaps in analyses if performed under the PC, and that the LSE is responsible for the planning and reliability related to their load. Given the need for an Applicability change, the remainder of the standard would need to be revised to coordinate with the Applicable entity.	Per the NERC Functional Model, the SDT believes the Planning Coordinator is the correct Applicable entity to carry out assessments and not the LSE. One of the relationships a Planning Coordinator has with a LSE is collecting Demand forecasts, and demand response program data from Load-Serving Entities. As such there should be no gaps in the analysis. The LSE may still be responsible for the planning and reliability related to their load imposed by other standards or tariff requirements.
2547	Sam Ciccone - Cleveland Electric Illuminating Company	Yes	We agree that the ultimate responsibility for resource adequacy assessment should be charged to the PC. The PC has the proper tools to gather and study the necessary generation and transmission data due to their wide-area coordination.	Thank you for your support

Question 2	Do you agree with the Requirements of this proposed standard? If no, provide specific suggestions that would make the requirements acceptable to you.

Answers	Frequency
Yes	2 (0 with comments)
No	4 (4 with comments)
Abstain	1 (0 with comments)

ID	Commenter	Answer	Comment	Response

2526	Matthew Swanson - MISO	No	 R1.6 Documentation of this requirement could be difficult. We would like the drafting team to clarify how that documentation should look; either in the standard, or in an FAQ document.  R1.7 Documentation of the load included in the study could be accomplished but the certification that each end use customer was included in only one Resource Adequacy analysis seems excessive and could be beyond the control of the Planning Coordinator. Take, for example the concurrent efforts of ATC and MISO. In this instance some end use customers would be included in two Resource Adequacy Analyses and it would not create issues for end use customers. Each Planning Coordinator should only be responsible for ensuring that their load is included in an analysis while Reliability First could handle the coordination of studies within their footprint. The second half of this requirement should be omitted.  R2.1 Removal of the phrase ?in the ten year period? would make this requirement clearer.	R1.6 has been modified based on your comment. R1.7 has been modified based on your comment. R2.1 has been modified based on your comment.
2533	Patrick Brown - PJM	No	PJM respectfully submits the following changes for the consideration of the Drafting Team R1.1.1 Change ?Demand Side Management? to ?Load Management?. Demand Side Management includes passive programs, such as energy efficiency & conservation. PJM believes that only ?dispatchable? programs such as Direct Load Control & contractually interruptible loads should be referenced here. R1.3.1 Bullet #2 should read ?Load forecast	R1.1.1 has been modified based on your comment. The NERC-defined terms Direct Control Load Management and Interruptible Demand have been utilized and added to the standard. R1.3.1 has been modified base on your

			uncertainty (reflects variability in the load forecast due to weather, regional economic forecasts and modeling error).? R1.3.3.1 PJM requests clarifying language to be added here to confirm that these ?transmission facility additions? are the ones included to confirm generator deliverability. R1.5 PJM believes that this could be valuable in the future, however, TADS is in its infancy, and not nearly enough data is available to draw credible conclusions. Definitions: PJM suggests that there are actually two definitions included in the Net Internal Demand definition. The NID definition should read ?Net Internal Demand - Total of all end-use customer demand and electric system losses within specified metered boundaries, less Load Management.? The rest of the text in that paragraph describes Load Management. That should appear as a new definition that reads ?Load Management - The amount of demand curtailment of all end-use customer demand that can contractually be curtailed or is under direct control to be curtailed within the specified metered boundaries by the system operator.?	comment. The SDT feels that the language in R1.3.3.1 is clear R1.5 bullet 2 has been removed based on your comment. The SDT believes that this is addressed in other areas. The SDT has included the NERC defined Terms Direct Control Load Management and Interruptible Demand to address your concern.
2548	Sam Ciccone - Cleveland Electric Illuminating Company	No	Although the requirements appear to be complete, they could use some general clean-up and possible enhancements. We have reviewed the requirements and provided comments, observations, and suggestions as follows: Title - As an observation, the MRO standard does not include analysis and documentation in title.	The intention is to be consistent with the intent of the MRO standard but not specifically identical. The SDT took the MRO standard and enhanced it based on industry experience.

			Purpose - As an observation, the MRO standard has a much simpler written purpose.	The intention is to be consistent with the intent of the MRO standard but not specifically identical. The SDT took the MRO standard and enhanced it based on industry experience.
			R1 - The SDT should consider removing the phrase "and document" since it is covered elsewhere and in R2.	The SDT believes that the requirement is correct as written.
			R1.1 - "Planning" should not be capitalized since it is not a NERC defined term.	R1.1 has been modified based on your comment.
			R1.1.1 - In the phrase "The utilization of Demand Side Management does", "does" should be replaced with "shall". Also, as an observation, this DSM requirement does not seem to be addressed by the MRO standard.	R1.1.1 has been modified based on your comment. The intention is to be consistent with the intent of the MRO standard but not specifically identical. The SDT took the MRO standard and enhanced it based on industry experience.
			R1.1.2 - Suggest adding term "margin" after "reserve". Also, with regard to the phrase "(planning reserve margin)", this phrase does not seem to be required.	R1.1.2 has been modified base on your comment.
			R1.2.1 - As an observation, the MRO standard seems to require analysis for all years of one through ten.	The intention is to be consistent with the intent of the MRO standard but not specifically identical. The SDT took the MRO standard and enhanced it based on industry experience.
			R1.3.1, R1.3.2, and R1.3.3 - As an observation, the MRO standard does not specifically require that all the characteristics in R1.3.1, R1.3.2, and R1.3.3 be used, just document why they were/were not used.	The intention is to be consistent with the intent of the MRO standard but not specifically identical. The SDT took the MRO standard and enhanced it based on industry experience.
			R1.3.4 - Is "interconnected" referring to the 3 interconnections? If so, this term should be capitalized since it is a NERC defined term. Also, "transmission" should be capitalized since it is a NERC defined term.	“Interconnected” does not refer to the 3 interconnections. “Transmission” has been capitalized based on your comment.
			R1.4 - "Resource" should not be capitalized since it is not a NERC defined term. Also,	R1.4 has been modified based on your comment.

			as an observation, the MRO standard includes Demand-Side Management, energy limitations of hydroelectric units, and merchant plant availabilities in these characteristics. Lastly, in the 2nd and 4th bullets, the term "Resource" and phrase "Response Programs" should not be capitalized, respectively, since they are not NERC defined terms. R2.3 - As a suggestion, instead of simply requiring the information to be publicly posted, it may be better if the specific entities that needed this information were specifically included in the requirement (i.e. TSP, TP, DP, state regulatory authorities, etc..) 1.3 - Data Retention - As an observation, the MRO standard requires five (5) years of data retention. Resource Adequacy Definition - We suggest that the SDT consider adding "(including losses)" after "energy requirements"; this would match the proposed definition in the current NERC SAR. Also, as an observation and for consideration, the MRO standard ends the definition with "with a specified degree of reliability". Net Internal Demand Definition - The term "curtailment" should be capitalized since it is a NERC defined term. Year One - Regarding the phrase "peak period" in this definition, the SDT may want to consider defining this period. As an observation, the MRO standard defines "peak period" in R1.1.2 as "a period consisting of two (2) or more calendar	 The SDT believes that if this information is publicly posted, it will be available to all entities including but not limited to the TSP, TP, DP, state regulatory authorities, etc. The SDT believes that any data retention past the two prior years is in excess. The intention is to be consistent with the intent of the MRO standard but not specifically identical. The SDT took the MRO standard and enhanced it based on industry experience. The definition has been modified based on your comment. the SDT did not intend to use the NERC definition for “Curtailment” in this standard and thus it is not capitalized. A definition for “Peak Period” has been added based on your comment.

			months but less than seven (7) calendar months, which includes the period during which the [responsible entity's] annual peak demand is expected to occur".	
2569	Howard Rulf - Wisconsin Electric Power	No	Given the need for an Applicability change, the Requirements would need to be revised. If the PC Applicability is retained then we have the following concerns: R1.6, R1.7 - If there are multiple PC's that have authority over the same geographical area, who is responsible to meet the standard. R1.3 - Although there is specificity of major inputs here, how to reconcile detailed assumption and methodology disagreements that stakeholders may have with the PC?	All PC in the RFC footprint are required to comply with this standard. It is up to both of the PC's which may have authority over the same geographical area to document how they meet requirements R1.6 and R1.7. R1.6 and R1.7 have been modified to further clarify. The SDT believes it is outside the scope of the standard to address a process for PCs to involve Stakeholders.

Question 3	Do you agree with the Measures of this proposed standard? If no, provide specific suggestions that would make the requirements acceptable to you.

Answers	Frequency
Yes	3 (0 with comments)
No	2 (2 with comments)
Abstain	2 (0 with comments)

ID	Commenter	Answer	Comment	Response
2549	Sam Ciccone - Cleveland Electric Illuminating Company	No	M1 - As a suggestion replace "documentation" with "evidence"; documentation is technically required per R2. M2 - This measure does not include evidence that the PC made the assessments available to the impacted entities.	The SDT feels that "documentation" is appropriate placed in M1 based on R1. The SDT believes R2.3 is adequately covered in M2.
2570	Howard Rulf - Wisconsin Electric Power	No	Given the need for an Applicability change, the Measures would need to be revised. If the PC Applicability is retatined then we have the following concerns: M1 - It is not clear how/who validates the analysis as a second party check. Does/Should RFC review/validate that the study was	You are correct; this standard does not include any requirements dealing with the review or validation of the analysis. It is in not the job of RFC to judge the quality of an analysis. This standard simply prescribes what items are to be included within the analysis.

			appropriately done in some way? It is also not clear what accountability that a PC would have for the results of the study.	

Question 4	Do you agree with the Violation Risk Factors of this proposed standard? If no, provide specific suggestions that would make the requirements acceptable to you.

Answers	Frequency
Yes	2 (0 with comments)
No	2 (1 with comments)
Abstain	3 (0 with comments)

ID	Commenter	Answer	Comment	Response
2550	Sam Ciccone - Cleveland Electric Illuminating Company	No	We believe that since Req. R2 requires documentation, per the guidelines for VRF in the NERC standard development procedure we believe that the VRF for R2 should be "Lower". This would also be consistent with MRO standard RES-501-MRO-01 Req. R2.	The VRF for R2 has been changed to “lower” based on your comment.

Question 5	Do you agree with the Violation Severity Levels of this proposed standard? If no, provide specific suggestions that would make the requirements acceptable to you.

Answers	Frequency
Yes	2 (0 with comments)
No	3 (3 with comments)
Abstain	2 (0 with comments)

ID	Commenter	Answer	Comment	Response
2529	Matthew Swanson - MISO	No	 Violation Severity Levels The removal of the Violation related to R1.6 may be appropriate as requirement R1.6 itself should be removed. Under the Severity Levels for R2 the wording associated with R2.1 in the Moderate Column should read. ?The Planning Coordinator failed to document its projected load and resource capability, for each area of transmission constrained sub-area identified in the Resource Adequacy analysis for one of the three years per R2.1.	R1.6 and associated VSL have been modified to further clarify. R2.1 and the associated VSL have been modified to further clarify.

2558	Chris Norton - American Municipal Power - Ohio, Inc.	No	"The Planning Coordinator Resource Adequacy analysis failed to document that all load in the Planning Coordinator area is included in a Resource Adequacy analysis and each end-use customer is included in one and only one Resource Adequacy analysis per R1.7." It is important that all load is included in the analysis. If a load is included twice it should not be considered a Moderate violation. Including load more than once would tend to create a more conservative estimate of the system's future condition. It would be akin to a high forecast. The one and only one reference should be eliminated or moved to lower.	R1.7 has been modified based on your comment.
2572	Howard Rulf - Wisconsin Electric Power	No	Given the need for an Applicability change, the VSL's would need to be revised. If the PC Applicability is retatined then we have the following concern: It is not clear whether this standard considers that the PC may not be able to obtain needed data from internal or external sources?	Based on the NERC Functional Model, the PC should already have access to the data needed to perform the analysis.

Question 6	Do you agree with the Implementation Plan of this proposed standard? If no, provide specific suggestions that would make the requirements acceptable to you.

Answers	Frequency
Yes	2 (0 with comments)
No	3 (3 with comments)
Abstain	2 (1 with comments)

ID	Commenter	Answer	Comment	Response
2530	Matthew Swanson - MISO	Abstain	 MRO Coordination If this standard development is to continue, coordination with MRO to ensure compatible standards will be necessary as any conflicts could create compliance issues for the Midwest ISO.	MRO and RFC are actively in coordination regarding these standards.
2415	Thad Ness - AEP	No	To ultimately be a NERC/FERC enforceable standard, FERC has to also ?approve? it, otherwise it would only be an RFC criteria.	You are correct.
2560	Chris Norton - American Municipal	No	The effective date should be upon FERC	The Implementation Plan has been modified to

	Power - Ohio, Inc.		approval for non-RFC members.	further clarify.
2574	Howard Rulf - Wisconsin Electric Power	No	It is not clear whether the implementation will be seamless and require a transition period so that Compliance requirements are coordinated	The proposed Implementation plan is only applicable to the PC within the RFC footprint.

Question 7	Do you agree that this standard is ready for Ballot? If no, provide specific suggestions that would make it acceptable to you.

Answers	Frequency
Yes	2 (1 with comments)
No	4 (4 with comments)
Abstain	1 (0 with comments)

ID	Commenter	Answer	Comment	Response
2531	Matthew Swanson - MISO	No	 Necessity of Standard With the approval of Module E of the Midwest ISO TEMT this standard seems to become superfluous as the Midwest ISO is already required by conditionally approved FERC tariff to perform a LOLE study.  Tariff Comparison To quote from Module E: ?The PRM analysis shall consider factors including, but not limited to: the Generator Forced Outage rates of Capacity Resources, Generator Planned Outages, expected performance of Load Modifying Resources, the LSE?s forecasted Demand uncertainty, system operating reserve requirements, transmission congestion, external firm capacity sales and available transmission import capability.? Thus, many of the requirements of the Standard are already mandated by the Midwest ISO?s Tariff.	It is outside of the scope of this SDT to determine the necessity of this standard. Since there are several PC within the RFC region, the SDT believes that one consistent regional standard is needed for reliability.
2538	Patrick Brown - PJM	No	If the SDT gives due consideration to the recommendations listed above, PJM believes that the standard will ready for Ballot.	Thank you for your support and see responses to your comments above.
2553	Sam Ciccone - Cleveland Electric Illuminating Company	No	We commend the SDT for making significant improvement to this standard in a relatively short time. Although we agree that the standard is close to being ready for ballot, we would like the SDT to consider	Thank you for your support. Please see responses to your previous comments.

			and respond to our comments from above. Please be aware that our "NO" answers above only refer to the need for additional considerations to enhance this standard and in no way implies that we are not supportive of the standard. We believe that the standard is necessary due to the lack of consistent resource adequacy requirements across the RFC footprint. Although MISO (through Module E) and PJM, as planning coordinators for a large portion of the RFC footprint, have been developing their own resource adequacy requirements for their member companies through FERC approved tariffs, there needs to be a tie between reliability, the tariff rules, and state or jurisdictional resource adequacy enforcement. We believe that the only way to properly begin this process of enforcement is the development of consistent reliability assessment requirements and believe that the development of this standard achieves that goal.	
2573	Howard Rulf - Wisconsin Electric Power	No	We believe there is more work needed to the Applicability Section before this is ready for Ballot.	Please see responses to your previous comments.
2539	Thad Ness - AEP	Yes	Yes providing the effective date (Implementation Plan) is fleshed out more, as needed.	Please see responses to your previous comments.

RFC Reliability Standards Voting Process
Detailed Ballot Voting Results

12/30/2008 7:36 am

BAL-502-RFC-2 Planning Resource Adequacy Analysis, Assessment and Documentation

Ballot Period: **1**

Voting Period: **10/16/2008** thru **10/30/2008**

Passing %: **50.00**

Certified Date: **11/03/2008**

Certified Outcome: **PASSED**

Distribution Provider	Yes	No	Abstain	Total Eligible Votes	Ballot Outcome
	11	0	0	11	PASSED

Yes Voters

Douglas GHohlbaugh	Ohio Edison Company
Edward PCox	Kingsport Power Company
Henry WStevens	Metropolitan Edison Company
Jeffery CHubbartt	Toledo Edison Company
Jeffrey CMueller	Public Service Electric and Gas Company
John DKruse	Commonwealth Edison
Ken Esber	Pennsylvania Electric Company
Mark AKoziel	Jersey Central Power & Light
Sam JCiccone	Cleveland Electric Illuminating Company
Vincent JCatania	PECO Energy Company
William CMitchell	Delmarva Power

Generator: Owner, Oper.	Yes	No	Abstain	Total Eligible Votes	Ballot Outcome
	10	0	0	11	PASSED

Yes Voters

Annette MBannon	PPL - Lower Mount Bethel Energy, LLC
Ken Dresner	FE Generation Corporation
Kent JKujala	Detroit Edison
Mark AHeimbach	PPL Martins Creek, LLC
Michael FGildea	Constellation Energy
Richard KDouglass	Conectiv Energy
Robin ARitzman	FirstEnergy Nuclear Operating Company
Steven LGaarde	Consumers Energy
Thomas JBradish	Reliant Energy Seward, LLC
William RDuge	FirstEnergy Nuclear Generating Co.

LSE, PSE, End User	Yes	No	Abstain	Total Eligible Votes	Ballot Outcome
	8	1	1	11	PASSED

Yes Voters

Bob CThomas	Illinois Municipal Electric Agency
David LFolk	Pennsylvania Power Company
James DHebson	PSEG Energy Resources & Trade LLC
James RNickel	Michigan Public Power Agency
Jim TSummers	ACE
Louis SSlade	Dominion Energy Marketing, Inc.
Mark Ringhausen	ODEC
Thomas WHyzinski	PPL EnergyPlus, LLC

No Voters

Chris Norton	American Municipal Power - Ohio, Inc.

Abstentions

Scott Berry	Indiana Municipal Power Agency

RC, PC, TP, RP, RTO, BA, Govt. Agency	Yes	No	Abstain	Total Eligible Votes	Ballot Outcome
	2	0	0	2	PASSED

Yes Voters

Lawrence EHartley	First Energy Solutions Corp.
Terry Bilke	MISO

Transmission: Owner, Oper., Serv. Prov.	Yes	No	Abstain	Total Eligible Votes	Ballot Outcome
	9	2	0	11	PASSED

Yes Voters

Damon WHolladay	Hoosier Energy
Edward Bedder	Orange and Rockland
Elizabeth Davis	PPL Electric Utilities Corporation
Jason Shaver	American Transmission Co.
Richard JKafka	Pepco
Robert MMartinko	American Transmission Systems, Inc.
Rodney LPhillips	Allegheny Power
Ronald CSnead	Duke Energy
Ronald KMcCrea	Appalachian Power

No Voters

Elizabeth AHowell	International Transmission Co.
Robert JMattey	Ohio Valley Electric Corp.

Voter Comments

Name: **Kent JKujala** Organization: **Detroit Edison**

Voted **YES**

Comment	Response
DTE supports BAL-502-RFC-2, as it stands however we do propose a revision for clarity to R1.1.1 as follows; R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand will be included in the net internal demand calculation, and not contribute to the loss of Load probability calculation.	Thank you for your response and suggested language. Your suggested language is consistent with the intent of R1.1.1. Since the draft standard has gone through the Category Ballot, no changes may be made to the standard prior to going in front of the RFC Board for action.

Name: **Terry Bilke** Organization: **MISO**

Voted **YES**

Comment	Response
While we are voting for this standard, we have several comments for consideration. Necessity of Standard With the approval of Module E of the Midwest ISO TEMT and a similar tariff requirement at PJM, as the ISOs are already required by FERC to perform a LOLE study.	Since there are several Planning Coordinators within the RFC region, the SDT believes that one consistent regional standard is needed for reliability.
Tariff Comparison To quote from Module E: ?The PRM analysis shall consider factors including, but not limited to: the Generator Forced Outage rates of Capacity Resources, Generator Planned Outages, expected performance of Load Modifying Resources, the LSE?s forecasted Demand uncertainty, system operating reserve requirements, transmission congestion, external firm capacity sales and available transmission import capability.? Thus, many of the requirements of the Standard are already mandated by the Midwest ISO?s Tariff.	
MRO Coordination If this standard development is to continue, coordination with MRO to ensure compatible standards will be necessary as any conflicts could create compliance issues for the Midwest ISO.	MRO and RFC are actively in coordination regarding these standards. Staff and members are on both drafting teams.
R1.6 Documentation of this requirement could be difficult. We would like the drafting team to clarify how that documentation should look; either in the standard, or in an FAQ document.	A FAQ has been added to the FAQ document regarding R1.6.
R1.7 Documentation of the load included in the study could be accomplished but the certification that each end use customer was included in only one Resource Adequacy analysis seems excessive and could be beyond the control of the Planning Coordinator. Take, for example the concurrent efforts of ATC and MISO. In this instance some	Version 3 of the standard (version out for Ballot) actually states: ?Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis.? The SDT believes R1.7 (as written) addresses your concern.

Comment	Response
end use customers would be included in two Resource Adequacy Analyses and it would not create issues for end use customers. Each Planning Coordinator should only be responsible for ensuring that their load is included in an analysis while Reliability First could handle the coordination of studies within their footprint. The second half of this requirement should be omitted.	
R2.1 Removal of the phrase ?in the ten year period? would make this requirement clearer.	Version 3 of the standard (version out for Ballot) actually states: ??of the years in Year One through ten.?
Violation Severity Levels The removal of the Violation related to R1.6 may be appropriate as requirement R1.6 itself should be removed.	A FAQ has been added to the FAQ document regarding R1.6.
Under the Severity Levels for R2 the wording associated with R2.1 in the Moderate Column should read. ?The Planning Coordinator failed to document its projected load and resource capability, for each area of transmission constrained sub-area identified in the Resource Adequacy analysis for one of the three years per R2.1.	The SDT disagrees. If the Moderate VSL associated with R2.1 is modified as suggested, there would be a conflict with the High VSL for R2.1. If the Planning Coordinator failed to document the projected Load and resource for year 1, the entity would fall under both a Moderate and High VSL thus causing the conflict.

Name: **Chris Norton** Organization: **American Municipal Power - Ohio, Inc.**

Voted **NO**

Comment	Response
If this is to be a standard it should be a national standard and not a regional standard. This should start at NERC.	RFC currently has an approved BAL-502-RFC-01 (Resource Adequacy) standard and the proposed BAL-502-RFC-02 is a revision to the current standard. Additionally, there is no corresponding NERC standard which deals with a Resource Adequacy analysis. There has been a SAR at the NERC level which has been dormant for over three years. If NERC develops a continent wide Resource Adequacy analysis standard which is duplicative or more restrictive than the RFC standard, the RFC requirements may be removed.

Name: **Elizabeth AHowell** Organization: **International Transmission Co.**

Voted **NO**

Comment	Response
While the draft standard has a weak reference to the reliance of transmission to meet Resource Adequacy requirements, the standard fails to properly address the dependency on transmission to meet these requirements. The language used does not comport with that used in NERC standards. For example, the failure to reference ?Generation Capacity Import Requirement (GCIR)? would be a severe oversight if missing from the RFC standard. NERC Standard MOD-004-001, which is currently being re-balloted, has a framework, including terminology, to appropriately address GCIR (& hence CBM) in RFC standards. We suggest that the RFC standard be delayed until the re-balloting is completed and this RFC standard	The SDT believes the standard is not in conflict with the draft MOD-004-01 standard. The dependency on transmission to meet these requirements may be dealt with in other reliability standards. This standard allows the flexibility to adopt any future transmission assessment frameworks.

aligned with MOD-004-01.

Name: **Robert JMattey** Organization: **Ohio Valley Electric Corp.**

Voted **NO**

Comment	Response
This should be an LSE function as originally envisioned; no allowance for smaller loads.	After examining the NERC Functional Model, the SDT believes the Planning Coordinator is the correct Applicable entity to carry out assessments and not the LSE. One of the relationships a Planning Coordinator has with a LSE is collecting Demand forecasts, and demand response program data from Load-Serving Entities. As such there should be no gaps in the analysis. The LSE may still be responsible for the planning and reliability related to their load imposed by other standards or tariff requirements.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Regional Reliability Standard Submittal Request

Region: ReliabilityFirst

Regional Standard Number: BAL-502-RFC-02

Regional Standard Title: Planning Resource Adequacy Analysis, Assessment and Documentation

Date Submitted: 02/24/09

Regional Contact Name: Bob Millard

Regional Contact Title: Director of Standards

Regional Contact Telephone Number: 330-247-3044

Request (check all that apply):

- ☒ Approval of a new standard
- ☐ Revision of an existing standard
- ☐ Withdrawal of an existing standard
- ☐ Urgent Action

Has this action been approved by your Board of Directors (if no please indicate date standard action is expected along with the current status (e.g., third comment period with anticipated board approval on mm/dd/year)):

- ☒ Yes
- ☐ No

[Note: The purpose of the remaining questions is to provide NERC with the information needed to file the regional standard(s) with FERC. The information provided may to a large degree be used verbatim. It is extremely important for the entity submitting this form to provide sufficient detail that clearly delineates the scope and justification of the request.]

Concise statement of the basis and purpose (scope) of request:

The basis and purpose of the Reliability*First* BAL-502-RFC-02 standard is to establish common criteria, based on “one day in ten year” loss of Load expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the Reliability*First* Corporation region in a consistent manner.

Each Reliability*First* Regional Reliability Standard shall enable or support one or more of the NERC reliability principles, thereby ensuring that each standard serves a purpose in support of the reliability of the regional bulk power system. Each of those standards shall also be consistent with all of the NERC reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence. The NERC reliability principles supported by this standard are the following:

- Reliability Principle 1 — interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

- Reliability Principle 2 — the frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

The Reliability*First* BAL-502-RFC-02 standard contains two main requirements on Planning Coordinators (PC's). The two main requirements address the following:

1. Requirements to perform and document a Resource Adequacy analysis annually

2. Requirements to annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis

Concise statement of the justification of the request:

The Standard Authorization Request (SAR) was submitted to the Reliability*First* Standards Committee on February 13th, 2008 followed by a supplemental SAR submitted on August 11th, 2008. Based on the two SARs the following key modifications were made to the Reliability*First* Board approved BAL-502-RFC-01 (Resource Planning Reserve Requirement) standard:

1. Enforcement was limited to reserve requirement analysis and assignment. Removed requirements from the Reliability*First* Board approved (BAL-502-RFC-01) standard that have been deemed unenforceable under law per section 215 of the Energy Policy Act.

2. Significant improvements based on Reliability*First* experience and Midwest Reliability Organization standards development

3. Modifications to conform to current Reliability*First* Standards Development Procedure, such as Violation Risk Factors, Violation Severity Levels, etc.

4. Assignment of applicability and responsibility for certain requirements in the existing approved (BAL-502-RFC-01) standard

Furthermore, there is currently no standard at the NERC/FERC level which addresses resource adequacy.

Other – please attach or include as separate files:

- **The text of the regional reliability standard in MS Word format that:**
  - **has either been, or is anticipated to be, approved by the regional entity's board, and**
  - **is in a format consistent with the NERC template for reliability standards.**
    1. BAL-502-RFC-02.doc
    2. Draft_BAL-502-RFC-02_092608_Redline.doc

- **An implementation plan.**
    1. BAL-502-RFC-02_Implementation_Plan.doc
- **The regional entity standard drafting team roster.**
    1. BAL-502-RFC-02_DT_Roster.doc
- **The names and affiliations of the ballot pool members or names and affiliations of the committee and committee members that approved the submittal of the standard.**
    1. BAL-502-RFC-02_Category_Ballot.pdf
- **The final ballot results, including a list of significant minority issues that were not resolved, and**
    1. BAL-502-RFC-02_Category_Ballot.pdf
- **For each public comment period, a copy of each comment submitted and its associated response along with the associated changes made to the standard.**
    1. BAL-502-RFC-02_First_Comment_Period.pdf
        - Draft_BAL-502-RFC-02_061908_Clean.doc
    2. BAL-502-RFC-02_Second_Comment_Period.pdf
        - Draft_BAL-502-RFC-02_080808_Clean.doc
        - Draft_BAL-502-RFC-02_080808_Redline.doc

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Regional Standard BAL-502-RFC-02 — Planning Resource Adequacy Analysis, Assessment and Documentation

ReliabilityFirst thanks all commenters who submitted comments on the regional reliability standard to BAL-502-RFC-02 — Planning Resource Adequacy Analysis, Assessment and Documentation. This standard was posted for a 45-day public comment period from January 26, 2009 through March 12, 2009. There were 6 sets of comments, including comments from 9 different people from approximately 6 companies representing 5 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/regional_standards/regional_reliability_standards_under_development.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

---

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Sam Ciccone	FirstEnergy Corp.	X		X	X	X	X				
	Dan Huffman		FirstEnergy Solutions	3									
	Dave Folk		FirstEnergy Corp.										
	Doug Hohlbaugh		FirstEnergy Corp.										
2.	Individual	Ray Kershaw	ITCTransmission, METC	X									
3.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X				
4.	Individual	Louis Slade	Dominion Resources Services, Inc.	X		X		X	X				
5.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
6.	Individual	Jianmei Chai	Consumers Energy			X	X	X					

1. Was the proposed standard developed in a fair and open process, using the associated Regional Reliability Standards Development Procedure?

Summary Consideration:

Organization	Yes or No	Question 1 Comment
FirstEnergy Corp.	Yes	
ITCTransmission, METC	Yes	
American Electric Power	Yes	This was evidenced by the SDT adjusting the SAR scope based on industry input.
Response: Thank you for your support.		
Dominion Resources Services, Inc.	Yes	
Duke Energy	Yes	
Consumers Energy	Yes	

2. Does the proposed standard pose an adverse impact to reliability or commerce in a neighboring region or interconnection?

Summary Consideration:

Organization	Yes or No	Question 2 Comment
FirstEnergy Corp.	No	
ITCTransmission, METC	No	
American Electric Power	No	
Dominion Resources Services, Inc.	No	
Duke Energy	No	
Consumers Energy	No	

3. Does the proposed standard pose a serious and substantial threat to public health, safety, welfare, or national security?

Summary Consideration:

Organization	Yes or No	Question 3 Comment
FirstEnergy Corp.	No	
ITCTransmission, METC	No	
American Electric Power	No	
Dominion Resources Services, Inc.	No	
Duke Energy	No	
Consumers Energy	No	

4. Does the proposed standard pose a serious and substantial burden on competitive markets within the interconnection that is not necessary for reliability?

Summary Consideration:

Organization	Yes or No	Question 4 Comment
FirstEnergy Corp.	No	FirstEnergy believes this revised Standard supports competitive markets by shifting the applicability from Load Serving Entities to Planning Coordinators where the requirements can be properly executed in a more efficient manner.
Response: Thank you for your support.		
ITCTransmission, METC	No	
American Electric Power	No	
Dominion Resources Services, Inc.	No	
Duke Energy	No	
Consumers Energy	No	

5. Does the proposed regional reliability standard meet at least one of the following criteria?

- The proposed standard has more specific criteria for the same requirements covered in a continent-wide standard
- The proposed standard has requirements that are not included in the corresponding continent-wide reliability standard
- The proposed regional difference is necessitated by a physical difference in the bulk power system.

Summary Consideration:

Organization	Yes or No	Question 5 Comment
FirstEnergy Corp.		The question is not applicable as no continent-wide standard yet exists regarding resource adequacy assessments. We commend RFC for its initiative in preparing this standard which will likely serve as a benchmark for developing a NERC standard on Resource Adequacy, as planned on the to be initiated NERC Standard Development Project 2009-05 Resource Adequacy Assessments. At the conclusion of that effort, the continued need for this RFC standard will be evaluated.
Response: You are correct, there is currently no standard at the NERC level dealing with resource adequacy assessments. At such time a Continent wide standard related to resource adequacy is approved at the NERC level, the RFC BAL-502-RFC-02 standard will be re-evaluted for its continued need.		
ITCTransmission, METC	Yes and No	ITC voted against this standard in the regional process because from our perspective this standard should work in conjunction with NERC standard MOD-004-1, Capacity Benefit Margin. The underlying basis for MOD-004 is Resource Adequacy as is BAL-502-RFC-02. BAL-502-RFC-02 has minimal reference to the dependency on import capability on some or all systems to meet Resource Adequacy represented by the LOLE requirements of the RFC standard and makes no mention of the need to set aside transmission capacity in the form of CBM to accomplish this. Without such assurances the capacity may not be there when it is needed. R3 and R4 of MOD-004-1 are requirements which include the determination of the Generation Capability Import Requirement or GCIR (R3 is a requirement of the LSE while

Organization	Yes or No	Question 5 Comment
		R4 is a requirement for the Resource Planner). Somewhere in BAL-502-RFC-02, there should have been a requirement to determine the GCIR by that name, or any name that represents the MW value of import required for an entity to meet LOLE requirements. To our knowledge, virtually all States within RFC allow the use of CBM to meet resource adequacy requirements. This is a historical fact. We believe that BAL-502-RFC-02 should be amended to provide a requirement for this calculation, which will be required to meet MOD-004-1 requirements. In its existing form, the regional RFC standard fails to provide for national standard requirements even though the compatibility of the two standards is obvious.
Response: The SDT believes the standard is not in conflict with the draft MOD-004-01 standard. The dependency on transmission to meet these requirements may be dealt with in other reliability standards. This standard allows the flexibility to adopt any future transmission assessment frameworks.		
American Electric Power	Yes	
Dominion Resources Services, Inc.	Yes	
Duke Energy	Yes	
Consumers Energy	Yes	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Regional Reliability Standard
Submittal Review Checklist

Region: Reliability First

Regional Standard Number: BAL-502-RFC-02

Regional Standard Title: Planning Resource Adequacy Analysis, Assessment and Documentation

Date Standard Received: 02/24/09

Date Region Notified of Receipt: 02/24/09

Date NERC Evaluation Completed: 04/07/09

Submittal Review Status:

☒ Complete
☐ Incomplete

Reviewed by:

Stephanie Monzon, Manager of Regional Standards

Gerry Adamski, Vice President and Director of Standards

John Seelke, Manager of Planning

Approved by:

Stephanie Monzon, Manager of Regional Standards

Review of Request for Completeness:

1. Was a concise statement of the basis and purpose (scope) of request supplied?

   ☒ Yes

   ☐ No

2. Was a concise statement of the justification of the request supplied?

   ☒ Yes

   ☐ No

3. Was the text of the regional reliability standard supplied in MS Word format?

   ☒ Yes

   ☐ No

4. Was an implementation plan supplied?

   ☒ Yes

   ☐ No

5. Was the regional entity standard drafting team roster supplied?

   ☒ Yes

   ☐ No

6. Were the names and affiliations of the ballot pool members or names and affiliations of the committee and committee members that approved the submittal of the standard supplied?

   ☒ Yes

   ☐ No

7. Were the final ballot results, including a list of significant minority issues that were not resolved, supplied?

   ☒ Yes

   ☐ No

8. For each public comment period, was a copy of each comment submitted and its associated response along with the associated changes made to the standard supplied?

   ☒ Yes

   ☐ No

Review of Standard for Completeness:

Title

9. Is there a title that provides a brief, descriptive phrase identifying the topic of the standard?

☒ Yes

☐ No

Number

10. Does the standard have a unique identification number not already used by any NERC reliability standard?

☒ Yes

☐ No

Purpose

11. Does the purpose explicitly state what reliability-related outcome will be achieved by the adoption of the standard?

☒ Yes

☐ No

Applicability

12. Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted?

☒ Yes

☐ No

13. Does this reliability standard identify the geographic applicability of the standard, such as the entire interconnection, or within a regional entity area?

☒ Yes

☐ No

14. Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria?

☐ Yes

☒ No (not applicable)

Effective Date

15. Does the effective date start on the 1st day of the 1st quarter after entities are expected to be compliant?

☐ Yes

☒ No

Effective Date:

Upon RFC Board approval

16. Does the effective date provide time to file with applicable regulatory authorities and provide notice to responsible entities of the obligation to comply?

☒ Yes

☒ No Unsure whether the revisions to this standard require implementation time.

Requirements

17. Does each requirement identify the functional entity that is responsible and the action to be performed or the outcome to be achieved?

☒ Yes

☐ No

18. Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest?

☒ Yes

☐ No

19. Are the requirements free of additional comments or statements for which compliance is not mandatory, such as background or explanatory information?

☐ Yes

☐ No

n/a

Violation Risk Factors

20. Is there a Violation Risk Factor (High, Medium, Lower) for each requirement?

☒ Yes

☐ No

Time Horizons

21. Is there a Mitigation Time Horizon (Long-term Planning; Operations Planning; Same-day Operations; Real-time Operations; Operations Assessment) for each requirement?

☐ Yes

☒ No

Measures

22. Does each measure identify to whom the measure applies and the expected level of performance or outcomes required to demonstrate compliance?

☒ Yes

☐ No

23. Is each measure tangible, practical, and as objective as is practical?

☒ Yes

☐ No

24. Does each measure clearly refer to the requirement(s) to which it applies?

☒ Yes

☐

25. Is there a measure for each requirement?

☒ Yes

☐ No

Compliance Monitoring Responsibility

26. Is the 'Electric Reliability Organization' identified as the Compliance Monitor?

☐ Yes

☒ No Compliance Monitor - ReliabilityFirst Corporation.

Compliance Monitoring Period

27. Does the standard identify the time period in which performance or outcomes is measured, evaluated, and then reset?

☐ Yes

☒ No (not applicable)

Data Retention

28. Does the standard identify the data retention requirements and assignment of responsibility for data archiving?

☒ Yes

☐ No

Additional Compliance Information

29. Does the standard identify the process that will be used to evaluate data or information for the purpose of assessing performance or outcomes?

☒ Yes

☐ No

30. Does the standard identify the specific data or information that is required to measure performance or outcomes?

☐ Yes

☒ No

31. Does the standard identify the entity that is responsible for providing data or information for measuring performance or outcomes?

☐ Yes

☒ No

Violation Severity Levels

32. Is there a Violation Severity Level (lower, moderate, high, severe) for violation of each of the requirements?

☒ Yes

☐ No

Associated Documents

33. If there are standards or forms that are referenced within a standard, are the full names and numbers of the standard identified under, 'Associated Documents'.

☐ Yes

☒ No

Definitions

34. Are the definitions used and provided in the standard consistent with the NERC definitions.

☒ Yes

☐ No

Other Observations:

35. Are there any additional comments?

☒ Yes RFC is proposing four regional definitions (if approved applicable to the RFC region)

☐ No

Resource Adequacy - the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses).

Net Internal Demand - Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Load Management and Interruptible Demand.

Peak Period - A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur

Year One - The planning year that begins with the upcoming annual Peak Period.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Reliability*First* (RFC) Resource Adequacy Regional Reliability Standard

Executive Summary

BAL-502-RFC-02 Planning Resource Adequacy Analysis, Assessment and Documentation

Reliability*First*, a Regional Entity, submitted a request to approve the regional reliability standard, BAL-502-RFC-02 Planning Resource Adequacy Analysis, Assessment and Documentation on February 24, 2009 (prior to the closing of the NERC 45-day posting). The basis of their request is that the proposed regional reliability standard is not covered by a NERC continent-wide standard (meeting FERC criteria for approval of a Regional Reliability Standard according to Order 672). NERC posted the regional reliability standard according to the NERC Rules of Procedure for a 45-day public comment period from January 26 – March 12, 2009. NERC submitted its comments to RFC for their review on March 16, 2009. RFC submitted the response to comments to NERC on March 17, 2009 and was subsequently posted on the NERC website. No substantive comments were received during the NERC posting and RFC adequately responded to all comments received. NERC performed an evaluation of the regional reliability standard according to the procedure outlined in the Regional Reliability Standards Evaluation Procedure (http://www.nerc.com/docs/sac/rrswg/NERC_Regional_Reliability_Standards_Development_Procedure_Version%200-0%202007-06-15_dwt.pdf) and found several minor shortcomings in the regional reliability standard.

Standard Review

NERC performed a quality assurance review of the RFC standard, BAL-502-RFC-01 and found several shortcomings as follows:

1. **Missing Time Horizons** the RFC standard does not include Time Horizons for each of the standard's main requirements. Time Horizons are used as described in the NERC Sanctions Guidelines.
2. **Effective Date** the proposed standard states that the effective date is upon RFC Board approval (approved on December 4, 2008). The effective date should follow the latest language found in the standards template to meet the needs of the compliance program, that is, the first day of the first quarter after regulatory approval).
3. **Complex Sub-requirements** the proposed standard contains multiple layers of sub-requirements. It is unclear whether this is absolutely necessary or whether the requirements could be written more concisely for ease of use by the entities expected to comply with the requirements.

116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com

Glossary of Terms

The proposed regional reliability standard is also proposing four defined terms as follows:

> **Resource Adequacy** - the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses).
>
> **Net Internal Demand** - Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Load Management and Interruptible Demand.
>
> **Peak Period** - A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur
>
> **Year One** - The planning year that begins with the upcoming annual Peak Period.

These terms do not appear in the NERC Glossary and do not conflict with existing terms; however, it is noted that the use of terms such as "Year One" represent commonly used terms. These definitions, while applicable to entities within RFC only, may have the unintended consequence of adding confusion to users of the NERC continent-wide standards or other regional entity standards that may also use these terms, albeit without having formally established definitions for them. The potential impact of these proposed definitions should be evaluated.

It is unclear whether the proposed standard is proposing a defined term for "Planning Reserve" as it is used in the standard (Requirement R2.2) and is referenced in capital letters. This term is not in the NERC Glossary nor is one of the terms listed above.

Compliance Elements

The proposed standard contains both Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs). These elements are assigned to the main requirements (R1 and R2); however, the main requirements contain many sub-requirements. The inclusion of sub-requirements, especially at the level of complexity being proposed, without associated compliance elements may conflict with the recent FERC Order (Order 722 Final FAC Order paragraph 42) that directed NERC to develop violation severity levels to all sub-requirements. This is of concern in particular because it is unclear how violation of a particular sub-requirement impacts the overall violation of the base requirement given that there are many sub-requirements, some of which also have their own sub-requirements.

Technical Review of Standard

The following technical suggestions and comments are being offered to RFC in addition to the process and quality evaluation of the proposed standard:

1. **Purpose** Since LOLE is footprint size dependent, a 0.1 day per year criterion won't equate to consistent reliability for the Planning Coordinators (PCs) that are subject to the standard. Please clarify how consistency will be achieved with the proposed standard.
2. **Purpose** There are some PCs within the RFC footprint that have load and resources outside the RFC footprint. Please clarify if PCs within the RFC footprint are expected to only include RFC load and resources in the analysis. If not, the assessment will not be applicable to the RFC region.
3. **Requirement R1.1** While the use of a daily peak (365 hrs. per year) is common, the use of DSM per R1.1.1 means that peaks will be shaved and flattened, which increases exposure to LOL. In other words, the peak may last for 3-4 hours instead of one hour under a heavy DSM scenario for a PC.
4. **Requirement R1.1.1** While it is clear that these interruptions do not constitute a LOL (consider defining LOL)), what is not addressed are these items.
    - Load must be curtailed if operating reserves cannot be maintained. The standard is silent on this topic.
    - What about voltage reductions? Some would count voltage reduction as load loss. See R1.4, seventh bullet.

    In short, the definition of what constitutes a LOL needs to be crisp.
5. **Requirement R1.3.1**
    - All interruptible loads should have an hourly load reduction associated with each daily peak load.
    - Should "curtailable" be stated "Direct Control Load Management" to be consistent with R1.1.1?
6. **Requirement R1.3.4** In addition to documenting the assistance from other interconnected systems add how the assumptions are coordinated.

ReliabilityFirst (RFC)
Resource Adequacy Regional Reliability Standard

Executive Summary

BAL-502-RFC-02 Planning Resource Adequacy Analysis, Assessment and Documentation

Reliability*First*, a Regional Entity, submitted a request to approve the regional reliability standard, BAL-502-RFC-02 Planning Resource Adequacy Analysis, Assessment and Documentation on February 24, 2009 (prior to the closing of the NERC 45-day posting). The basis of their request is that the proposed regional reliability standard is not covered by a NERC continent-wide standard (meeting FERC criteria for approval of a Regional Reliability Standard according to Order 672). NERC posted the regional reliability standard according to the NERC Rules of Procedure for a 45-day public comment period from January 26 – March 12, 2009. NERC submitted its comments to RFC for their review on March 16, 2009. RFC submitted the response to comments to NERC on March 17, 2009 and was subsequently posted on the NERC website. No substantive comments were received during the NERC posting and RFC adequately responded to all comments received. NERC performed an evaluation of the regional reliability standard according to the procedure outlined in the Regional Reliability Standards Evaluation Procedure (http://www.nerc.com/docs/sac/rrswg/NERC_Regional_Reliability_Standards_Development_Procedure_Version%200-0%202007-06-15_dwt.pdf) and found several minor shortcomings in the regional reliability standard.

Standard Review

NERC performed a quality assurance review of the RFC standard, BAL-502-RFC-01 and found several shortcomings as follows:

1. **Missing Time Horizons** the RFC standard does not include Time Horizons for each of the standard's main requirements. Time Horizons are used as described in the NERC Sanctions Guidelines.
   Time Horizons are not listed within the NERC and FERC approved Reliability*First* Reliability Standards Development Procedure. Including them in the regional standard would have been a deviation. Since the standard is focused on a "planning oriented" subject matter for one year and beyond, they could be interpreted on a relatively straight forward basis for compliance on an interim basis.

2. **Effective Date** the proposed standard states that the effective date is upon RFC Board approval (approved on December 4, 2008). The effective date should follow the latest language found in the

116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com

standards template to meet the needs of the compliance program, that is, the first day of the first quarter after regulatory approval).
The proposed standard effective date would only be applicable to Reliability*First* members on approval by the Reliability*First* Board and the enforcement mechanism would be as a "Term of Membership" under the Reliability*First* By-Laws (no financial penalties). Only after both NERC and FERC approval will the standard be effective to all applicable entities within the Reliability*First* footprint with the possibility of financial penalties. The "standards template" wording reference is designed for continent-wide standards applicable across all the regions. Development of a regional standard is focused on applicability, implementation and compliance within that region as best blends with that regions processes and characteristics.

3. **Complex Sub-requirements** the proposed standard contains multiple layers of sub-requirements. It is unclear whether this is absolutely necessary or whether the requirements could be written more concisely for ease of use by the entities expected to comply with the requirements.
The extent of the organizational structure of requirements is a functional of the depth and breath of the audience that the standard is being written for. This standard has a limited number of applicable entities, all of which were members of the drafting team that developed the language. Reliability*First* believes the multiple layers of sub-requirements are needed to clarify the intent of the standard and meet the understandability needs of the entities that will use it.

Glossary of Terms

The proposed regional reliability standard is also proposing four defined terms as follows:

Resource Adequacy - the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses).

Net Internal Demand - Total of all end-use customer demand and electric system losses within specified metered boundaries, less Direct Control Load Management and Interruptible Demand.

Peak Period - A period consisting of two (2) or more calendar months but less than seven (7) calendar months, which includes the period during which the responsible entity's annual peak demand is expected to occur

Year One - The planning year that begins with the upcoming annual Peak Period.

These terms do not appear in the NERC Glossary and do not conflict with existing terms; however, it is noted that the use of terms such as "Year One" represent commonly used terms. These definitions, while applicable to entities within RFC only, may have the unintended consequence of adding confusion to users of the NERC continent-wide standards or other regional entity standards that may also use these terms, albeit without having formally established definitions for them. The potential impact of these proposed definitions should be evaluated.

A word search of the approved NERC Reliability Standards indicated that the words "year one" are not used in any of such standards. NERC SDTs have considered developing such a definition but none have been finalized to date. The words have been interpreted, inferred and often times possibly mis-used in conversation and documents with probable confusion due to lack of a definition. Reliability*First* believes this regional definition not only eliminates confusion for this standard but also provides a starting point for all other drafting teams to work from. This definition provides a positive start for the elimination of confusion that will continue to exist if some focal point is not established. This issue is not unique to Reliability*First* and should be dealt with at the NERC level by promoting the development and refinement of definitions that will help eliminate industry confusion for words and terms that have generic understandings. This issue is currently being discussed at the Regional Reliability Standards Working Group (RRSWG) level.

It is unclear whether the proposed standard is proposing a defined term for "Planning Reserve" as it is used in the standard (Requirement R2.2) and is referenced in capital letters. This term is not in the NERC Glossary nor is one of the terms listed above.
"Planning Reserve" is not a proposed defined term. The capital letters were an inadvertent typing entry. The standard will be modified accordingly.

Compliance Elements

The proposed standard contains both Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs). These elements are assigned to the main requirements (R1 and R2); however, the main requirements contain many sub-requirements. The inclusion of sub-requirements, especially at the level of complexity being proposed, without associated compliance elements may conflict with the recent FERC Order (Order 722 Final FAC Order paragraph 42) that directed NERC to develop violation severity levels to all sub-requirements. This is of concern in particular because it is unclear how violation of a particular sub-requirement impacts the overall violation of the base requirement given that there are many sub-requirements, some of which also have their own sub-requirements.
This standard was developed under the directions and understanding provided to drafting teams, regional and NERC, at the time. This issue has affected all standards development at regional and NERC levels. It is currently being dealt with at the NERC level and Reliability*First* will closely watch the interaction and outcome of future NERC and FERC submissions/filings and Orders related to this issue and make revisions to the standards as required for compliance; however, the requirements themselves will remain as approved for this purpose.

Technical Review of Standard

The following technical suggestions and comments are being offered to RFC in addition to the process and quality evaluation of the proposed standard:

1. **Purpose** Since LOLE is footprint size dependent, a 0.1 day per year criterion won't equate to consistent reliability for the Planning Coordinators (PCs) that are subject to the standard. Please clarify how consistency will be achieved with the proposed standard.

From a practical standpoint, Reliability*First* consists of only four Planning Coordinators within its footprint (PJM and MISO will most likely be performing the analysis with ATC and OVEC delegating the responsibility to either PJM or MISO). Through the standard, the analysis and planning reserve margin will be calculated in a consistent manner. Also, if a study is done properly, including assistance that may be available from adjacent areas, size of footprint should not impact the result. Reliability*First* does not agree with the premise of this question unless the commenter is judging "reliability" on a different criterion than the stated formula in the standard.

2. **Purpose** There are some PCs within the RFC footprint that have load and resources outside the RFC footprint. Please clarify if PCs within the RFC footprint are expected to only include RFC load and resources in the analysis. If not, the assessment will not be applicable to the RFC region.
The intent is to cover all load within the RFC footprint. Planning Coordinators may include load outside the RFC footprint as deemed appropriate. Even if a Planning Coordinator has load outside of the Reliability*First* footprint, as long as it operates as a single area, the adequacy of that Planning Coordinator area will indicate adequacy of the part of the area within the Reliability*First* footprint. From a converse perspective, if the Planning Coordinator operates as a single area, that area must be assessed as a whole or the assessment will be inadequate for the area within the RFC footprint. (If transmission constraints exist, the Planning Coordinator's constrained areas would have to be addressed separately in any event.)

3. **Requirement R1.1** While the use of a daily peak (365 hrs. per year) is common, the use of DSM per R1.1.1 means that peaks will be shaved and flattened, which increases exposure to LOL. In other words, the peak may last for 3-4 hours instead of one hour under a heavy DSM scenario for a PC.
Such exposure to loss of load events of over one hour duration has always existed in calculating LOLE on the basis of daily one-hour peaks. Historically, duration of an event has not been a factor in the calculation. Even without DSM, there is some probability of multi-hour events that would only count as "one day" in the LOLE calculation. The use of hourly peaks and the 1 in 10 criterion is based on many years of experience. Actual system performance, which included huge variations in the use of DSM over many years and systems, has provided the basis for the correlation between such a calculated LOLE value and the fact that systems "approached" loss of load due to generation deficiencies. The criterion was established as a retrofit to what appeared to be acceptable reliability. Until and unless system performance changes over the course of many years, the Reliability*First* approach is appropriate and consistent with planning reserves established by many companies and regulators alike.

4. **Requirement R1.1.1** While it is clear that these interruptions do not constitute a LOL (consider defining LOL)), what is not addressed are these items.
    - Load must be curtailed if operating reserves cannot be maintained. The standard is silent on this topic.
    - What about voltage reductions? Some would count voltage reduction as load loss. See R1.4, seventh bullet.

    One must realize that the standard specifies a level of resource adequacy based on a defined calculation, primarily from the planner's and secondarily from the operator's perspective. It

is silent on issues such as maintaining operating reserves because it does not address the issue from the customer perspective. In other words, "loss of load" as used in the standard does not really mean "loss of customer load" -- though it might have meant something close to that several decades ago, when the term originated, when rules on maintaining operating reserves were loose. Even from an operating perspective, it is theoretically conceivable that real time operating reserves could go beyond normal levels without the operator dropping load provided he takes the risk. Such a situation has occurred over decades of system operations. The calculation has already considered the probability of additional units failing.

In short, the definition of what constitutes a LOL needs to be crisp.
Reliability*First* believes the requirements explicitly state what constitutes a LOL.

5. **Requirement R1.3.1**
   - All interruptible loads should have an hourly load reduction associated with each daily peak load.
     This would be covered by 1.3.1 bullet 5, Daily demand modeling assumptions. The standard does not need to be overly prescriptive.

   - Should "curtailable" be stated "Direct Control Load Management" to be consistent with R1.1.1?
     The BAL-502-RFC-02 standard has already been approved by industry and the Reliability*First* Board and no further changes are allowed. The suggested additional detail will be considered on next revision.

6. **Requirement R1.3.4** In addition to documenting the assistance from other interconnected systems add how the assumptions are coordinated.
   This assistance is from a study perspective only and includes projected assistance calculated on a probabilistic basis. Data for a study can be obtained from any number of sources, including, on one extreme, adjacent Planning Coordinators and, on the other, commercially available databases. Therefore no direct coordination needs to be prescribed.

Need for ReliabilityFirst Resource Adequacy Standard

Summary

NERC and the industry have long recognized the importance of an adequate supply of electricity in ensuring and maintaining a reliable bulk electric system. Indeed, adequacy has always been one of the foundations of NERC's definition of reliability. From NERC's document defining an adequate level of reliability:

"NERC's traditional definition of "reliability" was ubiquitous throughout the electric utility industry, and consists of two fundamental concepts: adequacy and operating reliability:

Adequacy is the ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.

Operating reliability is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

The NERC Operating Policies and Planning Standards were based on these concepts, and most of those policies and standards were translated into NERC's Reliability Standards."

With the advent of deregulation and retail choice, it has become more difficult to identify *who* is actually responsible for adequacy of electric supply today. The Reliability*First* footprint is comprised of both retail choice and non-retail choice states and there is no single organization or regulator responsible for resource adequacy. This necessitates a Reliability Standard to identify those responsible to properly plan and maintain the reserves necessary to safeguard reliability.

In order to fairly and completely apply such a standard, it is necessary that the standard become mandatory and enforceable uniformly across the entire footprint. Simply adopting requirements as criteria that are applicable only to the members of a Region could result in existing members discontinuing membership but continuing operations in the Region or new entities commencing operation without becoming members, putting the remaining members at an unfair disadvantage and also jeopardizing reliability. In addition making the standard mandatory and enforceable on every applicable entity operating in the Reliability*First* footprint that also operates in an adjacent region acts as a linchpin and incentive to foster the development of consistent requirements and more wide spread application of the industry accepted practices, thereby promoting system reliability.

The ReliabilityFirst standard has been developed in an open, transparent, inclusive fashion. Workshops were conducted jointly with other Regions and our RTO members and state regulators during the drafting of the standard. The standard has wide support from our ballot body and regulatory agencies, who see this as a meaningful and necessary step forward toward solving a long standing problem.

The standard has been reviewed by legal counsel to ensure that it is consistent with the provisions and stated goals of the Energy Policy Act of 2005. The standard does not require the building or acquisition of new generating capacity.

Background and Additional Details

For decades the electric power industry has acknowledged the importance of performing studies to determine when and how much generating capacity needs to be installed to ensure a reliable electric supply to customer loads in the event that some generating capacity is forced out of service due to equipment failure, taken out of service for maintenance or a combination of both. In addition the studies need to consider the deliverability of generating capacity based on location and the probability of the aggregated customer demand being greater than expected. Experience has demonstrated that correlating generating capacity and customer load in a “loss of load” methodology with a target of “one day in 10 year” criterion has provided adequate generating capacity in decades of real time operation (at some times in conjunction with operating measures such as voltage reduction and exercising interruptibles, etc.) to supply all customer firm loads even under extreme conditions.

NERC has also acknowledged the importance of this work when it initiated a SAR for the development of an associated Reliability Standard. This effort is still in the initial development stage and drafting of a standard has yet to begin. Reliability*First* (RFC) on the other hand has as a result of the activities of its legacy regions developed a resource adequacy standard which was approved by the RFC Board as early as 3/9/06. The MAIN legacy region had for years performed “loss of load” studies and established “planning reserve” levels to meet the “one day in 10 year” criterion. This methodology was traditionally used by numerous vertically integrated utilities to justify generating capacity to State Commissions. MAIN actually conducted a “supply” audit each year to verify resources were contracted for. The MAAC legacy region had even developed a program that verified adequate resources were in place to meet a “planning reserve” target backed by financial implications. Based on the importance of this work, RFC began development of a resource adequacy standard applicable across the entire region even before RFC officially commenced operation. Since that time RFC has updated the standard to the now acceptable Reliability Standard format and removed a requirement that has been questioned on its legal basis. The revised RFC standard was RFC Board approved 12/4/08.

RFC believes that this standard is vital to developing a reliable system power system. In some aspects the required studies could be viewed as even more important than operating reserves in the sense that operating reserves could not even exist if these required studies were not performed. When the industry was first deregulated, the dependence on operating signals giving sufficient notice to install additional generating capacity did not necessarily achieve the most reliable conditions. Although NERC may be in the development stage, waiting for a final NERC product will leave a time gap in requiring these studies. Implementating the RFC standard as a simple RFC criteria clearly downgrades its importance. Elevating this standard to the enforceable level stresses its importance and provides a basis for NERC and other regions to build further development on. Approval of the RFC standard for enforcement signals the need and importance of requiring these studies and provides an impedious to develop more wide spread and consistent application.

Exhibit D

Standard Drafting Team Roster

Planned Resource Adequacy Assessment Standard Drafting Team Roster

Contact	Company	Email	Phone
Guy V. Zito	NPCC	gzito@npcc.org	212-840-1070
Donald M. Schlegel	AEP Service Corp.	dmschlegel@aep.com	614-716-2320
Thomas M. Moleski	PJM Interconnection	moleski@pjm.com	610-666-8826
Jesse Moser	Midwest ISO	jmoser@midwestiso.org	651-632-8433
Daniel G. Huffman	FirstEnergy Solutions	huffmand@firstenergycorp.com	330-315-7262
Eric Mortenson	Exelon Energy Delivery	eric.mortenson@exeloncorp.com	630-576-6898
Kenneth Copp	American Transmission Company	kcopp@atcllc.com	262-506-6890
Thomas C. Mielnik	MidAmerican Energy Company	tcmielnik@midamerican.com	563-333-8129
Paul Kure	RFC Engineering	Paul.kure@rfirst.org	330-247-3057
Bob Millard	RFC Standards	Bob.millard@rfirst.org	330-247-3044
Anthony Jablonski	RFC Standards	anthony.jablonski@rfirst.org	330-247-3054

Exhibit E

BAL-502-RFC-02 Violation Severity Level Analysis

					EXPLANATION OF CONSISTENCY WITH GUIDELINES OR CHANGES, AS APPLICABLE Standard Number BAL-502-RFC-02 Planning Resource Adequacy Analysis, Assessment and Documentation					
Req#	Lower VSL	Moderate VLS	High VSL	Severe VSL	Explanation of Changes	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	**VSL Components**
R1					N/A	The VSLs for the stated requirement are not based on numeric gradations. Instead, they are based on the number of sub requirements an entity did not comply with. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic	The VSLs comply with Guideline 2. The requirement has gradated VSLs; therefore, Guideline 2a is not applicable. The gradated VSLs ensure uniformity and consistency among all approved Reliability Standards in the determination of penalties. Thus, no changes to the VSLs	The SDT reviewed the existing requirement VSLs to the stated requirement language to ensure the VSLs do not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance	The VSL assignments comply with Guideline 4, because they are based on a single violation of a Reliability Standard and are not based on a cumulative number of violations of the same requirement over a period of time.	The SDT rolled-up "sub-requirements" (now referenced as "components") into the primary requirement, because they were elements of the primary requirement and they work together to address a common reliability objective. As a result, the VSL(s)

						level of compliance.	were required. Additionally, the VSL DT has reviewed the VSL text and has determined that, as written, the VSL text is clear, specific and objective and does not contain general, relative or subjective language satisfying Guideline 2b. Thus, the text is not subject to the possibility of multiple interpretations of the VSL(s) and provides the clarity needed to permit the consistent and objective application of the VSL(s) in the determination of penalties by the Compliance Enforcement Authority.	can be determined objectively and with certainty.		associated with the sub-requirement(s) was/were rolled-up into the primary requirement. NERC submitted an informational filing on its comprehensive approach to the assignment of VSLs and Violation Risk Factors to FERC on August 10, 2009. This approach applies a single comprehensive set of VSLs to categorize noncompliance with the main requirement and the components that contribute to the main requirement. This new approach ensures consistency in the determination of sanctions. It provides clarity for the users, owners and operators of the bulk power system, and provides increased effectiveness in administration and oversight of the standards.

										Consistent with the approach set forth in that filing, Requirement elements formerly designated as “subrequirements” are now referenced as component parts of the main requirement. The main requirement VSL applies. Because the components are part of the main requirement and do not achieve a reliability objective separate from the main requirement.
R1.1					Rolled up “sub requirements” (components) into the primary requirement.					
R1.1.1					Rolled up “sub requirements” (components) into the primary requirement.					

R1.1.2					Rolled up “sub requirements” (components) into the primary requirement.					
R1.2					Rolled up “sub requirements” (components) into the primary requirement.					
R1.2.1					Rolled up “sub requirements” (components) into the primary requirement.					
R1.2.2					Rolled up “sub requirements” (components) into the primary requirement.					
R1.2.2.1					Rolled up “sub requirements” (components) into the primary requirement.					
R1.3					Rolled up “sub requirements” (components) into the primary requirement.					

R1.3.1					Rolled up “sub requirements” (components) into the primary requirement.					
R1.3.2					Rolled up “sub requirements” (components) into the primary requirement.					
R1.3.3					Rolled up “sub requirements” (components) into the primary requirement.					
R1.3.3.1					Rolled up “sub requirements” (components) into the primary requirement.					
R1.3.4					Rolled up “sub requirements” (components) into the primary requirement.					
R1.4					Rolled up “sub requirements” (components) into the primary requirement.					

R1.4					Rolled up "sub requirements" (components) into the primary requirement.					
R1.6					Rolled up "sub requirements" (components) into the primary requirement.					
R1.7					Rolled up "sub requirements" (components) into the primary requirement.					
R2					**N/A**	The VSLs for the stated requirement are not based on numeric gradations. Instead, they are based on the number of sub requirements an entity did not comply with. As written, the VSL assignments comply with Guideline 1, because the VSLs do not have the unintended consequence of lowering the current or historic level of compliance.	The VSLs comply with Guideline 2. The requirement has gradated VSLs; therefore, Guideline 2a is not applicable. The gradated VSLs ensure uniformity and consistency among all approved Reliability Standards in the determination of penalties. Thus, no changes to the VSLs were required. Additionally, the VSL DT has reviewed the VSL text and has determined that, as written, the VSL text is clear, specific and	The DT reviewed the existing requirement VSLs to the stated requirement language to ensure the VSLs do not redefine or undermine the requirement's reliability goal. In accordance with Guideline 3, the VSL assignment(s) are consistent with the requirement and the degree of compliance can be determined objectively and with certainty.	The VSL assignments comply with Guideline 4, because they are based on a single violation of a Reliability Standard and are not based on a cumulative number of violations of the same requirement over a period of time.	The VSL DT rolled-up sub-requirements into the primary requirement, because they were elements of the primary requirement and they work together to address a common reliability objective. As a result, the VSL(s) associated with the sub-requirement(s) was/were rolled-up into the primary requirement. NERC submitted an informational filing on its comprehensive

							objective and does not contain general, relative or subjective language satisfying Guideline 2b. Thus, the text is not subject to the possibility of multiple interpretations of the VSL(s) and provides the clarity needed to permit the consistent and objective application of the VSL(s) in the determination of penalties by the Compliance Enforcement Authority.			approach to the assignment of VSLs and Violation Risk Factors to FERC on August 10, 2009. This approach applies a single comprehensive set of VSLs to categorize noncompliance with the main requirement and the components that contribute to the main requirement. This new approach ensures consistency in the determination of sanctions. It provides clarity for the users, owners and operators of the bulk power system, and provides increased effectiveness in administration and oversight of the standards. Consistent with the approach set forth in that filing, Requirement elements formerly designated as “subrequirements” are now referenced as component parts

										of the main requirement. The main requirement VSL applies. Because the components are part of the main requirement and do not achieve a reliability objective separate from the main requirement.
R2.1					Rolled up "sub requirements" (components) into the primary requirement.					
R2.2					Rolled up "sub requirements" (components) into the primary requirement.					
R2.3					Rolled up "sub requirements" (components) into the primary requirement.					