



NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

June 29, 2010

VIA FEDERAL EXPRESS

Ms. Nancy McNeil
Regulatory Affairs Officer/Clerk
Nova Scotia Utility and Review Board
1601 Lower Water Street, 3rd Floor
Halifax, Nova Scotia B3J 3P6

RE: Application For Approval of Regional Reliability Criteria

Dear Ms. McNeil:

Pursuant to the May 11, 2010 Memorandum of Understanding between and among Nova Scotia Power Incorporated, the North American Reliability Corporation and the Northeast Power Coordinating Council, Inc. (NPCC), please find enclosed two (2) copies of NPCC's Application For Approval of Regional Reliability Criteria in Nova Scotia. An additional version will be sent to you electronically.

Yours very truly,

Edward A. Schwerdt
President and Chief Executive Officer

Enclosures

c (w/o enc.) Gerry Cauley, NERC
 David Cook, NERC
 S. Bruce Outhouse, Q.C., Board Counsel
 Nicole Godbout, Regulatory Counsel, NSPI
 Eric Ferguson, Director, Regulatory Affairs
 Margaret Mayora, NPCC

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**BEFORE THE
NOVA SCOTIA UTILITY AND REVIEW BOARD
OF THE PROVINCE OF NOVA SCOTIA**

**NORTHEAST POWER)
COORDINATING COUNCIL, INC.)**

APPLICATION FOR APPROVAL OF REGIONAL RELIABILITY CRITERIA

The Northeast Power Coordinating Council, Inc. (“NPCC”) hereby applies for approval of the Regional Reliability Criteria set out in Exhibit C by the Nova Scotia Utility and Review Board (“NSUARB”) on behalf of the Province of Nova Scotia. NPCC is a signatory to the May 11, 2010 Memorandum of Understanding (“MOU”) with Nova Scotia Power Incorporated (“NSPI”) and the North American Reliability Corporation (“NERC”) setting forth the framework in relation to the approval and implementation of mandatory NERC Reliability Standards and NPCC Regional Reliability Criteria in Nova Scotia and other related matters. The MOU supports a prior memorandum of understanding between NSUARB and NERC reflecting the mutual desire for a continuing and cooperative relationship in improving reliability of the North American bulk power system and the exchange of experience, information and data related to that system. In furtherance of the goals of that prior memorandum and pursuant to the terms of the MOU, NPCC respectfully submits this filing for approval of Regional Reliability Criteria.¹

¹ More specifically, the MOU, at section 2, provides that “NERC will prepare a consolidated filing for NSUARB approval which includes all approved NERC Reliability Standards. Concurrently, NPCC will prepare a consolidated filing for NSUARB approval which includes all NPCC Regional Reliability Criteria.”

1 NPCC, one of eight Regional Entities in North America, is responsible for promoting
2 and enhancing the reliability and efficient operation of the international interconnected
3 bulk power system in Northeastern North America. NPCC, as a cross-border Regional
4 Entity, has been delegated authority within the United States (“U.S.”) from NERC, a not-
5 for-profit corporation that is certified² by the U.S. Federal Energy Regulatory Commission
6 (“FERC”) as the “electric reliability organization” under Section 215 of the Federal Power
7 Act. That delegation is memorialized in the Amended and Restated Regional Delegation
8 Agreement that was approved by the FERC on June 5, 2007. Among other things, NPCC
9 exercises its delegated authority by:

- 10 • Actively participating in the development of North American Reliability
11 Standards for the bulk power system, and, as needed, development of Regional
12 Reliability Standards applicable within the NPCC international region
- 13 • Monitoring and enforcing approved Reliability Standards, including the
14 registration of responsible entities, and, as needed, certification of such entities
- 15 • Assessing the present and future reliability of the bulk power system
- 16 • Providing operational coordination and situational awareness support
- 17 • Performing event analysis and identifying lessons learned to improve reliability
- 18 • Providing effective training and education of reliability personnel
- 19 • Promoting the protection of critical electric infrastructure.

² Through its enactment of the Energy Policy Act of 2005 (“the Act”), the U.S. Congress entrusted FERC with the duties of approving and enforcing rules in the U.S. to ensure the reliability of the Nation’s bulk power system, and with the duties of certifying an electric reliability organization (“ERO”) that would be charged with developing and enforcing mandatory Reliability Standards, subject to FERC approval. On July 20, 2006, FERC certified NERC as the ERO, charged with developing mandatory and enforceable Reliability Standards, which are subject to FERC review and approval.

1 In Canada, NPCC has signed Memoranda of Understanding and Agreements with
2 applicable Canadian Provincial regulatory and/or governmental authorities to support the
3 approval and application of mandatory Standards and Criteria in the Canadian jurisdictions of
4 Ontario, Quebec, New Brunswick and Nova Scotia.

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1 **I. INTRODUCTION**

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3 NPCC is filing this notice to provide the Province of Nova Scotia a description of

4 the fourteen Regional Reliability Criteria proposed for adoption in the province. These

5 criteria are listed and summarized in Exhibits A and B, respectively. Exhibit C includes

6 the criteria that are currently published and these appear in two formats: Criteria

7 documents (denominated with the prefix “A”) and Directories. The Criteria document

8 format pre-dates the Directory format; NPCC is currently in the process of converting the

9 Criteria documents, and their associated criteria, into Directory documents and retiring

10 the Criteria document once the resulting Directory is approved. Upon completion of this

11 multi-year project, only NPCC Directories will exist. These Directories contain not only

12 the criteria but also additional supporting guidance documents on how an entity may

13 achieve the criteria’s reliability objective. In addition, the Directories utilize the most

14 recent NERC Functional Model language to identify to which functions the criteria apply

15 and also have any redundancy to NERC Reliability Standards removed. The NPCC

16 Directory documents also have been reviewed to ensure that there no inconsistency exists

17 with any NERC Reliability Standard.

18 All NPCC Reliability Criteria in this filing have been approved by a vote of the

19 Full Members of NPCC, including NSPI, on the dates listed in Exhibit A, based on

20 recommendations by the NPCC Reliability Coordinating Committee, in accordance with

21 the version of the NPCC Bylaws that were in effect at the time of the individual

22 Reliability Criteria’s approval, as amended to date. Under the NPCC Bylaws, each Full

1 Member of NPCC voluntarily agrees to plan, design and operate its bulk power system in
2 compliance with NPCC Reliability Criteria.

3 In support of its request for approval by the NSUARB of the Reliability Criteria,
4 NPCC submits the following information: (1) a listing of the Reliability Criteria approved
5 by the Full Members of NPCC (Exhibit A), which are currently effective; (2) a summary
6 of the current effective Reliability Criteria approved by Full Members of NPCC,
7 including the criteria's purpose and applicability (Exhibit B); and (3) copies of the
8 Reliability Criteria approved by Full Members of NPCC (Exhibit C).

9
10 **II. NOTICES AND COMMUNICATIONS**

11
12 Notices and communications regarding this Application may be addressed to:

13
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1 **III. REQUEST FOR APPROVAL OF RELIABILITY CRITERIA**

2 This section provides a summary of NPCC's proposed Regional Reliability
3 Standard to be filed at a later date and existing Regional Reliability Criteria.

4
5 **A. NPCC's Filing of Proposed Regional Reliability Standard**

6 Pursuant to the execution and implementation of a Regional Delegation
7 Agreement with the ERO and applicable Canadian Memoranda of Understanding or
8 Agreements that are backstopped by the FERC and Canadian Provincial governmental
9 and/or regulatory authorities, NPCC has been delegated the authority by the ERO to
10 create Regional Reliability Standards to enhance the reliability of the international,
11 interconnected bulk power system in Northeastern North America. These Regional
12 Reliability Standards are more specific and/or more stringent than the ERO Reliability
13 Standards. Regional Standards are developed and revised according to a NERC ERO and
14 FERC approved [NPCC Regional Reliability Standards Development Procedure](#). In the
15 development and enforcement of Regional Reliability Standards, NPCC, to the extent
16 possible, facilitates attainment of fair, effective, efficient, and competitive electric
17 markets while providing an open, transparent, fair and inclusive process that has no
18 financial barriers to participation. Anyone can submit a [Regional Standards](#)
19 [Authorization Request](#) to develop a new, or revise an existing Regional Standard.

20 These Standards will, in all cases, not be inconsistent with or less stringent than
21 any requirements of the NERC/ERO Reliability Standards. Each Regional Reliability
22 Standard shall enable or support one or more of the NERC reliability principles, thereby

1 ensuring that each Regional Standard serves a purpose in support of the reliability of the
2 regional bulk power system. Each Regional Reliability standard shall also be consistent
3 with all of pertinent reliability principles and criteria, thereby ensuring that no Regional
4 Reliability standard undermines reliability through an unintended consequence.

5 Currently, NPCC has one Regional Reliability Standard approved by the General
6 Members, including NSPI, which is on file with NERC. The standard, PRC-002-NPCC-
7 1 Disturbance Monitoring is scheduled for NERC approval in 2010 and ultimately will be
8 filed with FERC and the applicable Provincial Canadian regulatory and/or governmental
9 authorities for approvals. Three other standards are in various stages of development and
10 will be the subject of future filings with the NSUARB.

11 12 **B. Overview of NPCC's Regional Reliability Criteria**

13 The reliability criteria are contained in the Directories and Criteria documents
14 listed below:

15 Directory # 1, – Design and Operation of the Bulk Power System

16 Directory # 2, - Emergency Operations

17 Directory # 3, - Maintenance Criteria for Bulk Power System Protection

18 Directory # 4, - Bulk Power System Protection Criteria

19 Directory #7, - Special Protection Systems

20 Directory # 8, - System Restoration

21 Directory # 9, - Generator Gross/Net Real Power Capability

22 Directory # 10, - Generator Gross/Net Reactive Power Capability

23 Directory # 12, - Underfrequency Load Shedding Program Requirements

24 Criteria A-6, - Operating Reserve Criteria

25 Criteria A-7, - Glossary of Terms
26

1 Criteria A-8, - Reliability Enforcement and Compliance Program

2 Criteria A-10, - Classification of Bulk Power System Elements

3 Criteria A-15, - Disturbance Monitoring Equipment Criteria

4

5 The NPCC-approved Regional Reliability Criteria are found in Section 5 of each of the

6 above listed Directories and in the main body of the text appearing in the Criteria

7 documents. The Directories also include contextual information associated with the

8 criteria, including guidelines and procedures that are recommended to meet the reliability

9 objectives found in the criteria portions of the directories. These Directories with their

10 associated criteria and Criteria documents were adopted by the Full Members of NPCC

11 on the dates indicated in Exhibit A, based on recommendation by the NPCC Reliability

12 Coordinating Committee, in accordance with the NPCC Bylaws in effect at the time of

13 their approval, as amended to date.

14

15 “Executive level” summaries of the pertinent aspects of the submitted Directories

16 and Criteria documents appear in Exhibit B.

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19 **VI. CONCLUSION**

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21 By this filing, NPCC requests that the NSUARB approve the application of the

22 Regional Reliability Criteria appearing in the Directories and Criteria documents in

23 Exhibit C. NPCC looks forward to working with the Province of Nova Scotia to make its

24 Regional Reliability Criteria mandatory and enforceable in Nova Scotia.

1 NPCC also requests the Province to provide feedback on the adequacy of the
2 information provided with this filing and guidance on the appropriate information to be
3 included in future filings.

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10 Respectfully submitted,

11 */s/ Edward A. Schwerdt*

12
13 Edward A. Schwerdt
14 President and Chief Executive
15 Officer
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Exhibit A

List of Approved Directories and Criteria

Criteria Document Type, Number	Title	Date of Full Member Approval
Directory 1	Design and Operation of the Bulk Power System	December 1, 2009
Directory 2	Emergency Operations	October 21, 2008
Directory 3	Maintenance Criteria for Bulk Power System Protection	July 11, 2008
Directory 4	Bulk Power System Protection Criteria	December 1, 2009
Directory 7	Special Protection Systems	December 27, 2007
Directory 8	System Restoration	October 21, 2008
Directory 9	Verification of Generator Gross and Net Real Power Capability	December 22, 2008
Directory 10	Verification of Generator Gross and Net Reactive Power Capability	December 22, 2008
Directory 12	Underfrequency Load Shedding Program Requirements	March 3, 2010
Criteria A6	Operating Reserve Criteria	December 29, 2008
Criteria A7	Glossary of Terms	July 17, 2007
Criteria A8	Reliability Compliance Enforcement Program	December 20, 2007
Criteria A10	Classification of Bulk Power System Elements	December 1, 2009
Criteria A15	Disturbance Monitoring Equipment Criteria	August 23, 2007



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Exhibit B

Summary of Approved Directories and Criteria

Directory 1, **Design and Operation of the Bulk Power System**
Approved, December 1, 2009

The objective of these criteria is to provide a “design-based approach” to ensure the bulk power system is designed and operated to a level of reliability such that the loss of a major portion of the system, or unintentional separation of a major portion of the system, will not result from any design contingencies referenced in Sections 5.4.1 and 5.4.2. In NPCC the technique for assuring the reliability of the bulk power system is to require that it be designed and operated to withstand representative contingencies as specified in this Directory. Analyses of simulations of these contingencies include assessment of the potential for widespread cascading outages due to overloads, instability or voltage collapse. Loss of small portions of a system (such as radial portions) may be tolerated provided these do not jeopardize the reliability of the remaining bulk power system.

Criteria described in this document are to be used in the design and operation of the bulk power system. These criteria are applicable to all entities which are part of or make use of the bulk power system.

The characteristics of a reliable bulk power system include adequate resources and transmission to reliably meet projected customer electricity demand and energy requirements as prescribed in this document and include:

- a. Consideration of a balanced relationship among the fuel type, capacity, physical characteristics (peaking/base load/etc.), and location of resources.
- b. Consideration of a balanced relationship among transmission system elements to avoid excessive dependence on any one transmission circuit, structure, right-of-way, or substation.
- c. Transmission systems should provide flexibility in switching arrangements, voltage control, and other control measures.

Directory 2, **Emergency Operations**

Approved, October 21, 2008

The purpose of this Directory is to present the basic factors to be considered in formulating plans and procedures to be followed in an emergency or during conditions which could lead to an emergency, in order to facilitate mutual assistance and coordination within NPCC and adjacent areas.

The objectives in formulating plans related to emergency operating conditions are:

1. To avoid the interruption of service to firm load to the extent possible.
2. To minimize the occurrence of system disturbances.
3. To contain any system disturbance and limit its effects to the area initially affected.
4. To minimize the effects of any system disturbances on customers.
5. To avoid damages to system elements.
6. To avoid hazard to the public.

Directory 3, **Maintenance Criteria for Bulk Power System Protection**

Approved, July 11, 2008

The purpose of this Directory is to present the basic maintenance requirements for bulk power system protection systems. It is recognized that responsible entities may choose to apply more rigid requirements because of local considerations.

Directory 4, **Bulk Power System Protection Criteria**

Approved, December 1, 2009

The purpose of this Directory is to provide the protection criteria, for protection of the NPCC bulk power system. It is not a design specification.

Directory 7, **Special Protection Systems**
Approved, December 27, 2007

Provide the basic criteria for Special Protection Systems such that the Bulk Power System in NPCC Inc. member Areas is operated reliably.

The documents outlines the approval process that an entity must go through when installing an SPS on the NPCC Bulk Power System. NPCC also categorizes the SPS into Type 1, 2 or 3 depending on the impact such device could have on the Bulk Power System. Type 1 SPSs, which could have the greatest impact on Bulk Power System operation must receive a higher level of examination, analysis and approvals within the NPCC Committee and Task Force structure. Greater study and documentation is required for these Type 1 SPSs.

Directory 8, **System Restoration**
Approved, October 21, 2008

The purpose of this Directory is to present the basic criteria with which each applicable entity must plan for and perform power system restoration following a major or a total blackout.

Compliance to the criteria set forth in this Directory document by each applicable entity assures the capabilities to perform power system restoration. The functional requirements and performance of operational monitoring and control systems, operator voice communications and data telecommunications are beyond the scope of this Directory, except particular requirements for system restoration.

On an annual basis, the NPCC Inc. Task Force on Coordination of Operation shall review and accept each applicable entity's restoration plan for viability and coordination with other operating entities. The composite of the individual restoration plans, once reviewed and accepted by NPCC, comprises NPCC's regional restoration plan.

Directory 9, **Verification of Generator Gross and Net Real Power Capability**
Approved, December 22, 2008

This Directory presents the minimum criteria for verifying the Gross Real Power Capability and Net Real Power Capability of generators or generating facilities. Compliance to the criteria set forth in this Directory by each applicable entity assures accuracy of information used in the steady-state models to assess the reliability of the NPCC bulk power system. This Directory has been developed to

ensure that the requirements specified in NERC Standard MOD-024-1, “Verification of Generator Gross and Net Real Power Capability” are met by NPCC and its applicable members responsible for meeting the NERC Reliability Standards.

Directory 10, **Verification of Generator Gross and Net Reactive Power Capability**
Approved, December 22, 2008

This Directory presents the minimum criteria for verifying the Gross Reactive Power Capability and Net Reactive Power Capability of generators or generating facilities.

Compliance to the criteria set forth in this Directory by each applicable entity assures accuracy of information used in the steady-state models to assess the reliability of the NPCC bulk power system. This directory has been developed to ensure that the requirements specified in NERC Standard MOD-025-1, “Verification of Generator Gross and Net Reactive Power Capability” are met by NPCC and its applicable members responsible for meeting the NERC standards.

Directory 12, **Underfrequency Load Shedding Program Requirements**
Approved, March 3, 2010

This Directory presents the basic criteria for the design and implementation of under frequency load shedding programs to ensure that declining frequency is arrested and recovered in accordance with established NPCC performance requirements to prevent system collapse due to load-generation imbalance.

Criteria A6, **Operating Reserve Criteria**
Approved, December 29, 2008

In the continuous operation of electric power systems, operating capacity is required to meet forecast demand, including an allowance for error, to provide protection against equipment failure which has a reasonably high probability of occurrence, and to provide adequate regulation of frequency and tie line power flow. The operating capacity in excess of that required for actual load is commonly referred to as operating reserve.

This document establishes standard terminology and minimum requirements governing the amount, availability, distribution, and shared activation of operating reserve.

The objective is to facilitate a high level of reliability in the NPCC Region that is, as a minimum, consistent with the Operating Policies and Standards specified by

Criteria A7, Glossary of Terms

Approved, July 17, 2007

This document provides specific NPCC regional term definitions of those terms not listed in the NERC Glossary.

Criteria A8, Reliability Compliance Enforcement Program

Approved, December 20, 2007

The NPCC Inc. Reliability Compliance and Enforcement Program (the Program) described in this document is to be used to assess and enforce compliance with NPCC Inc. reliability criteria in such a way that the reliability objective stated above will be achieved. Actions taken by NPCC Inc. under the Program, including the imposition of sanctions, where applicable, shall in no way be construed as an acceptable alternative to the Member's continued obligation to comply with NPCC Inc. Criteria, Guides and Procedures. As such the Member, as stated in the NPCC Inc. Bylaws, remains responsible for providing its plan and schedule to achieve compliance. It is further noted that the Program requirements are applicable only to the elements of the bulk power system as classified by NPCC Inc. in Document A-10.

Criteria A10, Classification of Bulk Power System Elements

December 1, 2009

NPCC defines specific requirements applicable to design, operation, and protection of the bulk power system. The object of this Classification of Bulk Power System Elements (Document A-10) is to provide the methodology to identify the bulk power system elements, or parts thereof, of the interconnected NPCC Region.

The methodology in this document is used to classify elements of the bulk power system and may result in elements being added to or removed from the NPCC Bulk Power System List. The methodology in this document is based on the following:

- ☐ Results of an analysis done on a bus basis can be applied to identify which elements, or portions thereof, connected to the bus are part of the bulk power system.

□ Elements shall not automatically be included or excluded from the bulk power system based on voltage class. Application of this methodology may be omitted at buses that can be logically excluded from the bulk power system based on study results at other buses tested using this methodology. If a bus is determined to be bulk power system, all other buses with elements connected to that bus must be tested.

□ Elements shall be evaluated based on this methodology when significant changes occur on the system that could change an element's bulk power system status; the evaluation may be limited to the affected part of the system.

□ Areas and facility owners may adopt methodologies that exceed the requirements set forth in this document for their own purposes. However, only elements classified as bulk power system as a result of testing described in this document shall be included on the NPCC's list of bulk power system elements. NPCC criteria and compliance monitoring shall consider only the system elements listed on NPCC's list of bulk power system elements.

The Classification of Bulk Power System Elements is based on three defined terms: bulk power system, local area and significant adverse impact.

Criteria A15, **Disturbance Monitoring Equipment Criteria**

Approved, August 23, 2007

A prompt and accurate sequence of events must be established following a disturbance to provide timely analysis and reporting of the disturbance. The importance of Disturbance Monitoring Equipment (DME) in monitoring performance of protection equipment and validation of system simulation models has long been recognized in NPCC criteria. This document provides the application and functional requirements for NPCC DME, in accordance with NERC Reliability Standards PRC-002 and PRC-018.



NORTHEAST POWER COORDINATING COUNCIL, INC.
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Exhibit C

Approved Directories and Criteria



NORTHEAST POWER COORDINATING COUNCIL, INC.
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NPCC
Regional Reliability Reference Directory # 1
Design and Operation of the Bulk Power System

Task Force on Coordination of Planning Revision Review Record:
December 01, 2009

Adopted by the Members of the Northeast Power Coordinating Council, Inc., on December 01, 2009 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)

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This document, when downloaded or printed, becomes UNCONTROLLED. Users should check the NPCC website for the current CONTROLLED version of this document.

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1.0 Introduction

1.1 Title - Design and Operation of the Bulk Power System

1.2 Directory Number 1

1.3 Objective

The objective of these criteria is to provide a “design-based approach” to ensure the **bulk power system** is designed and operated to a level of reliability such that the loss of a major portion of the system, or unintentional separation of a major portion of the system, will not result from any design **contingencies** referenced in Sections 5.4.1 and 5.4.2. In NPCC the technique for assuring the reliability of the **bulk power system** is to require that it be designed and operated to withstand representative **contingencies** as specified in this Directory. Analyses of simulations of these **contingencies** include assessment of the potential for widespread cascading outages due to overloads, instability or voltage collapse. Loss of small portions of a system (such as radial portions) may be tolerated provided these do not jeopardize the reliability of the remaining **bulk power system**.

Criteria described in this document are to be used in the design and operation of the **bulk power system**. These criteria are applicable to all entities which are part of or make use of the **bulk power system**.

The characteristics of a reliable **bulk power system** include adequate **resources** and transmission to reliably meet projected customer electricity demand and energy requirements as prescribed in this document and include:

- a. Consideration of a balanced relationship among the fuel type, capacity, physical characteristics (peaking/base **load**/etc.), and location of **resources**.
- b. Consideration of a balanced relationship among transmission system **elements** to avoid excessive dependence on any one transmission circuit, structure, right-of-way, or substation.
- c. Transmission systems should provide flexibility in switching arrangements, voltage control, and other control measures

1.4 Effective Date - December 01, 2009

1.5 Background

This Directory was developed from the NPCC A-2 criteria document - Basic Criteria for the Design and Operation of Interconnected Power Systems (May 6, 2004 version). Guidelines and Procedures for consideration in the implementation of this Directory are provided in the Appendices.

1.6 Applicability

1.6.1 Functional Entities

Reliability Coordinators
Transmission Operators
Balancing Authorities
Planning Coordinators
Transmission Planners
Resource Planners

2.0 Terms Defined in this Directory

Terms appearing in bold typeface in this Directory (including the Appendices) are defined in Appendix A.

3.0 NERC ERO Reliability Standard Requirements

The NERC ERO Reliability Standards containing requirements that are associated with this Directory include, but may not be limited to:

- 3.1 [EOP-001-0 - Emergency Operations Planning](#)
- 3.2 [FAC-011-2 - System Operating Limits Methodology for the Operations Horizon](#)
- 3.3 [IRO-002-1 - Reliability Coordination - Facilities](#)
- 3.4 [IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators](#)
- 3.5 [MOD-010-0 - Steady-State Data for Transmission System Modeling and Simulation](#)
- 3.6 [MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures](#)
- 3.7 [MOD-012-0 — Dynamics Data for Transmission System Modeling and Simulation](#)
- 3.8 [MOD-013-1 — RRO Dynamics Data Requirements and Reporting Procedures](#)
- 3.9 [MOD-014-0 — Development of Interconnection-Specific Steady State System Models](#)
- 3.10 [MOD-015-0 — Development of Interconnection-Specific Dynamics System Models](#)
- 3.11 [MOD-016-1 — Actual and Forecast Demands, Net Energy for Load,](#)

Controllable DSM

- 3.12 [TOP-001-1 — Reliability Responsibilities and Authorities](#)
- 3.13 [TOP-002-2 — Normal Operations Planning](#)
- 3.14 [TOP-003-0 — Planned Outage Coordination](#)
- 3.15 [TOP-004-2 — Transmission Operations](#)
- 3.16 [TPL-001-0 — System Performance Under Normal Conditions](#)
- 3.17 [TPL-002-0 — System Performance Following Loss of a Single BES Element](#)
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- 3.18 [TPL-003-0 — System Performance Following Loss of Two or More BES](#)
[Elements](#)
- 3.19 [TPL-004-0 — System Performance Following Extreme BES Events](#)
- 3.20 [TPL-005-0 — Regional and Interregional Self-Assessment Reliability Reports](#)
- 3.21 [TPL-006-0 — Assessment Data from Regional Reliability Organizations](#)
- 3.22 [VAR-001-1 — Voltage and Reactive Control](#)

4.0 NPCC regional Reliability Standards Requirements

None

5.0 NPCC Full Member, More Stringent Criteria

NPCC provides a forum for coordinating the design and operations of its five Reliability Coordinator Areas. NPCC shall conduct regional and interregional studies, and assess and monitor Planning Coordinator Area studies and Reliability Coordinator operations to assure conformance to these criteria through committees, task forces, and working groups.

It is the responsibility of each Reliability Coordinator to ascertain that their portion of the **bulk power system** is operated in conformance with these criteria. It is the responsibility of each Transmission Planner and Planning Coordinator to ascertain that their portion of the **bulk power system** is designed in conformance with these criteria

5.1 General Requirements

Specific system conditions may require Planning Coordinators or Reliability Coordinators to develop criteria which are more stringent than those set out herein. Any constraints imposed by these more stringent criteria will be observed. It is also recognized that these Criteria are not necessarily applicable to those **elements** that are not a part of the **bulk power system** or in the portions of a system where instability or overloads will not jeopardize the reliability of the remaining **bulk power system**.

5.1.1 Design Criteria

These design criteria will be used in the assessment of the **bulk power system** by each of the NPCC Transmission Planners and Planning Coordinators, and in the reliability testing at the Transmission Operator, Reliability Coordinator and Regional Council levels.

Design studies shall assume **power** flow conditions utilizing transfers, **load** and generation conditions which stress the system. Transfer capability studies shall be based on the **load** and generation conditions expected to exist for the period under study. All **reclosing** facilities shall be assumed in service unless it is known that such facilities will be rendered inoperative.

Special protection systems (SPS) shall be used judiciously and when employed shall be installed, consistent with good system design and operating criteria found in Directory #7 – *Special Protection Systems*.

A SPS may be used to provide protection for infrequent **contingencies**, or for temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages. A **SPS** may also be applied to preserve system integrity in the event of severe facility outages and extreme **contingencies**. The decision to employ a **SPS** shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits.

The requirements of **special protection systems** are defined in the NPCC *Bulk Power System Protection Criteria*, (Document A-5), and the *Special Protection Systems*, (Directory #7).

5.1.2 Operating Criteria

Coordination among and within the Reliability Coordinator Areas of NPCC is essential to the reliability of interconnected operations. Timely information concerning system conditions shall be transmitted by the NPCC Reliability Coordinators to other NPCC Reliability Coordinators, adjacent Reliability Coordinators or other entities as needed to assure reliable operation of the **bulk power system**.

The operating criteria represent the application of the design criteria to inter-Reliability Coordinator Area, intra- Reliability Coordinator Area operation.

The operating criteria define the minimum level of reliability that shall apply to inter-Reliability Coordinator Area operation. Where inter-Reliability Coordinator Area reliability is affected, each Reliability

Coordinator shall establish limits and operate so that the **contingencies** stated in Section 5.5.1 and 5.5.2 can be withstood without causing a **significant adverse impact** on other Reliability Coordinator Areas.

When adequate **bulk power system** facilities are not available, **special protection systems** (SPS) may be employed to maintain system security.

Two categories of transmission transfer capabilities, normal and **emergency**, are applicable. Normal transfer capabilities are to be observed unless an **emergency** is declared.

5.1.3 Data Exchange Requirements for Modeling and System Analysis

It is the responsibility of NPCC and NPCC Members to protect the proprietary nature of the following information and to ensure it is used only for purposes of efficient and reliable system design and operation. Also, any sharing of such information must not violate anti-trust laws.

For reliability purposes, Reliability Coordinators shall share and coordinate forecast system information and real time information to enable and enhance the analysis and modeling of the interconnected **bulk power system** by security application software on energy management systems. Each Registered Entity within an NPCC Reliability Coordinator Area shall provide needed information to its Reliability Coordinator as required. Analysis and modeling of the interconnected power system is required for reliable design and operation. Data needed to analyze and model the electric system and its component facilities must be developed, maintained, and made available for use in interconnected operating and planning studies, including data for fault level analysis.

Reliability Coordinators and Registered Entities shall maintain and submit, as needed, data in accordance with applicable NPCC Procedures.

Data submitted for analysis representing physical or control characteristics of equipment shall be verified through appropriate methods. System analysis and modeling data must be reviewed annually, and verified on a periodic basis. Generation equipment, and its component controllers, shall be tested to verify data.

5.2 Resource Adequacy – Design Criteria

The probability (or risk) of disconnecting **firm load** due to resource deficiencies shall be, on average, not more than one day in ten years as

determined by studies conducted for each Resource Planning and Planning Coordinator Area. Compliance with this criterion shall be evaluated probabilistically, such that the loss of **load** expectation (LOLE) of disconnecting **firm load** due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or **load** relief from available operating procedures.

5.3 Resource Adequacy – Operating Criteria

Each Balancing Authority shall have procedures in place to schedule outages and deratings of **resources** in such a manner that the available **resources** will be adequate to meet the Resource Planner's and Planning Coordinator's forecasted demand and **reserve** requirements, in accordance with the NPCC *Operating Reserve Criteria* (Document A-6).

For consistent evaluation and reporting of **resource** adequacy, it is necessary to measure the net capability of generating units and **loads** utilized as a **resource** of each Planning Coordinator Area.

5.4 Transmission Design Criteria

The portion of the **bulk power system** in each Planning Coordinator Area and in each Transmission Planning Area shall be designed with sufficient transmission capability to serve forecasted demand under the conditions noted in Sections 5.4.1 and 5.4.2. These criteria will also apply after any critical generator, transmission circuit, transformer, series or shunt compensating device or HVdc pole has already been lost, assuming that the Planning Coordinator Area generation and **power** flows are adjusted between outages by the use of **ten-minute reserve** and where available, phase angle regulator control and HVdc control.

Anticipated transfers of **power** from one Planning Coordinator Area to another, as well as within Planning Coordinator Areas, shall be considered in the design of transmission facilities. Transmission transfer capabilities shall be determined in accordance with the conditions noted in Sections 5.4.1 and 5.4.2.

5.4.1 Stability Assessment

Stability of the **bulk power system** shall be maintained during and following the most severe of the **contingencies** stated below, with due regard to **reclosing**. For each of the **contingencies** below that involve a fault, **stability** shall be maintained when the simulation is based on

fault clearing initiated by the “**system A**” **protection group**, and also shall be maintained when the simulation is based on **fault clearing** initiated by the “**system B**” **protection group**.

- a. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section with **normal fault clearing**.
- b. Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with **normal fault clearing**. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded. Other similar situations can be excluded on the basis of acceptable risk, provided that the Reliability Coordinating Committee specifically accepts each request for exclusion.
- c. A permanent phase to ground fault on any transmission circuit, transformer, or bus section with **delayed fault clearing**.
- d. Loss of any **element** without a fault.
- e. A permanent phase to ground fault on a circuit breaker with **normal fault clearing**. (**Normal fault clearing** time for this condition may not always be high speed.)
- f. Simultaneous permanent loss of both poles of a direct current bipolar facility without an ac fault
- g. The failure of a circuit breaker to operate when initiated by a **SPS** following: loss of any **element** without a fault; or a permanent phase to ground fault, with **normal fault clearing**, on any transmission circuit, transformer or bus section.

5.4.2 Steady State Assessment

- a. Each Transmission Planner shall design its system in accordance with these criteria and its own voltage control procedures and criteria, and coordinate these with adjacent Transmission Planner Areas. Adequate **reactive power** resources and appropriate controls shall be installed in each Transmission Planner Area to maintain voltages within

normal limits for pre-**disturbance** conditions, and within **applicable emergency limits** for the system conditions that exist following the **contingencies** specified in 5.4.1.

- b. Line and equipment loadings shall be within normal limits for pre-**disturbance** conditions and within **applicable emergency limits** for the system conditions that exist following the **contingencies** specified in 5.4.1.

5.4.3 Fault Current Assessment

Each Transmission Planner and Planning Coordinator shall establish procedures and implement a system design that ensures equipment capabilities are adequate for fault current levels with all transmission and generation facilities in service for all potential operating conditions, and coordinate these procedures with adjacent Planning Coordinator Areas.

5.5 Transmission Operating Criteria

Scheduled outages of facilities that affect inter-Reliability Coordinator Area reliability shall be coordinated sufficiently in advance of the outage to permit the affected Reliability Coordinators to maintain reliability. Each Reliability Coordinator shall notify adjacent Reliability Coordinators of scheduled or forced outages of any facility on the NPCC Transmission Facilities Notification List and of any other condition which may impact on inter-Reliability Coordinator Area reliability. Work on facilities which impact inter-Reliability Coordinator Area reliability shall be expedited to minimize the time that the facilities are out of service.

Individual Reliability Coordinator Areas shall be operated in a manner such that the **contingencies** noted in Section 5.5.1 and 5.5.2 can be withstood and do not adversely affect other Reliability Coordinator Areas.

Appropriate adjustments shall be made to Reliability Coordinator Area operations to accommodate the impact of **protection group** outages, including the outage of a **protection group** which is part of a Type I **special protection system**. For typical periods of forced outage or maintenance of a **protection group**, it can be assumed, unless there are indications to the contrary, that the remaining **protection** will function as designed. If the **protection group** will be out of service for an extended period of time, additional adjustments to operations may be appropriate considering other system conditions and the consequences of possible failure of the remaining **protection group**.

5.5.1 Normal Transfers

Pre-**contingency** voltages, line and equipment loadings shall be within normal limits. Unless specific instructions describing alternate action are in effect, normal transfers shall be such that manual **reclosing** of a faulted **element** can be carried out before any manual system adjustment, without affecting the **stability** of the **bulk power system**.

Stability of the **bulk power system** shall be maintained during and following the most severe of the **contingencies** stated below, with due regard to **reclosing**. For each of the **contingencies** stated below that involves a fault, **stability** shall be maintained when the simulation is based on **fault clearing** initiated by the “**system A**” **protection group**, and also shall be maintained when the simulation is based on **fault clearing** initiated by the “**system B**” **protection group**.

- a. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section, with **normal fault clearing**.
- b. Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with **normal fault clearing**. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded. Other similar situations can be excluded on the basis of acceptable risk, provided that the Reliability Coordinating Committee specifically accepts each request for exclusion.
- c. A permanent phase to ground fault on any transmission circuit, transformer, or bus section with **delayed fault clearing**.
- d. Loss of any **element** without a fault.
- e. A permanent phase to ground fault on a circuit breaker, with **normal fault clearing**. (**Normal fault clearing** time for this condition may not always be high speed.)
- f. Simultaneous permanent loss of both poles of a direct current bipolar facility without an ac fault.
- g. The failure of a circuit breaker to operate when initiated by a **SPS** following: loss of any **element**

without a fault; or a permanent phase to ground fault, with **normal fault clearing**, on any transmission circuit, transformer or bus section.

Reactive power resources shall be maintained in each Reliability Coordinator Area in order to maintain voltages within normal limits for pre-**disturbance** conditions, and within **applicable emergency limits** for the system conditions that exist following the **contingencies** specified in the foregoing. Adjoining Reliability Coordinators shall mutually agree upon procedures for inter-Reliability Coordinator Area voltage control.

Line and equipment loadings shall be within normal limits for pre-**disturbance** conditions and within **applicable emergency limits** for the system conditions that exist following the **contingencies** specified in the foregoing.

Since **contingencies** b, c, e, f, and g, are not confined to the loss of a single **element**, individual Transmission Operators and Reliability Coordinators may choose to permit a higher post **contingency** flow on remaining facilities than for **contingencies** a and d. This is permissible providing operating procedures are documented to accomplish corrective actions; the loadings are sustainable for at least the anticipated time required to effect such action, and other Transmission Operator Areas or Reliability Coordinator Areas will not be subjected to the higher flows without prior agreement.

5.5.2 Emergency Transfers

When **firm load** cannot be supplied within normal limits in a Transmission Operator Area, or a portion of a Transmission Operator Area, transfers may be increased to the point where pre-**contingency** voltages, line and equipment loadings are within **applicable emergency limits**. **Emergency** transfer levels may require generation adjustment before manually **reclosing** faulted **elements**.

Stability of the **bulk power system** shall be maintained during and following the most severe of the following **contingencies**, and with due regard to **reclosing**:

- a. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section, with **normal fault clearing**.
- b. The loss of any **element** without a fault.

Immediately following the most severe of these **contingencies**, voltages, line and equipment loadings will be within **applicable emergency limits**.

5.5.3 Post Contingency Operation

Immediately after the occurrence of a **contingency**, the status of the **bulk power system** must be assessed and transfer levels must be adjusted, if necessary, to prepare for the next **contingency**. If the readjustment of generation, **load** resources, phase angle regulators, and direct current facilities is not adequate to restore the system to a secure state, then other measures such as voltage reduction and shedding of firm **load** may be required. System adjustments shall be completed as quickly as possible, but in all cases within 30 minutes after the occurrence of the **contingency**.

Voltage reduction need not be initiated and firm **load** need not be shed to observe a post **contingency** loading requirement until the **contingency** occurs, provided that adequate response time for this action is available after the **contingency** occurs and other measures will maintain post **contingency** loadings within **applicable emergency limits**.

Emergency measures, including the pre-**contingency** disconnection of **firm load** if necessary, must be implemented to limit transfers to within the requirements of 5.5.2 above.

5.5.4 Operation under High Risk Conditions

Operating to the **contingencies** listed in Sections 5.5.1 and 5.5.2 is considered to provide an acceptable level of **bulk power system** security. Under certain unusual conditions, such as severe weather, the expectation of occurrence of some **contingencies**, and the associated consequences, may be judged to be temporarily, but significantly, greater than the long-term average expectation. When these conditions, referred to as high risk conditions, are judged to exist in a Transmission Operator Area, consideration should be given to operating in a more conservative manner than that required by the provisions of Sections 5.5.1 and 5.5.2.

5.6 Extreme Contingency Assessment

Extreme **contingency** assessment recognizes that the **bulk power system** can be subjected to events which exceed, in severity, the **contingencies** listed in Section 5.4.1. One of the objectives of extreme **contingency** assessment is to

determine, through planning studies, the effects of extreme **contingencies** on system performance. This is done in order to obtain an indication of system strength, or to determine the extent of a widespread system **disturbance**, even though extreme **contingencies** do have low probabilities of occurrence.

The specified extreme **contingencies** listed below are intended to serve as a means of identifying some of those particular situations that could result in a widespread **bulk power system disturbance**. It is the responsibility of each Planning Coordinator Area to identify any additional extreme **contingencies** to be assessed.

Assessment of the extreme **contingencies** listed below shall examine post **contingency** steady state conditions, as well as **stability**, overload, cascading outages and voltage collapse. Pre-**contingency load** flows chosen for analysis shall reflect reasonable **power** transfer conditions within or between Planning Coordinator Areas.

Analytical studies shall be conducted to determine the effect of the following extreme **contingencies**:

- a. Loss of the entire capability of a generating station.
- b. Loss of all transmission circuits emanating from a generating station, switching station, dc terminal or substation
- c. Loss of all transmission circuits on a common right-of-way.
- d. Permanent three-phase fault on any generator, transmission circuit, transformer, or bus section, with **delayed fault clearing** and with due regard to **reclosing**.
- e. The sudden dropping of a large **load** or major **load** center.
- f. The effect of severe **power** swings arising from **disturbances** outside the Council's interconnected systems.
- g. Failure of a **special protection system**, to operate when required following the normal **contingencies** listed in Section 5.4.1.
- h. The operation or partial operation of a **special protection system** for an event or condition for which it was not intended to operate.
- i. Sudden loss of fuel delivery system to multiple plants, (i.e. gas pipeline **contingencies**, including both gas transmission lines and gas mains.)

Note: The requirement of this section is to perform extreme **contingency** assessments. In the case where extreme **contingency** assessment concludes there are serious consequences, an evaluation of implementing a change to design or operating practices to address such **contingencies** shall be conducted.

5.7 Extreme System Conditions Assessment

The **bulk power system** can be subjected to wide range of other than normal system conditions that have low probability of occurrence. One of the objectives of extreme system conditions assessment is to determine, through planning studies, the impact of these conditions on expected steady-state and dynamic system performance. This is done in order to obtain an indication of system robustness or to determine the extent of a widespread system **disturbance**. Each Transmission Planner and Planning Coordinator has the responsibility to incorporate special simulation testing to assess the impact of extreme system conditions.

Analytical studies shall be conducted to determine the effect of design **contingencies** under the following extreme conditions:

- a. Peak **load** conditions resulting from extreme weather conditions with applicable **rating** of electrical **elements**.
- b. Generating unit(s) fuel shortage, (i.e. gas supply adequacy)

After due assessment of extreme system conditions, measures may be utilized, where appropriate, to mitigate the consequences that are indicated as a result of testing for such system conditions. .

Prepared by: Task Force on Coordination of Planning

Review and Approval: Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval.

Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast.

Revisions pertaining to the Appendices or any other portion of the document such as Links glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document.

This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

References:

NPCC Glossary of Terms (Document A-7)
Bulk Power System Protection Criteria (NPCC Document A-5)
Emergency Operations (NPCC Directory #2)
Special Protection Systems (Directory #7))

Appendix A - Definition of Terms

Applicable emergency limits - These limits depend on the duration of the occurrence, and on the policy of the various member systems of NPCC regarding loss of life to equipment, voltage limitations, etc.

Emergency limits are those which can be utilized for the time required to take corrective action, but in no case less than five minutes.

The limiting condition for voltages should recognize that voltages should not drop below that required for suitable system **stability** performance, and should not adversely affect the operation of the **bulk power system**.

The limiting condition for equipment loadings should be such that cascading outages will not occur due to operation of protective devices upon the failure of facilities. (Various definitions of equipment **ratings** are found elsewhere in this glossary.)

Bulk power system - The interconnected electrical systems within north-eastern North America comprising **generation** and transmission facilities on which **faults** or **disturbances** can have a **significant adverse impact** outside of the local area. In this context, local areas are determined by the Council members.

Contingency - An event, usually involving the loss of one or more **elements**, which affects the **power** system at least momentarily.

NPCC Specific Definitions:

NPCC Emergency Criteria **Contingencies** - The set of **contingencies** to be observed when operating the **bulk power system** under **emergency** conditions. (Document C-1; also reference Document A-2, Section 6.2 - Emergency Transfers.)

NPCC Normal Criteria **Contingencies** - The set of **contingencies** to be observed when operating the **bulk power system** under normal conditions. (Document C-1; also reference Document A-2, Section 6.1 - Normal Transfers.)

Double Element Contingency - A **contingency** which involves the loss of two **elements**. (Document C-1)

Single Contingency - A single event which may result in the loss of one or more **elements**.

Single Element Contingency - A **contingency** involving the loss of one **element**. (Document C-1)

Limiting Contingency - The **contingency** which establishes the **transfer capability**. (Document C-1)

First Contingency Loss - The largest **capacity** outage including any assigned Ten-Minute Reserve which would result from the loss of a single **element** (Documents A-6 and C-1)

Second Contingency Loss - The largest **capacity** outage which would result from the loss of a single **element** after allowing for the First Contingency Loss. (Documents A-6 and C-1)

Disturbance - Severe oscillations or severe step changes of current, voltage and/or frequency usually caused by **faults**.

System Disturbance - An event characterized by one or more of the following phenomena: the loss of **power** system **stability**; cascading outages of circuits; oscillations; abnormal ranges of frequency or voltage or both.

Element - Any electric device with terminals that may be connected to other electric devices, such as a generator, transformer, circuit, circuit breaker, or bus section.

Limiting Element - The element that is either operating at its appropriate **rating** or would be, following a limiting **contingency** and, as a result, establishes a system limit.

Emergency - Any abnormal system condition that requires automatic or manual action to prevent or limit loss of transmission facilities or **generation** supply that could adversely affect the **reliability** of the electric system.

Specific to NPCC: An **Emergency** is considered to exist in an Area if **firm load** may have to be shed.

Fault Clearing

Delayed fault clearing - Fault clearing consistent with correct operation of a breaker failure **protection group** and its associated breakers, or of a backup **protection group** with an intentional time delay.

High speed fault clearing - Fault clearing consistent with correct operation of high speed relays and the associated circuit breakers without intentional time delay.

Notes: The specified time for high-speed relays in present practice is 50 milliseconds (three cycles on a 60Hz basis) or less. [IEEE C37.100-1981]. For planning purposes, a total clearing time of six cycles or less is considered high speed.

Normal fault clearing - Fault clearing consistent with correct operation of the **protection system** and with the correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that **protection system**.

Load - The electric **power** used by devices connected to an electrical generating system. (IEEE Power Engineering). Also see **Demand**.

NPCC Specific Definitions:

Firm Load - Loads that are not **Interruptible Loads**.

Interruptible Load - Loads that are interruptible under the terms specified in a contract.

Power

Apparent Power - The product of the volts and amperes. It comprises both *real* and *reactive* power, usually expressed in kilovoltamperes (kVA) or megavoltamperes (MVA).

Reactive Power - The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, **synchronous condensers**, or electrostatic equipment such as capacitors. Reactive power directly influences electric system voltage. It is usually expressed in kilovars (kVAr) or megavars (MVar).

Real Power - The rate of producing, transferring, or using electrical energy, usually expressed in kilowatts (kW) or megawatts (MW).

Protection - The provisions for detecting power system **faults** or abnormal conditions and taking appropriate automatic corrective action.

Protection group - A fully integrated assembly of **protective relays** and associated equipment that is designed to perform the specified protective functions for a power system **element**, independent of other groups.

Notes:

(a) Various identified as Main Protection, Primary Protection, Breaker Failure Protection, Back-Up Protection, Alternate Protection, Secondary Protection, A Protection, B Protection, Group A, Group B, System 1 or System 2.

(b) Pilot protection is considered to be one protection group. Protection system Element Basis One or more protection groups; including all equipment such as instrument transformers, station wiring, circuit breakers and associated trip/close modules, and communication facilities; installed at all terminals of a power system **element** to provide the complete protection of that **element**.

Terminal Basis

One or more protection groups, as above, installed at one terminal of a power system **element**, typically a transmission line.

Pilot Protection - A form of line protection that uses a communication channel as a means to compare electrical conditions at the terminals of a line.

Rating - The operational limits of an electric system, facility, or **element** under a set of specified conditions.

Reclosing

Autoreclosing - The automatic closing of a circuit breaker in order to restore an **element** to service following automatic tripping of the circuit breaker. Autoreclosing does not include automatic closing of capacitor or reactor circuit breakers.

High-speed autoreclosing - The autoreclosing of a circuit breaker after a necessary time delay (less than one second) to permit **fault** arc deionization with due regard to coordination with all **relay** protective systems. This type of autoreclosing is generally not supervised by voltage magnitude or phase angle.

Manual Reclosing - The closing of a circuit breaker by operator action after it has been tripped by **protective relays**. Operator initiated closing commands may originate from local control or from remote (supervisory) control. Either local or remote close commands may be supervised or unsupervised.

Supervision- A closing command is said to be supervised if closing is permitted to occur only if certain prerequisite conditions are met (e.g., **synchronism-check**).

Synchronism-check - refers to the determination that acceptable voltages exist on the two sides of the breaker and the phase angle between them is within a specified limit for a specified time.

Relay - An electrical device designed to respond to input conditions in a prescribed manner and after specified conditions are met to cause contact operation or similar abrupt change in associated electric control circuits. (Also: see **protective relay**).

Reliability - The degree of performance of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system — **Adequacy** and **Security**.

Adequacy — The ability of the electric system to supply the aggregate electrical **demand** and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system **elements**.

Security — The ability of the electric system to withstand **disturbances** such as electric **short circuits** or unanticipated loss of system **elements**.

Reserve - In normal usage, reserve is the amount of **capacity** available in excess of the **demand**

Reserve Requirement - That capability above firm system **demand** required to provide for regulation, **load** forecasting error, equipment forced and scheduled outages, and local area supply **adequacy**

NPCC Specific Definitions:

Non-Synchronized Reserve — That portion of operating capacity which is available by synchronizing a generator to the network, and that capacity which can be made available by reducing load that is dependent on starting a generator to replace energy that is supplied from the grid. Non-Synchronized Reserve also includes the capacity achieved through the implementation of voltage reduction. (Documents A-6 and C-1)

Operating Reserve - The sum of **ten-minute** and **thirty-minute reserve**. (Documents A-3, A-6, and A-1)

Reserve on **Automatic Generation Control (AGC)** - That portion of **synchronized reserve** which is under the command of an automatic controller to respond to **load demands** without need for manual action. (Documents A-6 and C-1)

Synchronized Reserve - The unused capacity from resources that are synchronized to the system and ready to achieve claimed capacity (Documents A-6 and C-1)

Ten-minute reserve - The sum of **synchronized** and **non-synchronized reserve** that is fully available in ten minutes. (Documents A-6 and C-1)

Thirty-Minute Reserve - The sum of synchronized and non-synchronized reserve that can be utilized within thirty minutes of receiving an activation request, excluding capacity assigned to ten minute reserve. (A-6, C-1)

Resource - Resource refers to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include utility and non-utility generation and purchases from neighboring systems. Demand-side facilities include measures for reducing load, such as conservation, demand management, and interruptible load.

Significant adverse impact - With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from **faults** or **disturbances**, shall be deemed as having **significant adverse impact**:

- a. instability:
 - any instability that cannot be demonstrably contained to a well defined local area,
 - any loss of synchronism of generators that cannot be demonstrably contained to a well-defined local area.
- b. unacceptable system dynamic response:

- an oscillatory response to a contingency that is not demonstrated to be clearly positively damped within 30 seconds of the initiating event.
- c. unacceptable equipment tripping:
 - tripping of an un-faulted **bulk power system** element (element that has already been classified as **bulk power system**) under planned system configuration due to operation of a protection system in response to a stable power swing,
 - the operation of a Type I or Type II **Special Protection System** in response to a condition for which its operation is not required
- d. voltage levels in violation of **applicable emergency limits**;
- e. loadings on transmission facilities in violation of **applicable emergency limits**.

Special Protection System (SPS) – A protection system designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted elements. Such action may include changes in load, generation, or system configuration to maintain system stability, acceptable voltages or power flows. Automatic underfrequency load shedding as defined in the NPCC Directory #2 - Emergency Operations - is not considered a SPS. Conventionally switched, locally controlled shunt devices are not **special protection systems**.

Stability - The ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or **disturbances**.

Small-Signal Stability - The ability of the electric system to withstand small changes or **disturbances** without the loss of synchronism among the synchronous machines in the system.

Transient Stability - The ability of an electric system to maintain synchronism between its parts when subjected to a **disturbance**, and to regain a state of equilibrium following that **disturbance**.

Appendix B - Guidelines and Procedures for NPCC Area Transmission Reviews

1.0 Introduction

NPCC has established a Reliability Assessment Program to bring together work done by NPCC, Transmission Planners and Planning Coordinators relevant to the assessment of **bulk power system reliability**. As part of the Reliability Assessment Program, the Task Force on System Studies (TFSS) is charged on an ongoing basis with conducting periodic reviews of the **reliability** of the planned bulk power transmission system of each Planning Coordinator Area of NPCC and the transmission interconnections to other Planning Coordinator Areas. The purpose of these reviews is to determine whether each Planning Coordinator Area's planned bulk power transmission system is in conformance with the NPCC *Design and Operation of the Bulk Power System* (Directory #1). Since it is the intention of the NPCC that the *Basic Criteria* in Directory #1 be consistent with the NERC *Standards*, conformance with the NPCC *Basic Criteria* in Directory #1 assures consistency with the NERC *Standards*.

To assist the TFSS in carrying out this charge, each NPCC Planning Coordinator shall conduct an annual assessment of the **reliability** of the planned bulk power transmission system within the Planning Coordinator Area and the transmission interconnections to other Planning Coordinator Areas (an Area Transmission Review), in accordance with these Guidelines, and present a report of this assessment to the TFSS for review. Each Planning Coordinator is also responsible for providing an annual report to the Compliance Committee in regard to its Area Transmission Review in accordance with the *NPCC Reliability Compliance and Enforcement Program* (Document A-8).

The NPCC role in monitoring conformance with the NPCC *Basic Criteria* in Directory #1 is limited to those instances where non-conformance could result in adverse consequences to more than one Planning Coordinator Area. If in the process of conducting the **reliability** review; problems of an intra-Reliability Coordinator Area nature are identified, NPCC shall inform the affected systems and the Planning Coordinator within which the systems are located, but follow-up concerning resolution of the problem shall be the Planning Coordinators responsibility and not that of NPCC. The affected Planning Coordinator will notify NPCC on a timely basis as to the resolution of the identified problem. If the problem is of an inter-Reliability Coordinator Area nature, NPCC shall inform the affected Planning Coordinators and, further, shall take an active role in following-up resolution of the identified problem.

2.0 Purpose of Area Review Presentation

The purpose of the presentation associated with an Area Transmission Review is to demonstrate that the Planning Coordinators planned transmission system, based on its projection of available **resources**, is in conformance with the NPCC *Basic Criteria* in Directory #1. By such a presentation, the Task Force will satisfy itself that the criteria have been met and, in general, that the **reliability** of the NPCC Interconnected Systems will be maintained. Analysis of this material should include a review of **Special Protection Systems**, as well as an assessment of the potential for widespread cascading due to overloads, instability or voltage collapse. In addition, the potential consequences of failure or misoperation of Dynamic Control Systems (DCS), which include Transmission Control Devices as defined in the NERC *Standards*, should be addressed.

This review by the TFSS does not alter Planning Coordinators and/or Company responsibilities with respect to their system's conformity with the NPCC *Basic Criteria* in Directory #1.

3.0 The Study Year to be considered

It is suggested that a study year of 4 to 6 years from the reporting date is a realistic one, both from the viewpoint of minimum lead times required for construction, and the ability to alter plans or facilities. The reviews may be conducted for a longer term beyond 6 years to address identified marginal conditions that may have longer lead-time solutions

4.0 Types and Frequency of Reviews

Each Planning Coordinator is required to present an annual transmission review to TFSS. However, the review presented by the Planning Coordinator may be one of three types: a Comprehensive (or Full) Review, an Intermediate (or Partial) Review, or an Interim Review.

A Comprehensive Review is a thorough assessment of the Planning Coordinator's entire bulk power transmission system, and includes sufficient analyses to fully address all aspects of an Area Transmission Review as described in Section 5.0. A Comprehensive Review is required of each Planning Coordinator at least every five years. TFSS may require a Planning Coordinator to present a Comprehensive Review in less than five years if changes in the Planning Coordinator's planned facilities or forecasted system conditions (system changes) warrant it.

In the years between Comprehensive Reviews, Planning Coordinators may conduct

either an Interim Review, or an Intermediate Review, depending on the extent of the Planning Coordinator's system changes since its last Comprehensive Review. If the system changes are relatively minor, the Planning Coordinator may conduct an Interim Review. In an Interim Review, the Planning Coordinator provides a summary of the changes in planned facilities and forecasted system conditions since its last Comprehensive Review and a brief discussion and assessment of the impact of those changes on the bulk power transmission system. No new analyses are required for an Interim Review.

If the Planning Coordinator's system changes since its last Comprehensive Review are moderate or concentrated in a portion of the Planning Coordinator's system, the Planning Coordinator may conduct an Intermediate Review. An Intermediate Review covers all the elements of a Comprehensive Review, but the analyses may be limited to addressing only those issues considered to be of significance, considering the extent of the system changes. If the system changes are major or pervasive, the Planning Coordinator should conduct a Comprehensive Review.

In March of each year, each Planning Coordinator shall present to the TFSS a proposal for the type of review to be conducted that year. TFSS will consider each Planning Coordinator's proposal and either indicate their concurrence, or require the Planning Coordinator to conduct a more extensive review if the Task Force feels that such is warranted based on the Planning Coordinator's system changes since its last Comprehensive Review. Area Interim Review reports shall be presented to TFSS by the end of that calendar year, and Area Intermediate and Comprehensive Review reports shall be presented to TFSS by April of the following year.

5.0 Format of Presentation – Comprehensive and Intermediate Review

Introduction

- Reference the most recent Area Comprehensive Review and any subsequent Intermediate or Interim reviews as appropriate.
- Describe the type and scope of this review.
- For a Comprehensive Review, describe the existing and planned **bulk power system** facilities included in this review.
- Describe changes in system facilities, schedules and **loads** since the most recent Comprehensive Review.
- Include maps and one-line diagrams of the system showing proposed changes as necessary.
- Describe the selected demand levels over the range of forecast system demands.

- Discuss projected firm transfers and interchange schedules.

Study results demonstrating conformance with Section 5.4 of NPCC Directory #1, *Design and Operation of the Bulk Power System* entitled, “Transmission Design Criteria”, which includes evaluation of contingencies after any critical generator, transmission circuit, transformer, series or shunt compensating device or HVDC pole has already been lost.

- a) Discuss the scope of the analyses. The analyses conducted for a Comprehensive Review should be thorough, but an Intermediate Review may focus on specific areas of the system, specific system conditions, or a more limited set of “critical” **contingencies**.
- b) Steady State Assessment
 - Discuss the **load** model, power factor, demand side management, and other modeling assumptions used in the analysis. Discuss the methodology used in voltage assessments. (An Intermediate Review may refer to the discussion from the last Comprehensive Review.)
 - Provide supporting information on the **contingencies** selected for evaluation and an explanation of why the remaining simulations would produce less severe results.
 - Include plots of "base case" **load** flows with all lines in service for the various conditions studied, e.g., peak, off-peak, and heavy transfers.
 - Discuss the **load** flows showing the effects of major planned changes on the system.
 - Discuss applicable transfer limits between contiguous areas.
 - Discuss the adequacy of voltage performance and voltage control capability for the planned bulk power transmission system.
 - Include in the study the planned (including maintenance) outage of any bulk electric equipment (including **protection** systems or their components) at those demand levels for which planned (including maintenance) outages are performed.
- c) Stability Assessment

Discuss and/or refer to significant studies showing the effect on the system of **contingencies** as specified in Section 5.4.1 of NPCC Directory #1, *Design and Operation of the Bulk Power System*, entitled "Stability Assessment" and report on the most severe **contingencies** in the following manner:

- Provide supporting information on the **contingencies** selected for evaluation and an explanation of why the remaining simulations would produce less severe results.
- Nature of fault, **elements** switched, switching times.
- Plots of angles versus time for significant machines, HVdc and SVC response, voltages at significant buses and significant interface flows.
- Include the effects of existing and planned **protection systems**, including any backup or redundant systems.
- Include the effects of existing and planned control devices.
- Include in the study the planned (including maintenance) outage of any bulk electric equipment (including **protection systems** or their components) at those demand levels for which planned (including maintenance) outages are performed.

For a Comprehensive or Intermediate Review, discuss the **load** model and other modeling assumptions used in the analysis. (An Intermediate Review may refer to the discussion from the last Comprehensive Review.)

d) Fault Current Assessment

- Discuss the methodology and assumptions used in the fault current assessment. (An Intermediate Review may refer to the discussion from the last Comprehensive Review.)
- Discuss instances where fault levels exceed equipment capabilities and measures to mitigate such occurrences.
- Discuss changes to fault levels at stations adjacent to other Planning Coordinator Areas.

Extreme Contingency Assessment

- a) Discuss the scope of the analyses. The analyses conducted for a Comprehensive Review should be thorough, but an Intermediate Review may focus on specific areas of the system, specific system conditions, or a more limited set of “critical” **contingencies**.
- b) Provide supporting information on the extreme **contingencies** selected for evaluation and an explanation of why the remaining simulations would produce less severe results.
- c) Discuss and/or refer to significant **load** flow studies showing the base case and the post fault conditions for the **contingencies** as specified in Section 5.6 of Directory #1 entitled "Extreme Contingency Assessment". Report on the most severe **contingencies** tested.
- d) Discuss and/or refer to significant **stability** studies showing the effect on the system of **contingencies** as specified in Section 5.6 of Directory #1. Report on the most severe **contingencies** tested.
- e) In the case where **contingency** assessment concludes serious consequences, conduct an evaluation of implementing a change to address such **contingencies**.

Extreme System Condition Assessment

- a) Discuss the scope of the analyses.
- b) Discuss and/or refer to significant **load** flow studies showing the effect on the steady state performance of extreme system conditions as specified in Section 5.7 of Directory #1, entitled "Extreme System Condition Assessment". Report on the most severe system conditions and **contingencies** tested.
- c) Provide supporting information on the **contingencies** selected for evaluation and an explanation of why the remaining simulations would produce less severe results.
- d) Discuss and/or refer to significant **stability** studies showing the effect on the dynamic performance of extreme system conditions as specified in Section 5.7 of Directory #1. Report on the most severe system conditions and **contingencies** tested.
- e) In the case where extreme condition assessment concludes serious consequences, conduct an evaluation of implementing measures to mitigate such consequences.

Review of Special Protection Systems (SPSs)

- a) Discuss the scope of review. A Comprehensive Review should review all the existing, new, and modified **SPSs** included in its transmission plan. An Intermediate Review may focus on the new and modified **SPSs**, and just those existing **SPSs** that may have been impacted by system changes since they were last reviewed.
- b) For those **SPSs** whose failure or misoperation has an inter-Planning Coordinator Area or interregional effect, discuss and/or refer to appropriate **load** flow and **stability** studies analyzing the consequences.
- c) For those **SPSs** whose failure or misoperation has only local or inter-company consequences, discuss and/or refer to **load** flow and **stability** studies demonstrating that this is still the case for the time period being reviewed.
- d) For instances where a **SPS** which was formerly considered to have only local consequences is identified as having the potential for inter-Planning Coordinator Area effects, for the time period being reviewed, the TFSS should notify the Task Forces on Coordination of Planning, System Protection and Coordination of Operation. In such instances a complete review of the **SPS** should be made, as per the *Procedure for NPCC Review of New or Modified Bulk Power System Special Protection Systems (SPS)* in Directory #7.

Review of Dynamic Control Systems (DCSs)

For those DCSs whose failure or misoperation may have an inter-Planning Coordinator Area or interregional effect, discuss and/or refer to appropriate **stability** studies analyzing the consequences of such failure or misoperation in accordance with the Joint Working Group (JWG)-1 report, "Technical Considerations and Suggested Methodology for the Performance Evaluation of Dynamic Control Systems". A Comprehensive Review should address all potentially impactful existing and new DCSs, but an Intermediate Review may focus on new DCSs and just those existing DCSs that may have been impacted by system changes since they were last reviewed.

Review of Exclusions to the *Basic Criteria*.

Review any exclusions granted under the NPCC *Guidelines for Requesting Exclusions to Sections 5.4.1(b) and 5.5.1(b) Directory #1 Design and Operation of the Bulk Power System* (Appendix F). A Comprehensive Review should address all exclusions, but an Intermediate Review may focus

on just those exclusions that may have been impacted by system changes since they were last reviewed.

Overview Summary of System Performance for Year Studied

6.0 Format of Presentation - Interim Review

Introduction of Interim Review

Reference the most recent Comprehensive Review and any subsequent Intermediate or Interim Reviews as appropriate.

Changes in Facilities (Existing and Planned) and Forecasted System Conditions Since the Last Comprehensive Review.

- a) **Load** Forecast
- b) Generation **Resources**
- c) Transmission Facilities
- d) **Special Protection Systems**
- e) Dynamic Control Systems
- f) Exclusions

Brief Impact Assessment and Overview Summary

The Planning Coordinator will provide a brief assessment of the impact of these changes on the **reliability** of the interconnected **bulk power system**, based on engineering judgment and internal and joint system studies as appropriate.

7.0 Documentation

The documentation required for a Comprehensive or Intermediate Review should be in the form of a report addressing each of the **elements** of the above presentation format. The report should be accompanied by the Planning Coordinator's **bulk power system** map and one-line diagram, summary tables, figures, and appendices, as appropriate. The report may include references to other studies performed by the Planning Coordinator or by utilities within the Planning Coordinator Area that are relevant to the Area review, with appropriate excerpts from those studies.

The documentation required for an Interim Review should be in the form of a

summary report (normally not exceeding 5 pages), containing a description of system changes and a brief assessment on their impact on the **reliability** of the interconnected **bulk power system**.

8.0 Task Force Follow-Up Procedures

- 8.1 Once a Planning Coordinator has presented its Review report to the TFSS, TFSS will review the Planning Coordinator's report and any supporting documentation and:
 - a. Consider whether to accept the report as complete and in full conformance with these Guidelines. If the report is found to be unacceptable, TFSS will indicate to the Planning Coordinator the specific areas of deficiency, and request the Planning Coordinator to address those deficiencies.
 - b. Consider their concurrence with the results and conclusion(s) of the Planning Coordinator's Review. If there is not concurrence, TFSS will indicate to the Planning Coordinator the specific areas of disagreement, and work with the Planning Coordinator to try to achieve concurrence. If agreement has not been reached within a reasonable period of time, TFSS shall prepare a summary of the results of its review, including a discussion of the Planning Coordinators of disagreement.
- 8.2 If the results of the Area Review indicates that the Planning Coordinator's planned bulk power transmission system is not in conformance with NPCC Directory #1, TFSS will request the Planning Coordinator to develop a plan to achieve conformance with the Criteria.
- 8.3 If the Area Review indicates an overall **bulk power system** reliability concern (not specific to the Planning Coordinator's planned bulk power transmission system), TFSS will consider what additional studies may be necessary to address the concern, and prepare a summary discussion and recommendation to the Task Force on Coordination of Planning.
- 8.4 Upon completion of an Area Review, TFSS will report the results of the review to the Task Force on Coordination of Planning and to the Reliability Coordinating Committee.

Appendix C - Procedure for Testing and Analysis of Extreme Contingencies

1.0 Introduction

Extreme **Contingencies** (ECs) are tested "as a measure of system strength", in order to identify potential patterns of weakness in the bulk power transmission system. This procedure for the testing and analysis of ECs should be used when testing ECs for NPCC studies or studies submitted for NPCC review.

This procedure applies to **reliability** studies that consider the overall performance of the interconnected systems of the NPCC Planning Coordinator Areas. It principally applies to NPCC - wide studies of the **bulk power system**, and generally does not apply to studies normally conducted by NPCC Planning Coordinators that concentrate on individual or a limited number of facilities. This procedure applies to NPCC Overall and Area Transmission Reviews, and may be applicable to other **reliability** studies conducted by the Planning Coordinators, and even to individual facility investigations, where such studies and investigations consider the overall performance of the interconnected systems of the NPCC Planning Coordinator Areas. Certain Transmission Planners or Planning Coordinators may elect to completely mitigate the effects of specific ECs.

Finally, this procedure should be followed in multi-regional **reliability** studies in which NPCC is an active participant, to the extent that this is possible within the framework of such multi-regional efforts.

2.0 Choosing Contingencies for Testing

The ECs are defined in the NPCC Directory #1- Design and Operation of the **Bulk Power System**, and in the NERC Standards. Testing should focus on those ECs expected to have the greatest potential effect on the interconnected system. Particular attention should be paid to contingencies which would result in major angular power shifts, e.g., interruption of shorter transmission paths carrying heavy power flows, leaving longer transmission paths as the only remaining paths. Additionally, contingencies which would result in reversal of major power transfers, e.g., loss of major ties in a neighboring region or Area when said region or Area was transferring power away from the area of interest, should be considered for their impact in subjecting the system to severe power swings (reference EC type "f"). In considering specific **contingencies** to be investigated in an NPCC **reliability** study, all relevant testing done at the Planning Coordinator level should first be reviewed.

In general, a **contingency** in a particular Planning Coordinator Area should be studied, if requested by any other Planning Coordinator, based on a reasonable surmise that the requesting Planning Coordinator may be adversely affected.

3.0 Modeling Assumptions

The assumed generation dispatch is a major consideration in all EC testing. In general, EC testing should use a dispatch pattern considered to be highly probable for the year and **load** level being studied. Intra-Reliability Coordinator Area inter-Reliability Coordinator Area and, where appropriate, inter-regional transfers should be simulated at a level which is experienced or expected at least 75% of the time on a flow duration basis, up to the maximum operating limit for the interfaces being tested. It is not the NPCC intent to test the worst imaginable extreme, but EC tests should be severe.

Each Planning Coordinator shall specify the appropriate Planning Coordinator **load** representation (e.g. active and reactive power as a function of voltage) for use in NPCC **reliability** studies. This applies to long term stability tests or post-transient loadflows as well as **transient stability** tests.

4.0 Evaluating Individual Test Results

A question in evaluating the results of a particular test run is - "Does the system "pass" or "fail" for this **contingency**?" While in the final analysis this is a matter of informed engineering judgment, factors which should be considered include:

1. Lines or transformers loaded above **short time emergency ratings**,
2. Buses with voltage levels in violation of **applicable emergency limits**, (which vary depending on the location within the system),
3. Magnitude and geographic distribution of such overloads and voltage violations across the system,
4. Transient generator angles, frequencies, voltages and power,
5. Operation of Dynamic Control Systems and **Special Protection Systems** (SPS),
6. Oscillations that could cause generators to lose synchronism or lead to dynamic instability,
7. net loss of source resulting from any combination of loss of synchronism of one or more units, generation rejection or runback initiated by SPS, or any other defined system separation,
8. Identification of the extent of the Planning Coordinator Area (s) involved for any indicated instability or islanding (the involvement of more than one

Planning Coordinator Area, should be a major consideration),

9. **Relay** operations or the proximity of apparent impedance trajectories to **relay** trip characteristics,
10. The angle across opened breakers,
11. Adequacy of computer simulation models and data.

Finally, a judgment should be attempted as to whether a "failure" is symptomatic of a basic system weakness, or just sensitivity to a particular EC. For example, should failures turn up for several EC tests in a particular part of the system, it is likely that a basic system weakness has been identified.

The loss of portions of the system should not necessarily be considered a failed result, provided that these losses do not jeopardize the integrity of the overall **bulk power system**.

NPCC study groups should avoid characterizations like "successful" and "unsuccessful" when commenting on individual runs. Rather, the specific initial conditions directly causing or related to the failure, the complete description of the nature of the failure (e.g., voltage collapse, instability, system separation, as well as the facilities involved), and the extent of potential impact on other Planning Coordinator Areas should be reported.

5.0 Evaluating the Results of a Program of EC Testing

The NPCC Directory #1 document - "*Design and Operation of **Bulk Power System***", calls for testing of Extreme **Contingencies** (EC) "as a measure of system strength." The results of all NPCC **reliability** studies are made available to the Planning Coordinators as a guide for planners and designers in the conduct of their future work. The focus of NPCC reports, then, should be on indicating those portions of the system in which basic system weaknesses may be developing, rather than on the results of one specific **contingency**.

Any patterns of weaknesses should be identified, which may include reference to earlier NPCC **reliability** studies and/or Planning Coordinator or member system investigations. There is also a need to distinguish between a "failed" test which indicates sensitivity only to a particular **contingency** run and a "failed" test which indicates a more general system weakness (always keeping in mind the severity of possible consequences of the **contingency**). Actions taken by member systems or Planning Coordinators to reduce the probability of occurrence or mitigate the consequences of the **contingency** should also be cited.

NPCC follow-up, after publication of a final report, is appropriate only for instances

of possible general system weakness. In these instances, the results should be specifically referred to the affected Planning Coordinator or Planning Coordinators for further and more detailed investigation with subsequent reporting to NPCC.

Appendix D - Guidelines for Area Review of Resource Adequacy

1.0 Introduction

NPCC has established a Reliability Assessment Program to bring together work done by the NPCC and Planning Coordinators relevant to the assessment of **bulk power system reliability**. As part of the Reliability Assessment Program, each Planning Coordinator submits to the Task Force on Coordination of Planning its resource adequacy assessment consistent with these guidelines. The Task Force is charged, on an ongoing basis, with reviewing and recommending NPCC Reliability Coordinating Committee approval of these reviews of **resource** adequacy of each Planning Coordinator Area of NPCC.

Resources refer to the total contributions provided by supply-side and demand-side facilities and actions. Supply-side facilities include all generation sources within a Planning Coordinator Area and firm capacity backed purchases from neighboring systems. Demand-side facilities include measures for reducing or shifting **load**, such as conservation, **load** management, interruptible **loads**, dispatchable **loads** and small identified generation which is not metered at the control centers.

The NPCC role in monitoring conformance with the NPCC Directory #1 - *Design and Operation of Bulk Power System* is essential because under this criterion, each Planning Coordinator determines its resource requirements by considering interconnection assistance from other Planning Coordinators, on the basis that adequate **resources** will be available in those Planning Coordinator Areas. Because of this reliance on interconnection assistance, inadequate **resources** in one Planning Coordinator Area could result in adverse consequences in another Planning Coordinator Area.

It is recognized that all Planning Coordinators may not necessarily express their own **resource** adequacy criterion as stated in the NPCC Basic Criteria in Directory #1. However, the NPCC Basic Criteria provides a reference point against which a Planning Coordinator's **resource** adequacy criterion can be compared.

The NPCC will not duplicate reviews and studies completed by member systems and Planning Coordinators. The NPCC may reference these reviews in appropriate NPCC reports.

2.0 Purpose of Presentation

The purpose of the presentation associated with a **resource** adequacy review is to show that each Planning Coordinator's proposed **resources** are in accordance with the NPCC Directory #1 - *Design and Operation of the Bulk Power System*.

By such a presentation, the Task Force will satisfy itself that the proposed **resources** of each NPCC Planning Coordinator will meet the NPCC Resource Adequacy -

Design Criteria, as defined NPCC Directory #1, over the time period under consideration. The review by the Task Force on Coordination of Planning does not replace Planning Coordinator and/or company responsibility to assess their systems in conformity with the NPCC Basic Criteria in Directory #1.

3.0 Time Period to be Considered

The time period to be considered for a Planning Coordinator's Comprehensive **Resource** Review will be five years and be undertaken every three years. In subsequent years, the Planning Coordinator shall conduct Annual Interim Reviews that will cover, at a minimum, the remaining years studied in the Comprehensive Review. Based on the results of the Annual Interim Review, the Task Force may recommend that the Planning Coordinator conduct the next Comprehensive Review at a date earlier than specified above. Comprehensive and Interim reviews are normally expected to be presented to the Task Force before the beginning of the first time period covered by the assessment.

4.0 Format of Presentation and Report – Comprehensive Review

Each Planning Coordinator should include in its presentations and in the accompanying report documentation, as a minimum, the information listed below. At its own discretion, the Planning Coordinator may discuss other related issues not covered specifically by these guidelines.

4.1 Executive Summary

- 4.1.1 Briefly illustrate the major findings of the review.
- 4.1.2 Provide a table format summary of major assumptions and results.

4.2 Table of Contents

- 4.2.1 Include listing of all tables and figures.

4.3 Introduction

- 4.3.1 Reference the previous NPCC Area Review.
- 4.3.2 Compare the proposed **resources** and **load** forecast covered in this NPCC review with that covered in the previous review

4.4 Resource Adequacy Criterion

- 4.4.1 State the Planning Coordinator's **resource** adequacy criterion.
- 4.4.2 State how the Planning Coordinator criterion is applied; e.g., **load** relief steps.
- 4.4.3 Summarize **resource** requirements to meet the criteria for the time period under consideration. If interconnections to other Planning Coordinators and regions are considered in determining this requirement, indicate the value of the interconnections in terms of megawatts.
- 4.4.4 If the Planning Coordinator criterion is different from the NPCC criterion, provide either an estimate of the **resources** required to meet the NPCC criteria or a statement as to the comparison of the two criteria.
- 4.4.5 Discuss **resource** adequacy studies conducted since the previous Area Review, as appropriate.

4.5 Resource Adequacy Assessment

- 4.5.1 Evaluate proposed **resources** versus the requirement to reliably meet projected electricity demand assuming the Planning Coordinator's most likely **load** forecast.
- 4.5.2 Evaluate proposed **resources** versus the requirement to reliably meet projected electricity demand assuming the Planning Coordinator's high **load** growth scenario.
- 4.5.3 Discuss the impact of **load** and **resource** uncertainties on projected Planning Coordinator Area **reliability** and discuss any available mechanisms to mitigate potential **reliability** impacts.
- 4.5.4 Review the impacts that major proposed changes to market rules may have on Planning Coordinator Area **reliability**.

4.6 Proposed Resource Capacity Mix

- 4.6.1 Discuss any **reliability** impacts resulting from the proposed **resources** fuel supply and transportation or environmental considerations.
- 4.6.2 Describe available mechanisms to mitigate any potential **reliability** impacts of **resource** fuel supply, demand resource response, transportation issues and/or environmental considerations.

- 4.6.3 Discuss any **reliability** impacts related to an **Area**'s compliance with state, Federal or Provincial requirements (such as environmental, renewable energy, or greenhouse gas reductions).

5.0 Format of Presentation and Report – Annual Interim Review

The Annual Interim Review should include a reference to the most recent Comprehensive Review; a listing of major changes in: facilities and system conditions, **load** forecast, generation resources availability; related fuel supply and transportation information, environmental considerations, demand response programs, transfer capability and **emergency** operating procedures. In addition, the assessment should also include a comparison of major changes in market rules, implementation of new rules, locational requirements, and installed capacity requirements. Finally, the report should include a brief impact assessment and an overall summary.

The Planning Coordinator will provide a brief assessment of the impact of these changes on the **reliability** of the interconnected **bulk power system**. This assessment should be based on engineering judgment, internal system studies and appropriate joint interconnected studies. To the extent that engineering judgment or existing studies can be used to clearly demonstrate that a Planning Coordinator Area is expected to meet the NPCC resource adequacy criterion, detailed system LOLE studies are not required.

The documentation for the Annual Interim Review should be in the form of a summary report (normally not exceeding three to five pages.)

Sections A and B should describe the **reliability** model and program used for the **resource** adequacy studies discussed in Section 4.5. Section C should describe the Task Force follow-up procedures.

A. Description of Resource Reliability Model

1.1 Load Model

- 1.1.1 Description of the **load** model and basis of period **load** shapes.
- 1.1.2 How **load** forecast uncertainty is handled in model.
- 1.1.3 How the electricity demand and energy projections of interconnected entities within the Planning Coordinator Area that are not members of the Planning Coordinator Area are addressed.

- 1.1.4 How the effects (demand and energy) of demand-side management programs (e.g., conversion, interruptible demand, direct control **load** management, demand (**load**) response programs) are addressed.
- 1.2 Supply Side **Resource** Representation
 - 1.2.1 Resource Ratings
 - 1.2.1.1 Definitions.
 - 1.2.1.2 Procedure for verifying **ratings**.
Reference NPCC Document B-9, *Guide for Rating Generating Capability*.
 - 1.2.2 Unavailability Factors Represented
 - 1.2.2.1 Type of unavailability factors represented; e.g., forced outages, planned outages, partial derating, etc.
 - 1.2.2.2 Source of each type of factor represented and whether generic or individual unit history provides basis for existing and new units.
 - 1.2.2.3 Maturity considerations, including any possible allowance for in-service date uncertainty.
 - 1.2.2.4 Tabulation of typical unavailability factors.
 - 1.2.3 Purchase and Sale Representation.
 - 1.2.3.1. Describe characteristics and level of dependability of transactions.
 - 1.2.4 Retirements.
 - 1.2.4.1 Summarize proposed retirements.
- 1.3 Representation of Interconnected System in Multi-Area **Reliability** Analysis, including which Planning Coordinator Areas and regions are considered, interconnection capacities assumed, and how expansion plans of other Planning Coordinators and regions are considered.

- 1.4 Modeling of Variable and Limited Energy Sources.
- 1.5 Modeling of Demand Side Resources and Demand (**Load**) Response Programs.
 - 1.5.1 Description should include how such factors as in-service date uncertainty, **rating**, availability, performance and duration are addressed.
- 1.6 Modeling of all **Resources**.
 - 1.6.1 Description should include how such factors as in-service date uncertainty; capacity value, availability, **emergency** assistance, scheduling and deliverability are addressed.
- 1.7 Other assumptions i.e., internal transmission limitations, maintenance over-runs, fuel supply and transportation and environmental constraints.
- 1.8 Incorporate the **reliability** impacts of market rules.

B. Other Factors, If Any, Considered in Establishing Reserve Requirement Documentation

The documentation required to meet the requirements of the above format should be in the form of summaries of studies performed within a Planning Coordinator Area, including references to applicable reports, summaries of reports or submissions made to regulatory agencies.

C. Task Force Follow-Up Procedures

Once a specific Planning Coordinator has made a presentation or a series of presentations to the Task Force on Coordination of Planning, the latter shall:

- 1. Prepare a brief summary of key issues discussed during the presentation.
- 2. Note where further information was requested and the results of such further interrogations.
- 3. Note the specific items that require additional study and indicate the responsibilities for undertaking these studies.

4. Recommend approval to the Reliability Coordinating Committee.

Appendix E - Guidelines for Requesting Exclusions to Sections 5.4.1 (B) and 5.5.1 (B) of NPCC Directory #1 – *Design and Operation of the Bulk Power System*

1.0 Introduction

The Northeast Power Coordinating Council (NPCC) was formed to promote the **reliability** and efficiency of electric service of the interconnected **bulk power system** of the members of the NPCC by extending the coordination of their system design and operations as cited in the NPCC Memorandum of Agreement. Towards that end, the Member Systems of NPCC adopted the *Basic Criteria for Design and Operation of Interconnected Power Systems* (Directory #1 – *Design and Operation of the Bulk Power System*), which establishes the minimum standards for design and operation of the interconnected **bulk power system** of NPCC. In accordance with those standards, the **bulk power system** should be designed and operated so as to withstand certain specific **contingencies**.

One such **contingency**, listed under Section 5.4.1(b), Transmission Design Criteria - **Stability** Assessment, and under Section 5.5.1(b), Transmission Operating Criteria - Normal Transfers, involves "simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with normal **fault clearing**." Although this **contingency** is normally included in the NPCC Criteria, the Basic Criteria in Directory #1 define specific conditions for which a multiple circuit tower situation is an acceptable risk and, therefore, can be excluded.

Directory #1 also allows for requests for exclusion from this **contingency**, on the basis of acceptable risk, for other instances of multi-circuit tower construction. All exclusions must be approved by the Reliability Coordinating Committee (RCC). An acceptance of a request for exclusion is dependent on the successful demonstration that such exclusion is an acceptable risk. These guidelines describe the procedure to be followed and the supporting documentation required when requesting exclusion, and establishes a procedure for periodic review of exclusions of record.

2.0 Documentation

The documentation supporting a request for exclusion to Sections 5.1(b) and 6.1(b) of the Basic Criteria must include the following:

- 2.1 A description of the facilities involved, including geographic location, length and type of construction, and electrical connections to the rest of the interconnected power system;
- 2.2 Relevant design information pertinent to the assessment of acceptable risk, which might include: details of the construction of the facilities, geographic or

atmospheric conditions, or any other factors that influence the risk of sustaining a multi-circuit **contingency**;

- 2.3 An assessment of the consequences of the occurrence of a multi-circuit **contingency**, including, but not limited to, a discussion of levels of exposure and probability of occurrence of **significant adverse impact** outside the local area;
- 2.4 For existing facilities, the historical outage performance, including cause, for multi-circuit **contingencies** on the specific facility (facilities) involved as compared to that of other multi-circuit tower facilities;
- 2.5 For planned facilities, the estimated frequency of multi-circuit **contingencies** based on the historical performance of facilities of similar construction located in an area with similar geographic climate and topography.

3.0 Procedure for obtaining an Exclusion

The following procedure shall be used in obtaining exclusion to Sections 5.4.1(b) or 5.5.1(b) of Directory #1:

- 3.1 The entity requesting the exclusion (the Requestor) shall submit the request and supporting documentation to the Task Force on System Studies (TFSS) after acceptance has been granted by the Requestor's own Planning Coordinator, if such process is applicable.
- 3.2 TFSS shall review the request, verify that the documentation requirements have been met, and determine the acceptability of the request.
- 3.3 If TFSS deems the request acceptable, TFSS shall request the Task Force on Coordination of Planning (TFCP), the Task Force on Coordination of Operation (TFCO), and the Task Force on System Protection (TFSP) to review the request. The Requestor shall provide copies of the request and supporting documentation to the other Task Forces as directed by TFSS. If additional information is requested by the other Task Forces as part of their assessment, the Requestor will provide this information directly to the interested Task Force, with a copy to the TFSS. The other Task Forces shall review the request and indicate their acceptance or non-acceptance to TFSS.
- 3.4 If any of the four Task Forces determines the request is not acceptable, TFSS will respond to the Requestor with the determination and inform the RCC and the other Task Forces of the decision.
- 3.5 TFSS shall notify TFCP, TFCO, and TFSP of an exclusion that has been accepted by the Task Forces and the basis for the exclusion. The TFSS will then make a recommendation to the RCC regarding the exclusion.

- 3.6 The NPCC Policy for Alternative Dispute Resolution is available for use if the decision is unacceptable to the Requestor.

Upon acceptance of the requested exclusion by the RCC, TFSS shall so notify the Requestor and update a summary list of the exclusions. The summary list and supporting documents shall be maintained by NPCC.

4.0 Periodic Review of Exclusions of Record

Exclusions shall be reviewed within the Planning Coordinator's transmission reviews as provided in *Guidelines for NPCC Area Transmission Reviews* (NPCC Directory #1 – Appendix C). This review shall verify that the basis for each exclusion is still valid. TFSS shall notify TFCP, TFCO, TFSP, and the RCC when a Planning Coordinator's transmission review has determined exclusion is no longer applicable, and revise the exclusion summary list accordingly.

Appendix F – Procedure for Operational Planning Coordination

1.0 Introduction

The Reliability Coordinators (RC) of the Northeast Power Coordinating Council, Inc. (NPCC) require access to the security data specified in this procedure in order to adequately assess the reliability of the NPCC bulk power system. All users of the electric systems, including market participants, must supply such data to the NPCC Reliability Coordinators. Coordination among and within the Reliability Coordinator Areas (RC Area) of NPCC is essential to the reliability of interconnected operations. Timely information concerning system conditions should be transmitted by the NPCC RC Areas to other RC Areas as needed to assure reliable operation of the **bulk power system**. One aspect of this coordination is to ensure that adjacent RC Areas and neighboring systems are advised on a regular basis of expected operating conditions, including generator, transmission and **system protection**, including Type I **special protection system**, outages that may materially reduce the ability of an RC Area to contribute to the reliable operation of the interconnected system, or to receive and/or render assistance to another RC Area. To the extent practical, the coordination of outage schedules is desirable in order to limit the severity of such impacts.

To ensure that there is effective coordination for system **reliability** concerns, this document establishes procedures for the exchange of information regarding load/capacity forecasts, including firm sales and firm purchases, generator outage schedules, and transmission outage schedules for those facilities that may have an adverse impact on other RC Area(s). It also details general action that may be taken to improve the communication of problems as well as specific topics that may be discussed in regularly scheduled, pre-arranged conference call meetings or in conference calls arranged in anticipation of problems such as capacity deficiency or inadequate light load margin in one or more RC Areas.

Participants and other recipients of the information provided by this process must adhere to the NERC *Confidentiality Agreement for Electric System Operating Reliability Data*.

2.0 Load/Capacity Forecasts

- 2.1 Twice yearly, by May 15th and November 15th respectively, the Operations Planning Working Group (CO 12) will perform a summer and winter assessment for the next season. The methodology and format of the seasonal report will be presented in NPCC Document C-45, "CO-12 Seasonal Assessment Methodology," currently under development.

The results will be reviewed by the NPCC Task Force on Coordination of Operation (TFCO) and the NPCC Reliability Coordinating Committee (RCC) in advance of the spring and autumn meetings of both groups.

- 2.2 Each week, each RC Area will review its weekly net resource capacity margin, as defined in Attachment A, for the twelve weeks to follow and forward the information to the NPCC Staff for distribution to all NPCC RC Areas. If an NPCC RC Area identifies a deficiency or light load condition, the RC Area should identify the cause(s) and mitigation measures that have been implemented, or will be implemented, to manage the issue.

3.0 Generator Outage Coordination

- 3.1 Each RC Area should exchange current and expected critical generation outages.

4.0 Transmission Outage Coordination

4.1 Advance Planning of Transmission Facility Outages

NPCC Document A-2, *Basic Criteria for Design and Operation of Interconnected Power Systems*, requires that scheduled outages of transmission facilities that affect **reliability** between RC Areas be coordinated sufficiently in advance of the outage to permit the affected RC Area to maintain **reliability**. For the purposes of this procedure, each RC should exchange critical transmission outages as identified in coordination agreements with their interconnected neighbors and jointly develop and maintain a Facilities Notification List.

4.2 Facilities Notification List

The NPCC Facilities Notification List, Attachment D, has two components:

- 1) the NPCC Transmission Facilities Notification List; and
- 2) the list of NPCC Type I **special protection systems**.

The Facilities Notification List is developed by each RC Area and specifies all facilities that, if removed from service, may have a significant, direct or indirect impact on another RC Area's transfer capability. The cause of such impact might include stability, voltage, and/or thermal considerations.

Prior to October 1st of each year, each RC Area will review and update its Facilities Notification List and coordinate necessary changes with other appropriate NPCC RC Areas. Prior to January 1st, and after review by the TFCO, the approved, updated Facilities Notification List will be posted on the NPCC secure website.

The Task Force on System Protection develops yearly the list of NPCC Type 1 **special protection systems** with input from the Task Force on System Studies.

It should be noted that revisions to the Facilities Notification List only will not follow the NPCC Process for Open Review due to the secure nature of the information contained, and Attachment D is not openly published with this Procedure.

A temporary reconfiguration of the network may result in an outage to one or more facilities not listed in Attachment D having an impact on other NPCC RC Areas. It is the responsibility of the RC experiencing the condition to notify impacted RCs in a timely manner and provide updated status reports during the condition.

4.3 Notifications of Work

4.3.1 Notification requirements should be defined in interconnected coordination agreements. The time frames identified below are the minimum notification requirements.

4.3.2 The initiating RC will advise affected RCs of all applications for outages of facilities on the Facilities Notification List, including those which have been planned.

All outages to equipment listed in the Facilities Notification List should be planned with as much lead time as practical.

Normally, notification for work on facilities covered by this instruction will be submitted to the appropriate RC Areas at least two (2) working days prior to the time the facility is to be taken out of service.

When an RC Area receives an outage notification from another RC Area, prompt attention will be given to the notification and appropriate comments rendered. Analysis will be conducted by each RC Area in accordance with internal procedures.

4.3.3 An RC Area will not normally remove from service any transmission facility, which might have a **reliability** impact on an RC Area without prior notification to and appropriate review by that RC Area. In the event of an **emergency** condition, each RC Area may take action as deemed appropriate. Other RC Areas should be notified immediately.

An RC Area will make every effort to reschedule routine (non-emergency) transmission outages that severely degrade the reliability of an adjacent RC Area or neighboring system.

4.3.4 Each RC Area will advise the other affected RC Areas of any protection outage associated with RC Area tie line facilities. Coordination agreements may identify additional reporting

requirements associated with protection outages.

5.0 Data Providers

NPCC entities are to provide the data in order to adequately assess the reliability of the NPCC bulk power system.

6.0 Specific Communications

Conditions in an RC Area that may have an impact on another RC Area should be communicated in a clear and timely manner. Specific communications are conducted as follows:

6.1 Weekly

Each Thursday a conference call will be initiated by the NPCC Staff to discuss operations expected during the seven-day period starting with the following Sunday. Operations personnel from the NPCC RC Areas will participate. In advance of the conference call, each RC Area will prepare the data specified in Attachments A and B, and forward it to the NPCC Staff a minimum of one hour in advance of the scheduled call. The completed “NPCC Weekly Conference Call Generating Capacity Worksheet,” Attachment B, together with the list of “Twelve Weeks Projections of Net Margins,” Attachment C, will be forwarded to the conference call participants by the NPCC Staff.

Each RC will review its weekly capacity margins for the next twelve week period. If a deficiency or light load condition is identified, the RC will identify the cause of the deficiency or light load condition and discuss proposed mitigation measures.

The NPCC Staff will prepare Conference Call Notes that will be forwarded to the conference call participants and members of the TFCO by the following Friday afternoon.

If a deficiency or light load condition, or if adverse system operating conditions are expected within the next week, any RC Area may recommend that an Emergency Preparedness Conference Call (NPCC Document C-01) take place at an appropriate time.

Items of particular concern that should be discussed during the weekly conference call are described in Attachment C.

6.2 Emergency Preparedness Conference Call

Whenever adverse system operating or weather conditions are expected, any RC Area may request the NPCC Staff to arrange an Emergency Preparedness Conference Call (NPCC Document C-01) to discuss operating details with appropriate operations management personnel from the NPCC RC Areas and neighboring systems.

6.3 Daily Conference Calls

Each of the NPCC Reliability Coordinator Area control rooms participate in a regularly scheduled daily conference call. The goal of this call is to alert NPCC Reliability Coordinators of any potential emerging problems. Subjects for discussion are limited to credible events which could impact the ability of a Reliability Coordinator to serve its load and meet its operating reserve obligations, or which would impose a burden to the Interconnection.

Procedure for Operational Planning Coordination – Attachment A

Load and Capacity Table Instructions and Generating Capacity Worksheet Instructions

Week Beginning	The seven day period for which data is to be reported is defined as starting with the Sunday following the conference call through the following Saturday.
Installed Generating Capacity (Line Item 1)	Include all available generation at its maximum demonstrated capability for the appropriate seasonal capability period.
Firm Purchases (Line Item 2)	Include only those transactions where capacity is delivered. Exclude “energy only” transactions.
Firm Sales (Line Item 3)	Include only those transactions where capacity is delivered. Exclude “energy only” transactions.
Net Capacity (Line Item 4)	Add Installed Generating Capacity and Firm Purchases. Subtract Firm Sales. (Line 1+Line 2-Line3)
Peak Load Forecast (Line Item 5)	The peak load forecast should be the best estimate of the RC Area’s maximum peak load exposure anticipated for the week reported.
Available Reserve (Line Item 6)	Subtract Peak Load Forecast from Net Capacity. (Line 4-Line5.)
Demand Side Management (Line Item 7)	Include only maximum capability which can be obtained by operator initialization within four (4) hours.

Attachment A (continued)	
Known Unavailable Capability (Line Item 8)	Include all known outages, as well as those deratings or unit outages presently forced out, unavailable, on extended cold standby or which are anticipated to remain out of service. This would also include capacity unavailable due to transmission constraints.
Net Reserve (Line Item 9)	Available Reserve plus Demand Side Management minus Known Unavailable Capacity. (Line 6+Line 7-Line 8)
Required Operating Reserve (Line Item 10)	The methodology used by each RC Area in calculating operating reserve must, as a minimum, meet the requirements of NPCC Document A-06, "Operating Reserve Criteria." Methodologies differing from the A-06 requirements should be clarified in Attachment B, "NPCC Weekly Conference Call Generating Capacity Worksheet," under the tab for "Operating Reserve."
Gross Margin (Line Item 11)	Subtract Required Operating Reserve from Net Reserve. (Line 9-Line 10)
Unplanned Outages (Line Item 12)	Estimate the amount of generating capacity which will be unavailable. This quantity should be based on historical averages for forced outages and deratings.
Net Resource Capacity Margin (Line Item 13)	Subtract Unplanned Outages from Gross Margin. A positive value reflects surplus reserve. A negative value reflects a deficiency. (Line 11-Line 12)
Forecast High / Low Temperatures and Days (Line Item 14)	Include the expected high and low temperatures for the RC Area for the week, and indicate the day on which they are expected to occur.

Attachment A (continued)	
Seasonal High / Low Temperatures (Line Item 15)	Include the expected high and low forecast seasonal temperatures for the RC Area.
Minimum Load Forecast (Line Item 16)	The minimum load forecast should be the best estimate of the RC Area's minimum load exposure anticipated for the week reported.
Minimum Resources (Line Item 17)	The Minimum Resources are the Reliability Coordinator Area's total expected on-line generator minimum output capability and must-take purchases.
Light Load Margin (Line Item 18)	Subtract Minimum Resources from Minimum Load Forecast. A negative number indicates a light load condition. (Line 16-Line 17)

Procedure for Operational Planning Coordination – Attachment B

NPCC Weekly Conference Call Generating Capacity Worksheet

The “NPCC Weekly Conference Call Generating Capacity Worksheet” is an active Excel spreadsheet used each week to assist in the calculation of the data discussed during the weekly conference call. A blank template, in Microsoft Office Excel 2003, is available from the NPCC office.

Procedure for Operational Planning Coordination - Attachment C

CONDITIONS FOR DISCUSSION

Items of particular concern that should be discussed during a conference call include, but are not limited to, the following:

- anticipated weather;
- largest first and second contingencies;
- operating reserve requirements and expected available operating reserve;
- capacity deficiencies;
- potential fuel shortages or potential supply disruptions which could lead to energy shortfalls;
- light load margins;
- general and specific voltage conditions throughout each system or RC Area;
- status of short term contracts and other scheduled arrangements, including those that impact on operating reserves;
- additional capability available within twelve hours and four hours;
- generator outages that may have a significant impact on an adjacent RC Area or neighboring system;
- transmission outages that might have an adverse impact on internal and external energy transfers;
- potential need for emergency transfers;
- expected transfer limits and limiting elements;
- a change or anticipated change in the normal operating configuration of the system, such as the temporary modification of relay protection schemes so that the usual and customary levels of protection will not be provided, or the arming of special protection systems not normally armed, or the application of abnormal operating procedures; and
- update of the abnormal status of NPCC Type I special protection systems forced out of service.

Attachment D
NPCC Facilities Notification List

Attachment D is not publicly available due to the confidential nature of the information presented.

Appendix G - Procedures for Inter Reliability Coordinator Area Voltage Control

1.0 Introduction

This Procedure provides general principles and guidance for effective inter-Transmission Operator Area voltage control, consistent with the NPCC, Directory #1, “Design and Operation of the Bulk Power System,” and applicable NERC Standards. Specific methods to implement this Procedure may vary among Transmission Operators, depending on local requirements. Coordinated inter-Transmission Operator Area voltage control is necessary to regulate voltages to protect equipment from damage and prevent voltage collapse. Coordinated voltage regulation reduces electrical losses on the network and lessens equipment degradation. Local control actions are generally most effective for voltage regulation. Occasions arise when adjacent Transmission Operators can assist each other to compensate for deficiencies or excesses of **reactive power** and improve voltage profiles and system security.

2.0 Principles

Each Transmission Operator develops, and operates in accordance with, its own voltage control procedures and criteria which are consistent with NPCC, Inc. Criteria and NERC Standards. Adjacent Transmission Operators should be familiar with the respective criteria and procedures of their neighboring Transmission Operators should mutually agree upon procedures for inter-Transmission Operator Area voltage control. Whether inter-Transmission Operator Area voltage control is carried out through specific or general procedures, the following should be considered and applied:

- 2.1 To effectively coordinate voltage control, location and placement of metering for **reactive power** resources and voltage controller status should be consistent between adjacent Transmission Operators.
- 2.2 the availability of **voltage regulating transformers** in the proximity of **tie lines**;
- 2.3 voltage levels, limits, and regulation requirements for stations on either side of an inter-Transmission Operator Area interface;
- 2.4 the circulation of **reactive power** (export at one tie point in exchange for import at another);
- 2.5 **tie line** reactive losses as a function of real **power** transfer;
- 2.6 reactive **reserve** of on-line generators;
- 2.7 shunt reactive device availability and switching strategy; and
- 2.8 **static VAR compensator** availability, reactive **reserve**, and control strategy.

3.0 Procedure

Transmission Operators maintain normal voltage conditions, in accordance with their own individual or joint operating policies, procedures and applicable interconnection agreements. In the event the system state changes to an abnormal voltage condition, the Transmission Operator in which the abnormal condition is originating should immediately take corrective action. If the corrective control actions are ineffective, or the Transmission Operator has insufficient reactive resources to control the problem, assistance may be requested from other Transmission Operators.

3.1 Normal Voltage Conditions

The **bulk power system** is operating with Normal Voltage Conditions when:

- actual voltages are within applicable normal (pre-**contingency**) voltage ranges; and
- expected post-**contingency** voltages are within applicable post-**contingency** minimum and maximum levels following the most severe **contingency** specified in Directory #1 “Design and Operation of the Bulk Power System.”

Each Transmission Operator should maintain a mix of static and dynamic resources, including reactive **reserves**.

3.1.1 Providing that it is feasible to regulate reactive flows on its **tie lines**, each Transmission Operator should establish a mutually agreed upon voltage profile with adjacent Transmission Operators and with other neighboring systems. This voltage profile should conform to the provisions of the relevant interconnection agreements and may provide for:

- The minimum and maximum voltage at stations at or near terminals of inter-Transmission Operator Area tie lines;
- The receipt of reactive flow at one tie point in exchange for delivery at another;
- The sharing of the reactive requirements of **tie lines** and series regulating equipment (either equally or in proportion to line lengths, etc.); and
- The transfer of **reactive power** from one Transmission Operator to another.

This voltage profile, adjusted for changes in operating conditions, should be considered as the basis for determining which Transmission Operator should implement necessary measures to alleviate abnormal voltage conditions affecting more than one Transmission Operator as discussed in 3.2.10 below.

3.1.2 Each Transmission Operator should anticipate voltage trends and initiate corrective action in advance of critical periods of heavy and light **loads**.

4.0 Procedure for Triennial Monitoring and Reporting of Inter-Area Voltage Control

- 4.1 On, or shortly before, the first of July, the TFCO Secretary will write to each TFCO member, requesting a written response by the end of July in the form of:
- a) A copy of any new procedures and principles between the reporting Reliability Coordinator and adjacent Reliability Coordinators providing detailed application, or,
 - b) a copy of any new understanding, such as the minutes of an operating committee meeting between Reliability Coordinators, indicating that such detailed application is not required, and why;
 - c) a copy of any revisions to the procedures and principles, or understandings currently on file at NPCC, that exists between the reporting Reliability Coordinator and adjacent Reliability Coordinators;
 - d) a response indicating no change to existing procedures and principles, or understandings currently on file at NPCC.
- 4.2 The TFCO Secretary will draft a report summarizing the extent to which responses indicated conformance with the NPCC Procedures, and will forward it to TFCO members at least two weeks prior to the October TFCO meeting.
- 4.3 Following TFCO review and adoption, the TFCO Chairman will forward the report to the Chairman of the Reliability Coordinating Committee (RCC) recommending acceptance or other action as deemed appropriate. This will normally be forwarded three weeks prior to the next regularly scheduled RCC meeting.



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NPCC Regional Reliability Reference Directory # 2 Emergency Operations

Task Force on Coordination of Operations Revision Review Record:
October 21, 2008

Adopted by the Members of the Northeast Power Coordinating Council, Inc. this October 21, 2008 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	10/21/08	Effective Date	New
1	6/26/09	Transfer Auto UFLS language to D#12	Revision
2	8/19/09	Removed references to Automatic UFLS in Section 7 to reflect transfer of Automatic UFLS language to D#12.	Errata

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1.0 Introduction

1.1 Title Emergency Operations

1.2 Directory Number 2

1.3 Objective

The purpose of this Directory is to present the basic factors to be considered in formulating plans and procedures to be followed in an emergency or during conditions which could lead to an emergency, in order to facilitate mutual assistance and coordination within NPCC and adjacent areas.

The objectives in formulating plans related to emergency operating conditions are:

1. To avoid the interruption of service to firm **load** to the extent possible.
2. To minimize the occurrence of **system disturbances**.
3. To contain any **system disturbance** and limit its effects to the area initially affected.
4. To minimize the effects of any **system disturbances** on customers.
5. To avoid damages to system **elements**.
6. To avoid hazard to the public.

1.4 Effective Date **October 21, 2008**

1.5 Background

This Directory was developed from the NPCC A-03 Emergency Operations Criteria and associated B-3 Guideline and C-20 Procedure documents. Guidelines and procedures for consideration in the implementation of this Directory are provided in Appendix B.

1.6 Applicability

1.6.1 Functional Entities

Reliability Coordinators
Balancing Authorities
Transmission Operators
Generator Operators

2.0 Terms Defined in this Directory

The definitions of terms found in this Directory appearing in bold typeface can be found in the Appendix A.

3.0 NERC ERO Reliability Standard Requirements

The NERC ERO Reliability Standards containing Requirements that are associated with this Directory include, but may not be limited to:

- 3.1 [BAL-005: Automatic Generation Control](#)
- 3.2 [COM-001: Telecommunications](#)
- 3.3 [COM-002: Communications and Coordination](#)
- 3.4 [EOP-001: Emergency Operations Planning](#)
- 3.5 [EOP-002: Capacity and Energy Emergency](#)
- 3.6 [EOP-003: Load Shedding Plans](#)
- 3.7 [PRC-006: Development and Documentation of RRO's UFLS Programs](#)
- 3.8 [PRC-007: Assuring Consistency with Regional UFLS Requirements](#)
- 3.9 [TOP-001: Reliability Responsibilities and Authorities](#)
- 3.10 [TOP-004: Transmission Operations](#)
- 3.11 [TOP-006: Monitoring System Controls](#)
- 3.12 [IRO-003: Reliability Coordination – Wide Area View](#)
- 3.13 [IRO-005: Reliability Coordinator – Current Day Operation](#)
- 3.14 [IRO-015: Notification and Information Exchange Between RCs](#)
- 3.15 [IRO-016: Coordination of Real Time Activities Between RCs](#)
- 3.16 [BAL-001: Real Power Balancing Control Performance](#)
- 3.17 [BAL-002: Disturbance Control Performance](#)
- 3.18 [BAL-003: Frequency Response and Bias](#)

4.0 NPCC Regional Reliability Standard Requirements

None.

5.0 NPCC Full Member, More Stringent Criteria

These Criteria are in addition, more stringent or more specific than the NERC or any Regional Reliability standard requirements

5.1 General Criteria

Normal Transfer Capabilities shall be observed unless there is insufficient **capacity** or voltage support in a Balancing Authority or Transmission Operator area, in which case **Emergency Transfer Capabilities** may be used prior to shedding firm **load**. **Emergency transfer capabilities** shall not be exceeded.

The circumstances under which each of these system operating limits are

applied shall be clearly indicated by written instructions.

5.2 Manual **Load Shedding** Requirement

Each Balancing Authority shall have the capability of manually shedding at least fifty percent of its area **load** in ten minutes or less. Manual **load shedding** plans shall not interrupt **bulk power system** elements.

5.2.1 Manual **load shedding** procedures shall be reviewed at least annually by the Balancing Authority and Transmission Operator, to ensure that the proper amount of **load** can be shed within the time limits prescribed.

5.2.2 Studies shall be performed by the affected Transmission Operator to ensure satisfactory voltage and loading conditions after manual **load shedding**.

6.0 Measures and Assessments

None developed at this time.

7.0 Compliance Monitoring

The monitoring of manual **load shedding** requirements (Section 5.2) will be carried out by the NPCC Compliance Committee.

Prepared by: Task Force on Coordination of Operation

Review and Approval: Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval.

Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC Bylaws" in effect at the time the ballots are cast.

Revisions pertaining to the Appendices or any other portion of the document such as Links, glossary of terms, etc., will only require RCC Members' approval. Errata may be corrected by the Lead Task Force at any time and provide the appropriate notifications to the NPCC Inc. membership.

This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

References: None

Appendix A Definition of Terms¹

Automatic Generation Control (AGC) — Equipment that automatically adjusts a **Control Area's generation** to maintain its **interchange schedule** plus its share of frequency regulation.

The following AGC modes are typically available:

- a. **Tie Line Bias Control** — Automatic generation control with both frequency and net **interchange** terms of **Area Control Error** considered.
- b. **Constant Frequency (Flat Frequency) Control** — Automatic generation control with the net **interchange** term of **Area Control Error** ignored. This Automatic Generation Control mode attempts to maintain the desired frequency without regard to **interchange**.
- c. **Constant Net Interchange (Flat Tie Line) Control** — Automatic generation control with the frequency term of **Area Control Error** ignored. This Automatic Generation Control mode attempts to maintain net **interchange** at the desired level without regard to frequency.

Bulk power system — The interconnected electrical systems within northeastern North America comprising **generation** and transmission facilities on which **faults** or **disturbances** can have a **significant adverse impact** outside of the local area. In this context, local areas are determined by the Council members.

Capacity — The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of **generation**, transmission, or other electrical equipment.

Element — Any electric device with terminals that may be connected to other electric devices, such as a generator, transformer, circuit, circuit breaker, or bus section.
Limiting Element — The element that is either operating at its appropriate **rating** or would be following a limiting **contingency** and, as a result, establishes a system limit.

Emergency — Any abnormal system condition that requires automatic or manual action

¹ These terms will be moved and grouped under a separate Directory when all other Directories are developed.

This document, when downloaded or printed, becomes UNCONTROLLED. Users should check the NPCC website for the current CONTROLLED version of this document.

to prevent or limit loss of transmission facilities or **generation** supply that could adversely affect the **reliability** of the electric system.

Specific to NPCC, an **Emergency** is considered to exist in an Area if **firm load** may have to be shed.

Emergency Transfer Capability — The amount of **power** transfer allowed between **Areas** or within an **Area** when operating to meet NPCC **emergency** criteria contingencies.

Generation (Electricity) — The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatt-hours (kWh) or megawatt hours (MWh).

Gross Generation — The electrical output at the terminals of the generator, usually expressed in megawatts (MW).

Net Generation — Gross generation minus station service or unit service **power** requirements, usually expressed in megawatts (MW).

Interchange — Electric **power** or energy that flows from one entity to another.

Interchange Schedule — An agreed-upon transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of **power** and energy between the contracting parties and the **Control Area(s)** involved in the transaction.

Interface — The specific set of transmission **elements** between two areas or between two areas comprising one or more electrical systems.

Island — A portion of a **power** system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission system **elements**.

Load — The electric **power** used by devices connected to an electrical generating system. (IEEE Power Engineering). Also see **Demand**.

NPCC Specific Definitions:

Firm Load — Loads that are not **Interruptible Loads**.

Interruptible Load — Loads that are interruptible under the terms specified in a contract.

Load Shedding — The process of deliberately removing (either manually or automatically) preselected customers' **load** from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall

customer outages.

Normal Transfer Capability — The amount of **power** transfer allowed between **Areas** or within an **Area** when operating to meet NPCC normal criteria contingencies.

Protective relay — A **relay** that detects a power system **fault** or abnormal condition and initiates appropriate control system action.

Real Power — The rate of producing, transferring, or using electrical energy, usually expressed in kilowatts (kW) or megawatts (MW).

Reactive Power — The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, **synchronous condensers**, or electrostatic equipment such as capacitors. Reactive power directly influences electric system voltage. It is usually expressed in kilovars (kVAr) or megavars (MVar).

Relay — An electrical device designed to respond to input conditions in a prescribed manner and after specified conditions are met to cause contact operation or similar abrupt change in associated electric control circuits. (Also: see **protective relay**).

Reliability - The degree of performance of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system — **Adequacy** and **Security**.

Adequacy - The ability of the electric system to supply the aggregate electrical **demand** and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system **elements**.

Security - The ability of the electric system to withstand **disturbances** such as electric **short circuits** or unanticipated loss of system **elements**.

Special protection system (SPS) – A **protection system** designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted **elements**. Such action may include changes in **load**, **generation**, or system configuration to maintain system **stability**, acceptable voltages or power flows. Automatic underfrequency **load shedding** as defined in this Directory, is not considered a **Special Protection System**. Conventionally switched, locally controlled shunt devices are not **Special Protection Systems**.

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System Disturbance - An event characterized by one or more of the following phenomena: the loss of **power** system **stability**; cascading outages of circuits; oscillations; abnormal ranges of frequency or voltage or both.

Operator, System - Person responsible for operating control of the **bulk power system** in an **Area** of NPCC or an adjoining system interconnected with NPCC. This could be a Security Coordinator, a **Control Area** Operator or in some cases a bulk power utility operator (e.g. NYPA, Niagara Mohawk, etc)

Voltage Reduction - A means to reduce the **demand** by lowering the customer's voltage.

Appendix B

Guideline and Procedure for Emergency Operation

1.0 Introduction

This Appendix provides the guidelines and procedures for anticipating and operating under emergency conditions. These guidelines and procedures are intended to provide specific instructions to the **System Operator** during such conditions in an NPCC Balancing Authority area or Transmission Operator area or Reliability Coordinator area with an objective to minimize, when possible, the impact of an evolving event and to prevent, contain and control an **emergency**.

2.0 Minimizing the Impact of Events

- 2.1 It is recognized that provisions are made in the design of a power system for the satisfactory performance of the system during certain **faults** or incidents of **equipment** failure. It is also recognized that the power system should be operated in a prescribed manner to withstand these contingencies.
- 2.2 When planning for near term forecast conditions, each Balancing Authority and Transmission Operator should develop operating strategies that provide for sufficient generation and transmission to meet the following objectives:
 - 2.2.1 **Operating reserve** requirements.
 - 2.2.2 **Automatic generation control** and frequency control requirements.
 - 2.2.3 Line/tie line loadings within applicable normal operating limits.
 - 2.2.4 **Bulk power system** voltage within normal limits.
- 2.3 When operating conditions deviate from the boundaries that are planned for, a Balancing Authority area or a Transmission Operator area may experience abnormal operating conditions. If such conditions persist, the Balancing Authority or the Transmission Operator may need to declare and enter into an **emergency**. When operating under abnormal and emergency conditions, the guideline and procedure as presented in Sections 3.0 to 6.0 should be followed.

3.0 Operating Under Abnormal Voltage Conditions

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3.1 The **bulk power system** is operating with abnormal voltage conditions when:

- 3.1.1 actual voltages are outside applicable normal (pre-contingency) voltage ranges.
- 3.1.2 expected post-contingency voltages violate applicable post-contingency minimum and maximum levels following applicable NPCC Normal or Emergency Criteria Contingencies.

Transmission Operators that anticipate or experiencing an abnormal voltage condition should follow the procedures specified in Section 3.2.

3.2 Correction of Abnormal Voltage Conditions

Abnormal voltage conditions in a Transmission Operator area can be caused by changes within the Transmission Operating area or external Transmission Operator areas, or by changes in load-generation-interchange balance in external Balancing Authority areas. In determining the appropriate steps to correct abnormal voltage conditions, attempts should be made to identify the root cause of the problems.

- 3.2.1 If a Transmission Operator area is experiencing abnormal voltage conditions, the Transmission Operator should implement the steps in Section 3.2.2 and 3.2.3 to return voltages to normal condition.
- 3.2.2 If the **bulk power system** voltage is rapidly decaying, the Balancing Authority or Transmission Operator area, if identifiable, causing the decay should immediately implement all possible action, including the shedding of **firm load**, to correct the problem. All other Transmission Operator areas experiencing the rapid voltage decay should immediately implement all possible action, including the shedding of **firm load**, to correct the problem, until such time that the Balancing Authority or Transmission Operator area causing the decay has implemented actions to correct the problem.
- 3.2.3 When a Transmission Operator anticipates or is experiencing an abnormal, but stable, or gradually changing **bulk power system** voltage condition, it should implement steps to correct the situation. Recognizing that voltage problems are most effectively corrected by control actions as close to the source as possible, the Transmission Operator should use its own resources, but may request assistance from adjacent Transmission Operator areas. Provided below is a guide for the implementation of potential control actions with the

provision that individual steps may be eliminated if considered ineffective for the particular situation.

3.2.3.1 The Transmission Operator area anticipating or experiencing the abnormal **bulk power system** voltage condition should implement the following control actions, where effective and as available, in accordance with the Transmission Operator's voltage control procedures:

3.2.3.1.1 adjust transformer taps.

3.2.3.1.2 switch capacitors/reactors.

3.2.3.1.3 adjust static VAR compensators.

3.2.3.1.4 utilize full reactive capability of on-line generators.

3.2.3.1.5 deploy synchronous condensers.

3.2.3.1.6 other actions as local voltage control procedures allow.

3.2.3.1.7 dispatch additional generation.

3.2.3.2 If the steps in Section 3.2.3.1 are insufficient to correct the problem, adjacent Transmission Operators should be advised of the need to depart from normal reactive schedules and should be requested to provide assistance if this will be effective. The adjacent Transmission Operators should assist by using some or all of the control actions listed in Section 3.2.3.1 where effective and as available, in accordance with their respective voltage control procedures.

3.2.3.3 If the steps in Sections 3.2.3.1 and 3.2.3.2 are insufficient to correct the problem, the Transmission Operator experiencing the abnormal voltage condition should take the following actions, where effective and as available, in accordance with its voltage control procedure:

3.2.3.3.1 request the Balancing Authority to modify economy transactions with other Balancing

Authority areas, and/or deviate from economic dispatch.

- 3.2.3.3.2 operate hydraulic units as synchronous condensers, where possible.
- 3.2.3.3.3 reschedule pumped hydro units to generate or motor over the critical period.
- 3.2.3.3.4 purchase energy.
- 3.2.3.3.5 reduce generator **real power** output to increase reactive capability.
- 3.2.3.3.6 start additional generation.
- 3.2.3.3.7 switch out internal transmission lines provided system operating limits are not violated.

3.2.3.4 If the steps listed in Section 3.2.3.3 fail to correct the problem, the Transmission Operator experiencing the **bulk power system** voltage problem should request adjacent Transmission Operators to assist by using some or all of the steps listed in Section 3.2.3.3 where effective and as available.

3.2.3.5 If the steps listed in Section 3.2.3.3 and 3.2.3.4 are insufficient to correct the problem, the Transmission Operator experiencing the problem should implement voltage reduction procedures if this will improve transmission voltage levels. If, after this step, additional assistance is required, adjacent Transmission Operators should be requested to reduce customer supply voltage if this will be effective, providing the Transmission Operator in difficulty has already taken this step.

3.2.3.6 If the problem is low voltage and it persists after the steps up to Section 3.2.3.5 are exhausted, or if the **bulk power system** voltage is rapidly decaying, the Transmission Operator in difficulty will shed **firm load** as required.

3.2.4 When assistance is provided by an adjacent Balancing Authority and/or Transmission Operator, Emergency Transfer Criteria must not be exceeded.

- 3.2.5 If two or more Transmission Operators are experiencing voltage problems simultaneously, they will assist each other as above to the extent feasible. If the problem is so severe as to require the shedding of **firm load**, the shedding should be done to the extent required to control the situation. Transmission Operators that have mutually agreed upon a normal schedule of **reactive power** flow should adhere to this schedule to the extent possible.
- 3.2.6 If the abnormal voltage is caused by conditions external to NPCC, the following steps should be implemented by the NPCC Transmission Operator experiencing abnormal voltage conditions as required and appropriate.
 - 3.2.6.1 Using available voltage and **reactive power** flow information, determine which system is causing the abnormal voltage or the trend toward abnormal voltage.
 - 3.2.6.2 Establish communication with the system causing the abnormal voltage
 - 3.2.6.3 All NPCC Transmission Operators in a position to assist should take any available action to relieve the abnormal voltage condition, excluding the shedding of **firm load** or opening transmission circuits. Assistance should normally only be requested after similar action has been implemented by the requesting Transmission Operator(s).
 - 3.2.6.4 If the action in 3.2.6.3 above is insufficient, the Transmission Operator experiencing the difficulty should promptly take all steps necessary to relieve the abnormal voltage condition, including shedding **firm load** and/or opening transmission circuits.

4.0 Actions to Contain an Emergency

If preventative measures as outlined under Sections 2.0 and/or 3.0 have not been adequate, the Balancing Authority or the Transmission Operator experiencing the abnormal conditions may need to declare and enter into an **emergency**. Actions to contain the emergency should then be taken. These actions should apply to both the Balancing Authority area and Transmission Operator area causing the emergency (if identifiable) and the Balancing Authority area and Transmission Operator area experiencing the emergency. The following is thus a continuation of the preventative and corrective measures implemented in Sections 2.0 and/or 3.0 above. Sections 4.1 and 4.2 apply to scenarios in which operation in one Balancing

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Authority area or Transmission Operator area is having an adverse impact on the reliability of another Balancing Authority or Transmission Operator area. Section 4.3 applies to the scenario that a Balancing Authority is experiencing difficulties in controlling frequency and/or ACE due to capacity/energy shortfall.

4.1 Action of a Balancing Authority and Transmission Operator Experiencing a Transmission **Emergency**

If a Transmission Operator area is in a transmission emergency because of conditions in another Transmission Operator area, it should implement any of the following actions that removes or lessens the threat to its reliability.

- 4.1.1 Attempt to identify the specific cause(s) and communicate with relevant Transmission Operator. Request assistance if required.
- 4.1.2 Manually shed **firm load** or reject **generation** as appropriate.
- 4.1.3 Communicate (if time permits and only if beneficial) to the adjacent Transmission Operator that the tie lines will be opened if immediate action is not taken to alleviate the **emergency**.
- 4.1.4 Open tie lines to prevent damage to equipment, if necessary.
- 4.1.5 If a Balancing Authority area is experiencing a capacity or **emergency**, it should issue the appropriate NERC Energy Emergency Alert level and follow procedures in NERC Standard *Emergency Preparedness and Operations* EOP-002-0 Attachment 1.

4.2 Action of a Balancing Authority or Transmission Operator Causing the Transmission **Emergency**

If operation in a Balancing Authority or Transmission Operator area is having an adverse reliability impact in another area, the Balancing Authority and Transmission Operator are required by NERC and NPCC Standards to respond to requests for assistance from the area in difficulty that remove or lessen the threat to its reliability, including:

- 4.2.1 Attempt to identify the specific cause(s) and communicate with relevant Balancing Authority or Transmission Operator. Request assistance if required.
- 4.2.2 Manually shed **firm load** until transmission loading and voltage return to acceptable values at all known problem locations.
- 4.2.3 Open or close tie lines as required.

4.2.4 Issue the appropriate NERC Energy Emergency Alert level and follow procedures in NERC Standard *Emergency Preparedness and Operations* EOP-002-0 Attachment 1.

4.3 Actions of a Balancing Authority to control Frequency and operate under a Capacity/Energy Emergency

A Balancing Authority area may from time to time experience difficulty in controlling frequency or ACE. Under these situations, the Balancing Authority should consider implementing the following actions.

4.3.1 Large Frequency Deviation

When a large frequency excursion occurs during normal operations, Balancing Authority areas connected synchronously to the Eastern Interconnection shall continue to operate in the tie line bias area control mode unless continued operation in the tie line bias area control mode would have an adverse impact on reliability.

4.3.2 Manual **Load Shedding** for Capacity Shortage and Frequency Control

Each Balancing Authority should normally carry out the following unless an alternative plan is submitted for review by the NPCC Task Forces on Coordination of Operation and System Studies and approved by the NPCC Reliability Coordinating Committee:

4.3.2.1 The first half of the **load** shed manually should not include load which is part of any automatic load shedding plan unless following manual **load shedding**, the requirements of Section 5.2.1 of this Directory can still be met.

4.3.2.2 The plan should include the capability of shedding **load** proportionately over the whole system, unless operating requirements limit load shedding to one part of a system.

4.3.3 Suspension of Tie Line Bias Area Control Mode

Balancing Authority areas connected synchronously to the Eastern Interconnection should continue to operate in the tie line bias area control mode unless reliability concerns such as but not limited to those shown below require alternative actions:

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- 4.3.3.1 The Balancing Authority area loses synchronism with the Eastern Interconnection.
- 4.3.3.2 The Balancing Authority area is uncertain whether it is still connected to the Eastern Interconnection.
- 4.3.3.3 Values included in the ACE equation are suspect and may result in significant errors in control signals issued.
- 4.3.3.4 Continued operation in the tie line bias area control mode is, or has a reasonable probability of, adversely affecting reliability.

In this case, an alternative area control mode should be implemented.

4.3.4 Use of Alternative Balancing Authority Control Mode

Balancing Authority areas connected synchronously to the Eastern Interconnection should develop alternative AGC operation strategies to address the concerns of 4.3.1 and 4.3.2 above as needed

4.3.5 Sustained Negative Area Control Error (ACE) Causing A Burden

If a Balancing Authority area has a negative ACE that cannot be returned to zero within fifteen minutes with regulation resources presently available and other planned energy resource deployments due to a known and persisting shortage, and the Balancing Authority area is burdening other Balancing Authority areas or Interconnection frequency, then the Balancing Authority should implement **load shedding** sufficient to return ACE to zero and perform the following notifications:

- 4.3.5.1 Inform the senior shift authority in each of the other affected Balancing Authorities of the NPCC.
- 4.3.5.2 Initiate, or request NPCC Staff to initiate, an NPCC Emergency Preparedness Conference Call, as defined in NPCC Reference Document RD-01, *NPCC Emergency Preparedness Conference Call Procedures – NPCC Security Conference Call Procedures*.
- 4.3.5.3 Issue the appropriate NERC Energy Emergency Alert level and follow procedures in NERC Standard *Emergency Preparedness and Operations EOP-002-0 Attachment 1*.

5.0 Correction of Transmission Loading if Exceeding Limits

5.1 When a Transmission Operator area is experiencing internal circuit or tie line loading in excess of applicable system operating limits, the following steps should be implemented as required and appropriate based on industry-wide and/or local procedures (assistance from the Reliability Coordinators may be required to implement some of these actions):

5.1.1 Implement local congestion management procedures including but not limited to:

5.1.1.1 adjust internal **generation**,

5.1.1.2 transfer **load**,

5.1.1.3 adjust phase angle regulators (phase shifters), and

5.1.1.4 redeploy reactive resources:

5.1.2 Restore out-of-service transmission facilities where possible.

5.1.3 Recall **generation** and transmission **element** outages.

5.1.4 Discontinue **generation** and transmission **element** commissioning.

5.1.5 Activate/implement voltage reduction.

5.1.6 Utilize the NERC TLR process.

5.1.7 Operate to **emergency condition limits**.

5.1.8 Establish communication with areas inside and/or outside NPCC and request relief.

5.1.9 All Balancing Authorities and Transmission Operators in a position to assist should take any available action, excluding **load shedding**, to keep loading from exceeding applicable system operating limits. Assistance should normally only be requested after similar action has been implemented by the requesting Transmission Operator.

5.1.10 The Balancing Authority or Transmission Operator causing the overload (if identifiable) should adjust **generation** or perform other actions up to and including **load shedding** to keep loading below applicable system operating limits.

5.1.11 The Transmission Operator experiencing the overload should, when effective, reconfigure the system or implement **load shedding** to return the load on **elements** to within applicable system operating limits.

6.0 Generation Tripping at Low Frequency

During a declining frequency event in a Balancing Authority area, generators may trip by underfrequency trip protection. This may aggravate the already declining frequency, possibly leading to a collapse of the area. To arrest the frequency decline, the loss in generation may need to be compensated for by **load shedding**.

6.1 Generator Tripping at Frequency Below the Curve in Figure 1

If the frequency decays below the curve shown in Figure 1 of this Directory, steps may be taken to protect generating equipment, including separation from the system with or without **load**. In such cases isolation onto a generator's own auxiliaries is preferred to facilitate rapid resynchronization as soon as system conditions permit. For time periods exceeding 300 seconds, manual load shedding may need to be implemented to correct the low frequency problem.



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NPCC
Regional Reliability Reference Directory # 3
Maintenance Criteria for Bulk Power System Protection

Task Force on System Protection Revision Review Record:
July 11, 2008

Adopted by the Members of the Northeast Power Coordinating Council, Inc. this July 11, 2008 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)

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1.0 Introduction

1.1 Title Maintenance Criteria for BPS Protection

1.2 Directory Number 3

1.3 Objective

The purpose of this Directory is to present the basic maintenance requirements for **bulk power system protection systems**. It is recognized that responsible entities may choose to apply more rigid requirements because of local considerations.

1.4 Effective Date July 11, 2008

1.5 Background

This Directory was developed from the NPCC A-04 Maintenance Criteria for Bulk Power System Protection and B-23 Guideline document. Guidelines and procedures for consideration in the implementation of this Directory are provided in Appendix B.

1.6 Applicability

1.6.1 Functional Entities¹

Transmission Owners
Generator Owners
Distribution Providers

1.6.2 Facilities

These criteria shall apply to all **protection** of the NPCC **bulk power system**, including Type I **special protection systems** and **protection** required for the NPCC Automatic Underfrequency **Load Shedding** Program.

Automatic underfrequency **load shedding protection systems** and generator underfrequency tripping **relays** are not generally located at **bulk power system** stations; however, they have a direct effect on the operation of the **bulk power system** during major **emergencies**, and as such, they are subject to this Criteria.

¹ Any of these entities that own a transmission protection system and/or a Underfrequency Load Shedding (UFLS) facility/program

2.0 Terms Defined in this Directory

The definitions of terms found in this Directory appearing in bold typeface can be found in Document A-07, NPCC Glossary of Terms.

3.0 NERC Reliability Standard Requirements

The NERC Reliability Standards containing Requirements that are associated with this Directory include:

- 3.1 [PRC-005-1 – Transmission and Generation Protection System Maintenance and Testing](#)
- 3.2 [PRC-008-0 - Implementation and Documentation of UFLS Equipment Maintenance Program](#)
- 3.3 [PRC-011-0 – UVLS System Maintenance and Testing](#)
- 3.4 [PRC-012-0 – Special Protection System Review Procedure](#)
- 3.5 [PRC-017-0 – Special Protection System Maintenance and Testing](#)

4.0 NPCC Regional Reliability Standard Requirements

None developed at this time.

5.0 NPCC Full Member, More Stringent Criteria

5.1 General Criteria

Minimum periodic testing of each **protection group** shall be conducted to verify that the **protection group** is capable of performing its intended **protection** function. Such testing shall include **protection** assembly testing (as illustrated in attached Figure 1) and **protection group** system testing. To assure satisfactory operation of the protective equipment as a system, test procedures and test facilities must ensure that related tests properly overlap.

5.2 **Protection** Assembly Testing Requirements

Refer to Figure 1, equipment marked as [1]

The following **Protection** Assembly testing shall be performed on an interval not exceeding that specified in Table 1 for **bulk power system protection groups**:

5.2.1 Make visual inspections,

- 5.2.2 Verify inputs and outputs,
- 5.2.3 Confirm that the intended version of software is installed (microprocessor-based **relays**),
- 5.2.4 Verify correct **protection** operation,
- 5.2.5 Verify the integrity of current and voltage transformers and associated circuitry. This verifies that the correct secondary quantities are input to the **relay**. For microprocessor **relays**, verify the internal analog inputs with an independent source.

TABLE 1
INTERVALS FOR PROTECTION ASSEMBLY TESTING

	Non-Self Monitored Protection Assembly Note (1)	Microprocessor-Based Protection Assembly Note (2)	Microprocessor-Based Protection Assembly Note (3)
All Protection Groups	4 years	6 years	8 years

Notes:

- (1) Non-Self Monitored **protection** assemblies include electromechanical **relays** and solid state **relays**.
- (2) Microprocessor-based **protection** assemblies where the principal fault-sensing and logic components include self monitoring or self checking, and the failure alarm is monitored to an Operator.
- (3) Microprocessor-based **protection** assemblies as per Note (2), plus additional self monitoring or self checking of ac voltage and current input integrity, and the failure alarm is monitored to an Operator.

5.3 Protection Group DC Circuits Testing Requirements

Refer to Figure 1, equipment marked as [2]

Tests performed in Section 5.2 above verify the operation of the ac signaling, measuring **relays**, and verify a **protection** assemblies' ability to initiate a trip output(s). However, to verify operation of the **protection group** as a system, DC circuit testing is required. These tests verify the **protection** equipment operation from the trip outputs of the protection assembly up to breaker trip coils. DC circuit testing can be achieved by verifying overlapping **protection group** equipment zones, normally bound

by test switches, or by test tripping the **protection group**.

DC circuit test tripping shall be performed on an interval not exceeding that specified in Table 2 for **bulk power system protection groups**:

TABLE 2
INTERVALS FOR DC CIRCUIT TEST TRIPPING

	Non-Monitored	Monitored Note (1)
DC Circuit Tripping	4 years	6 years

Note (1): Trip coil and DC circuit continuity is continuously monitored to an Operator.

5.4 Battery Banks and Chargers Testing Requirements

Refer to Figure 1, equipment marked as [5]

Voltage verification of the station battery(s) shall be performed on an interval not exceeding that specified in Table 3 for **bulk power system protection groups**:

TABLE 3
BATTERY BANKS AND CHARGER TESTING

	Non-Monitored	Monitored Note (1)
Battery Voltage	Every month	Continuous

Note (1): Battery Voltage alarms are continuously monitored to an Operator

5.5 Breaker Test Tripping Requirements

Refer to Figure 1, equipment marked as [4]

The ability of the breaker(s) to trip via each trip coil shall be verified every two years. Nuclear plants can complete these tests at an interval not to exceed three years.

5.6 Telecommunication Testing Requirements

Refer to Figure 1, equipment marked as [3a] and [3b]

5.6.1 Terminal Equipment

Telecommunications terminal equipment shall be tested on the same time interval as the protection assemblies as per Table 1 above.

5.6.2 Channel Health

For trip equipment which uses frequency shift keying (FSK) mode of communication, such as Power Line Carrier systems, the ability to perform its intended trip function shall be verified every twelve months. This testing is not required for telecommunication systems that continuously verify this functionality to an Operator – alarmed and monitored.

The signal adequacy shall be tested every month and the ability of a channel to perform its intended function shall be verified every twelve months on telecommunication systems that are not continuously monitored. An example of such a system is on/off Power Line Carrier.

5.7 Underfrequency Load Shedding and Generator Trip Testing Requirements

Protection group DC circuit tests for protection required by the NPCC Automatic Underfrequency **Load Shedding** Program need not be performed more frequently than the protection group DC circuit tests for other **protection** on the same breaker. Because of the distributed nature of this **load shedding protection**, random failures to trip do not compromise the objectives of the NPCC Automatic Underfrequency **Load Shedding** Program.

The successful operation of the NPCC Automatic Underfrequency **Load Shedding** Program requires the proper coordination of generator underfrequency tripping, as described in Directory 2. For generators rated 20 MW and above, the correct calibration of generator underfrequency tripping **relays** shall be verified at an interval not exceeding that specified in Table 1.

6.0 Measures and Assessments

None developed at this time.

7.0 Compliance Monitoring

Adherence to requirements in this Directory must be reported in a manner and form designated by the Compliance Committee. Exceptions to the requirements

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stipulated herein are acceptable if the exceptions are completely removed within five (5) months of the end of the calendar year in which the testing is due. The intervals specified in this document refer to calendar year in which testing is due regardless of the date.

Prepared by: Task Force on System Protection

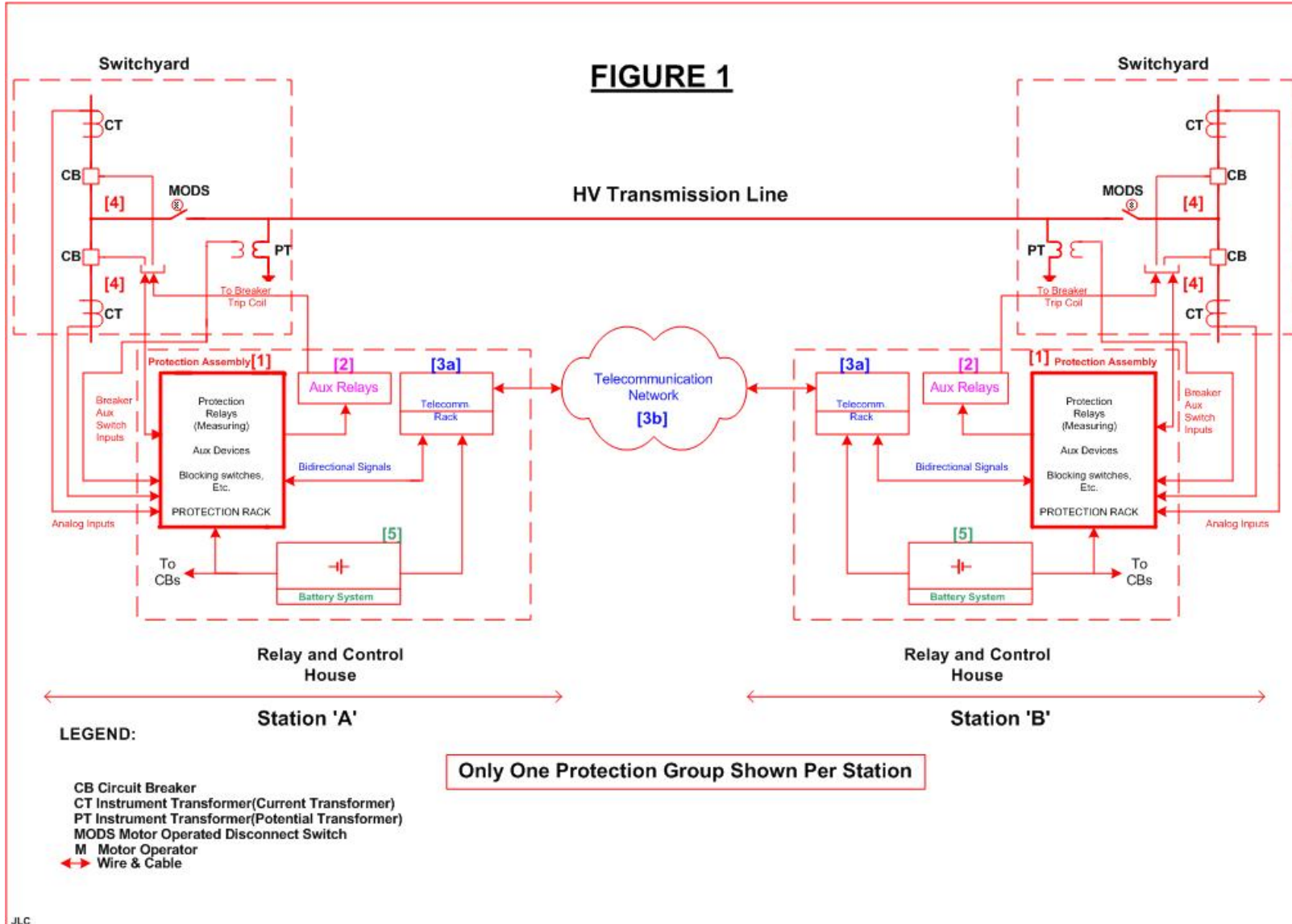
Review and Approval: Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval.

Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast.

Revisions pertaining to the Appendices or any other portion of the document such as Links glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document.

This Directory will be updated at least once every 3 years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

References: NPCC Glossary of Terms (Document A-7)



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Appendix A Definition of Terms

Bulk power system - The interconnected electrical systems within northeastern North America comprising **generation** and transmission facilities on which faults or disturbances can have a significant adverse impact outside of the local area. In this context, local areas are determined by the Council members.

Element — any electric device with terminals that may be connected to other electric devices, such as a generator, transformer, circuit, circuit breaker, or bus section.
Limiting Element — the element that is either operating at its appropriate **rating** or would be following a limiting **contingency** and, as a result, establishes a system limit.

Load — the electric **power** used by devices connected to an electrical generating system. (IEEE Power Engineering). Also see **Demand**.

NPCC Specific Definitions:

Firm Load — Loads that are not **Interruptible Loads**.

Interruptible Load — Loads that are interruptible under the terms specified in a contract.

Load Shedding — the process of deliberately removing (either manually or automatically) preselected customers' **load** from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.

Protection - The provisions for detecting power system **faults** or abnormal conditions and taking appropriate automatic corrective action.

Protection group — a fully integrated assembly of **protective relays** and associated equipment that is designed to perform the specified protective functions for a power system **element**, independent of other groups.

Notes:

(a) Various identified as Main **Protection**, Primary **Protection**, Breaker Failure **Protection**, Back-Up **Protection**, Alternate **Protection**, Secondary **Protection**, A **Protection**, B **Protection**, Group A, Group B, System 1 or System 2.

(b) Pilot **protection** is considered to be one **protection group**.

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Protection system

Element Basis

One or more **protection** groups; including all equipment such as instrument transformers, station wiring, circuit breakers and associated trip/close modules, and communication facilities; installed at all terminals of a power system **element** to provide the complete **protection** of that **element**.

Terminal Basis

One or more **protection** groups, as above, installed at one terminal of a power system **element**, typically a transmission line.

Pilot Protection — a form of line **protection** that uses a communication channel as a means to compare electrical conditions at the terminals of a line.

Relay — an electrical device designed to respond to input conditions in a prescribed manner and after specified conditions are met to cause contact operation or similar abrupt change in associated electric control circuits. (Also: see **protective relay**).

Special protection system (SPS) – A **protection system** designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted **elements**. Such action may include changes in **load**, **generation**, or system configuration to maintain system **stability**, acceptable voltages or power flows. Automatic underfrequency **load shedding** as defined in the *Emergency Operation Criteria* A-3, is not considered a **Special Protection System**. Conventionally switched, locally controlled shunt devices are not **Special Protection Systems**.

Appendix B

Guideline and Procedure for Maintenance of Bulk Power System Protection

1.0 Introduction

This Appendix provides the guidelines and procedures for consideration in the implementation of this Directory.

2.0 General

2.1 Generator Under-frequency Tripping

For generators rated less than 20 MW, consideration may be given to verifying the calibration of generator underfrequency **relays** at an interval not exceeding that specified in Table 1.

3.0 Microprocessor-based Protective Relays

The use of computer based technology for **protective relays** has influenced what is considered sufficient for periodic maintenance of microprocessor-based **relays**. The purpose of this document is to provide guidance for the maintenance of microprocessor-based **protective relays** as required in Section 5.2 and in notes (2) and (3) of Table 1 of this Directory.

This Section applies only to the maintenance of microprocessor-based **protective relays** (**Protection** Assembly Testing Requirements, verify correct **protection** operation). It does not include other **protection** maintenance that is still required, as outlined in the remaining Sections of this Directory.

This Section is not intended to be a maintenance procedure, but rather a guide for member systems to develop their maintenance procedures.

3.1 Testing of Microprocessor-Based Relays

For the purposes of maintenance testing, microprocessor-based **relays** or Intelligent Electronic Devices (IEDs), can be viewed as being composed of four sections:

- 3.1.1 Analog Input Section;
- 3.1.2 Digital Input/Output Section;
- 3.1.3 Processor Section; and;
- 3.1.4 Power supply Section

3.2 Analog Input Section

Measurements of magnitude and angle (calculate where not available directly) of metered values should be compared with known quantities. This supposes that the device uses the same hardware for both protection and metering. If this is not the case, then a calibration test should be conducted to verify the analog inputs.

It is not sufficient to compare the magnitudes as measured by the IED. The input section has filtering with active and passive components, which are vulnerable to change over time and cause changes in the phase characteristics of the channel. Measuring and recording of the phase angle readings is, therefore, required.

3.3 Digital Input and Output Sections

Each digital input and output that is utilized should be verified for proper functions.

3.3.1 Inputs

Operation of all used physical inputs should be verified by applying the DC control voltage, and observing associated display, or the computer interface.

3.3.2 Outputs

Outputs of the IED should be verified either by:

3.3.2.1 Asserting the output element using appropriate relay commands and observe the status of the output relay, or;

3.3.2.2 Where such features are not available, the appropriate output contact can be verified by asserting the associated logic settings that permit contact operation.

3.4 Processor Section

The processor section samples the analog and digital inputs, executes the algorithm and logic, and provides the outputs. It includes program memory, non-volatile memory for settings and volatile memory for sequence of events and oscillography. The processor section also

performs self-checking.

All of the downloaded settings and the firmware version should be compared with the official copy of the protection settings to verify that the **relay** contains the intended settings, and it is working with the intended version of firmware.

3.5 Power Supply Section

Most microprocessor-based IEDs provide measurement of the power supply voltages and/or continuously monitor the power supply voltages, and provide a **relay** failure alarm if they go out of limits. Where these values are accessible, they should be checked against specified ranges. Alternatively, the alarm should be checked on loss of dc voltage to the power supply.

3.6 Integrity Testing

This test is intended to verify the integrity of operation of the **relay** program execution and the processing of the phase voltages and current signals. Verify the correct operation of one of the three-phase protection elements, or a single phase, for a single-phase **relay**. As an example, for a distance **relay**, test one of a zone's A-G, B-G, and C-G elements.

3.7 Multi-Processor Based IEDs

Most **relays** are designed using a single processor; however, some **relay** designs use multiple processors. If the processing is divided among several processors, then tests should be conducted to include testing of functions that are executed in the respective processors. The manufacturer and/or manual should be consulted to verify hardware configuration. As an example, if a **relay** uses two processors, one each for phase and ground elements, then integrity testing should be repeated for phase and ground elements respectively.



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NPCC
Regional Reliability Reference Directory # 4
Bulk Power System Protection Criteria

Task Force on System Protection Revision Review Record:
December 01, 2009

Adopted by the Members of the Northeast Power Coordinating Council, Inc. December 01, 2009 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)

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1.0 Introduction

1.1 Title Protection Criteria

1.2 Directory Number 4

1.3 Objective

The purpose of this Directory is to provide the **protection** criteria, for **protection** of the NPCC **bulk power system**. It is not a design specification.

1.4 Effective Date December 01, 2009

1.5 Background

This Directory was developed from the draft NPCC A-05 Bulk Power Protection Criteria document dated December 4, 2008 and approved B-05, B-07, B-24 and C-22 documents. Guidelines and procedures for consideration in the implementation of this Directory are provided in Appendix A.

1.6 Applicability

1.6.1 Functional Entities

Transmission Owners
Generator Owners

1.6.2 Facilities

1.6.2.1 New Facilities

These criteria shall apply to all new Bulk Power System (BPS) facilities.

1.6.2.2 Existing Facilities

It is the responsibility of individual companies to assess the **protection systems** at existing facilities and to make modifications which are required to meet the intent of these criteria as follows.

1.6.2.2.1 Planned Renewal or Upgrade to Existing BPS Facilities

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It is recognized that there may be portions of the **bulk power system**, which existed prior to each member's adoption of the *Bulk Power System Protection Criteria* (Document A-5) that do not meet these criteria. However, if **protection systems** or sub-systems of these facilities are replaced as part of a planned renewal or upgrade to the facility and do not meet all of these criteria, then an assessment shall be conducted for those criteria that are not met.

The result of this assessment shall be reported, It is recommended this reporting be in accordance with the procedure stipulated in Section 4.0 of Appendix A of this Directory and using the appropriate portion of the "Protection System Review forms" (formerly C-22 forms), for review and disposition by the TFSP, or in a form consistent with the intent of the procedure.

1.6.2.2.2 Facility Classification Upgraded to **Bulk Power System**.

These criteria apply to all existing facilities which become classified as **bulk power system**. A mitigation plan shall be required to bring such a facility into compliance with these criteria.

Where the owner of the **protection system** has determined that the cost and risks involved to implement physical separation, as per Section 5.12, cannot be justified, the reason for this determination and an assessment shall be reported to the TFSP.

It is recommended this reporting be in accordance with the procedure stipulated in Section 4.0 of Appendix A of this Directory and using the appropriate portion of the "Protection System Review forms" (formerly C-22 forms), for review and disposition by the TFSP, or in a form consistent with the intent of

the procedure.

1.6.2.2.3 Additions to **Bulk Power System** Facilities

If a **bulk power system element** is added to an existing **bulk power system** facility that is recognized under Section 1.6.2.2.1, Planned Renewal or Upgrade to Existing Facilities, these criteria apply to the **protection systems** for the new **element**.

1.6.2.2.4 “In-Kind” Replacement of **Bulk Power System** Equipment

If a **bulk power system element** (e.g., breaker, transformer, capacitor bank, reactor, etc.) or a **protective relay** is replaced “in kind” as a result of an unplanned event, then it is not required to upgrade the associated **protection system** to comply with these criteria.

1.6.2.2.5 Change in **Bulk Power System** Facility Status

When a facility was originally on the BPS list of April 2007 and has been shown to be non-BPS but later was determined to be BPS again, Section 1.6.2.2.1 would apply. When the facility returns to BPS status, it shall be maintained in accordance with Directory #3 within two years timeframe.

1.6.3 Responsibility

Whenever changes are anticipated in generating sources, transmission facilities, or operating conditions, Generator Owners and Transmission Owners shall review those **protection system** applications (i.e., settings, ac and dc supplies) which can reasonably be expected to be impacted by those changes.

2.0 Terms Defined in this Directory

The definitions of terms found in this Directory appearing in bold typeface, can be found in Document A-07, NPCC *Glossary of Terms*.

3.0 NERC ERO Reliability Standard Requirements

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The NERC ERO Reliability Standards containing requirements that are associated with this Directory include, but may not be limited to:

- 3.1 PRC-001
- 3.2 PRC-002
- 3.3 PRC-012

4.0 NPCC Regional Reliability Standard Requirements

None.

5.0 NPCC Full Member, More Stringent Criteria

These Criteria are in addition, more stringent or more specific than the NERC or any Regional Reliability standard requirements.

5.1 General Criteria

The intent of the criteria established in this Directory is to ensure dependable and secure operation of the **protection systems** for **Bulk Power System** facilities. For those **protective relays** intended for removal of **faults** from the **bulk power system**, dependability is paramount, and the redundancy provisions of the criteria shall apply. For **Protective relays** installed for reasons other than **fault** sensing such as overload, etc., security is paramount, and the redundancy provisions of the criteria do not apply. The relative effect on the **bulk power system** of a failure of a **protection system** to operate when desired versus an unintended operation shall be weighed carefully in selecting design parameters as follows.

5.2 Criteria for Dependability

- 5.2.1 Except as identified otherwise in these criteria, all elements of the **bulk power system** shall be protected by two protection **groups**, each of which is independently capable of performing the specified protective function for that **element**. This requirement also applies during energization of the **element**.
- 5.2.2 Except as identified otherwise in these criteria, the two **protection groups** shall not share the same component.
- 5.2.3 Means shall be provided to trip all necessary local and remote breakers in the event that a breaker fails to clear a fault. This **protection** need not be duplicated.

5.3 Criteria for Security

Protection systems shall be designed to isolate only the faulted **element**, except in those circumstances where additional **elements** are tripped intentionally to preserve system integrity, or where isolating additional **elements** has no impact outside the local area.

5.4 Criteria for Dependability and Security

5.4.1 The thermal capability of all **protection system** components shall be adequate to withstand rated maximum short time and continuous loading of the associated **protected elements**.

5.4.2 Communication link availability, critical switch positions, and trip circuit integrity, shall be monitored to allow prompt attention by appropriate operating authorities.

5.4.3 When remote access to **protection systems** is possible, the design shall include security measures to minimize the probability of unauthorized access to the protection systems.

5.4.4 Short Circuit Models used to assess **protection** scheme design and to develop **protection** settings shall take into account minimum and maximum fault levels and mutual effects of parallel transmission lines. Details of neighboring systems shall be modeled wherever they can affect results significantly.

5.5 Operating Time Criteria

Bulk power system protection shall take corrective action within times determined by studies with due regard to security, dependability and selectivity.

5.6 Current Transformer Criteria

Current transformers (CTs) associated with **protection systems** shall have adequate steady-state and transient characteristics for their intended function as follows:

5.6.1 The output of each current transformer secondary winding shall be designed to remain within acceptable limits for the connected burdens under all anticipated **fault** currents to ensure correct operation of the **protection system**.

5.6.2 The thermal and mechanical capabilities of the CT at the operating

tap shall be adequate to prevent damage under maximum **fault** conditions and normal or **emergency** system loading conditions.

- 5.6.3 For **protection groups** to be independent, they shall be supplied from separate current transformer secondary windings.
- 5.6.4 Interconnected current transformer secondary wiring shall be grounded at only one point.
- 5.6.5 Current transformers shall be connected so that adjacent **protection** zones overlap.

5.7 Voltage Transformer and Potential Devices Criteria

Voltage transformers and potential devices associated with **protection systems** shall have adequate steady-state and transient characteristics for their intended functions as follows:

- 5.7.1 Voltage transformers and potential devices shall have adequate volt-ampere capacity to supply the connected burden while maintaining their **relay** accuracy over their specified primary voltage range.
- 5.7.2 The two **protection groups** protecting an element shall be supplied from separate voltage sources. The two protection groups may be supplied from separate secondary windings on one transformer or potential device, provided all of the following requirements are met:
 - 5.7.2.1 Complete loss of one or more phase voltages does not prevent all tripping of the protected **element**;
 - 5.7.2.2 Each secondary winding has sufficient capacity to permit fuse **protection** of the circuit;
 - 5.7.2.3 Each secondary winding circuit is adequately fuse protected.
- 5.7.3 The wiring from each voltage transformer secondary winding shall not be grounded at more than one point.

5.8 Batteries and Direct Current (DC) Supply Criteria

DC supplies associated with **protection** shall be designed to have a high degree of dependability as follows:

- 5.8.1 No single battery or dc power supply failure shall prevent both

independent **protection groups** from performing the intended function. Each battery shall be provided with its own charger. Physical separation shall be maintained between the two station batteries or dc power supplies used to supply the independent **protection groups**.

- 5.8.2 Each station battery shall have sufficient capacity to permit operation of the station, in the event of a loss of its battery charger or the ac supply source, for the period of time necessary to transfer the **load** to the other station battery or re-establish the supply source. Each station battery and its associated charger shall have sufficient capacity to supply the total dc **load** of the station.
- 5.8.3 A transfer arrangement shall be provided to permit connecting the total **load** to either station battery without creating areas where, prior to failure of either a station battery or a charger, a single event can disable both dc supplies.
- 5.8.4 The battery chargers and all dc circuits shall be protected against short circuits. All protective devices shall be coordinated to minimize the number of dc circuits interrupted.
- 5.8.5 Dc systems shall be continuously monitored or annunciated to detect abnormal voltage levels (both high and low), dc grounds, and loss of ac to the battery chargers, in order to allow prompt attention by the appropriate operating authorities.
- 5.8.6 **Protection group** dc sources shall be continuously monitored to detect loss of voltage in order to allow prompt attention by the appropriate operating authorities.

5.9 Station Service ac Supply Criteria

On **bulk power system** facilities there shall be two sources of station service ac supply, each capable of carrying at least all the critical **loads** associated with **protection systems**.

5.10 Circuit Breaker

No single trip coil failure shall prevent both independent **protection groups** from performing the intended function. The design of a breaker with two trip coils shall be such that the breaker will operate if both trip coils are energized simultaneously. The correct operation of this design shall be verified by tests.

5.11 Teleprotection Criteria

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- 5.11.1 Communication facilities required for **teleprotection** shall be designed to have a level of performance consistent with that required of the **protection system**, and shall meet the following:
 - 5.11.1.1 Where each of the two **protection groups** protecting the same **bulk power system element** requires a communication channel, the equipment and channel for each **protection group** shall be separated physically and designed to minimize the risk of both **protection groups** being disabled simultaneously by a single event or condition.
 - 5.11.1.2 **Teleprotection** equipment shall be monitored to detect loss of equipment and/or channels to allow prompt attention by the appropriate operating authorities.
 - 5.11.1.3 **Teleprotection** equipment shall be provided with means to test for proper signal adequacy.
 - 5.11.1.4 **Teleprotection** equipment shall be powered by the substation batteries or other sources independent from the power system.
 - 5.11.1.5 Except as identified otherwise in these criteria, the two **teleprotection** groups shall not share the same component.
 - 5.11.1.5.1 The use of a single communication tower for the radio communication systems used by two **protection groups** protecting a single **element** is permitted as long as directional diversity of the communication signals is achieved.

5.12 Environment

- 5.12.1 Each separate **protection group** and **teleprotection** protecting the same system **element** shall be on different non-adjacent vertical mounting assemblies or enclosures.
- 5.12.2 Wiring for separate **protection groups** and **teleprotections** protecting the same system **element** shall not be in the same cable.
- 5.12.3 Cabling for separate **protection groups** and **teleprotections** protecting the same system **element** shall be physically separated. This can be accomplished by being in different raceways, trays,

trenches, etc.

- 5.12.4 In the event a common raceway is used, cabling for separate **protection groups** protecting the same system **element** shall be separated by a fire barrier.

5.13 Grounding Criteria

Station grounding is critical to the correct operation of **protection systems**. The design of the ground grid directly impacts proper **protection system** operation and the probability of false operation from **fault** currents or transient voltages. Each member shall have established as part of its substation design procedures or specifications, a mandatory method of designing the substation ground grid, which:

- 5.13.1 Can be traced to a recognized calculation methodology
- 5.13.2 Considers cable shielding
- 5.13.3 Considers equipment grounding

5.14 Transmission Line Protection Criteria

- 5.14.1 **Protection system** settings shall not constitute a loading limitation as per NERC requirement/standard. In cases where NERC approved exceptions are used the limits thus imposed shall be adhered to as system operating constraints.
- 5.14.2 A **pilot protection** shall be so designed that its failure or misoperation will not affect the operation of any other **pilot protection** on that same **element**.

5.15 Breaker Failure Protection Criteria

Means shall be provided to trip all necessary local and remote breakers in the event that a breaker fails to clear a **fault**, as follows.

- 5.15.1 Breaker failure **protection** shall be initiated by each of the **protection groups** which trip the breaker, with the optional exception of a breaker failure **protection** in an adjacent zone.
- 5.15.2 Fault current detectors shall be used to determine if a breaker has failed to interrupt a **fault**.

5.16 Generating Station Protection Criteria

All under- and over-frequency **protection systems** designed to disconnect generators from the power system shall be coordinated with automatic under frequency **load shedding** programs, in accordance with the *Emergency Operation Criteria* (Directory #2).

5.17 Automatic Under frequency Load Shedding Protection System Criteria

5.17.1 The requirements and guides for the operation of these **Protection Systems** are detailed in the *Emergency Operation Criteria* (Directory #2). The guideline for automatic under frequency **load shedding protective relaying** design is provided in Appendix A of this Directory.

5.18 HVdc System Protection Criteria

5.18.1 The ac portion of an HVdc converter station, up to the valve-side terminals of the converter transformers, shall be protected in accordance with these criteria.

5.18.2 Multiple commutation failures, unordered power reversals, and **faults** in the converter bridges and the dc portion of the HVdc link which are severe enough to disturb the **bulk power system** shall be detected by more than one independent control or **protection group** and appropriate corrective action shall be taken, in accordance with the considerations in these criteria.

5.19 Protection System Testing and Maintenance Criteria

5.19.1 **Protection systems** shall be maintained in accordance with the *Maintenance Criteria for Bulk Power System Protection* (Directory #3).

5.19.2 The design of **protection systems** both in terms of circuitry and physical arrangement shall facilitate periodic testing and maintenance.

5.19.3 Each **protection group** shall be functionally tested to verify the dependability and security aspects of the design, when initially placed in service and when modifications are made.

5.20 Analysis of Protection Performance Requirements

- 5.20.1 **Bulk power system** automatic operations shall be analyzed to determine proper **protection system** performance. Corrective measures shall be taken promptly if a **protection group** fails to operate or operates incorrectly.
- 5.20.2 Event and fault recording capability shall be provided to the extent required to permit analysis of **system disturbances** and **protection system** performance.
- 5.20.3 Internal clocks in event and **fault** recording equipment shall be time synchronized to within 2 milliseconds or less of Universal Coordinated Time scale. The time zone shall be clearly identified as either universal time zone or local time zone.
- 5.20.4 Each **protective relay** which trips **Bulk Power System** equipment shall provide separate target indication.

6.0 Measures and Assessments

None developed at this time.

7.0 Compliance Monitoring

- 7.1 Each member shall provide the Task Force on System Protection (TFSP) with advance notification of any of the member's new **bulk power system protection systems**, or significant changes in the member's existing **bulk power system protection systems**.
- 7.2 Each member shall also provide the TFSP with advance notification of non-member **protection** facilities as required per *NPCC Bylaws*.
- 7.3 Each new or revised **protection system** shall be reported to the TFSP. It is recommended this reporting be in accordance with the procedure detailed in Section 4.0 of Appendix A of this Directory, or in a form consistent with the intent of the procedure.
- 7.4 Adherence to these Criteria shall be reported by the responsible entity in a manner and form designated by the Compliance Committee.

Prepared by: Task Force on System Protection

Review and Approval: Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review

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and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval.

Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast.

Revisions pertaining to the Appendices or any other portion of the document such as Links glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document.

This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

Appendix A

Guideline and Procedure for Bulk Power System Protection

1.0 Introduction

This Appendix provides the guidance for consideration in the implementation of the **bulk power system Protection** criteria stipulated in this Directory, and the procedure on reporting new and revised **bulks power system protection** facilities.

2.0 Design Considerations

2.1 General Considerations

In general, the function of a **protection system** is to limit the severity and extent of **system disturbances** and possible damage to system equipment.

The Directory's criteria objectives can be met only if **protection systems** have a high degree of dependability and security. In this context dependability relates to the degree of certainty that a **protection system** will operate correctly when required to operate. Security relates to the degree of certainty that a **protection system** will not operate when not required to operate.

Often increased security (fewer unintended operations) results in decreased dependability (more failures to operate), and vice versa. As an example, consideration is given to the consequence of applying permissive line **protection** schemes, which often are more secure, but less dependable, than blocking line protection schemes. The relative effect on the **bulk power system** of a failure of a **protection system** to operate when desired versus an unintended operation should be weighed carefully in selecting design parameters. Considerations for specific aspects of **protection** design are provided below.

2.2 Issues Affecting Dependability

2.2.1 Some portions of **elements** may not in themselves be part of the **bulk power system**. Those portions do not require two **protection groups**.

2.2.2 Two identical measuring **relays** should not be used in independent **protection groups** due to the risk of simultaneous failure of both groups because of design deficiencies or equipment problems.

2.2.3 In addition to the separation requirements in the criteria, areas of common exposure should be kept to a minimum to reduce the possibility of both **protection groups** being disabled by a single

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Appendix A

event such as fire, excavation, water leakage, and other such incidents.

- 2.2.4 On installations where free-standing or column-type current transformers are provided on one side of the breaker only, resulting in a **protection** blind spot, **protection** should be provided to detect a **fault** to ground on the primaries of such current transformers. When frame ground **protection** is used, then frame ground and breaker failure **protections** are the two local independent **protections** for the blind spot between the current transformer and the circuit breaker. Neither of these **protections** need be duplicated. Both of these **protections** should be designed so as to not be disabled by the same failure. The frame ground **protection** and breaker failure **protection** will in fact provide independent **protections** for the blind spot.

2.3 Issues Affecting Security

- 2.3.1 For **faults** external to the protected zone, each **protection group** should be designed either to not operate, or to operate selectively with other groups and with breaker failure **protection**.
- 2.3.2 For planned system conditions, **protection systems** should not operate to trip for stable power swings.

2.4 Issues Affecting Dependability and Security

- 2.4.1 **Protection systems** should be no more complex than required for any given application.
- 2.4.2 The components and software used in **protection systems** should be of proven quality, as demonstrated either by actual experience or by stringent tests under simulated operating conditions.
- 2.4.3 **Protection systems** should be designed to minimize the possibility of component failure or malfunction due to electrical transients and interference or external effects such as vibration, shock and temperature.
- 2.4.4 **Protection system** circuitry and physical arrangements should be designed so as to minimize the possibility of incorrect operations due to personnel error.
- 2.4.5 **Protection system** automatic self-checking facilities should be designed so as to not degrade the performance of the **protection**

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Appendix A

system.

- 2.4.6 Consideration should be given to the consequences of loss of instrument transformer voltage inputs to **protection systems**.
- 2.4.7 **Protection systems**, including intelligent electronic devices (IEDs) and communication systems used for **protection**, should comply with applicable industry standards for utility grade **protection** service. Utility Grade **Protection System** Equipment are equipment that are suitable for protecting transmission power system elements, that are required to operate reliably, under harsh environments normally found at substations. Utility grade equipment should meet the applicable sections of all or some of the following types of industry standards, to ensure their suitability for such applications:
- IEEE C37.90.1-2002 (oscillatory surge and fast transient)
 - IEEE C37.90.1-2002 (service conditions)
 - IEC 60255-22-1, 2005 (1 MHz burst, i.e. oscillatory)
 - IEC 61000-4-12, 2001 (oscillatory surge)
 - IEC 61000-4-4, 2004 (EFT)
 - IEC 60255-22-4, 2002 (EFT)
 - IEEE C37.90.2-2004 (narrow-band radiation)
 - IEC 60255-22-3, 2000 (narrow-band radiation)
 - IEC 61000-4-3, 2002 (narrow-band radiation)
 - IEEE 1613 (communications networking devices in Electric power Substations)

2.5 Operating Time

Adequate time margin should be provided taking into account study inaccuracies, differences in equipment, and **protection** operating times. In cases where clearing times are deliberately extended, consideration should be given to the following:

- Effect on system **stability** or reduction of **stability** margins.
- Possibility of causing or increasing damage to equipment and subsequent extended repair and/or outage time.
- Effect of **disturbances** on service to customers.

.

2.6 Current Transformer

None.

Appendix A

2.7 Voltage Transformers and Potential Devices

Voltage transformer installations should be designed with due regard to ferroresonance.

- 2.7.1 Special attention should be given to the physical properties (e.g. resistance to corrosion, moisture, fatigue) of the fuses used in **protection** voltage circuits.

2.8 Batteries and Direct Current (dc) Supply

- 2.8.1 The circuitry between each battery and its first protective device cannot be protected and therefore should be designed so as to minimize the possibility of electrical short circuit.
- 2.8.2 The design for the regulation of the dc voltage should be such that, under all anticipated charging and loading conditions, voltage within acceptable limits will be supplied to all devices, while minimizing ac ripple and voltage transients.

2.9 Station Service ac Supply

None.

2.10 Circuit Breakers

The indication of the circuit breaker position in **protection systems** should be designed to reliably mimic the main contact position.

2.11 Teleprotection

- 2.11.1 **Teleprotection** systems should be designed to prevent unwanted operations such as those caused by equipment or personnel.
- 2.11.2 Two identical **teleprotection** equipments should not be used in independent **protection groups**, due to the risk of simultaneous failure of both groups because of design deficiencies or equipment problems.
- 2.11.3 Areas of common exposure should be kept to a minimum to reduce the possibility of both groups being disabled by a single event such as fire, excavation, water leakage, and other such incidents.
- 2.11.4 **Teleprotection** systems should be designed to mitigate the effects of signal interference from other communication sources and to

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Appendix A

assure adequate signal transmission during **bulk power system disturbances**.

2.12 Environment

Means should be employed to maintain environmental conditions that are favorable to the correct performance of **protection systems**.

2.13 Grounding

None.

2.14 Transmission Lines Protection

For planned system conditions, line **protection systems** associated with transmission facilities should not operate to trip for stable **power swings**.

2.15 Breaker Failure Protection

2.15.1 It is not necessary to duplicate the breaker failure **protection** itself.

2.15.2 Auxiliary switches may also be required in instances where the **fault** currents are not large enough to operate the **fault** current detectors. In addition, auxiliary switches may be necessary for high-speed detection of a breaker failure condition.

2.16 Generating Station Protection

2.16.1 Each **protection system** should be designed to minimize the effects to **the bulk power system** of **faults** and **disturbances**, while itself experiencing a single failure.

2.16.2 Generators should be protected to limit possible damage to the equipment. The following are some of the abnormal (not necessarily **fault**) conditions that should be detected:

- Unbalanced phase currents, loss of excitation
- Overexcitation, generator out of step, field ground
- inadvertent energization.

2.16.2.1 **Protections** for the above conditions, which are applied for equipment **protection**, need not be duplicated.

Appendix A

- 2.16.2.2 When a directional over current or distance **relay** is applied to remove the generator for slowly cleared **faults** on the external system, such **protection** is a backup and need not be duplicated.
 - 2.16.2.3 The apparatus should be protected when the generator is starting up or shutting down as well as running at normal speed; this may require additional **relays** as the normal **relays** may not function satisfactorily at low frequencies.
 - 2.16.2.4 Generator **protection systems** should not operate for stable **power swings** except when that particular generator is out of step with the remainder of the system. This does not apply to **Special Protection Systems** designed to trip the generator as part of an overall plan to maintain **stability** of the power system.
 - 2.16.2.5 Loss of excitation and out of step **relays** should be set with due regard to the performance of the excitation system.
 - 2.16.2.6 It is recognized that the overall **protection** of a generator involves non-electrical considerations that have not been included as a part of the criteria in this Directory.
 - 2.16.2.7 All over frequency, overvoltage and under voltage **protection systems** designed to disconnect generators from the power system should be coordinated with automatic under frequency **load shedding** programs.
- 2.17 Automatic Under frequency Load Shedding Protection Systems
- 2.17.1 Automatic under frequency **load shedding protection systems** are not generally located at **bulk power system** stations; however, they have a direct effect on the operation of the **bulk power system** during major **emergencies**.
 - 2.17.2 Automatic under frequency **load shedding protection** need not be duplicated.
 - 2.17.3 Under frequency **relays** which operate at a discrete frequency value are called “under frequency threshold **relays**.” Selection of under frequency sensing devices should be on a threshold basis. Alternatively, rate of change of frequency **load shedding** may be used when the requirements of the Balancing Authority indicate that this method will achieve the intent of the **load shedding** program.

Appendix A

Appropriate studies are necessary to determine the application and settings of the rate of change of frequency **relays** for a particular Balancing Authority area.

2.17.4 In order for each Balancing Authority within NPCC to **shed** approximately the same proportion of **load**, given the same frequency condition, all styles and manufacture of under frequency **relays** should trip at essentially the same time. For electromechanical **relays**, time delay depends on rate of frequency decline, and it is not possible to achieve uniform response for different rates of decline. The recommendations in this guideline are based on the goal of a uniform response at a rate of frequency decline of 0.2 Hz per second.

2.17.5 Additional Application Considerations

2.17.5.1 Where undesired under frequency **relay** operation can be caused by decaying frequency due to isolated generation or motor load, additional supervising undercurrent or voltage **relays** may be used to prevent misoperation.

2.17.5.2 Where the AC voltage source for an under frequency **relay** is derived from a potential device connected to a cable circuit, care should be taken to estimate the voltage present during deenergization of the circuit. The natural frequency of the decaying cable voltage may be less than 60 Hz, and thus cause an incorrect **relay** operation.

2.17.5.3 The AC Voltage Inhibit feature available on some relays may be useful as a security tool to restrain operation during cable deenergization, depending on the voltage decay time constant

2.17.5.4 Due regard should be given to the expected power system voltage during events for which the underfrequency **relays** are expected to operate. The **relay's** minimum AC voltage operating characteristic should not inhibit proper **relay** operation, nor should the Voltage Inhibit feature, where it exists, be set to prevent proper operation.

2.17.6 Settings and Maintenance Recommendations

2.17.6.1 Pickup Time Delay Settings

Appendix A

Pickup and time delay settings of underfrequency threshold **relays** should be applied in accordance with the requirements specified in Section 5.2 and Section 5.4 of *Emergency Operation Criteria* (Directory #2).

2.17.6.2 Relay Performance Considerations

Any underfrequency **relay** which has been found to have drifted more than ± 0.2 Hz from its set point or ± 0.1 seconds from its time delay should be recalibrated and then retested in six months. If, at that time, the **relay** has drifted ± 0.2 Hz or more from its set point or ± 0.1 seconds or more from its fixed time delay, the cause of the drift should be corrected or the **relay** should be replaced.

2.17.6.3 Maintenance

Underfrequency **load shedding relays** have a direct effect on the operation of the **bulk power system** during major **emergencies**. These **relays** should be maintained in accordance with requirements stipulated in *Maintenance Criteria for Bulk Power System Protection* (Directory 3), even though they are usually located in non-**bulk power system** stations.

2.18 HVdc Systems Protection

2.18.1 Converter terminals should be protected to avoid excessive equipment stresses and to minimize equipment damage and outage time. These **protections** are usually specific to the design of the converter station(s) and are determined by the manufacturer to comply with availability guarantees. The followings are some conditions which should be detected:

- ac and dc undervoltage,
- ac and dc overvoltage,
- valve misfire,
- excessive harmonics on the dc,
- dc ground **faults** and open circuits,
- dc switching device failures,
- thyristor failures,
- valve and snubber circuit overloads.

2.18.2 The overall **protection** and control of an HVdc link may also involve the initiation of actions in response to abnormal conditions

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Appendix A

on the ac interconnected system. The control and **protection systems** associated with such conditions are not considered part of the HVdc systems **protection**.

2.19 Protection System Testing and Maintenance

Test facilities and test procedures should be designed such that they do not compromise the independence of **protection groups** protecting the same **bulk power system element**. Test devices or switches should be used to eliminate the necessity for removing or disconnecting wires during testing.

2.20 Analysis of Protection System

Insofar as possible, each active protective function within a **protective relay** should provide separate target information.

2.21 Transmission Station Protection

2.21.1 The **protection systems** should operate properly for the anticipated range of currents.

2.21.2 For planned system conditions, all station **protection systems** should not operate for **load** current or stable **power swings**.

2.21.3 **Load** responsive **protection relays** applied to transmission autotransformers should allow all possible load ability, consistent with equipment **protection** requirements.

2.21.4 Fault pressure or Buchholz **relays** used on transformers, phase shifters or regulators should be applied so as to minimize the likelihood of their misoperation due to through **faults**.

2.22 Capacitor Banks

2.22.1 Each **protection system** should be designed to minimize the effects to the **bulk power system** of **faults** and **disturbances**, while itself experiencing a single failure.

2.22.2 Capacitor bank **protection** should be applied with due consideration for capacitor bank transients, power system voltage unbalance, and system harmonics.

Appendix A

2.22.3 Protection may be provided to minimize the impact of failures of individual capacitor units on the remaining capacitor units, however, these types of **protections** do not need to be duplicated:

- a. Overvoltage Protection
- b. Individual fuses for each capacitor unit
- c. Overvoltage Protection for each capacitor units

2.23 Static Var Compensation (SVC) Protection

2.23.1 The low voltage branch circuits contain the reactive controlling equipment, filters, etc. These may include all or some of the following:

- a. Thyristor Controlled Reactors (TCR)
- b. Thyristor Switched Capacitors (TSC)
- c. Switched or Fixed Capacitors
- d. Harmonic Filters

2.23.2 **Protection** for the branch circuits that are not part of the **bulk power system** need not be duplicated. **Protection** for these branch circuits should be applied with due consideration for capacitor bank transients, power system voltage unbalance, and system harmonics.

2.23.3 **Protection** against abnormal non-**fault** conditions within the SVC via control of the TSC and TCR valves should be designed so as to not interfere with the proper operation of the SVC.

2.24 Logic System

The design should recognize the effects of contact races, spurious operation due to battery grounds, dc transients, radio frequency interference or other such influences.

It is recognized that timing is often critical in logic schemes. Operating times of different devices vary. Known timing differences should be accounted for in the overall design.

2.25 Microprocessor-Based Equipment and Software

Appendix A

A **protection system** may incorporate microprocessor-based equipment. Information from this equipment may support other functions such as power system operations. In such cases, the software and the interface should be designed so as to not degrade the **protection system** functions.

2.26 Control Cable, Wiring and Ancillary Control Devices

Control cables and wiring and ancillary control devices should be highly dependable and secure. Due consideration should be given to published codes and standards, fire hazards, current-carrying capacity, voltage drop, insulation level, mechanical strength, routing, shielding, grounding and environment.

2.27 Environment

Means should be employed to maintain environmental conditions that are favorable to the correct performance of **protection systems**.

3.0 Guideline for Application of Remote Access to Protection System

The following guideline is established for the application of remote access to **protection system** Intelligent Electronic Devices (IEDs), such as relays, programmable logic controllers (PLC), and teleprotection equipment that have remote access capabilities, and are designed and configured for remote access applications. It is intended to assist in meeting the requirement stipulated in Section 5.1.3.3 of this Directory, and Section 3.3.1.6 of the *Special Protection System Criteria* (Directory 7).

This guideline assumes that appropriate physical measures are in place, and that they meet all applicable standards.

3.1 Definitions for Use in this Guideline Only

The following defined terms are used for illustration of the guideline presented in this Section only. These terms are not defined in Appendix A of this Directory, or any other NPCC documents.

IED - Intelligent Electronic Device, normally computer based, equipped with digital communication abilities, some examples are **protective relays**, RTUs, SERs, DFRs, PLCs, data concentrators, telecommunications equipment, and general monitoring equipment.

PLC - Programmable Logic Controller, used to create and implement logical actions and automation.

Appendix A

Remote Access - accessing a device from a remote geographical area via a communications link; once accessed, provides similar local device functionality, at a distance.

Authenticate - to prove to be genuine or is an approved user.

Intrusion - An unauthorized electronic entry into an IED. Access normally provides user access to the functionality of the device.

Cryptography – is the study and application of codes and ciphers. Codes or encryption is used to transform data into a form that is not directly usable. Decryption transforms encrypted data using a decryption key back into the original useful form.

VPN – Virtual Private Network. It uses encryption to provide a private channel between private networks using a public network as its carrier i.e., two users using the Internet to provide confidentiality, integrity, and authentication.

3.2 Governing Principles

The industry has become more reliant on computer technology for power **system protection**, control, communications, and automation of its power system. Electromechanical and solid-state technologies are being replaced with microprocessor devices, offering, among other functions, local and remote communications access. **Protection system** IEDs are employed to protect, and or operate power system elements. Unauthorized access to an IED could result in interruption of electric service, damage to the power system equipment, major **disturbances**, or a danger to life and property. **Protection system** IEDs also contain a large amount of information that utility personnel have come to rely on, including telemetry, power system **disturbance** analysis, fault location, preventive maintenance information, as well as asset condition and optimization data. However, this technology has also created vulnerabilities that are similar to those seen in traditional computer networks. Therefore, the following should be the governing principles of any cyber security program:

- Prevent penetration from cyber attacks.
- Prevent local and remote access to critical cyber assets by non-authorized personnel.
- Monitor cyber assets to detect unauthorized access or attempts to access.
- Limit exposure.

3.3 Guideline

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Appendix A

3.3.1 Authentication

One of the foundations of the cyber security program is controlled, or secure, access. This dictates that some form of user authentication be used. Three common means of authenticating a user's identity are:

- 3.3.1.1 Something the user knows, such as passwords, or IP addresses.
- 3.3.1.2 Something the user has, such as a key, or cryptographic token.
- 3.3.1.3 Something the user is, such as fingerprints and voiceprints

At minimum, at least two factors of authentication should be used, e.g., passwords, and a destination – telephone number, or an IP address. The use of more factors such as encryption, etc. will result in providing more secure authentication. However, most present day and legacy **protection system** IEDs do not yet support this technology. Existing equipment often contains some level of security features. At a minimum, they usually provide multi-level passwords. These features should be activated as a first step in security implementation

3.3.2 Substation IED Access Point

A list of all substation IEDs that have remote electronic access configured should be compiled and maintained. This list should also include the access method(s) (e.g., dial-in, WAN, etc), the associated phone numbers and/or IP address, passwords, and other pertinent data.

3.3.3 Approved Remote Access Authorization List

A list of approved users, and the station IEDs they are authorized to access, should be established and maintained. It is vital that all such access information be classified as confidential, and managed as such.

Appendix A

3.3.4 Remote Access Configuration

Protection system IEDs should be configured to afford remote access only where needed and approved, and then, only when proper authentication is provided.

3.3.5 Password

Most **protection system** IEDs offer multiple access levels, each with separate passwords. Normally, a “view” only level is provided which allows a user to extract and or view information only. An alternate access level is provided to allow trained and authorized users to “make” settings and configuration changes, and initiate breaker operations. It is this level of access that is susceptible to an intrusion which could cause the most damage to the power system. Only limited users should have access to this level by considering the followings:

3.3.5.1 Establish multi-tiered passwords with different privileges for different classes of users.

3.3.5.2 Default passwords should be changed when remote access is configured.

3.3.5.3 Make sure that all IEDs have "strong" passwords, i.e., passwords that are not dictionary words, not easily guessable, not blank, or have no password at all. It is recommended that all passwords contain a combination of letters and numbers, and should be at least six characters long.

3.3.6 Logging/Alarming

When remote connections are used to access the relay beyond “view-only” mode, this should be alarmed and/or logged where possible.

3.3.7 Controlling Authority Approval

For both local and remote communications, excluding viewing, notification and approval of the Controlling Authority should be required to access in-service **protection system** IEDs. Only authorized users, as per Sections 3.3.3 and 3.3.5 above, should have remote access capabilities.

Appendix A

3.3.8 Disable User Function

Often, **protection system** IEDs are put into service with functions that are not used. These functions can create vulnerabilities, and therefore, should be disabled if possible.

3.4 Other Available Higher Level Authentication Factors and Some General Good Practices

As stated in Section 3.3.1, a minimum of two factors of authentication should be used. However, the use of more factors will result in providing more secure authentication. This Section is intended to provide additional factors and practices that could be implemented where warranted, and where the technology allows.

3.4.1 For WAN based access systems, implement Virtual Private Network (VPN) technology. VPN technology is also applicable when using ISDN, DSL, and cable.

3.4.2 Limit, as far as possible, dependence on the public telephone network for substation communications to IEDs. Instead, use secure communications facilities whenever possible.

3.4.3 Call back (where the IED device or modem hangs up on the original caller and calls back on a second line to a preconfigured phone number) may be utilized as a portion of an IED's security to prevent unauthorized access. This security measure added to other security measures will improve the IEDs security. Security can be further enhanced by using a different telephone line for the return call.

3.4.4 For dial-up modem access, use a hardware lock and key dongle on the analog phone line at each modem and the lock and key combination will act as a gatekeeper. When a call is initiated, the lock at the called modem will verify the existence of a valid key at the calling modem Time.

Appendix A

3.4.5 Isolation from the Business/Corporate Network

Isolation of the substation **protection system** IEDs from the Corporate Network should be provided where possible. Data can be transferred from the substation IEDs to a server connected to a Corporate Network via appropriate firewalls. This practice is warranted because most Corporate Networks are Internet connected and therefore are exposed to external users.

4.0 Procedure for Reporting New and Revised **Protection Systems**

Paragraph 7.1 of this criteria states that **Protection system** owners shall provide the Task Force on System Protection (TFSP) with advance notification of any of their new **bulk power system protection** facilities, or significant changes in their existing **bulk power system protection** facilities. Paragraph 7.2 of this criteria states that **Protection system** owners shall also provide the TFSP with advance notification of non-member **protection** facilities as required per NPCC Bylaws. Notification will be made to the TFSP early in the engineering design stage.

4.1 Additional Requirements for Presentation and Review

- 4.1.1 A presentation will be made to the TFSP on new facilities or a modification to an existing facility when requested by either a member entity or the TFSP.
- 4.1.2 A presentation will be made to the TFSP when the design of the **protection** facility deviates from the criteria set forth in this Directory.
- 4.1.3 A presentation will be made to the TFSP when a member entity is in doubt as to whether a design meets the **protection** criteria set forth in this Directory.

4.2 Data Required for Presentation and Review of Proposed Protection Facilities

- 4.2.1 The **protection system** owner will advise the TFSP of the basic design of the proposed system. The data will be supplied on the "Protection System Review Forms" (formerly C-22 forms) as listed below, accompanied by a geographical map, a one-line diagram of all affected areas, and the associated **protection** and control function diagrams. A physical layout of **protection** panels and batteries for the purpose of illustrating physical separation will also be included.

Appendix A

Protection System Details
Line Relaying (Phase)
Line Relaying (Ground)
Transformer/Reactor Relaying
Generator Relaying
Bus Relaying
Shunt Capacitors and Filters Relaying
HVdc Converter Relaying
Special Protection Systems
Communication links
Equipment Details
Current Transformers
Voltage Transformers
Station Battery
Physical Separation
Breakers
Disturbance Monitoring Equipment
Transmission Relay Loadability
Exception Request

4.2.2 The proposed **protection system** will be explained with due emphasis on any special conditions or design restrictions existing on the particular power system.

4.3 Procedure for Presentation

4.3.1 The **protection system** owner will arrange to have a technical presentation made to the TFSP

4.3.2 To facilitate scheduling, the chairman of the TFSP will be notified approximately four months prior to the desired date of presentation.

4.3.3 Copies of materials to be presented will be distributed to TFSP members 30 days prior to the date of the presentation.

4.4 TFSP Procedures

4.4.1 The TFSP will review the material presented and develop a position statement concerning the proposed **protection system**. This statement will indicate one of the following:

4.4.1.1 The need for additional information to enable the TFSP to reach a decision.

Appendix A

4.4.1.2 Acceptance of the member statement of conformance to the Protection Criteria.

4.4.1.3 Acceptance of the submitted proposal

4.4.1.4 Conditional acceptance of the submitted proposal*.

4.4.1.5 Rejection of the submitted proposal*.

* Position Statements 4.4.1.4 and 4.4.1.5 will include an indication of areas of departure from the intent of the **protection** criteria and suggestions for modifications to bring the **protection system** into conformance with the NPCC criteria.

4.4.2 The results of the TFSP review will be documented in the following manner:

4.4.2.1 A position statement will be included in the minutes of the meeting at which the proposed **protection system** was reviewed.

4.4.2.2 If necessary, a letter outlining areas of nonconformance with the **protection** criteria stipulated in this Directory and recommendations for correction will be submitted to the **protection system** owner. If necessary, the matter will be brought to the attention of the RCC.

4.4.2.3 The Task Force will maintain a record of all the reviews it has conducted.



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**NPCC
Regional Reliability Reference Directory # 7
Special Protection Systems**

Task Force on System Protection Revision Review Record
December 27, 2007

Adopted by the Members of the Northeast Power Coordinating Council Inc., this December 27, 2007, based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 and as amended to date.

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**Procedure For NPCC Review Of New Or Modified Bulk
Power System Special Protection Systems (SPS) (Figure) 26**

Introduction

1.1 Title Special Protection Systems

1.2 Directory Number 7

1.3 Objective

Provide the basic criteria for **Special Protection Systems** such that the **Bulk Power System** in NPCC Inc. member **Areas** is operated reliably.

1.4 Effective Date Immediately upon Approval by the NPCC Full Members

1.5 Background

This directory establishes the basic **protection** criteria for **Special Protection Systems**. It is not intended to be a design specification. It is recognized that responsible entities in certain **Areas** may choose to apply more rigid criteria because of local considerations.

Guidance for consideration in the implementation of these criteria is provided in Appendix A, and the procedure for reviewing new and revised **Special Protection Systems** is provided in Appendix B.

1.6 Applicability

1.6.1 Functional Entities

Transmission Owner, Generator
Owner, Distribution Provider

1.6.2 Facilities

1.6.2.1 New Facilities

The standard requirements and criteria stipulated in this Directory apply to all new Type I and Type II **Special Protection Systems** (SPSs) as defined below. In the application of Type II SPSs, their security is the prime concern (see Section 3.3.1 of this document). As such, Sections 3.3.1.1, 3.3.2.3, 3.3.3.2, 3.3.6 and 3.3.8.1 in this document do not apply to Type II.

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1.6.2.2 Existing Facilities

It is the responsibility of individual Transmission Owners (TO), Generator Owners (GO) and Distribution Providers (DP) to assess their existing **Special Protection Systems** and to make modifications which are required to meet the intent of these standards as follows:

a. Planned Renewal or Upgrade to Existing Facilities It is recognized that there may be **SPSs**, which existed prior to each TO's, GO's and DP's adoption of the *Special Protection System Criteria* that do not meet these criteria. If any **Special Protection Systems** or sub-systems of these facilities are replaced as part of a planned renewal or upgrade to the facility and do not meet all of these criteria, then an assessment shall be conducted for those criteria that are not met. The result of this assessment shall be reported on TFSP Form #1-5.

b. SPS Re-classified to Type I or Type II

These requirements apply to all existing SPSs which are reclassified as Type I or Type II due to system changes. A mitigation plan shall be required to bring such a SPS into compliance with these criteria.

c. In-kind Replacement of SPS Equipment

If SPS equipment is replaced "in-kind" as a result of an unplanned event, then it is not required to upgrade the associated protection system to comply with these criteria.

1.6.3 Classification of **Special Protection Systems**

Special Protection Systems are sub-divided into three types. Reference can be made to the NPCC *Basic Criteria for Design and Operation of Interconnected Power Systems* (Document A-2) where design criteria contingencies are described in Section 5.0; operating criteria contingencies, in Section 6.0; and extreme contingencies, in Section 7.0 of Document A-2.

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Type I	A Special Protection System which recognizes or anticipates abnormal system conditions resulting from design and operating criteria contingencies , and whose misoperation or failure to operate would have a significant adverse impact outside of the local area. The corrective action taken by the Special Protection System along with the actions taken by other protection systems are intended to return power system parameters to a stable and recoverable state.
Type II	A Special Protection System which recognizes or anticipates abnormal system conditions resulting from extreme contingencies or other extreme causes, and whose misoperation or failure to operate would have a significant adverse impact outside of the local area.
Type III	Special Protection System whose misoperation or failure to operate results in no significant adverse impact outside the local area. The practices contained in this document for a Type I SPS should be considered but are not required for a Type III SPS. It should be recognized that a Type III SPS may, due to system changes, become Type I or Type II.

2.0 Terms Defined in this Directory

The following terms are defined in this Directory. Their definitions are provided in Attachment 1.

Bulk Power System
Contingency
Fault
Operating Procedures
Protection
Special Protection System (SPS)
Teleprotection

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3.0 Requirements

3.1 The NERC ERO Reliability Standards containing Requirements that are associated with this Directory include, but may not be limited to:

- 3.1.1 [PRC-012-0 — Special Protection System Review Procedure](#)
- 3.1.2 [PRC-013-0 Special Protection System Database](#)
- 3.1.3 [PRC-014-0 — Special Protection System Assessment](#)
- 3.1.4 [PRC-015-0 — Special Protection System Data and Documentation](#)
- 3.1.5 [PRC-016-0 — Special Protection System Misoperations](#)
- 3.1.6 [PRC-017-0 - Special Protection System Maintenance and Testing](#)

3.2 NPCC Regional Reliability Standard Requirements

None at this time. To be developed.

3.3 NPCC “Full Member”, More Stringent Criteria

3.3.1 General Criteria

A **Special Protection System** shall be designed to recognize or anticipate the specific power system conditions associated with the intended function.

Due consideration shall be given to dependability and security. The relative effect on the **bulk power system** of a failure of an SPS to operate when desired versus an unintended operation shall be weighed carefully in selecting design parameters as follows:

- 3.3.1.1 To enhance dependability, a **Special Protection System** shall be designed with sufficient redundancy such that the **Special Protection System** is capable of performing its intended function while itself experiencing a single failure.
- 3.3.1.2 Multiple protection groups that are used to obtain redundancy within a **Special Protection System** shall not share the same component.
- 3.3.1.3 A **Special Protection System** shall be designed to avoid false operation while itself experiencing a credible failure.

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- 3.3.1.4 The thermal capability of all **Special Protection System** components shall be adequate to withstand the maximum short time and continuous loading conditions to which the associated power system elements may be subjected.
- 3.3.1.5 Communication link availability, critical control switch and test switch positions, and trip circuit integrity, shall be monitored to allow prompt attention by appropriate operating authorities.
- 3.3.1.6 When remote access to **Special Protection Systems** is possible, the design shall include security measures to minimize the probability of unauthorized access to the **Special Protection System**.
- 3.3.1.7 An SPS shall be designed to take corrective action within times determined by studies with due regard to security, dependability and selectivity.
- 3.3.1.8 Status of SPS arming shall be monitored to allow prompt attention by appropriate operating authorities.
- 3.3.1.9 An SPS shall be equipped with means to enable its arming and to independently verify the arming.

3.3.2 Current Transformer Criteria

Current transformers (CTs) associated with **Special Protection Systems** shall have adequate steady-state and transient characteristics for their intended function.

- 3.3.2.1 The output of each current transformer secondary winding shall be designed to remain within acceptable limits for the connected burdens under all anticipated currents, including **fault** currents, to ensure correct operation of the **Special Protection System**.
- 3.3.2.2 The thermal and mechanical capabilities of the CT at the operating tap shall be adequate to prevent damage under maximum **fault** conditions and normal or **emergency** system loading conditions.
- 3.3.2.3 For **protection groups** to be independent, they shall be supplied from separate current transformer secondary windings.
- 3.3.2.4 Interconnected current transformer secondary wiring shall be grounded at only one point.

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3.3.3 Voltage Transformer and Potential Device Criteria

Voltage transformers and potential devices associated with **Special Protection Systems** shall have adequate steady-state and transient characteristics for their intended functions.

3.3.3.1 Voltage transformers and potential devices shall have adequate volt-ampere capacity to supply the connected burden while maintaining their **relay** accuracy over their specified primary voltage range.

3.3.3.2 If a **Special Protection System** is designed to have multiple **protection groups** at a single location for redundancy, each of the **protection groups** shall be supplied from separate voltage sources. The **protection groups** may be supplied from separate secondary windings on one transformer or potential device, provided all of the following requirements are met:

- . Complete loss of one or more phase voltages does not prevent operation of both SPS protection groups;
- . Each secondary winding has sufficient capacity to permit fuse **protection** of the circuit;
- . Each secondary winding circuit is adequately fuse protected.

3.3.3.3 The wiring from each voltage transformer secondary winding shall not be grounded at more than one point.

3.3.3.4 Voltage transformer installations should be designed with due regard to ferroresonance.

3.3.4 Battery and Direct Current (dc) Supply Criteria

dc supplies associated with a **Special Protection System** shall be designed to have a high degree of dependability as follows.

3.3.4.1 If a **Special Protection System** is designed to have multiple **protection groups** at a single location for redundancy, no single battery or dc power supply failure shall prevent the independent **protection groups** from performing the intended function. Each battery shall be provided with its own charger.

3.3.4.2 Each battery shall have sufficient capacity to permit operation of the **Special Protection System**, in the event of a loss of its battery charger or the ac supply source, for the period of time necessary to transfer the load to

the other battery or re-establish the supply source.

- 3.3.4.3 The battery chargers and all dc circuits shall be protected against short circuits. All protective devices should be coordinated to minimize the number of dc circuits interrupted.
- 3.3.4.4 dc battery systems shall be continuously monitored to detect abnormal voltage levels (both high and low), dc grounds, and loss of ac to the battery chargers in order to allow prompt attention by the appropriate operating authorities.
- 3.3.4.5 **Special Protection System** dc supply circuits shall be continuously monitored to detect loss of voltage in order to allow prompt attention by the appropriate operating authorities.

3.3.5 Station Service ac Supply Criteria

If a **Special Protection System** is designed to have multiple **protection groups** at a single location for redundancy, there shall be two sources of station service ac supply, each capable of carrying at least all the critical loads associated with the **Special Protection System**.

3.3.6 Circuit Breakers Criteria

Where **Special Protection System** redundancy is achieved by use of independent **protection groups** tripping the same circuit breakers without overarming, each circuit breaker shall be equipped with two independent trip coils.

3.3.7 Teleprotection Criteria

Communication facilities required for **teleprotection** shall be designed to have a level of performance consistent with that required of the **Special Protection System**, and shall meet the following:

- 3.3.7.1 Where the design of a **Special Protection System** is composed of multiple **protection groups** for redundancy and each group requires a communication channel, the equipment and channel for each group shall be separated physically and designed to minimize the risk of more than one **protection group** being disabled simultaneously by a single event or condition.
- 3.3.7.2 **Teleprotection** equipment shall be monitored to detect loss of equipment and/or channel to allow prompt attention by the appropriate operating authorities.
- 3.3.7.3 **Teleprotection** systems shall be designed to assure adequate signal transmission

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during **bulk power system** disturbances, and shall be provided with means to test for proper signal adequacy.

3.3.7.4 **Teleprotection** equipment shall be powered by the substation batteries or other sources independent from the power system.

3.3.7.5 Except as identified otherwise in these criteria, the two **teleprotection** groups shall not share the same component. The use of a single communication tower for the radio communication systems used by the two SPS groups is permitted.

3.3.8 Physical Separation/Environment Criteria

3.3.8.1 In addition to the physical separation as referenced in sections 3.3.1.2 and 3.3.9.5, if a **Special Protection System** is designed to have multiple **protection groups** at a single location for redundancy, each separate protection group and **Teleprotection** of an SPS shall be on different non-adjacent vertical mounting assemblies or enclosures.

3.3.8.2 In the event a common raceway is used, cabling for separate groups of an SPS shall be separated by a fire barrier.

3.3.9 Grounding Criteria

Station grounding is critical to the correct operation of **Special Protection Systems**. The design of the ground grid directly impacts proper **Special Protection System** operation and probability of false operation from **fault** currents or transient voltages.

3.3.9.1 Each TO, GO and DP shall have established as part of its substation design procedures or specifications, a mandatory method of designing the substation ground grid, which:

- . Can be traced to a recognized calculation methodology
- . Considers cable shielding
- . Considers equipment grounding

3.3.10 Provision for Breaker Failure Criteria

Type I SPS shall include breaker failure **protection** for each circuit breaker whose operation is critical to the adequacy of the action taken by the SPS with due regard to the power system conditions this SPS is required to detect. Options for breaker failure **protection**:

3.3.10.1 A design which recognizes that the breaker has not achieved or will not achieve the

intended function required by the **Special Protection System** and which takes independent action to achieve that function. This provision needs not be duplicated and can be combined with conventional breaker failure schemes if appropriate.

3.3.10.2 Overarming the **Special Protection System** such that adequate action is taken even if a single breaker fails.

3.3.10.3 The redundancy afforded by actions taken by other independent schemes or devices.

3.3.11 Testing and Maintenance Criteria

3.3.11.1 Each SPS shall be maintained in accordance with the Maintenance Criteria for Bulk Power System Protection (Document A-4).

3.3.11.2 The design of an SPS both in terms of circuitry and physical arrangement shall facilitate periodic testing and maintenance.

3.3.11.3 Test facilities or test procedures shall be designed such that they do not compromise the independence of the redundant design aspects of the SPS.

3.3.11.4 An SPS shall be functionally tested when initially placed in service and when modifications are made.

3.3.11.5 If a segmented testing approach is used, test procedures and test facilities shall be designed to ensure that related tests properly overlap. Proper overlap is ensured if each portion of circuitry is seen to perform its intended function, such as operating a relay, from either a real or test stimulus, while observing some common reliable downstream indicator.

3.3.11.6 All positive combinations of input logic shall be tested regardless of the maintenance strategy used.

3.3.11.7 Sufficient testing shall be employed to ensure that timing races do not exist within hardwired or electronic logic, and that the SPS operating time is within design limits.

3.3.11.8 Each time the SPS is maintained, its hardware shall be tested in conjunction with the control facilities, related computer equipment, software and **operating procedures** to ensure compatibility and correct operation.

3.3.12 Analysis of SPS Performance

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3.3.12.1 **Bulk power system** automatic operations shall be analyzed to determine proper **Special Protection System** performance. Corrective measures must be taken promptly if the **Special Protection System** or a **protection group**

within the SPS fails to operate or operates incorrectly.

3.3.12.2 Event recording capability shall be provided to permit analysis of system operations and **Special Protection System** performance.

4.0 Measures and Assessments

None developed at this time.

Prepared by: Lead Task Force- Task Force on System Protection

Review and Approval: Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval.

Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC Inc. Bylaws" in effect at the time the ballots are cast.

Revisions pertaining to the Appendices or any other portion of the document such as Links, Glossary Terms, etc., will only require RCC Member approval of the document. Errata may be corrected by the Lead Task Force at any time and provide the appropriate notifications to the NPCC Inc. membership.

This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC Regional Reliability Standards and other NPCC documents.

References: NPCC RRS PRC-XXX-X (Future NPCC Regional Standard)

Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2)

Emergency Operation Criteria (Document A-3)

Maintenance Criteria for Bulk Power System Protection (Document A-4)

NPCC Glossary of Terms (Document A-7)

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Attachment 1 Definition of Terms

Bulk power system - The interconnected electrical systems within northeastern North America comprising **generation** and transmission facilities on which **faults** or **disturbances** can have a **significant adverse impact** outside of the local area. In this context, local areas are determined by the Council members.

Contingency – An event, usually involving the loss of one or more **elements**, which affects the **power** system at least momentarily.

Fault – An electrical short circuit.

Permanent Fault — A fault which prevents the affected **element** from being returned to service until physical actions are taken to effect repairs or to remove the cause of the fault.

Transient Fault — A fault which occurs for a short or limited time, or which disappears when the faulted **element** is separated from all electrical sources and which does not require repairs to be made before the **element** can be returned to service either manually or automatically.

Operating Procedures -A set of policies, practices, or system adjustments that may be automatically or manually implemented by the system operator within a specified time frame to maintain the operational integrity of the interconnected electric systems.

Automatic Operating Systems — **Special protection systems**, remedial action schemes, or other operating systems installed on the electric systems that require *no intervention* on the part of **system operators**.

Normal (Precontingency) Operating Procedures — Operating procedures that are normally invoked by the **system operator** to alleviate potential facility overloads or other potential system problems in anticipation of a **contingency**.

Postcontingency Operating Procedures — Operating procedures that may be invoked by the **system operator** to mitigate or alleviate system problems after a **contingency** has occurred.

Protection -The provisions for detecting power system **faults** or abnormal conditions and taking appropriate automatic corrective action.

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Protection group — A fully integrated assembly of **protective relays** and associated equipment that is designed to perform the specified protective functions for a power system **element**, independent of other groups.

Notes:

(a) Various identified as Main **Protection**, Primary **Protection**, Breaker Failure **Protection**, Back-Up **Protection**, Alternate **Protection**, Secondary **Protection**, A **Protection**, B **Protection**, Group A, Group B, System 1 or System 2.

(b) Pilot **protection** is considered to be one **protection group**.

Protection system

Element Basis

One or more **protection** groups; including all equipment such as instrument transformers, station wiring, circuit breakers and associated trip/close modules, and communication facilities; installed at all terminals of a power system **element** to provide the complete **protection** of that **element**.

Terminal Basis

One or more **protection** groups, as above, installed at one terminal of a power system **element**, typically a transmission line.

Pilot Protection — A form of line **protection** that uses a communication channel as a means to compare electrical conditions at the terminals of a line.

Significant adverse impact — With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from **faults** or **disturbances**, shall be deemed as having **significant adverse impact**:

- a. instability;
 - . any instability that cannot be demonstrably contained to a well defined local area.
 - . any loss of synchronism of generators that cannot be demonstrably contained to a well-defined local area
- b. unacceptable system dynamic response;
 - . an oscillatory response to a **contingency** that is not demonstrated to be clearly positively damped within 30 seconds of the initiating event.

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- c. unacceptable equipment tripping
 - . tripping of an un-faulted **bulk power system** element (element that has already been classified as **bulk power system**) under planned system configuration due to operation of a **protection** system in response to a stable power swing
 - . operation of a Type I or Type II **Special Protection System** in response to a condition for which its operation is not required
- d. voltage levels in violation of applicable **emergency** limits;
- e. loadings on transmission facilities in violation of applicable **emergency** limits;

Special protection system (SPS) – A **protection system** designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted **elements**. Such action may include changes in **load**, **generation**, or system configuration to maintain system **stability**, acceptable voltages or power flows. Automatic underfrequency **load shedding** as defined in the *Emergency Operation Criteria* A-3, is not considered a **Special Protection System**. Conventionally switched, locally controlled shunt devices are not **Special Protection Systems**.

Teleprotection - A form of **protection** that uses a communication channel

Appendix A

Guidance for Consideration in SPS Design

Introduction

This Appendix provides the guidance for consideration in the implementation of the **Special Protection System** design criteria stipulated in Section 3.3 of this Directory.

The general objective for any SPS is to perform its intended function (generator rejection, load rejection, etc.) in a dependable and secure manner. In this context, dependability relates to the degree of certainty that the SPS will operate correctly when required to operate. Security relates to the degree of certainty that the SPS will not operate when not required to operate.

The relative effects on the **bulk power system** of a failure to operate when desired versus an unintended operation should be weighed carefully in selecting design parameters. For example, the choice of duplication as a means of providing redundancy improves the dependability of the SPS but can also jeopardize security in that it may increase the probability of an unintended operation. This general objective can be met only if the SPS can dependably respond to the specific conditions for which it is intended to operate and differentiate these from other conditions for which action must not take place.

Close coordination should be maintained among system planning, design, operating, maintenance and **protection** functions, since both initially and throughout their life cycle, SPSs are a multi-discipline concern.

2.0 Considerations Affecting Dependability

- 2.1 Redundancy is normally provided by duplication. Some aspects of duplication may be achieved by overarming, which is defined as providing for more corrective action than would be necessary if no failures are considered. The redundancy requirements for an SPS apply only with respect to its response to the conditions it is required to detect.
- 2.2 For a **Special Protection System** that is composed of multiple **protection groups**, the risk of simultaneous failure of more than one **protection group** because of design deficiencies or equipment failure should be considered, particularly if identical equipment is used in each **protection group**. The extent and nature of these failures should be recognized in the design and operation of the **Special Protection System**.
- 2.3 Area of common exposure should be kept to a minimum to reduce the possibility of all groups being disabled by a single event such as fire, evacuation, water leakage, and other such incidents.

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3.0 Considerations Affecting Security

- 3.1 An SPS should be designed to operate only for conditions which require its specific protective or control actions.
- 3.2 **Special Protection Systems** should be no more complex than required for any given application.
- 3.3 The components and software used in **Special Protection Systems** should be of proven quality, as demonstrated either by actual experience or by stringent tests under simulated operating conditions.
- 3.4 **Special Protection Systems** should be designed to minimize the possibility of component failure or malfunction due to electrical transients and interference or external effects such as vibration, shock and temperature
- 3.5 **Special Protection Systems**, including intelligent electronic devices (IEDs) and communication systems used for **protection**, should comply with applicable industry standards for utility grade **protection** service. Utility Grade **Protection** System Equipment are equipment that are suitable for protecting transmission power system elements, that are required to operate reliably, under harsh environments normally found at substations. Utility grade equipment should meet the applicable sections of all or some of the following types of industry standards, to ensure their suitability for such applications:
 - . IEEE C37.90.1-2002 (oscillatory surge and fast transient)
 - . IEEE C37.90.1-2002 (service conditions)
 - . IEC 60255-22-1, 2005 (1 MHz burst, i.e. oscillatory)
 - . IEC 61000-4-12, 2001 (oscillatory surge)
 - . IEC 61000-4-4, 2004 (EFT)
 - . IEC 60255-22-4, 2002 (EFT)
 - . IEEE C37.90.2-2004 (narrow-band radiation)
 - . IEC 60255-22-3, 2000 (narrow-band radiation)
 - . IEC 61000-4-3, 2002 (narrow-band radiation)
 - . IEEE 1613 (communications networking devices in Electric power Substations)
- 3.6 **Special Protection System** circuitry and physical arrangements should be carefully designed so as to minimize the possibility of incorrect operations due to personnel error.
- 3.7 **Special Protection System** automatic self-checking facilities should be designed so as to not degrade the performance of the **Special Protection System**.
- 3.8 Consideration should be given to the consequences of loss of instrument transformer voltage inputs to **Special Protection Systems**.
- 3.9 Consideration should be given to the effect of the means of arming on overall security and dependability of the **Special Protection System**. Arming should have a level of security and dependability commensurate with the requirements of the SPS.

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4.0 Considerations Affecting Performance

4.1 Control Cable, Wiring and Ancillary Control Device

Control cables and wiring and ancillary control devices should be highly dependable and secure. Due consideration should be given to published codes and standards, fire hazards, current-carrying capacity, voltage drop, insulation level, mechanical strength, routing, shielding, grounding and environment.

4.2 Environment

Means should be employed to maintain environmental conditions that are favorable to the correct performance of **Special Protection Systems**.

5.0 Operating Time of an SPS

Adequate time margin should be provided taking into account study inaccuracies, differences in equipment, and **protection** operating times.

6.0 Arming of an SPS

Arming is the selection, which may be external to the **Special Protection System**, of desired output action based on power system conditions and recognized contingencies. Arming requirements of a Special Protection System are normally based upon the results of system studies which take into account recognized contingencies, operating policies/procedures and current power system load/generation conditions. For a simple **Special Protection System**, arming may be an on/off function. A **Special Protection System** can be armed either automatically or manually.

6.1 Automatic arming is implemented without human intervention.

6.2 Arming manually if the recognition, decision or implementation requires human intervention. Sufficient time with adequate margin for recognition, analysis and the taking of corrective action should be allowed.

7.0 Maintenance Considerations

7.1 Additional periodic maintenance is recommended on the following **protection** equipment:

- . On continuously monitored analog **teleprotection** channels, verify signal adequacy every twelve months.
- . On non-monitored analog **teleprotection** channels, verify signal adequacy every month.
- . On digital **teleprotection** systems, which are inherently monitored, verify local function every two years.
- . On batteries and chargers, verify proper operation and general condition every month.
- . On circuit breakers, verify ability to trip via each trip coil every two years, with due regard to critical trip paths between sensing relays and the breaker trip coils.

7.2 It is the responsibility of each TO, GO and DP to evaluate its own particular circumstances and determine if any additional maintenance should be performed on its system. More extensive maintenance may be required but not limited to:

- . during the initial break-in period,
- . where **protection** systems are exposed to abnormal conditions such as temperature extremes, vibration, corrosive atmosphere, etc.,
- . when the operating condition of **protection** system control wiring is suspect..

7.3 The design of a **Special Protection System** both in terms of circuitry and physical arrangement should facilitate periodic testing and maintenance in a manner that mitigates the risk of inadvertent operation. As a **Special Protection System** may be complex and may interface with other protection systems or control systems, special attention should be placed on ensuring that test devices and test interfaces properly support a clearly defined maintenance strategy.

7.4 Proper overlap is ensured if each portion of circuitry is seen to perform its intended function, such as operating a relay, from either a real or test stimulus, while observing some common reliable downstream indicator.

- 7.5 Whenever practicable, some of the maintenance testing requirements may be met by analyzing and documenting the detailed performance of the **Special Protection System** during actual events to demonstrate that the specific testing requirements have been fulfilled. Such an approach can reduce the probability of false operation during maintenance while effectively reducing the extent of planned maintenance.

Appendix B

Procedure for Review of Special Protection Systems

Introduction

This Appendix provide the procedure to follow to obtain concurrence from NPCC if an entity concludes that a new **Special Protection System** or a modification of an existing **Special Protection System** will be required which affects the **bulk power system**. The procedure is also shown on the attached flow chart.

2.0 NPCC Review and Concurrence

- 2.1 Allowing for sufficient lead time to ensure an orderly review, the entity will notify the chairman of the Task Force on Coordination of Planning (TFCP) of its proposal to install a new **Special Protection System** or modify an existing **Special Protection System**. The entity will send copies of the complete notification to TFCO and TFSP. This notification will include statements that describe possible failure modes and whether misoperation, unintended operation or failure of the **Special Protection System** would have local, inter-company, inter-Area or inter-Regional consequences, when the **Special Protection System** is planned for service, how long it is expected to remain in service, the specific **contingency(s)** for which it is designed to operate and whether the **Special Protection System** will be designed according to the NPCC *Bulk Power System Protection Criteria* (Document A-5) and the *Special Protection System Criteria* and Standards requirements listed in this document.
- 2.2 If the **Special Protection System** is expected to have only local consequences, TFCP will request that the Task Force on System Studies (TFSS) and the Task Force on System Protection (TFSP) review the proposal.
 - 2.2.1 TFSP will be notified of the proposed **Special Protection System**. TFSP will advise TFCP of any concerns.

- 2.2.2 TFSS will review the analyses that the proposing entity has performed. A presentation may be required from the proposing entity. The purpose of the review will be to confirm that there are no adverse inter-Area or inter-Regional consequences of either a failure of the **Special Protection System** to operate when and how it is required or an inadvertent or unintended operation of the **Special Protection System**. If necessary, TFSS will request that the proposing entity conduct additional analyses.
- 2.2.3 If the TFSS review confirms the **Special Protection System** has only local consequences, TFSS will send the information to TFCP. If TFCP concurs, they will then notify the proposing entity of NPCC's conclusions that the **Special Protection System** has only local consequences. TFCP will also notify the Reliability Coordinating Committee (RCC), all the Task Forces, the Compliance Committee (CC), the proposing entity and other Members that concurrence has been given to the proposing entity to modify an existing **Special Protection System** or install a new **Special Protection System**, at which time, the **Special Protection System** may be deployed.
- 2.2.4 If the TFSS review concludes that the **Special Protection System** could have inter-Area or inter-Regional consequences, they will inform the TFCP. Upon receipt of the TFSS conclusion or if TFCP separately determines the **Special Protection System** could have inter-Area or inter-Regional consequences, TFCP will arrange for an overall NPCC review as detailed in Step 3.
- 2.2.5 TFSS will update the NPCC **Special Protection System** list/database.
- 2.3 If the proposing entity expects the **Special Protection System** to have inter-Area or inter-Regional consequences, or if the TFSS or TFCP review concludes this to be the case, TFCP will request the Task Force on Coordination of Operation (TFCO), the Task Force on System Protection (TFSP) and TFSS to review it. Each of the Task Forces may require a presentation from the proposing entity.
 - 2.3.1 TFSP will confirm the failure modes of the **Special Protection System**, including actions of back-up **protection**, and whether or not the **Special Protection System** complies with NPCC system **protection** standards. TFSP will review whether the new or modified **Special Protection System** is in conformance with the NPCC *Bulk Power System Protection Criteria* (Document A-5) and the *Special*

Protection System Criteria and Standards requirements listed in this document and forward a summary of their findings to TFCO, TFCP and TFSS. This summary will include a statement as to whether the **Special Protection System** is in conformance with the *Bulk Power System Protection Criteria* (Document A-5) and the *Special Protection System Criteria* and Standards requirements listed in this document and whether the Task Force has any objections to its modification or installation.

- 2.3.2 TFSS will review the analysis that the proposing entity has performed. The purpose of the review will be to assess the **Special Protection System** is in conformance with the *Basic Criteria for Design and Operation of Interconnected Power Systems* (Document A-2) and to determine the inter-Area or inter-Regional consequences of either a failure of the **Special Protection System** to operate when and how it is required or an inadvertent or unintended operation of the **Special Protection System**. If necessary, TFSS will request that the proposing entity conduct additional studies. When their review is completed, TFSS will forward a summary of their findings to TFCO, TFCP and TFSP. This summary will include a statement as to whether the **Special Protection System** is in conformance with the *Basic Criteria* (A-2) and whether the Task Force has any objections to its modification or installation.
- 2.3.3 TFCO will review the operability of the **Special Protection System** and forward a summary of their findings to TFCP, TFSS and TFSP. This summary will include a statement as to whether the Task Force has any objections to its modification or installation.
- 2.3.4 TFCP will prepare an overall summary for the RCC. This summary will include the findings of the other Task Forces and whether there are any objections to the modification of the existing **Special Protection System** or the installation of the new **Special Protection System** and as a minimum, include the following information:
- . Function, i.e. GR-generation rejection etc.
 - . Identification
 - . Initiating condition
 - . Action(s) resulting
 - . Name of the **Special Protection System**, and owner, identification number
 - . Arming, i.e. percentage of time, system conditions for which it's needed, manual vs. automatic, etc.
 - . Reason for the installation
 - . Comments, explanations, such as "temporary until such time..."
 - . Company, owner
 - . SPS Number, drawn by NPCC staff
 - . Current Status, i.e. New, Changed or Removed
 - . Type Determination

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- . Determinations of the Task Forces' analyses
- . Consequences of operation, misoperation and failure to operate
- . Approximate of load or generation rejected by **Special Protection System** operation
- . Proposed date of deployment
- . Proposed date of retirement/deactivation

2.3.5 The RCC will review the summary report and act on the proposal to modify an existing **Special Protection System** or install a new **Special Protection System**. The RCC may also remand the review of the **Special Protection System** back to the TFCP if further analyses are determined to be needed.

2.3.6 The TFCP will notify the RCC, all the Task Forces, the CC, the proposing entity and other Members of the outcome of the review. Upon NPCC approval of the type and compliance with Criteria, the **Special Protection System** may be deployed.

2.3.7 The TFSS will then update the NPCC **Special Protection System** list/database.

3.0 Presentation and Review of Special Protection Systems

Each new or modified Type I or Type II **Special Protection System** shall be reported to the Task Force on System Protection in accordance with the following presentation and review procedure.

3.1 A presentation will be made to the TFSP on new facilities or a modification to an existing facility when requested by an NPCC Member or the TFSP.

3.2 A presentation will be made to the TFSP when the design of the **protection** facility deviates from the *Bulk Power System Protection Criteria* (Document A-5).

3.3 A presentation will be made to the TFSP when an NPCC Member is in doubt as to whether a design meets the *Protection Criteria*.

3.4 Data Required for Presentation and Review of Proposed **Special Protection System**:

3.4.1 The TO, GO or DP will advise the TFSP of the basic design of the proposed system. The data will be supplied on the attached forms, accompanied by a geographical map, a one-line diagram of all affected areas, and the associated **protection** and control function diagrams. A physical layout of **protection** panels and batteries for the purpose of illustrating physical separation will also be included.

3.4.2 The proposed **protection** system will be explained with due emphasis on

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any special conditions or design restrictions existing on the particular power system:

3.5 Procedure for Presentation:

3.5.1 The TO, GO or DP will arrange to have a technical presentation made to the TFSP.

3.5.2 To facilitate scheduling, the chairman of the TFSP will be notified approximately four months prior to the desired date of presentation.

3.5.3 Copies of materials to be presented will be distributed to TFSP members 30 days prior to the date of the presentation.

3.6 Review by TFSP

The TFSP will review the material presented and develop a position statement concerning the proposed **protection** system. This statement will indicate one of the following:

3.6.1 The need for additional information to enable the TFSP to reach a decision.

3.6.2 Acceptance of the TO, GO or DP statement of conformance to the *Protection Criteria*.

3.6.3 Acceptance of the submitted proposal.

3.6.4 *Conditional acceptance of the submitted proposal.

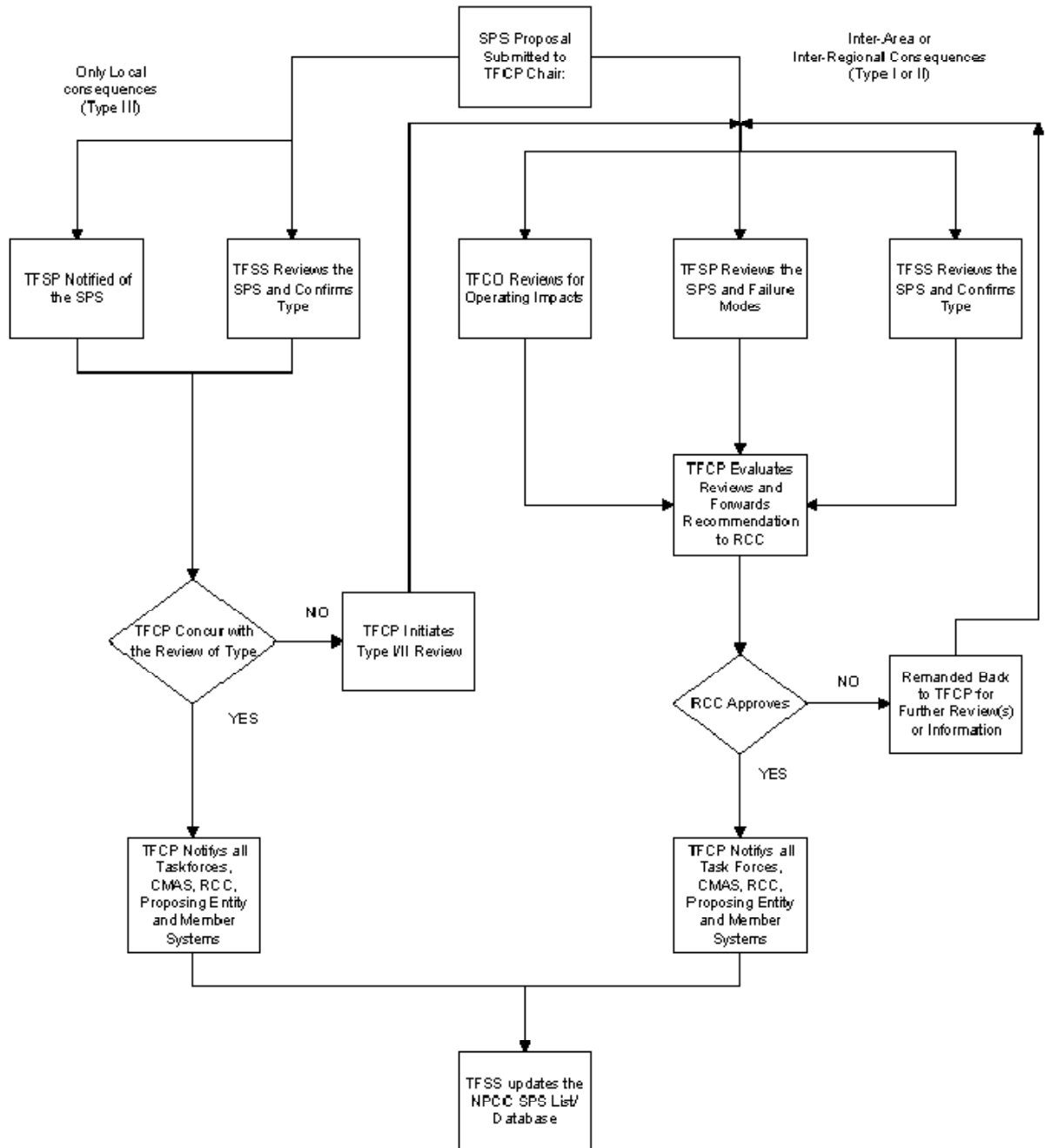
3.6.5 *Rejection of the submitted proposal

* Position Statements to include an indication of areas of departure from the intent of the *protection criteria* and suggestions for modifications to bring the **protection** system into conformance with the NPCC criteria.

3.6.6 The results of the TFSP review will be documented in the following manner.

- . A position statement will be included in the minutes of the meeting at which the proposed **protection** system was reviewed.
- . If necessary, a letter outlining areas of nonconformance with the NPCC *Protection Criteria* and recommendations for correction will be submitted to the TO, GO or DP.
- . The Task Force will maintain a record of all the reviews it has conducted.

**PROCEDURE FOR NPCC REVIEW OF NEW OR MODIFIED BULK POWER SYSTEM
SPECIAL PROTECTION SYSTEMS (SPS)**



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NPCC Regional Reliability Reference Directory # 8 System Restoration

Task Force on Coordination of Operations Revision Review Record:
October 21, 2008

Adopted by the Members of the Northeast Power Coordinating Council, Inc. this October 22, 2008, based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	10/21/08	Effective Date	New
1	1/30/09	Sect. 3.1 & 3.2 updated current Version of NERC Standards EOP-005 &EOP-006	Errata

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1.0 Introduction

1.1 Title System Restoration

1.2 Directory Number 8

1.3 Objective

The purpose of this Directory is to present the basic criteria with which each applicable entity must plan for and perform power system restoration following a major or a total blackout.

Compliance to the criteria set forth in this Directory document by each applicable entity assures the capabilities to perform power system restoration.

The functional requirements and performance of operational monitoring and control systems, **operator** voice communications and data telecommunications are beyond the scope of this Directory, except particular requirements for system restoration.

On an annual basis, the NPCC Inc. Task Force on Coordination of Operation shall review and accept each applicable entity's restoration plan for viability and coordination with other operating entities. The composite of the individual restoration plans, once reviewed and accepted by NPCC, comprises NPCC's regional restoration plan.

1.4 Effective Date **October 21, 2008**

1.5 Background

This Directory was developed from the draft NPCC A-12 System Restoration Criteria document (January 10, 2008 version) and associated C-35 Procedure document. Guidelines and procedures for consideration in the implementation of this Directory are provided in Appendix B.

1.6 Applicability

1.6.1 Functional Entities

Reliability Coordinators
Transmission Operators
Balancing Authorities
Transmission Owners
Generator Owners

2.0 Terms Defined in this Directory

The definitions of terms found in this Directory appearing in bold typeface, including those terms used in Appendix B, can be found in the Appendix A.

3.0 NERC ERO Reliability Standard Requirements

The NERC ERO Reliability Standards containing requirements that are associated with this Directory include, but may not be limited to:

3.1 [EOP-005-1](#)

3.2 [EOP-006-1](#)

4.0 NPCC Regional Reliability Standard Requirements

None.

5.0 NPCC Full Member, More Stringent Criteria

These Criteria are in addition to and more stringent or more specific than the NERC or any Regional Reliability standard requirements.

5.1 System Restoration Plan Requirements

Each Reliability Coordinator and Transmission Operator shall develop and maintain a system restoration plan for its operating area¹ that meets NERC requirements. In addition, the restoration plan shall:

5.1.1 identify the operating area's **basic minimum power system(s)**;

5.1.2 address the priority of restoring off-site power to nuclear plants;

5.1.3 identify interconnection points with adjacent operating areas;

5.1.4 identify **synchronization** parameters;

5.1.5 address coordination of system restoration with neighboring operating areas;

5.1.6 provide for the reenergization of transmission systems to major generating stations , including inter-area tie points;

5.1.7 address electrical **island** stabilization;

¹ Operating area means the Reliability Coordinating area or the Transmission Operator area as defined in the NERC Functional Model.

- 5.1.8 identify adequate on-site fuel resources for any supplementary generators (e.g., a diesel generator) used to sustain the supply of station service in whole or in part necessary for operating **key facilities**.

5.2 **Basic Minimum Power System** Determination Requirements

- 5.2.1 The **basic minimum power system** shall consist of one or more generating stations, transmission lines, and substations operating in the form of an **island** for the purpose of initiating the restoration process. The Reliability Coordinator and Transmission Operator shall each identify its area's **basic minimum power system(s)** within its system restoration plan.

- 5.2.2 A Reliability Coordinator and Transmission Operator may utilize more than one **basic minimum power system** to initiate the restoration process. In determining such a system(s), the Reliability Coordinator and the Transmission Operator shall involve all affected parties or entities.

- 5.2.3 The **basic minimum power system** shall include the capability to:

- 5.2.3.1 utilize **blackstart** generators;

- 5.2.3.2 form an electrical **island**;

- 5.2.3.3 **synchronize** electrical **islands**; and

- 5.2.3.4 permit the continuation of the system restoration plan.

5.3 Identification of **Key Facilities** and Associated **Critical Components**

- 5.3.1 The Reliability Coordinator shall identify the **key facilities**.

- 5.5.2 The Transmission Owners and Generator Owners of the **key facility** shall identify the associated **critical components**.

5.4 Power System Restoration Event Analysis

5.4.1 Reliability Coordinator Restoration Evaluation

Following an event where the system restoration plan was invoked, the Reliability Coordinator shall report on the performance of its restoration plan..

5.4.2 Transmission Operator Restoration Evaluation

Following an event where the system restoration plan was invoked, the Transmission Operator shall report on the performance of its restoration plan.

5.5 Testing Requirements for Facilities Associated with Interconnection Points

Each Transmission Owner of facilities that connect the **basic minimum power system** to interconnection points as agreed to by adjacent areas shall have a maintenance and testing program for the associated equipment required for continued and proper operation in the event of a total loss of grid supply. Upon request, a summary of the maintenance and testing records shall be provided to the Reliability Coordinator.

5.6 Testing Requirements for Facilities Associated with Offsite Power to Nuclear Generating Plants

Each Transmission Owner of facilities that connect the **basic minimum power system** to nuclear plants shall have a maintenance and testing program for the associated equipment required for continued and proper operation in the event of a total loss of grid supply. Upon request, a summary of the maintenance and testing records shall be provided to the Reliability Coordinator.

5.7 Testing Requirements for Critical Components Associated with Key Facilities

Each Transmission Owner and Generator Owner of a **key facility** shall:

- maintain a list of **critical components** associated with each **key facility**;
- perform the tests outlined in Table 1;
- maintain records of the test results; and
- provide the above upon request to the Reliability Coordinator and Transmission Operator.

Note that the occurrence of an actual successful event can be considered as a completed test, provided it can be demonstrated that the operation of the facility during the event met the test objectives and performance of these criteria.

The NPCC Compliance Committee stipulates the reporting requirements by the Transmission Owner and Generator Owner.

5.7.1 Reporting on Failure of Critical Components Associated with Key Facilities

The Transmission Operator shall report to its Reliability Coordinator, failure of a test or the failure of **critical components** associated with

key facilities:

5.7.1.1 As soon as possible and no later than 15 minutes after its control room has confirmed the loss of functionality at a **key facility** due to the failure of **critical components**. Loss of functionality at a **key facility** is defined as the loss of operability which can negatively impact the restoration plan. Examples of such conditions are:

- Loss of equipment control;
- Complete loss of AC or DC service supply;
- Loss of Blackstart facilities

5.7.1.2 As soon as possible and no later than 24 hours after their control room staff becomes aware of the failure of **critical components** associated with **key facilities** which results in a loss of redundancy at a **key facility**. Examples of such conditions are:

- Loss of a redundant AC or DC service supply;
- Loss of redundant Blackstart facilities

The report shall identify remedial actions to be undertaken, including the date by which the work is to be completed.

5.7.2 Blackstart Generating Unit Startup Test (Reference: Table 1; Test BS-1)

5.7.2.1 The Generator Owner having generating facilities designated as having **blackstart capability** shall annually verify the facilities' **blackstart capability** without dependencies on **power** sources unavailable during a partial or complete system blackout. Once the facility has been started, it shall continue to demonstrate its capability to operate in a stable condition while isolated from the **power** system for a minimum of ten minutes. The number of units within a generating facility that shall be **blackstarted** for this test is determined by the Reliability Coordinator and Transmission Operator as needed by their respective system restoration plans.

5.7.2.2 Each Reliability Coordinator and Transmission Operator shall ensure that the Generator Owner of a blackstart **generation** facility included in its restoration plan complete a successful blackstart test consistent with the objectives of its system restoration plan.

5.7.2.3 Operations voice communications and system control and data acquisition (SCADA) that are required for **blackstart** shall be verified to operate adequately without dependency on the interconnected system or other unrelated unit support for any source of station service.

5.7.3 Backup Pressurization System of Underground Transmission Cables Test (Reference: Table 1; Test UG-1)

Certain underground transmission cables require the capability to pressurize the insulating medium to maintain dielectric strength. The capability to do so during a **blackout** is essential to maintain the availability of such underground cables for service and to preclude any damage to the cables upon energizing. The Transmission Owner shall test the underground transmission cable's capability either by testing the cable's backup pressurization system or by powering the cable's normal pressurizing system from a backup power source (e.g. backup generator). This test shall be conducted every six (6) months by demonstrating that the required pressures can be maintained for a minimum of thirty (30) minutes.

5.7.4 Substation and Telecommunication Backup Power Supplies - Batteries and Generators Test (Reference: Table 1; Tests ST-1 to ST-6)

Transmission Owners shall test the backup power supplies in substations and telecommunication sites that are identified as **critical components** as specified below. Separate backup power arrangements for these substations and sites shall be separately identified in the **critical components** listing, and shall be inspected and tested individually.

The required tests are as follows:

5.7.4.1 Battery charger and batteries shall be inspected annually and meet the Transmission Owner's / Transmission Operator's battery integrity standards. (Reference: Table 1; Test ST-1)

5.7.4.2 Interruption of AC supply to a battery charger shall be carried out annually to ensure a battery picks up and carries **load**. Alternatively, a discharge test may be performed. (Reference: Table 1; Test ST-2)

5.7.4.3 The Transmission Owner's design and commissioning requirements must ensure that all **critical component loads** are supplied from batteries and battery charger as part of the engineering and design. If, and when, modifications are

made, and/or every five years, the Transmission Owner shall reconfirm through its design review and/or through testing that all **critical component loads** are connected to the battery and the battery charger. (Reference: Table 1; Test ST-3)

5.7.4.4 Performance testing of batteries in substations and telecommunication sites shall be done at least once every five (5) years. A recognized discharge (load) test will be conducted at least once every five years for a minimum of two hours. The success of this test is when average and individual cell voltages do not drop below prescribed design limits for the specific battery type. (Reference: Table 1; Test ST-4)

5.7.4.5 For substations and telecommunication sites provided with backup power generators, a startup and run test shall be performed monthly for a minimum run time of fifteen (15) minutes. (Reference: Table 1; Test ST-5)

5.7.4.6 For substations and telecommunication sites provided with automatically started backup power generators, the Transmission Owner shall verify that the generators will pickup the required **load** during the loss of station service, a startup, transfer and run test simulating the loss of station service will be performed annually for a duration of at least thirty (30) minutes. (Reference: Table 1; Test ST-6) For manually started back-up emergency generators, the Transmission Owner shall verify manual start of the generator and stable operation for thirty (30) minutes. (Reference: Table 1; Test ST-6)

5.7.5 Control Center and Telecommunication Center Facilities Test
(Reference: Table 1; Tests CC-1 To CC-5)

5.7.5.1 Each Reliability Coordinator, Transmission Operator and Balancing Authority shall test its facilities in the control centers and the telecommunication centers to demonstrate the computer systems will be functional when required for system restoration, without dependencies on power sources unavailable during a partial or complete system blackout. The uninterruptible power supply (UPS) systems in control centers and telecommunication centers shall be tested annually by interrupting AC supply and verifying that all **critical component loads** are supplied for a time that is sufficient for backup power sources to restore the AC input to the UPS. (Reference: Table 1; Test CC-1)

- 5.7.5.2 Performance testing of batteries in control centers and telecommunication sites shall be done at least once every five (5) years. A recognized discharge (load) test will be conducted at least once every five years for a minimum of two hours. The success of this test is when average and individual cell voltages do not drop below prescribed design limits for the specific battery type. (Reference: Table 1; Test CC-2)
- 5.7.5.3 For control centers and telecommunication centers provided with a backup power generator, a startup and run test shall be performed monthly for at least fifteen (15) minutes. (Reference: Table 1; Test CC-3)
- 5.7.5.4 For control centers and telecommunication centers provided with a backup power generator, verification that the generators will pick up the required **load** (including heating, ventilation and air conditioning (HVAC) for computer systems) during the loss of station service shall be provided. A startup, transfer and run test simulating the loss of station service shall be performed annually for a duration of at least thirty (30) minutes. During the test, the operation of the auxiliaries shall be verified. (Reference: Table 1; Test CC-4)
- 5.7.5.5 Each Reliability Coordinator, Transmission Operator and Balancing Authority shall test its computer redundancy features every six (6) months to ensure computer systems continue to function adequately. (Reference: Table 1; Test CC-5)

6.0 Measures and Assessments

- M1.** Each Reliability Coordinator and Transmission Operator shall have a dated, documented System restoration plan developed in accordance with Section 5.1, "System Restoration Plans."
- M2.** Each Reliability Coordinator shall have documentation identifying the Basic Minimum Power System for its area, in accordance with Section 5.2, that incorporates the components and the Key Facilities identified in Section 5.3.
- M3.** Each Transmission Owner and Generator Owner shall have documentation identifying the Critical Components of Key Facilities in its area or facility, in accordance with Section 5.3.
- M4.** If there has been a Disturbance in which elements of the restoration plan have been utilized, each Reliability Coordinator and Transmission Operator involved shall provide evidence of conducting an event analysis in accordance with Section 5.4.

- M5.** Each Transmission Owner shall provide self-certification of a maintenance and testing program for the associated equipment required for continued and proper operation of facilities between interconnection points and the Basic Minimum Power System, in accordance with Section 5.5.
- M6.** Each Transmission Owner shall provide self-certification of a maintenance and testing program for the associated equipment required for continued and proper operation of facilities between nuclear plants and the Basic Minimum Power System, in accordance with Section 5.6.
- M7.** Each Transmission Operator shall ensure Transmission Owners and Generator Owners of a key facility test these facilities in accordance with Section 5.7.

7.0 Compliance Monitoring

Adherence to these Criteria shall be reported by the responsible entity in a manner and form designated by the Compliance Committee.

Prepared by:	Task Force on Coordination of Operation and Task Force on System Studies
Review and Approval:	Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval. Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast. Revisions pertaining to the Appendices or any other portion of the document such as Links glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document. This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.
References:	None

Table 1 - Standard Test Procedures for key facilities
and associated critical components required for system restoration

Table 1 - Standard Test Procedures for key facilities and associated critical components required for system restoration				
Test No.	Critical Component	Test	Test Frequency and Duration	Criteria for Successful Test
BS-1	Blackstart Generating Units	Startup test of generating unit blackstart capability without dependencies on the power system	<u>Frequency:</u> annual <u>Duration:</u> 10 minutes of stable operation	Successful startup and 10 minutes of stable operation All operating aids and auxiliary systems are independent.
UG-1	Pressurization system of underground transmission Cables	Test backup pressurization system by switching from normal to backup pressurization scheme or test cable's normal pressurization system from a backup power source (e.g. backup generator)	<u>Frequency:</u> every 6 months <u>Duration:</u> minimum of 30 minutes; verify that backup pressurization system or backup generator is able to maintain dielectric strength of insulating medium for the expected time required for restoration	Maintains safe dielectric pressure for the minimum test period Backup pressurization system or backup generator can maintain dielectric fluid pressure for the expected time required for system restoration

Table 1 - Standard Test Procedures for key facilities and associated critical components required for system restoration				
Test No.	Critical Component	Test	Test Frequency and Duration	Criteria for Successful Test
ST-1	Battery charger and batteries in substation and Telecommunication site	Check battery integrity as per Transmission Owner / Operator maintenance practices	<u>Frequency:</u> annually	Meet Transmission Owner / Operator battery integrity standards
ST-2	Battery charger and batteries in substation and Telecommunication site	Interruption of AC supplies to battery charger to ensure that battery picks up and carries load	<u>Frequency:</u> annually	Maintain acceptable voltage levels for the duration of the test
ST-3	Battery charger and batteries in substation and Telecommunication site	Confirm by design review and/or testing that all critical loads are connected to the battery via commissioning requirements and when modifications are made or if practicable, interruption of AC station service.	<u>Frequency:</u> once every 5 years or when modifications are made	Confirm that all critical loads are supplied from battery charger and batteries.

Table 1 - Standard Test Procedures for key facilities and associated critical components required for system restoration				
Test No.	Critical Component	Test	Test Frequency and Duration	Criteria for Successful Test
ST-4	Batteries in substation and telecommunication site	Perform recognized performance test of battery capacity including discharge (load) test	<u>Frequency:</u> at least once every five years <u>Duration:</u> minimum 2 hours	The success of this test is when average/individual cell voltage does not drop below prescribed design limits for the specific battery type.
ST-5	Backup generator in substation and Telecommunication site	Startup and run test for backup generator	<u>Frequency:</u> monthly <u>Duration:</u> minimum of 15 minutes	Successful startup followed by 15 minutes of stable operation
ST-6	Backup generator in substation and Telecommunication site	Backup generator startup, transfer and run test to simulate loss of station service	<u>Frequency:</u> annually <u>Duration:</u> minimum of 30 minutes	- Successful startup (automatically started type) - Transfer scheme operates correctly (automatically started type) - 30 minutes of stable operation supplying critical loads (both automatically and manually started backup generators)

Table 1 - Standard Test Procedures for key facilities and associated critical components required for system restoration				
Test No.	Critical Component	Test	Test Frequency and Duration	Criteria for Successful Test
CC-1	Uninterruptible power supply (UPS) system in control center and Telecommunication center	Interruption of AC supply to UPS to ensure it can continue to support all critical loads	<u>Frequency:</u> annually <u>Duration:</u> for a time that is sufficient for backup power sources to restore AC supply to the UPS	No impact on computer or telecommunication functions during testing
CC-2	Batteries in control center and telecommunication center	Perform recognized performance test of battery capacity including discharge (load) test	<u>Frequency:</u> at least once every five years <u>Duration:</u> minimum 2 hours	The success of this test is when average/individual cell voltage does not drop below prescribed design limits for the specific battery type.
CC-3	Backup generator in control center and Telecommunication center	Startup and run test for backup generator	<u>Frequency:</u> monthly <u>Duration:</u> minimum of 15 minutes	Successful startup followed by 15 minutes of stable operation

Table 1 - Standard Test Procedures for key facilities and associated critical components required for system restoration				
Test No.	Critical Component	Test	Test Frequency and Duration	Criteria for Successful Test
CC-4	Backup generator in control center and Telecommunication center	Backup generator startup, transfer and run test to simulate loss of station service	<u>Frequency:</u> annually <u>Duration:</u> minimum of 30 minutes	- Successful startup - Transfer scheme operates correctly - 30 minutes of stable operation supplying loads critical to system restoration - When HVAC system restarts, ambient temperature is in the range of equipment working temperature
CC-5	Computer systems	Verify computer redundancy or (n-1) check by failing over the EMS	Redundancy check every 6 months	- No impact on computer functions during testing. - Successful switching / testing without equipment failure.

Appendix A Definition of Terms²

Area — An **Area** (when capitalized) refers to one of the following: New England, New York, Ontario, Quebec or the Maritimes (New Brunswick, Nova Scotia and Prince Edward Island); or, as the situation requires, area (lower case) may mean a part of a system or more than a single system. Within NPCC, Areas (capitalized) operate as **control areas** as defined by the North American Electric Reliability Council (NERC) (the definition can be found on page 6 of this glossary).

Area Control Error — The instantaneous difference between actual and net **scheduled interchange**, taking into account the effects of frequency bias.

Automatic Generation Control (AGC) — Equipment that automatically adjusts a **Control Area's generation** to maintain its **interchange schedule** plus its share of frequency regulation.

Basic Minimum Power System —Consists of one or more generating stations, transmission lines, and substations operating in the form of an island for the purpose of initiating the restoration process. The Reliability Coordinator and Transmission Operator shall each identify its area's basic minimum power system(s) within its system restoration plan.

Bipolar — Operation of **HVdc** with two **poles** of opposite polarity with negligible ground current.

Blackstart Capability — The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering **power** without assistance from the electric system.

Critical Component — Equipment required for continued and proper operation of a **key facility** in the event of a total loss of grid supply. Critical components include but are not limited to the following:

- blackstart generating units;
- substation backup power supplies;
- control center and telecommunication center backup power supplies and computer systems;
- control center and telecommunication center computer room HVAC;
- telecommunication facilities backup power supplies.; and
- cable pressurization systems at or between key facilities shall be tested.

Disturbance – Severe oscillations or severe step changes of current, voltage and/or

² These terms will be moved and grouped under a separate Directory when all other Directories are developed.

frequency usually caused by **faults**.

System Disturbance — An event characterized by one or more of the following phenomena: the loss of **power** system **stability**; cascading outages of circuits; oscillations; abnormal ranges of frequency or voltage or both.

Emergency — Any abnormal system condition that requires automatic or manual action to prevent or limit loss of transmission facilities or **generation** supply that could adversely affect the **reliability** of the electric system.

Specific to NPCC: An **Emergency** is considered to exist in an Area if **firm load** may have to be shed.

Energize — To make a piece of equipment or circuit alive.

First Contingency Loss — The largest **capacity** outage including any assigned Ten-Minute Reserve which would result from the loss of a single **element**

HVdc Link — A high Voltage direct current connection between two **power** systems, often used to interconnect two asynchronous **power** systems.

Interconnection — When capitalized, any one of the five major electric system networks in North America: Eastern, Western, ERCOT, Québec, and Alaska. When not capitalized, the facilities that connect two systems or **Control Areas**. Additionally, an interconnection refers to the facilities that connect a non-utility generator to a **Control Area** or system.

Interface — The specific set of transmission **elements** between two areas or between two areas comprising one or more electrical systems.

Island — A portion of a **power** system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission system **elements**.

Key Facilities — Facilities required to establish a **basic minimum power system** following a system blackout. These facilities are essential to the restoration plan of the **Control Area** and include generating stations having blackstart units and other selected generating stations, transmission **elements** which are part of the **basic minimum power system**, control centers and telecommunication centers and telecommunication facilities which are necessary to support **protection** and control facilities, voice and data between and within control centers and voice and data between control centers and key generating / transmission substations.

Load — The electric **power** used by devices connected to an electrical generating system. (IEEE Power Engineering). Also see **Demand**.

NPCC Specific Definitions:

Firm Load — Loads that are not **Interruptible Loads**.

Interruptible Load — Loads that are interruptible under the terms specified in a contract.

Load Shedding — The process of deliberately removing (either manually or automatically) preselected customers' **load** from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.

Operator, System - Person responsible for operating control of the **bulk power system** in an **Area** of NPCC or an adjoining system interconnected with NPCC. This could be a Security Coordinator, a **Control Area** Operator or in some cases a bulk power utility operator (e.g. NYPA, Niagara Mohawk, etc)

Power

Apparent Power — The product of the volts and amperes. It comprises both *real* and *reactive* power, usually expressed in kilovoltamperes (kVA) or megavoltamperes (MVA).

Reactive Power — The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, **synchronous condensers**, or electrostatic equipment such as capacitors. Reactive power directly influences electric system voltage. It is usually expressed in kilovars (kVAr) or megavars (MVar).

Real Power — The rate of producing, transferring, or using electrical energy, usually expressed in kilowatts (kW) or megawatts (MW).

Rating — The operational limits of an electric system, facility, or **element** under a set of specified conditions.

Reclosing

Autoreclosing — The automatic closing of a circuit breaker in order to restore an **element** to service following automatic tripping of the circuit breaker.

Autoreclosing does not include automatic closing of capacitor or reactor circuit breakers.

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High-speed autoreclosing — The autoreclosing of a circuit breaker after a necessary time delay (less than one second) to permit **fault** arc deionization with due regard to coordination with all **relay** protective systems. This type of autoreclosing is generally not supervised by voltage magnitude or phase angle.

Manual Reclosing — The closing of a circuit breaker by operator action after it has been tripped by **protective relays**. Operator initiated closing commands may originate from local control or from remote (supervisory) control. Either local or remote close commands may be supervised or unsupervised.

Supervision — A closing command is said to be supervised if closing is permitted to occur only if certain prerequisite conditions are met (e.g., **synchronism-check**).

Synchronism-check — refers to the determination that acceptable voltages exist on the two sides of the breaker and the phase angle between them is within a specified limit for a specified time.

Reserve — In normal usage, reserve is the amount of **capacity** available in excess of the **demand**

Reserve Requirement — That capability above firm system **demand** required to provide for regulation, **load** forecasting error, equipment forced and scheduled outages, and local area supply **adequacy**

Synchronize — The process of connecting two previously separated alternating current apparatuses or systems after matching frequency, voltage, phase angles, etc. (e.g., paralleling a generator to the electric system).

Synchronism-check Relay — A verification **relay** whose function is to operate when two input voltages satisfy predetermined operating parameters.

Tie Line — A circuit connecting two or more **Control Areas** or systems of an electric system

Appendix B

Guideline and Procedure for Blackstart and System Restoration

1.0 Introduction

This Appendix provides the guidelines and procedures to the Reliability Coordinator, Transmission Operator and Balancing Authority to manage system restoration events that affect the NPCC member Areas and adjoining operating areas. This Procedure does not prescribe or supplant the specific restoration plans developed by each Reliability Coordinator and Transmission Operator within NPCC. This Procedure is structured to stipulate restoration actions on the part of the responsible entity, and includes the following broad categories:

1. A quick reference of each Reliability Coordinator and Transmission Operator area's restoration plan;
2. Actions to stabilize remaining electrical islands;
3. Assessment of conditions prior to interconnecting;
4. Establishing interconnections;
5. Actions to remain stable following an interconnection; and
6. Training and testing to validate plans.

Although the risk of a complete **power** system shutdown in North America is minimized by operating to reliability standards specified by NERC, NPCC and appropriate authorities within the region, there remains a requirement to be prepared for the worst case scenario. NERC and NPCC require that all Reliability Coordinators and Transmission Operators maintain viable system restoration plans and restoration capabilities.

The Reliability Coordinators and Transmission Operators within NPCC have detailed individual restoration plans that meet both NERC and NPCC requirements. These Plans address the possibility of a complete system blackout by calling for the building of a **basic minimum power system** from designated **key facilities**. The ultimate goal of this rebuilding process is to reconnect electrical areas to reestablish a fully interconnected system. At the same time, these restoration plans recognize that it is impossible to predict the extent to which each individual Reliability Coordinator and Transmission Operator area will be disrupted in a blackout event, nor the specific order in which facilities will become available for service after a system collapse. These partial blackout scenarios have been addressed by the prescription of technical guidelines that can be used to restore the **power** system following any type of blackout event.

In recognition of the fact that it is impossible to predict the extent of a blackout event nor the ensuing order of resource availability, this document does not attempt to provide specific procedures as to when and where to reconnect NPCC's Reliability Coordinator and Transmission Operator areas and neighboring operating areas. Instead, it provides

technical guidelines for **system operators** to reconnect the Reliability Coordinator and Transmission Operator areas and provide mutual assistance in a manner that reestablishes interconnected operation in a responsibly expeditious manner.

To preclude compromising the physical and cyber security of critical assets, specific information related to facilities is to be treated as confidential and thus restricted from the public domain. Access to such information is permitted only through controlled mechanisms on a “need to know” basis.

2.0 Minimizing the Impact of Events

Within NPCC, the Reliability Coordinator and Transmission Operator restoration plans are developed in accordance with all relevant NPCC Criteria and NERC Standards and reflect the best practices of the industry concerning power system restoration. These restoration plans provide specific direction for recovery from a total or major blackout; and they also provide general guidelines for partial blackouts. Each restoration plan establishes the following major priorities:

- 2.1 Establish the **basic minimum power system** within the Reliability Coordinator and Transmission Operator area;
- 2.2 Provide AC supply to nuclear generating units and non-blackstart generating units;
- 2.3 Restore enough **load** to stabilize generating units and transmission conditions; and
- 2.4 Establish inter-area **tie lines**.

Table 2-1 below summarizes, at a very high level, the restoration plans of each NPCC Reliability Coordinator and Transmission Operator area; Table 2-2 following similarly summarizes the restoration plans of adjoining Reliability Coordinator and Transmission Operator areas. Attachments 1 to 7 provide a detailed overview of the restoration plans of each of these areas.

Table 2-1 NPCC Reliability Coordinator and Transmission Operator Area

				Priority in

RC and TOP Area ³	Type of Restoration Plan	Primary Priority	Secondary Priority	Restoring Interconnections
Maritimes Area (New Brunswick System Operator)	Detailed switching plans and duties of the control centers are documented using defined and / or alternate paths.	Restore AC station service to nuclear generating site.	Restore AC supply to station service to all other plants and transmission substations.	At the earliest opportunity in a controlled fashion.
New England Area (ISO-NE)	The ISO-NE and Local Control Centers have a coordinated set of restoration plans. Detailed paths are defined to restore from a complete blackout. Technical guides are prescribed to restore from partial blackouts. Plans identify where and when ties between electrical islands can be made.	Restore AC Station Service to nuclear generation sites.	Restore AC Supply to generating stations, transmission stations and control centers.	Interconnections are made when technically viable. Procedures advocate interconnecting early.
New York Area (NYISO)	In the event of a complete system shutdown the plan defines a specific switching sequence along with general guidelines to restore the system. In the event of a partial system shutdown only the applicable guidelines and steps are followed.	Restore the basic minimum power system to expedite restoration of AC station service to nuclear generating sites.	Load restoration, but when limited energy is available within the NY system, preference is given to generating station start-up.	High priority given to establishment of tie line operation.
Ontario Area (IESO)	Strategies for restoration	Restore AC station	Restore AC Supply to Critical Loads	At the earliest opportunity in a

³ All member Areas in NPCC are registered as the Reliability Coordinator and Transmission Operator. Hence, only the member Areas names are shown in this column to indicate they represent both the RC and the TOP.

	established at time of incident based on, sources of potential for restart / blackstart, equipment availability and restoration plan priorities. “Rules of Thumb” developed to guide operators through stages of restoration. IESO directs restoration to create multiple islands simultaneously. There are 8 recognized restoration paths within 4 electrical island strategy diagrams for reference.	service to nuclear generating sites.	(AC & DC station service) for Switchyards, Substations, Generating Stations, Control Centers and interdependent infrastructure (i.e. telecommunications).	controlled fashion.
Québec Area (HQTE)	The available restoration paths allow for the partition of the main system into five basic minimum power systems .	Restore AC station service to nuclear plant and critical facilities of the five basic minimum power systems .	Restore AC station service to all other facilities.	Emphasis placed on restoring the Gatineau and the Abitibi-Témiscamingue islands from Ontario sources and Gaspé Island from New-Brunswick sources. Otherwise Interconnections are made when technically viable.

Table 2-2 Adjacent Reliability Coordinator/Transmission Operator Areas

				Priority in

RC (TOP) Area ⁴	Type of Restoration Plan	Primary Priority	Secondary Priority	Restoring Interconnections
MISO (Manitoba)	Manitoba uses a defined path approach for system restoration applied over two restoration areas, the Northern collector system and the remainder of the bulk power system . The bulk power system is further subdivided into two areas that are paralleled at predefined locations.	The primary priority for restoration is to restore station service to the valve group on the Southern system.	Secondary priorities are to restore station service to the specified HVdc bipolar pole within time limits and to restore station service to the remainder of plants in the Southern system and in the Northern system to the HVdc collector plants.	There are no specified priority tie lines , but any available tie lines are used as an anchor for the system.
MISO (Michigan)	The portion of Michigan adjacent to Ontario uses a defined path approach for system restoration. Alternate paths are also defined.	The primary priority for restoration is to restore AC Station service to nuclear plants and to establish a cranking path to provide start up power to all other plants and connect them together.	A secondary priority is to return the City of Detroit to normal power .	It is a priority to reestablish interconnected operation if the tie lines are available. Re establishing tie lines with Ontario is a special consideration due to their proximity to the 120 kV system and plants.
MISO (Minnesota)	Minnesota uses a defined path approach utilizing the 115 kV system.	The primary priority for restoration is to provide start up power to major generating plants.	The secondary priority is to provide station light and power to remaining stations.	Interconnected operation is reestablished with neighboring jurisdictions as soon as tie lines become available, with tie lines to

⁴ MISO is registered as a Reliability Coordinator, whereas its members Manitoba, Michigan and Minnesota are registered as Transmission Operators, which are indicated in brackets. PJM is registered as an RC and a TOP.

				Manitoba being the priority.
PJM	Each member company of PJM has its own restoration plan. PJM will coordinate and direct all transmission tie connections to external RC and TOP areas.	Restore off site power supply to nuclear plants.	Restore AC supply to switchyards, hydroelectric and fossil sites.	The restoration of tie lines will be evaluated as the facilities become available.

3.0 Voice Communication Overview

3.1 The ability to communicate is essential to the restoration process. The options for direct voice communications between control centers include the following:

3.1.1 Public Switched Telephone Networks (PSTN)

1. NERC Hot Line
2. Cellular Telephones

3.1.2 Direct Ring Down Circuits

3.1.3 Utility Owned Voice Channels

3.1.4 Satellite Telephones

3.2 Alternative means of communication to the PSTN can include direct ring down circuits and satellite telephones. All NPCC member **Areas** are Reliability Coordinators (and Transmission Operators), and therefore they are members of the NERC Hotline; the telephones associated with this service operate through the PSTN. Finally, cellular telephones are available for use in all Reliability Coordinator areas, although they have proven to be unreliable during major events due to excessive phone traffic.

Communication paths directly between Reliability Coordinator and Transmission Operator areas within NPCC (referred to as primary paths) contain multiple communications media options. In the improbable event that all primary paths between two areas are interrupted, alternate communication paths, where possible, have been identified. If available, a communication media on the direct or primary path between the Reliability Coordinator and Transmission Operator areas should be used at all times unless otherwise directed by the Reliability Coordinators and Transmission Operators to use an alternate path for coordination among them.

4.0 Actions to Stabilize Remaining Electrical **Islands**

4.1 Immediate Actions to Stabilize Conditions Within Electrical **Islands**

After a significant **power system disturbance**, electrical **islands** can result due to the separation and survival of sub-areas from the **Interconnection**. It is imperative to immediately monitor and assess conditions within these electrical **islands** and take any warranted actions to stabilize their operation. Actions taken to stabilize the **islands** may include the switching of reactive control devices, **generation** dispatch actions, transmission switching or **load shedding** to secure thermal, voltage or frequency conditions.

4.2 Requirement for Manual Generation Dispatch

If the **power** system has been severely disrupted, economic dispatch signals may be inaccurately calculated by energy management system software or may be ineffective in their application. Consequently, the Reliability Coordinator and Transmission Operator may request the Balancing Authority to suspend use of economic dispatch signals and change over to manual dispatch orders.

4.3 **Tie Line** Regulation

The Balancing Authority should appropriately select flat frequency or **tie line** bias control to stabilize frequency depending on the status of their **tie lines**. If a Balancing Authority area is electrically isolated, the flat frequency control mode should be implemented. If two or more Balancing Authority areas have remained connected, combinations of different control modes may have to be explored. Use of flat frequency control by the largest area and tie line bias control by other smaller connected areas could produce the best frequency regulation.

4.4 Inadvertent **Synchronization** of Electrical **Islands**

The Transmission Operator should recognize that the circuit breakers of transmission circuits that opened during the event, and whose terminals are **energized** within separate electrical **islands**, may automatically **reclose**. This action can be done by automatic **synchronism-check relays** that were actually installed for a separate purpose, namely the supervision of steady state angles across, and appropriate **reclosure** of, an open circuit whose terminals are **synchronized**. The unintentional byproduct of **reclosing** two electrical **islands** through **synchronism-check relays**, whose frequencies and voltages happen to match for a sufficient period of time, may be followed by the immediate trip of the circuit as the **islands** continue to pull away from each other, and the circuit is too weak to hold them together. The Transmission Operator should recognize and address this potential inadvertent automatic **reclosing**. Furthermore, it

should also consider the potential for manual inadvertent **reclosure** of circuits between electrical **islands** and take any necessary actions to preclude or prepare for an inadvertent **reclosure**. If warranted, it should consider blocking the circuit breaker automatic **reclosure**.

5.0 Assessment of Conditions Prior to Interconnecting

When assistance is required from an external Reliability Coordinator or Transmission Operator area, communications between the requesting and assisting Reliability Coordinator and Transmission Operator areas must ensure that there is a sufficient level of understanding of:

1. Existing system conditions after stabilization, and;
2. Types of assistance that may be sought after synchronization.

The existing system conditions to be assessed include, but are not limited to, the following:

1. **Load;**
2. **Synchronized Generation;**
3. Prevailing Voltage and Frequency;
4. System Topology;
5. System Operating **Reserves;**
6. System Reactive **Reserves;** and
7. **First Contingency Loss.**

The types of assistance may include, but are not limited to, the following:

1. Start-up for **Generation;**
2. Frequency Control;
3. **Tie Line** Regulation; and
4. System **Reserves** and Restoration of **Loads.**

Assessment of these technical considerations will identify the conditions under which a **tie line** will be established and maintained, reducing the risk of a subsequent separation and the loss of **load** and / or **generation**.

These guidelines are offered to guide **system operators** on technical considerations prior to agreeing to mutually assist a neighbor in an **emergency** in order to maintain the reliability of their operating areas (or portion thereof) while enabling such assistance to occur. It is recognized that, in cases where interconnection agreements are in place together with jointly agreed to operating procedures governing mutual assistance in an **emergency**, their requirements should be met in conjunction with implementing the actions offered in this document.

It must be understood that any assistance agreed to between the operating areas is based on acceptable conditions identified and agreed to by the **system operators**.

Once the assessment of conditions prior to interconnecting is completed, and if **resources** are available, the **assisting** operating area should be prepared to assist to the maximum extent that is reliably possible.

5.1 Inadvertent Synchronization of Electrical Islands

Relaying and **reclosing** on **tie lines** should be assessed. While the operation of protection **relaying** may not be significantly impacted by the presence of an unusually sparse transmission system, **system operators** may want to disable any automatic **reclosing** on **tie lines**, especially if only one **tie line** is in service, or if only a few remote, low voltage **tie lines** are in service.

5.2 Tie Line Regulation

Prior to interconnecting, **system operators** within the operating areas on either side of the tie line must determine whether the areas are already interconnected to any other systems and, if so, what are the interconnection point(s). If **synchronization** is needed, it will be easier to make frequency adjustments in the smaller system.

System operators should also discuss the conditions under which interconnection points may be deliberately opened. Acceptable ranges of deviations in **tie line** flows caused by system restoration activities should be established using direction from Section 6.0, “Mutual Assistance Guidelines.” Restoration activities should strive to follow these guidelines as conditions permit on the system. At the same time, **system operators** must appreciate the levels of post-**contingency tie line** flows that could occur (and have to be temporarily sustained) and be ready to delay restoration activities to restore tie line security in response to a **contingency**.

5.3 Assessment of Reserves Prior to Synchronizing Electrical Islands

Prior to **synchronizing** electrical **islands** between operating areas, an assessment of the **reserves** should be made such that the **reserves** for the new electrical **island** can be determined and additional **reserves** be made available if required or an activation plan be adopted for **contingency** recovery.

Considerations to be assessed prior to **synchronizing** the electrical **islands** include, but are not limited to, the following:

1. What is the largest single **contingency** loss?
2. Are operating **reserves** adequate to cover the loss?
3. What is the amount of spinning **reserve**?
4. Is a **load shedding** plan being utilized for **reserve**?
5. If **reserves** are activated, will any transmission facilities be overloaded?
6. If either of the largest **contingency** losses in the two **islands** occurs after the

combined **island** is formed, will the interconnection circuit(s) be able to accommodate the resultant **power** flows within their **rating(s)**?

It is recommended to place additional interconnection circuits in service once the initial **synchronization** of the two electrical **islands** has been accomplished to guard against the contingent loss of the path and provide additional transfer capability between the two operating areas.

5.4 Frequency Control

The energy management systems of the NPCC Balancing Authorities utilize the following control mechanisms to perform interconnected regulation using **Automatic Generation Control (AGC)** applications:

1. **Flat Tie Line**

Only the **tie line** mismatch between **scheduled interchange** and **actual interchange** flow is used to determine **area control error (ACE)**.

2. **Flat Frequency**

Only frequency deviation is used to determine the **ACE**.

3. **Tie Line Bias**

Both frequency deviation and **tie line** mismatch are used to determine the **ACE**.

Following a major **system disturbance**, Balancing Authorities must determine the status of their respective **Automatic Generation Control (AGC)** systems, and, if still in service, whether its continuing functioning is desired.

When **synchronizing** electrical **islands** between, the smaller **island** can more readily adjust its frequency to match that of the larger **island**. Once synchronized, the Balancing Authorities should appropriately select flat frequency or **tie line bias** control to stabilize frequency depending on the status of their **tie lines**. If two or more Balancing Authority areas have remained connected, or have re-**synchronized** with each other, combinations of different control modes should be explored. If the above control modes are incorrectly applied, the resulting control actions could actually have a negative impact on the Balancing Authority areas.

For instance, if the larger of the Balancing Authority areas was in flat frequency control (as it should be), and the adjacent smaller Balancing Authority area was in flat **tie line** control, the smaller area would not provide its frequency response as it should for additional **contingencies**, because the **AGC** would be controlling to **tie line** deviations only. Its generators would initially provide some frequency

response, but the **AGC** control would back them down to maintain the **tie line** on schedule, thereby negating the frequency response contribution of the smaller areas. The use of flat frequency control by the largest Balancing Authority area, and **tie line bias** control by other smaller connected Balancing Authority areas should produce the best frequency regulation.

Each Balancing Authority should determine if economic dispatch continues to be accurate and / or effective, and if it is determined that it is no longer viable, the Balancing Authority should switch to manual dispatch of **generation**.

The Balancing Authority should determine if **tie line** regulation continues to be accurate and / or effective by determining the following:

1. The external Balancing Authority area to which it is connected
2. The relative sizes of the Balancing Authority area(s) to which it is connected

If it is determined that the Balancing Authority area remains tied to the massive **Eastern Interconnection**, the Balancing Authority may use normal **tie line** regulation (**tie line bias**). However, if only two Balancing Authority areas, or a few Balancing Authority areas, remain tied together, the concerned Balancing Authorities should:

1. Use flat frequency control in the largest Balancing Authority area
2. Use tie line bias control in the smaller Balancing Authority area(s)

5.5 Synchronization or Paralleling of Electrical Islands

It is desirable to **synchronize** electrical **islands** between operating areas to enhance the stability of both by gaining electrical inertia (generators and motor loads).

Considerations to be assessed prior to **synchronizing** the electrical **islands** include, but are not limited to:

1. Determining which circuit and circuit breaker to use to **synchronize** the electrical **islands**, then apply the guidelines of Section 7.1, “Synchronous Ties” in this Appendix; and
2. Estimating the total nominal generator synchronized capacity that will exist in the new combined electrical **island** after it is **synchronized** such that the size of single shot **load** restoration can be determined and agreed to by both operating areas as outlined in Section 5.6 below.

If a major **system disturbance** has completely separated two operating areas, the **reclosing** of their first **synchronous** interconnection will require **synchronization** of the two areas. If the two areas have already **synchronized** and established a **tie line**, before energizing any additional **tie lines**, the Reliability Coordinator

and/or the Transmission Operator should assess the electrical configurations on either side of the **tie line** under consideration and determine if its **reclosing** will simply parallel the existing **tie lines(s)**, or if **synchronization** is required. The principles in section 7.0, “Principles of Restoring Inter-area **Ties Lines**,” in this Appendix should be followed.

5.6 Provision of External Restoration Service

External restoration service may be provided to an adjacent blacked-out Reliability Coordinator or Transmission Operator area. When the assisting area has strong **tie lines** remaining with the Eastern **Interconnection**, load restoration should be limited to the tie capability to the area to be restored.

When the assisting area is itself an electrical island, it is necessary to limit the incremental amount of load to be restored to 5 % of the total **synchronized** nominal **capacity** of the generators in the electrical **island**. It is important to note that this constraint is based on the nominal **synchronized capacity** of the generator, representing the inertia of the machine, and not on the actual output of the generator. This is to preclude the resulting frequency and voltage transients from operating any underfrequency **load shedding relays**, generator underfrequency protection **relays** or line protection **relays**.

Caution should be exercised in marginal situations due to cold **load** pickup, which, when **energizing** feeder **loads**, can be two to five times their normal **load**.

Additional considerations to be assessed prior to providing assistance include, but are not limited to, the following:

1. Are there any large station service motor **loads** (As an example, boiler feed pumps **synchronous** motors can draw four to five times the rated running **load** on start up.)?
2. In **energizing** transmission lines to generating stations, will customer **loads** be restored, and, if so, what will be their expected MWs?
3. Will long transmission lines or high voltage cables be energized? If so, what is the expected charging current in MVAR?
4. State any restrictions on the MW or MVAR flow on the Reliability Coordinator’s or Transmission Operator’s **tie line(s)** that will be used to provide the assistance

5.7 Radially Energize and Restore a Portion of an Adjacent Area’s System

Situations can occur where it is desirable for an operating area to supply generating stations, substations and customer **load** in an adjacent operating area. In doing so, caution must be exercised in determining points of separation between the two systems.

Considerations to be assessed prior to providing the assistance include, but are not

limited to the following:

1. Determine the current **load** expected to be supplied.
2. Determine the expected peak **load**.
3. Determine the **generation** available.
4. Identify real or reactive restrictions (MW and / or MVAR) on the interconnected circuit(s) used to provide the assistance.
5. If sourced from an electrical island, then the considerations of Section 5.6 are applicable.
6. Determine the expected duration of this arrangement, if known, until the assisted area is in a position to return normal configuration.

6.0 Establishing Interconnection via Inter-Area Tie Lines

When two systems are to be interconnected, options may be available as to where the interconnection may take place. When these options exist, it is up to the Reliability Coordinator or the Transmission Operator to determine the best location and voltage level to govern the interconnection

6.1 Synchronous Tie Line

When synchronizing Reliability Coordinator or Transmission Operator areas, the following guidelines should be followed:

Synchronize at locations where:

1. **Synchronism-check relays** and / or manual synchroscopes are available;
2. Voltage control **resources** are at, or in close proximity to, the open points;
3. **Generation** sources are easily manipulated or controlled; and
4. Good multi-party communications are available between the personnel directing the **synchronization**, the personnel controlling the **synchronizing** breaker, and the personnel controlling the **generation** facilities on both sides of the open points.

For locations where manual **synchronizations** are performed, the voltage magnitude of the two systems to be paralleled should be matched as closely as possible. A rule of thumb would be to close the paralleling circuit breaker with not more than a 3% voltage difference between the two **islands**. After any warranted coarse adjustments are made within each **island**, the **island** with the dynamic voltage control device closest to the **synchronizing** location should perform final voltage adjustments. If possible, the smaller **island** should have the slightly higher voltage.

The frequency of the two systems must also be closely matched before **synchronization**. First, the difference in the frequencies of the two systems should be no greater than 20 degrees of relative phase angle rotation per second,

or one full synchroscope revolution in 18 seconds. The smaller or incoming island should adjust the frequency and be running at the slightly higher frequency. Finally, the synchroscope phasing should be done as close to the 12 o'clock position as possible, and certainly within $\pm 20^\circ$ (approximately ± 3 minutes) of vertical upon the closing of the breaker.

Where available, automatic, programmable **synchronism-check relays** can be used for **synchronizing islands** or **tie lines** if known to be effective. The Transmission Operator's operating personnel may still have to work to achieve adequate voltage and frequency matches on either side of these automatic **relays** to allow their operation. Consequently, the required operating conditions for these automatic **relays** should be known by the Transmission Operator's operating personnel.

6.2 Non-Synchronous Tie Lines

Non-synchronous **tie lines**, such as **HVdc tie lines** or variable frequency transformers, can present special concerns during system restoration.

The start-up of older model asynchronous **HVdc tie lines** must be left until the later stages of system restoration when a strong AC system is in place to support:

1. AC / **HVdc commutation**;
2. short circuit requirements; and
3. the switching of large MVAR devices.

Newer technology **HVdc tie lines** and variable frequency transformers may be reliably **energized** or started even with weak, partially restored AC power systems.

Each Transmission Operator should develop and maintain the criteria for the restoration of each of their **HVdc tie lines** and variable frequency transformers. These criteria will take into consideration the capabilities of the equipment to operate effectively in a weakened power system.

The Transmission Operator should consider situations where non-synchronous **tie lines** have remained in service following the event. The operating personnel should determine if these facilities can remain in-service without having a negative impact on the restoration procedures due to their ability to remain stable.

7.0 Considerations to Remain Stable Following Interconnection

Once interconnected, the increase in **tie line** flow(s) into an **island**, in response to a **generation contingency** within the **island**, is proportional to the relative amounts of generating **capacity** in each island. The resulting flow can be estimated as follows:

$\left\{ \left(\text{the MW size of the islanded generation contingency} \right) \times \left(\text{the MW size of the island} \right) \right\} \text{ divided by } \left\{ \text{the MW size of the combined synchronized system} \right\}$

The size is best based on the total **capacity** of **synchronized generation**, but this value is hard to determine, and therefore **load** can be used as an approximate substitute. This information, combined with the considerations addressed in Sections 6.1 through 6.3 in this Appendix, will help operating personnel establish secure flows on **tie lines**.

7.1 Frequency Considerations

In general, once operating areas are tied together and receiving or supplying assistance, operating personnel should continue restoration efforts in a manner that prevents excessive frequency or voltage deviations. The target for maximum transient frequency swings while receiving assistance is 59.5 to 60.5 Hz. Before performing switching that would introduce **load** or **generation resources**, operating personnel should check and, if needed, take action to ensure that steady state system frequency prior to switching is at a level that will avoid excessive frequency excursions immediately after switching.

7.2 Voltage Considerations

Operating personnel should also discuss desired voltage levels that would be sustainable during the event. The general voltage range for maximum voltage deviation while receiving assistance is 5% of nominal transmission voltages.

7.3 Thermal Considerations

Operating personnel should be aware of three key parameters noted below. The specific amounts for each facility need to be communicated between the Interconnecting operating areas. These amounts may be revised as system condition change.

7.3.1 Maximum Tie Line Interface Export Loading

It is the maximum **tie-line** or **interface** loadings possible based on equipment **ratings** and operation to provide **contingency** coverage.

Some operating area ties points consist of multiple circuits in parallel and are constrained by the thermal capability of the facilities making up the interface. It should be expected that the **tie line** interface loading of these interfaces will not exceed:

1. The normal continuous rating of any single facility making up the interface; or

2. The appropriate emergency rating of any facility, as a result of the worst contingency impacting the interface.

7.3.2 Maximum Tie Line Interface Loading Rate

It is the maximum loading rate of a **tie line** or **interface** as allowed by the assisting operating area.

The typical maximum **tie line interface** loading rates may range from 15 MW per minute to 50 MW per minute, depending on the **tie line** configuration.

7.3.3 Maximum Tie Line Interface Deviation for Step Changes in **Load** or **Generation**

This is the parameter that indicates the maximum step change allowed, from a mutually agreed to schedule flow, on a **tie line** or **interface**.

These deviations are typically the lesser of:

1. 5% of the synchronized capacity, or
2. The cumulative effect of the loading rates of **generation** within the operating area adjacent to the interconnection point.

The typical maximum **tie line** interface deviation for step changes in **load** or **generation** may range from 15 MW to 100 MW

8.0 Training and Exercises

To maintain the ability of the Reliability Coordinator, Transmission Operator and Balancing Authority operating personnel to respond effectively to a **power** system emergency, they are certified and trained within NPCC in accordance with all NERC requirements. In addition to operator training conducted within a given NPCC member operating entity, exercises serve as a means to demonstrate and sustain this ability. Exercises can also be referred to as drills or simulations. When such activities include operating personnel working together from more than one NPCC operating entity, or with jurisdictions external to the NPCC, inter-area coordination of the emergency response of the operating personnel is greatly enhanced.

Each Reliability Coordinator, Transmission Operating and Balancing Authority within NPCC conducts regular system restoration exercises for their operating personnel and support staff. These exercises focus primarily on procedures specific to the concerned operating area. The NPCC Dispatcher Training Working Group (Working Group CO-02) develops and conducts semiannual training seminars. Exercises conducted as part of the NPCC Working Group CO-02 training program involve operating personnel from multiple Reliability Coordinators, Transmission Operators and Balancing Authorities within NPCC and therefore can help to also evaluate the coordination of each operating

area's restoration plans.

Exercises may include:

1. Simulated emergency response activities;
2. Table top simulations;
3. Exercise participants participating from their normal work headquarters;
4. Minimal to zero coaching by exercise coordinators; and
5. Interventions into the conduct of the exercise by exercise coordinators, usually being limited to that necessary to run the exercise and interjecting complications and changed conditions to add credibility and challenge.

Exercises are typically conducted by dedicated exercise coordinators.

For purposes of evaluating the exercise against its objectives, a post exercise assessment, is usually conducted, with feedback gathered to support the creation of an evaluation report to disseminate lessons learned.

The specific requirements for any coordinated inter-area exercise will be determined by the NPCC Inter-Control Area Restoration Coordination Working Group (Working Group CO-11), with input from the NPCC Dispatcher Training Working Group and relevant operating personnel critiques. Coordinated inter-area exercises should be considered as an additional step when a Reliability Coordinator or transmission Operator is scheduling its own internal restoration exercise in order to foster and sustain inter-area coordination in performing system restoration.

In general, both the individual entity's and NPCC's exercises should include experiences and lessons learned from actual restoration events.

Attachment 1⁵

Maritimes Area Restoration Overview

Objective

This restoration summary is a brief overview of how the Maritimes **Area** restores the **power** system following a complete blackout of the Maritimes **Area**. It does not attempt to cover details of the individual system restoration plans or all the possible blackout scenarios.

Background

The Maritimes **Area** consists of three Canadian provinces: New Brunswick (NB), Nova Scotia (NS) and Prince Edward Island (PEI), as well as a radially connected portion of the state of Maine {Northern Maine Independent System Administrator (NMISA)}. The New Brunswick System Operator (NBSO) is the Reliability Coordinator for the Maritimes **Area**, and as such coordinates **synchronization** between the systems within the **Area**, and / or with adjacent **Areas**.

Each entity within the Maritimes **Area** operates its own electrical grid. NB is connected to NS via two 138 kV lines and one 345 kV line. NB is connected to PEI via two 138 kV cables. Northern Maine ISA is radially connected to NB via two 138 kV lines and three 69 kV lines. There is no direct connection from NS to PEI. In 2004, the total Maritime peak load was approximately 6,000 MW.

Basic Plan

The restoration plan assumes no assistance from adjacent **Areas**. Each entity within the Maritimes **Area** has **blackstart capability** and, therefore, individually establishes their **power** system according to their detailed switching plans. Each system uses the “open all breaker” method in the beginning of the restoration process. When the **power** systems are established and stable, the electrical islands will **synchronize** with each other. The Reliability Coordinator in NB will coordinate the **synchronization** between NB and NS, NB and PEI, NB and NMISA, as well as the load pick-up in any system from this point on until the systems are fully established. At any time throughout the restoration process, NB may **synchronize** with an adjacent **Area**.

⁵ Attachments 1 to 7 have been developed for some time by NPCC member Areas, MISO and PJM, and have not been revised for this Directory. Hence, the term Area(s) instead of the functional entities as described in the NERC Functional Model may still appear in some of the attachments. It is expected that changes to replace “Area” will occur over time when these attachments are revised in the future.

Attachment 2

New England Area Restoration Overview

Introduction

This procedure addresses restoration of the **bulk power system** (115 kV and above) after a partial or complete system blackout. Expeditious restoration of the **bulk power system** depends on independent actions and interactions by NEPOOL Participants, Local Control Centers and the ISO New England Inc. (ISO). Depending on the expanse of the blackout (local area or widespread) numerous Participant and Local Control Center restoration procedures, and this procedure, may need to be implemented simultaneously.

During system restoration, a high priority must be given to the restoration of off-site AC **power** sources to nuclear generators. Also, technical aspects of system restoration (i.e. unit startups, load pickups, switching surges, voltages, frequency, **synchronization** of islands, etc.) will be crucial. Recognizing these concerns, this procedure and all Local Control Center and Participant restoration procedures have been developed in a coordinated fashion.

Responsibilities

A. Local Control Centers

1. Determine the extent of the blackout within each Local Control Center and inform the ISO as soon as possible of existing generation and transmission capabilities. (The ISO will determine the extent of the blackout within New England and adjacent power systems and inform the Local Control Centers.)
2. Implement Local Control Center restoration procedures (including necessary coordination with the ISO and adjacent Local Control Centers).
3. Should communications with the ISO fail, 345 kV circuits and inter-Local Control Center and inter-**Area tie lines** may be **energized** if prudent to total system restoration, and if communications between the affected parties exist.

B. ISO New England

1. Determine the extent of the blackout throughout New England and adjacent power systems and inform all Local Control Centers of existing **generation** and transmission capabilities.
2. Implement the ISO restoration procedure (including necessary coordination with the Local Control Centers and adjacent power systems).
3. If the blackout is severe and unit dispatch must be temporarily returned to the Local Control Centers, be prepared to assist the Local Control Centers with the loading function if the Local Control Centers request such assistance.

4. Authorize the closing of inter-Local Control Center and inter-**Area** transmission lines.
5. Once inter-Local Control Center or inter-**Area tie lines** are **energized**, oversee and coordinate **load** pickups within the interconnected parties.
6. Select priority for start-up **power** supply to generating stations when the choice is to supply a station in one Local Control Center or a station in another Local Control Center from the same source.
7. Direct **load shedding**, if necessary, to enable continued reliable restoration of interconnected parties or the closing of inter-Local Control Center or inter-**Area tie lines**.
8. Monitor **bulk power system** transmission and generation facilities and, as practical, take action to promote system reliability.

System Restoration Guidelines

The following lists guidelines regarding the technical aspects of system restoration that are provided in New England restoration procedures:

- A. **Restoration of Off-Site AC Power to Nuclear Generators**
- B. **Opening Circuit Breakers and Switches**
- C. **Reviewing Load Tap Changer (LTC) Positions**
- D. **Generator Start Ups and MW Loading**
- E. **Spinning Reserves**
- F. **Load Pickups**
- G. **Transmission Line Charging**
- H. **Voltage Schedules at Generators**
- I. **Circuit Energizations**
- J. **Synchronization**
- K. **Inter-Local Control Center Ties**
- L. **Inter-Area Ties**

Recognizing the numerous scenarios of possible system blackouts (the expanse of the blackout and resources available for restoration), knowledge of these guidelines is important. They represent a general-purpose tool for system restoration. More specific guidelines for restoration of the 345 kV system in the event of a complete blackout are also provided in the New England restoration procedures. The specific actions in these guides reflect the general guidelines. Where appropriate, the Local Control Center and the ISO procedures have been coordinated.

Attachment 3

New York Area Restoration Overview

Introduction

This procedure establishes the guidelines to be used in the restoration of the New York state power system following a major disturbance. Since the exact extent or nature of the disturbance cannot be predicted, the procedure is presented as a general guide.

1. In the event of a complete system shutdown, the Transmission Providers are trained and expected to work from a planned sequence of steps to develop a 345 kV back bone system across the state.
2. If a partial shutdown occurs, or if a portion of the NYS Power System becomes isolated, the Transmission Owners shall execute only those steps required to restore the area in which the outage exists.

Prompt restoration of the NYISO total customer **load** is best accomplished by the restoration of the New York state power system. Although some customer **load** may be picked up during this procedure to maintain stability and voltage levels, priority must be assigned to the restoration of the major transmission **tie lines**. Each Transmission Owner may restore **load** within its area in accordance with its own restoration plan, but **load** restoration must not delay the restoration of inter-and intra-**Area tie lines**.

Throughout the restoration process, it is the objective of these procedures that the restored facilities be operated in accordance with the operating criteria of the NY State Reliability Council, the New York ISO, the Northeast Power Coordinating Council and the North American Electric Reliability Council.

Each Transmission Owner is responsible for performing the actions listed below in the substations and facilities within its jurisdiction. As these actions are carried out, the Transmission Owner shall inform the NYISO Shift Supervisor, who is responsible for overall coordination of the restoration procedure.

Attachment 4

Ontario Area Restoration Overview

Operational Authority Structure

In accordance with the Ontario Electricity Act of 1998, the Independent Electricity System Operator (IESO) is responsible for managing the reliability of the IESO controlled grid, operating a competitive marketplace for electricity and mitigating the impacts of electricity **emergencies** on public health and safety.

To accomplish the above, the IESO directs the operation of the IESO controlled grid in accordance with operating agreements with the Ontario Transmission Operators. These agreements identify what transmission system **elements** are included in the IESO controlled grid and the terms and conditions by which the IESO directs their operation. The IESO has no direct physical control of the devices that comprise the transmission system.

The IESO administers Ontario's market rules by which market participants are bound by their participation agreements to fulfill specified obligations necessary for reliability.

To operate the interconnections to fulfill its obligations to the Electricity Act, NERC and the Northeast Power Coordinating Council, the IESO has interconnection agreements and associated joint operating procedures with adjacent Reliability Coordinators and Transmission Operators.

To operate the marketplace, the IESO runs an automated dispatch every five minutes. The dispatch algorithm achieves the most **economic dispatch** in accordance with submitted bids and offers and scheduled transactions given the prevailing electrical security constraints. The dispatch algorithm simultaneously solves for **operating reserve**.

The IESO can manually dispatch generators by direct voice communication to generator operators when circumstances dictate this be done to manage reliability.

As defined in the NERC functional model, the IESO is a Reliability Coordinator, Transmission Operator, Balancing Authority, Interchange Authority, Transmission Service Provider, Market Operator and Compliance Monitor.

Overview of System Restoration Plan for Ontario

The Ontario Power System Restoration Plan (OPSRP) is structured to address what is needed to enable successful system restoration in four related subject areas:

1. Operational;
2. Testing;
3. Training; and
4. Administration.

The primary objective of the Ontario Power System Restoration Plan (OPSRP) is to restore the

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IESO controlled grid to a secure operating state, to the maximum extent possible, based on the equipment that returns to service after a partial or complete blackout.

The OPSRP priorities are to restore critical station service to the nuclear plants, other generating and transmission facilities, operational control centers and telecommunication installations. This is given top priority to minimize reliance on stored energy systems (batteries, compressed air systems, etc.). **Islands** containing nuclear and fossil generators are **synchronized** at the earliest opportunity in an effort to increase the chances of their survival by expediting their return to service.

Since the post-**contingency** system configuration is not predictable, the plan was designed to be sufficiently flexible to be applicable to the wide range of possible configurations. The OPSRP does not require a step by step restoration of predefined paths; rather, its successful implementation is predicated on strategies, procedures, identified limitations and rules of thumb to overcome them (based on worst case scenarios) that give the **system operators** guidance for each stage of the restoration. The OPSRP focuses on controlling voltage and frequency deviations to magnitudes that are non-impactive and on reducing the exposure to additional disturbances.

Subsequent to the post disturbance assessment and actions to stabilize any surviving electrical **islands**, the four stages of system restoration are:

1. Recovery of generation;
2. **Energizing** transmission lines;
3. Load restoration (initially to lower voltage), and
4. **Synchronizing** electrical **islands**.

By off line study, modeling and engineering analysis, rules of thumb have been developed to guide **system operators** in overcoming the constraints that are encountered during each of the above four stages of system restoration.

The OPSRP also specifies mandatory independent actions by Restoration Participants to carry out the following:

1. Maintain the availability of generators post disturbance;
2. Shed load on underfrequency;
3. Open circuit breakers that are off potential in preparation for system restoration;
4. Restore station service at step-down transformer stations; and
5. Synchronize bypass their units at speed no load (SNL) to sustain their in plant station service, including the switching of any units from condense mode to generate mode.

Should any adjacent interconnected system be stable and secure, or an electrical **island** within Ontario survive, the IESO controlled grid would be restored using this source of potential. Should Ontario lack a source of restart potential from the aforementioned sources, the OPSRP relies on designated blackstart sites. Certified blackstart service providers must perform an annual test, including the energization of one of the transmission circuits out of the generating station. Their performance is strictly monitored by the IESO for adherence to their ancillary service contract. In addition, it is estimated that, as a minimum, one fossil / nuclear unit at each

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station is expected to survive, and all available generating sources are expected to aid in the restoration process.

The large size of the IESO-controlled grid led to dividing the system into smaller areas for the purpose of restoration after a complete system shutdown. Depending upon the post-**contingency** configurations and **resources**, the plan can be implemented in whole or in part. The IESO can manage the simultaneous creation of, and restoration of, a number of electrical **islands**. Once formed, these **islands** are **synchronized** together, or are **synchronized** with adjacent areas, in a controlled fashion.

To guide operations staff, the OPSRP contains high level system restoration path diagrams for eight potential paths, and four restoration strategy diagrams for Ontario as a whole in accordance with four large electrical islands. Additionally the IESO has introduced two way communications guidelines to enhance the effectiveness of operational communications with the operations staff of nuclear and fossil generating stations.

Administration to Sustain Emergency Response Capabilities

The IESO has implemented all identified opportunities for improvement identified in the various blackout investigations following the power system collapse of August, 2003.

In consideration of the 1998 ice storm and the advent of Ontario's competitive marketplace in 2002, the associated market rules were strengthened in the area of **emergency** preparedness. As a consequence, Ontario requires all market participants to file an Emergency Preparedness Plan, and those participants that operate facilities impactive to the restoration process must file and certify a restoration plan attachment. There are currently ninety-six Restoration Participants in Ontario as of April 2005. To maintain Ontario's collective level of emergency preparedness, the IESO annually conducts large scale exercises supported by localized tabletop drill and training sessions with many of the Restoration Participants.

All OPSRP revisions are achieved with input from all Restoration Participants in Ontario, and the OPSRP fully conforms to NERC and NPCC requirements.

The OPSRP also covers the training requirements for operations staff, testing requirements of facilities, restoration tests (blackstarts) and simulations conducted through tabletop exercises and large scale exercises. All are critical elements to the success of any system restoration plan.

Attachment 5

Québec Area Restoration Overview

1.0 Introduction

Every utility takes, in designing and operating its system, all the necessary precautions to limit **contingencies** leading to a blackout of the system. However, the possibility of such a shutdown still exists, and the utilities must have a plan to restore their system and resume normal operation.

Note: The information contained in this document derives from the system restoration plan of Hydro-Québec TransÉnergie which consists primarily of hydroelectric generation. Therefore some of the information might not be applicable to a different system, and some features particular to fully thermal systems might not have been covered in this text.

2.0 Objective

To allow restoration of the system, safely, in the shortest possible time.

3.0 Methodology

The design of the restoration plan contains the following elements:

1. Basic plan;
2. Regular follow-up;
3. Personnel and material required; and
4. Testing of **critical components** associated with **key facilities**.

3.1 Basic Plan

The primary priority of the basic restoration plan is the restoration of AC station service to the nuclear plant.

If a blackout occurs, the configuration of the system has to be examined to identify possible restoration paths allowing the partition of the main system into **basic minimum power systems** (BMPS). A BMPS consists of one or more generating stations, transmission lines and substations. These BMPSs are stand alone and can be restored independently. To restore the total system, the **system operator** in charge of the restoration process will select one BMPS as the main system upon which all the other BMPSs are to be **synchronized**. While waiting for that **synchronization**, as much **load** as its **generation** capacity permits continues to be independently restored in each BMPS.

A special case is recognized if a subsystem stays synchronous or can be rapidly **synchronized** with a neighboring utility, its final integration to the main system

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will be carried out according to the rules governing exchanges between the two systems, in accordance with the relevant operating agreement.

The selection of the restoration paths is based on practical criteria. The plan is also subject to technical criteria and a number of precautions required for a smooth restoration process. Taking into account these three factors will ensure an optimal restoration procedure having the minimum risk and the shortest duration.

3.2 Follow-up

The following activities are required to ensure the continuous validity of the plan.

3.2.1 Daily Follow-up of the System Configuration

Once the restoration plan is set up, it must be constantly updated to keep track of equipment outages. Some equipment is designated as necessary for the restoration process (i.e., they are within, or directly affect, the restoration path), and a listing is produced and continually updated. If any such equipment is unavailable, an analysis is performed to identify alternate paths or equipment. Some of these substitutes may already be part of the **key facilities** list, but it is important to analyze each occurrence of simultaneous outages and validate the alternative options accordingly.

Also, an assessment of the yearly maintenance schedule avoids situations that could affect the restoration process.

3.2.2 System Expansion Plan

The impacts of additions and modifications must be assessed and their impact on the restoration procedure thoroughly evaluated.

3.2.3 Presentation of the Plan

The total blackout of a system being an infrequent and sudden event, it is important to keep the operations staff up to date regarding the plan. A formal presentation is scheduled at least once a year with all the operations personnel concerned.

3.3 Personnel and Material

To ensure fast and efficient application of the plan, proper logistics is required.

3.3.1 Personnel

One **system operator** is selected to be in charge of the restoration process, and his role is clearly defined, along with the role of all other people

involved in the process.

Backup Team

Each control center, system control center and remote control center must have a multidisciplinary backup team able to solve any problem that might occur during the process. This team includes experts in the following fields: operating procedures, **power** system analysis, electrical apparatus, automatic controls and remote systems, **protective relaying**, telecommunications and computer controlled systems.

A list of the backup team, with the phone numbers, is prepared and continuously updated. It is available at all control centers.

3.3.2 Material

Emergency Procedures

The plan must be broken down into a set of **emergency** procedures for each **key facility**. These procedures state in a short and precise way the operations that are to be performed to isolate the station (preliminary operations) and then to initiate the restoration process. They do not include technical or administrative information. Their application is compulsory.

Following a blackout, the procedures are to be applied step by step. Any abnormal event preventing the application of one procedure must be reported to the **system operator** in charge. No modification is allowed without his permission, since all these procedures are part of a coordinated plan and depend on operations performed before and after that particular operation.

To facilitate the restoration process, system control and remote system control sets of **emergency** procedures summarize the main steps to follow.

Blackstart Procedures:

These procedures state in a short and precise way the operations to be performed, to start generating units designated as having **blackstart capability** and used to initiate the BMPS restoration process.

Restoration Process Diagram:

A diagram of the restoration plan, showing all the BMPSs, will assist the on-shift **system operator** to implement the plan in a step-by-step manner in case of computer deficiencies.

Key facilities and Critical Components Lists:

These lists are continuously kept up to date.

Audio Communication System:

An instantaneous and efficient means for the **system operator** in charge to communicate with each station.

Automated Functions:

The control centers using computer operating systems use the following functions:

1. Blackout Function

To avoid computer overload due to the avalanche of alarms and status changes following the system shutdown, this function should be active only for a very short time and be very selective to allow posting of all the major alarms.

2. Reset Function

This function allows the operation, through the remote control center, of any critical circuit breaker in order to speed up the restoration process.

3. Load Restoration Function

This function permits the automatic recording of the progress of the **load** restoration, station by station, for each subsystem.

4.0 Testing of Critical Components Associated With Key Facilities

Testing of **critical components** associated with **key facilities** shall be performed at a frequency and for a duration that is sufficient to reasonably ensure that the **critical components** will function properly when isolated from all **power** sources not available during a partial or complete system blackout. As a minimum, this frequency and duration of testing is stated in NPCC Document A-03, "Emergency Operation Criteria."

5.0 Control of the Restoration Process

5.1 Control Centers

As soon as the shutdown of the system is acknowledged, all remote control center **system operators** and neighboring **system operators** are notified. Application of

the **emergency** procedures is initiated at once. The corporate **emergency** response hierarchy is immediately informed of the situation and the following actions are initiated:

1. Backup teams are called in;
2. Other **system operators** are called in;
3. An operator is dispatched to every unattended key facility;
4. An inventory of all unavailable equipment (already out before the blackout and equipment which failed during the event) is set and transmitted to the **system operator** in charge and to his backup team;
5. Information or questions unrelated to the restoration process are not forwarded to the control centers. Only authorized personnel involved in the restoration process are allowed in the control rooms;
6. The **system operator** follows carefully the restoration of the BMPS and checks that all is done according to the plan. Any reported discrepancy is addressed and transmitted to the backup team for analysis. The team then formulates alternate solutions;
7. Voltage and frequency profiles are the preferred monitoring indicators to speed up or to slow down the **load** restoration;
8. **Synchronization** of the different BMPSs is coordinated by the **system operator**. **Load** restoration is stopped during **synchronization** of the BMPS;
9. **Synchronization** of the different subsystems is coordinated by the **system operator**;
10. The next step is to continue **load** restoration until all the **load** is back on the system;
11. The last step is to resume normal operation and **reenergize** the **tie lines** with neighboring utilities.

5.2 Individual Facility

After the blackout has occurred, determine:

1. Tripped equipment;
2. **Energized** or in service equipment;
3. Breakers which have remained closed;
4. Unavailable equipment;
5. Proceed with **emergency** procedures; and
6. Contact the remote control **system operator** in charge to report any problem.

6.0 Debriefing

As soon as possible after the event a meeting is held to identify any problem, malfunction or difficulty observed during the restoration process.

A final report is prepared to disclose any difficulty encountered and propose corrective actions.

Attachment 6

External Power Systems-Midwest ISO Restoration Overview

Operational Authority Structure

The Midwest ISO (MISO) reliability footprint is divided into three regions (Central, East and West). The Central and East regions are handled in the Carmel, Indiana, office, with the West region controlled from the St. Paul, Minnesota, office. Both offices have the same Reliability Coordinator (RC) authority.

The East Region deals with MECS (Michigan Electric Coordinated System), which in turn directs the ITC (International Transmission Company) on operational matters. The MECS is the Balancing Authority, and the ITC is the Transmission Owner.

The West Region deals with Minnesota Power and Manitoba Hydro, both of which are Balancing Authorities and Transmission Owners.

The MISO dispatches all **generation** for its member companies, and it has functional control of their operations, meaning that the MISO has the authority to direct actions to be taken by the Balancing Authorities and / or Transmission Owners. The MISO does not have the capability to physically control equipment on the system (this is done by the Transmission Owner). The MISO approves transmission access request, and the MISO scheduling coordinates schedules on a footprint wide basis.

Emergency Preparedness

The MISO reliability coordinators and real-time operational staff handle system **emergencies** according to NERC guidelines and internal MISO procedures. Information for dissemination to public entities comes from the MISO real-time management; this is then provide to the MISO public relations department which issues the information for public consumption.

System Restoration Summary

The MISO has detailed coordinated restoration plans. These are reviewed yearly with participation from the MISO member companies. MISO uses a sub-regional structure and philosophy to coordinate and plan for restoration. There are nine identified sub-regions in the MISO footprint that are geographical and electrical in nature. This allows for response to be flexible depending on where the restoration needs exist. The MISO system restoration plan contains all pertinent infrastructure information involved in restoration, including blackstart unit locations, synchroscope locations, critical paths, critical **loads**, etc. Given that the location or magnitude of a system separation cannot be predicted, the MISO plan and structure give it the ability to respond to any given restoration situation. The MISO also has developed an interconnection checklist to ensure **island** stability and enhance successful **synchronizing** when tying **islands** together. The MISO also has data collection forms that are utilized during

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restoration to allow for quick assessment and dissemination of information during actual restoration events.

Plans are practiced yearly through exercises to assess the response plan, Reliability Coordinator action, Balancing Authority operator action and Transmission Operator reaction to a system separation event. Past exercises have focused on operator understanding of the restoration plan, concepts of restoration, testing all aspects of communication protocols among operating entities (e.g. Reliability Coordinator to Reliability Coordinator, Reliability Coordinator to Transmission Operator and Balancing Authority, Transmission Operator to Transmission Operator, etc.), island operation, and interconnections.

Attachment 7

External Power Systems-PJM Restoration Overview

In the PJM RTO, during the initial stages of a restoration, each Load Serving Entity is responsible for restoring its own customer **load** with internal **generation** or through coordinated efforts with other Transmission / Generation Owner. After a subsystem is stabilized, requests from neighboring entities for cranking **power** are a higher priority than restoring additional customer **load** of the supplying **Load Serving Entity** / Transmission Owner. Any **Load Serving Entity** / Transmission Owner that is not operating in parallel with adjacent **Load Serving Entities** / Transmission Owners is free to restore or shed **load** in any manner or at any rate it may deem reasonable.

Local Control Centers that share common transmission or **generation** facilities (345 kV or below) must develop pre-arranged plans for the priority operation of these facilities during restoration. These plans include the maintenance of good communications during the period of the **emergency**.

The PJM dispatcher immediately establishes communications with the Transmission Owners and adjacent operating areas experiencing the disturbance to establish the extent and severity of the separation. If direct communication channels are not functioning, communications are established via whatever means are available (i.e., routing calls through alternate channels, outside phone lines, radio communications, and / or PJM Satellite Phone System).

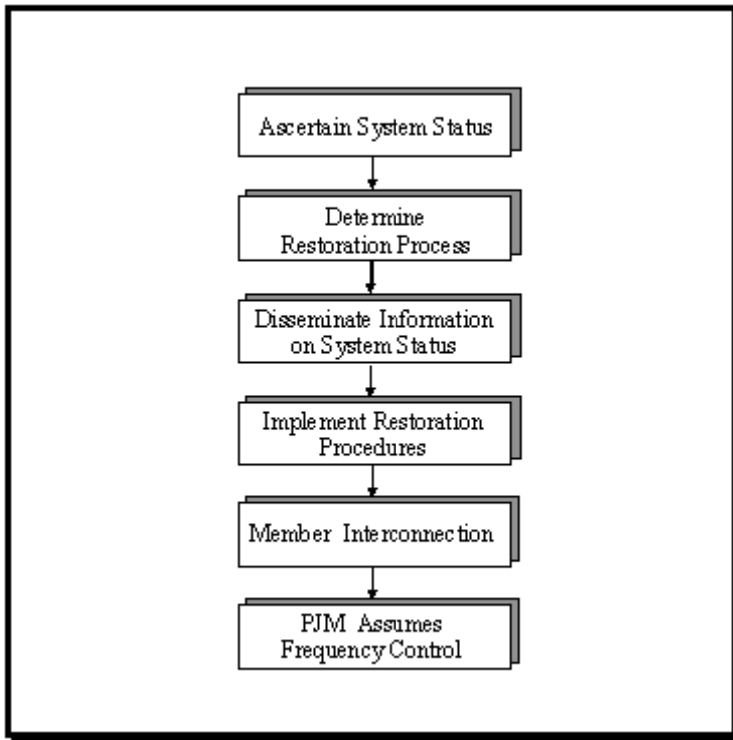
PJM Operator Responsibilities During the Restoration Process

The PJM System Operator has certain responsibilities regardless of the stage of the system restoration process. Transmission Owners will have primary responsibility of restoring their transmission system until such time as PJM is returning to normal operation and resumes authority over the transmission system. PJM actions during a system restoration include:

1. PJM will coordinate all interchange schedules with external operating areas.
2. PJM will coordinate and direct all restoration of the 500 kV transmission system.
3. PJM will develop and calculate **area control error** (ACE) as required when appropriate data is available to perform this calculation.
4. PJM will coordinate and direct all transmission tie connections to external operating areas.
5. PJM will identify opportunities for interconnection between PJM internal Transmission Owners and / or neighboring operating areas.
6. PJM will collect system status information and provide status updates to members on system restoration status.
7. PJM will conduct periodic System Operations Subcommittee (SOS) conference calls, as appropriate.

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The following table presents the general steps that are performed to restore the PJM RTO following separation:



Ascertain System Status

After a system disturbance occurs that results in a significant loss of customer **load** in a widespread area, it is important to determine transmission and **generation** loss, equipment damage, and the extent of the service interruption.

Determine Restoration Process

The purpose of this step is to develop and implement a restoration strategy. This step is performed after the status of the PJM RTO is determined.

Disseminate Information

The purpose of this step is to provide updated information of the system status to appropriate personnel. After system restoration plans are established and implemented, all participants must be apprised of system conditions.

Implement Restoration Procedure

The purpose of this step is to direct the restart of Generation Owners internal **generation** and **load** on-line **generation** in planned steps while maintaining system **load**, scheduled frequency, voltage control and **reserves**. This step is performed when a Transmission

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Owner / Generation Owner is in a completely isolated or blacked-out condition and must restart their system without outside assistance.

Member Interconnection

The purpose of this step is to provide guidelines for the Transmission Owners to interconnect and control frequency, **tie line**, voltage schedules, share **reserves** and coordinate **emergency** procedures. This step is performed after the Transmission Owners have restarted and desire to interconnect and share reserves or Transmission Owners have coordinated plans to restart while interconnected.

PJM Assumes Frequency Control

This occurs when the control of an interconnected area is too burdensome for any one Local Control Center



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NPCC
Regional Reliability Reference Directory # 9
Verification of Generator
Gross and Net Real Power Capability

Task Force on Coordination of Operations Revision Review Record:
December 22, 2008

Adopted by the Members of the Northeast Power Coordinating Council, Inc. this December 22, 2008 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	12/22/2008		New
1	07/07/2009	Included FAC-008 in Section 3.0	Errata

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1.0 Introduction

1.1 Title Verification of Generator Gross and Net Real Power Capability

1.2 Directory Number 9

1.3 Objective

This Directory presents the minimum criteria for verifying the **Gross Real Power Capability** and **Net Real Power Capability** of generators or generating facilities.

Compliance to the criteria set forth in this Directory by each applicable entity assures accuracy of information used in the steady-state models to assess the reliability of the NPCC bulk power system. This Directory has been developed to ensure that the requirements specified in NERC Standard MOD-024-1, “Verification of Generator Gross and Net Real Power Capability” are met by NPCC and its applicable members responsible for meeting the NERC Reliability Standards.

1.4 **Effective Date** **December 22, 2008**

1.5 Background

This Directory was developed from the draft NPCC A-13 Verification of Generator Gross and Net Real Power Capability Criteria document whose technical content was approved by the Reliability Coordinator Committee on March 5, 2008 for conversion into a Directory.

1.6 Applicability

1.6.1 Functional Entities

Generator Owners

Transmission Operators (in whose area the generator or generation facility resides)

2.0 Terms Defined in this Directory

The definitions of terms appearing in bold typeface in this Directory can be found in Appendix A.

3.0 NERC ERO Reliability Standard Requirements

The NERC ERO Reliability Standards containing requirements that are associated with

this Directory include:

- 3.1 [MOD-024-1](#) -Verification of Generator Gross and Net Real Power Capability
 - 3.2 [TOP-002-2](#) - Normal Operations Planning
 - 3.3 [FAC-008-1](#) - Facility Ratings Methodology
 - 3.4 [FAC-009-1](#) - Establish and Communicate Facility Ratings
- 4.0 NPCC Regional Reliability Standard Requirements

None.

5.0 NPCC Specific Criteria

5.1 Developing the List of Generators or Generation Facilities to be Verified

The Transmission Operator shall identify and maintain documentation of those generators and generation facilities subject to periodic seasonal **Gross Real Power Capability** and **Net Real Power Capability** verification. The documentation maintained by the Transmission Operator shall at least include the following:

- 5.1.1 Listing of all generators or generation facilities and their **Declared Gross Real Power Capability** and **Net Real Power Capability**.
- 5.1.2 Listing of all generators' or generation facilities' **Verified Gross Real Power Capability** and **Net Real Power Capability**, verification date and method of verification.
- 5.1.3 Listing for each generator's or generation facility's discrepancies between a Generator Owner's declared and verified **Gross Real Power Capability** and **Net Real Power Capability** (Sections 5.2.2 and 5.6.1.3), the reason for such discrepancies and a Generator Owner's plan to address the discrepancies.
- 5.1.4 Copies of Generator Owner supplied **Gross Real Power Capability** and **Net Real Power Capability** testing, manufacturer data, performance tracking or operating historical data, certification documentation, as specified by the Transmission Operator.
- 5.1.5 Listing of generators exempted from the verification requirements and the basis for their exemption (see Section 5.5).

5.2 Establishing the Generator Real Power Capability Verification Program

- 5.2.1 The Transmission Operator shall establish and maintain a program to periodically verify the **Gross Real Power Capability** and **Net Real Power Capability** of all generators and generation facilities that are subject to periodic seasonal **Gross Real Power Capability** and **Net Real Power Capability** verification.
- 5.2.2 The Transmission Operator shall establish requirements for a Generator Owner to notify the Transmission Operator within a specified time period when its generator or generation facility cannot achieve the **Declared Gross** or **Net Real Power Capability** because of equipment issues. The Transmission Operator shall specify a time frame for the Generator Owner to address this discrepancy.
- 5.2.3 The Transmission Operator shall report annually to NPCC about the status of its program including any changes in verification process related to verification of **Gross Real Power Capability** and **Net Real Power Capability**, and provide copies of any changes to its verification process to the Generator Owners and NPCC within 30 days of issue.

5.3 Implementing the Generator Real Power Capability Verification Program

The Transmission Operator shall request the Generator Owners to verify the seasonal **Gross Real Power Capability** and **Net Real Power Capability** of their generators or generation facilities that are subject to periodic seasonal **Gross Real Power Capability** and **Net Real Power Capability** verification in accordance with the verification schedule specified in Section 5.3.1. The two (2) capability seasons are defined as summer and winter as specified by the Transmission Operator.

- 5.3.1 Generator and generation facility **Gross Real Power Capability** and **Net real Power Capability** shall be re-verified every three (3) years or as required by the Transmission Operator.

- 5.3.1.1 If a Transmission Operator determines that only one seasonal generating capability value will suffice for NPCC Bulk Power System reliability analysis, then periodic verification will be required only for that particular season.
 - 5.3.1.2 If a Transmission Operator determines that the difference between **Gross Real Power** and **Net Real Power Capability** of a generator or generation facility is insignificant for NPCC Bulk Power System reliability analysis, then periodic verification will be required for only one numerical value.

5.4 Verification Criteria for Generator and Generation Facility Real Power Capability

The Generator Owners shall comply with the Transmission Operator's requests for periodic verification of **Gross Real Power Capability** and **Net Real Power Capability** of their generators or generation facilities. The Generator Owners shall apply the following criteria to verify the **Gross Real Power Capability** and **Net Real Power Capability** of their generators or generation facilities according to their types, as specified by the Transmission Operator.

5.4.1 Thermal Generators

The verification of **Gross Real Power Capability** and **Net Real Power Capability** of a generator shall be determined on the basis of operation for no less than one hour.

The verification of a thermal generator's capability can include testing, use of operating historical data, commissioning data (for new generators only) and performance tracking data acquired during the same seasonal capability testing period.

5.4.2 Internal Combustion Generators and Gas Turbine Generators

The verification of **Gross Real Power Capability** and **Net Real Power Capability** for internal combustion generators and gas turbine generators shall correspond to the ambient conditions normally expected for the seasonal period for which the **Gross Real Power Capability** and **Net Real Power Capabilities** are being claimed for no less than one hour.

The verification of internal combustion and gas turbine generator's capability can include testing, use of operating historical data, commissioning data (for new generators only) and performance tracking data acquired during the same seasonal capability period.

5.4.3 Hydro Generators

5.4.3.1 Hydro capability shall be determined on a generation facility or an individual generator basis.

5.4.3.2 The **Gross Real Power Capability** and **Net Real Power Capability** shall be determined on the basis of the availability of sufficient water at an adequate head to provide the output for no less than one hour.

5.4.3.3 The verification of a Hydro generator's capability can include testing, use of operating historical data, commissioning data (for new generators only) and performance tracking data acquired during the same seasonal capability period.

5.4.4 Combined Cycle Generators

- 5.4.4.1 Combined cycle generator capability shall be determined on a generation facility, individual generator or on a generator stage basis.
- 5.4.4.2 The verification of **Gross Real Power Capability** and **Net Real Power Capability** for combined cycle generators shall correspond to the ambient conditions normally expected for the seasonal period for which the Gross Real Power Capability and Net Real Power Capabilities are being claimed for no less than one hour.
- 5.4.4.3 The verification of a combined cycle generator's capability can include testing, use of operating historical data, commissioning data (for new generators only) and performance tracking data acquired during the same seasonal capability period.

5.4.5 Intermittent Power Sources

For intermittent power resources (wind, solar, tidal or geo-thermal generators) the manufacturer's data, performance tracking and operating historical data shall be used to determine generator or generation facility **Gross Real Power Capability** and **Net Real Power Capability**.

5.4.6 Multiple Generator facilities Forming a Generation Facility

The verification of **Gross Real Power Capability** and **Net Real Power Capability** for multiple generator facilities when limited by common elements shall be based on the real power capability of the facility and not the sum of the capabilities of the individual generators.

5.4.7 Consideration of Other Limitations

The Generator Owner shall identify any equipment or other factor that will limit the capability of the generator or generation facility to meet its **Declared Gross Real Power Capability** and **Net Real Power Capability**.

5.5 Exemption of Generators or Generation Facilities from Verification Testing

- 5.5.1 The Generator Owner shall notify the Transmission Operator and request for exemption if it cannot conduct seasonal capability testing on a generator or generation facility for any of the reasons listed below. For

existing generators, the Generator Owner shall submit generator operation records, manufacturer data, or performance tracking for the same previous seasonal verification period for this generator or generation facility. For new generators only, the Generator Owner shall submit commissioning data.

1. Adverse impact on transmission system reliability
2. Potential damage to transmission system or generator equipment
3. Environment conditions
4. Governmental regulatory or operating license limitations

5.5.2 The Transmission Operator shall, within 30 days of receiving notification by a Generator Owner that it cannot perform verification testing for the required seasonal period, notify the Generator Owner that its generator will be exempted from the seasonal capability testing.

5.6 Documenting and Reporting Verified Generator and Generation Facility Gross and Net Real Power Capabilities

5.6.1 Each Generator Owner shall, as specified by the Transmission Operator:

5.6.1.1 Provide generator or generation facility **Declared Gross Real Power Capability** and **Net Real Power Capability** to the Transmission Operator.

5.6.1.2 Provide evidence, upon request, to the Transmission Operator that generator or generation facility **Gross Real Power Capability** and **Net Real Power Capability** have been verified.

5.6.1.3 Report to the Transmission Operator any discrepancies between **Declared** and **Verified Gross Real Power Capability** or **Net Real Power Capability** within a time frame specified by the Transmission Operator as required in Section 5.2.2, and develop and implement a plan to resolve the discrepancies.

5.6.1.4 Determine and report the generator or generation facility real power seasonal auxiliary **loads** (including common station **loads**) to the Transmission Operator.

5.6.2 The Transmission Operator shall:

- 5.6.2.1 Document any discrepancies between system modeling and generator verified capabilities, the reason for such discrepancies and resolve the discrepancy with the Generator Owner.
- 5.6.2.2 Specify a time frame for the Generator Owner to address the discrepancy between the **Declared** and **Verified Gross Real Power Capability** or **Net Real Power Capability** of its generators or generation facilities.
- 5.6.2.3 Report to NPCC annually any discrepancies between **Declared** and **Verified Gross Real Power Capability** or **Net Real Power Capability**.

6.0 Measures and Assessments

None developed at this time.

7.0 Program Validation and Compliance Monitoring

The NPCC Task Force on Coordination of Operation shall annually validate that each Transmission Operator has implemented the **Gross Real Power Capability** and **Net Real Power Capability** verification program.

The NPCC Compliance Committee shall conduct periodic compliance audits to review the effectiveness of the Transmission Operator's **Gross Real Power Capability** and **Net Real Power Capability** verification program and ensure compliance to the criteria in this Directory by the responsible entities.

Adherence to these criteria shall be reported by each responsible entity in a manner and form designated by the Compliance Committee.

Prepared by: Task Force on Coordination of Operation / Task Force on Coordination of Planning

Review and Approval: Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and

comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval.

Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast.

Revisions pertaining to the Appendices or any other portion of the document such as links, glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document.

This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

References: NPCC Glossary of Terms (Document A-7)

Appendix A

Definition of Terms¹

Declared Capability (of a generator or generating facility) – The facility ratings submitted by the Generator Owner to the respective Transmission Operator as per NERC Standard FAC-009.

Gross Real Power Capability (of a generator or generating facility) – The maximum megawatt output at the generator terminals, at the normally expected system conditions for that seasonal capability period.

Load — The electric **power** used by devices connected to an electrical generating system. (IEEE Power Engineering). Also see **Demand**.

Interruptible Load — Loads that are interruptible under the terms specified in a contract.

NPCC Specific Definitions:

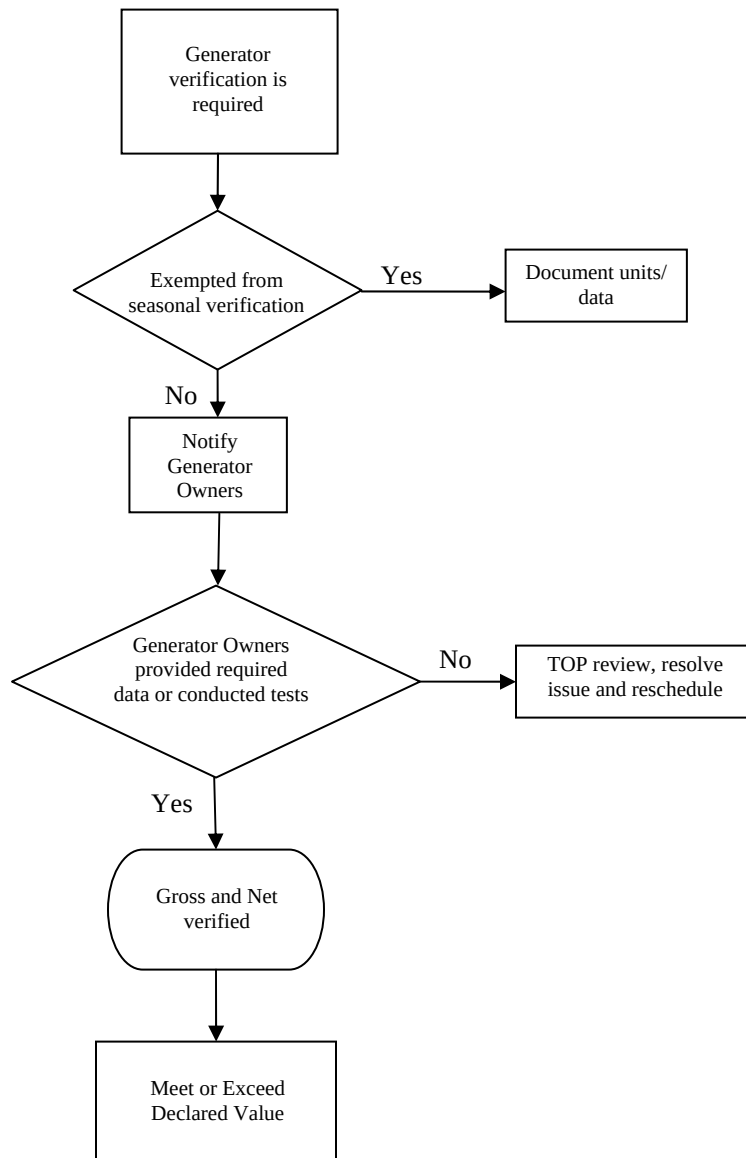
Net Real Power Capability (of a generator or generating facility) – The Gross Real Power Capability, less the auxiliary real power loads necessary to operate the generator at maximum real power output.

Verified Capability (of a generator or generating facility) – The capability as demonstrated by the methods specified in this Directory and accepted by the Transmission Operator.

Appendix B

Basic Flow Chart for Verification of Generator Gross and Net Real Power Capability

¹ These terms will be moved and grouped under a separate Directory when all other Directories are developed.





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NPCC

Regional Reliability Reference Directory # 10 Verification of Generator Gross and Net Reactive Power Capability

Task Force on Coordination of Operations Revision Review Record:
December 22, 2008

Adopted by the Members of the Northeast Power Coordinating Council, Inc. this December 22, 2008, based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	12/22/08		New
1	07/07/09	Included FAC-008 in Section 3.0	Errata

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1.0 Introduction

1.1 Title Verification of Generator Gross and Net Reactive Power Capability

1.2 Directory Number 10

1.3 Objective

This Directory presents the minimum criteria for verifying the **Gross Reactive Power Capability** and **Net Reactive Power Capability** of generators or generating facilities.

Compliance to the criteria set forth in this Directory by each applicable entity assures accuracy of information used in the steady-state models to assess the reliability of the NPCC bulk power system. This directory has been developed to ensure that the requirements specified in NERC Standard MOD-025-1, “Verification of Generator Gross and Net Reactive Power Capability” are met by NPCC and its applicable members responsible for meeting the NERC standards.

1.4 Effective Date **December 22, 2008**

1.5 Background

This Directory was developed from the draft NPCC A-14 Verification of Generator Gross and Net Reactive Power Capability Criteria document whose technical content was approved by the Reliability Coordinator Committee on March 5, 2008 for conversion into a Directory.

1.6 Applicability

1.6.1 Functional Entities

Generator Owners

Transmission Operators (in whose **area** the generator or generation facility resides)

2.0 Terms Defined in this Directory

The definitions of terms appearing in bold typeface in this Directory can be found in Appendix A.

3.0 NERC ERO Reliability Standard Requirements

The NERC ERO Reliability Standards containing requirements that are associated with this Directory include:

- 3.1 MOD-025-1 - Verification of Generator Gross and Net Reactive Power Capability
 - 3.2 TOP-002-2 - Normal Operations Planning
 - 3.3 FAC-008-1- Facility Ratings Methodolgy
 - 3.4 FAC-009-1 - Establish and Communicate Facility Ratings
- 4.0 NPCC Regional Reliability Standard Requirements
- None.
- 5.0 NPCC Specific Requirements
- 5.1 Developing The List of Generators or Generation Facilities to be Verified

The Transmission Operator shall identify and maintain documentation of those generators and generation facilities subject to periodic seasonal **Gross Reactive Power Capability** and **Net Reactive Power Capability** verification. The documentation maintained by the Transmission Operator shall at least include the following:

- 5.1.1 Listing of all generators or generation facilities and their **Declared Gross Reactive Power Capability** and **Net Reactive Power Capability** and seasonal auxiliary load reactive power requirements. (Reference Appendix B-2).
- 5.1.2 Listing of all generators' or generation facilities' **Verified Gross Reactive Power Capability** and **Net Reactive Power Capability**, verification date and method of verification.
- 5.1.3 Listing of each generator's or generation facility's discrepancies between a Generator Owner's **Declared** and **Verified Gross Reactive Power Capability** and **Net Reactive Power Capability**, the reason for such discrepancies and a Generator Owner's plan to address the discrepancies.
- 5.1.4 Copies of Generator Owner supplied **Gross Reactive Power Capability** and **Net Reactive Power Capability** testing, manufacturer data, performance tracking or operating historical data, certification documentation, as specified by the Transmission Operator.
- 5.1.5 Listing of generators exempted from the verification requirements and the basis for their exemption (see Section 5.5).

5.2 Establishing the Generator Reactive Power Capability Verification Program

- 5.2.1 The Transmission Operator shall establish and maintain a program in accordance with the criteria outlined in this Document to periodically verify the **Gross Reactive Power Capability** and **Net Reactive Power Capability** of all generators and generation facilities that are subject to periodic seasonal **Gross Reactive Power Capability** and **Net Reactive Power Capability** verification.
- 5.2.2 The Transmission Operator shall establish requirements for a Generator Owner to notify its Transmission Operator within a specified time period when its generator or generation facility cannot achieve the **Declared Reactive Power Capability** because of equipment issues.
- 5.2.3 The Transmission Operator shall report annually to NPCC about the status of its program including any changes in the verification process related to verification of **Gross Reactive Power Capability** and **Net Reactive Power Capability** and provide copies of any changes to its verification process to the Generator Owners and NPCC within 30 days of issue.

5.3 Implementing the Generator Reactive Power Capability Verification Program

The Transmission Operator shall request the Generator Owners to verify the seasonal **Gross Reactive Power Capability** and **Net Reactive Power Capability** of their generators or generation facilities that are subject to periodic seasonal **Gross Reactive Power Capability** and **Net Reactive Power Capability** verification in accordance with the verification schedule specified in Section 5.3.1. The two (2) capability seasons are defined as summer and winter as specified by the Transmission Operator.

- 5.3.1 Generator and generation facility **Gross Reactive Power Capability** and **Net Reactive Power Capability** shall be re-verified every five (5) years or as required by the Transmission Operator.
 - 5.3.1.1 If a Transmission Operator determines that only one seasonal generating capability value will suffice for NPCC Bulk Power System reliability analysis, then periodic verification will be required only for that particular season.
 - 5.3.1.2 If a Transmission Operator determines that the difference between **Gross Reactive Power** and **Net Reactive Power Capability** of a generator or generation facility is insignificant for NPCC Bulk Power System reliability analysis, then periodic verification will be required for only one numerical value.

- 5.3.1.3 If a Transmission Operator determines that only lagging or leading **Gross Reactive Power** and **Net Reactive Power Capability** of a generator or generation facility is required for NPCC Bulk Power System reliability analysis, then periodic verification will be required only for that specific reactive power capability value.
- 5.3.2 A Generator Owner shall notify the Transmission Operator within a specified time period when its generator or generation facility cannot achieve the **Declared Capability** because of equipment issues. The Transmission Operator shall specify a time frame for the Generator Owner to re-verify a generator or generation facility that could not meet its **Declared Capability**.
- 5.3.3 The Transmission Operator shall specify the real power level at which the verification shall be performed, recognizing that the verification of lagging and leading reactive power capabilities should normally be performed during on-peak and off-peak hours, respectively.
- 5.3.4 The Transmission Operator shall specify those intermittent or small generating units whose capability may be represented by verification results of a single unit.
- 5.4 Verification Criteria for Generator or Generation Facility Reactive Power Capability

The Generator Owners shall comply with the Transmission Operator's requests for periodic verification of **Gross Reactive Power Capability** and **Net Reactive Power Capability** of their generators or generation facilities, and apply the following criteria to verify the **Gross Reactive Power Capability** and **Net Reactive Power Capability** of their generators or generation facilities according to their types. The verification can include testing, use of performance tracking with any required supplemental engineering analysis, or commissioning data (for new generators only) acquired during the same seasonal capability period, as specified by the Transmission Operator.

- 5.4.1 Thermal Generators, Internal Combustion Generators, Gas Turbine Generators, Combined Cycle and Hydro Generators

The verification of **Gross Reactive Power Capability** and **Net Reactive Power Capability** of a generator or a generator operated as a synchronous condenser shall be determined from the average leading reactive power output for at least a 15 consecutive minute period and average lagging reactive power output for a 60 consecutive minute period.

5.4.2 Intermittent Power Resources

For intermittent power resources (wind, tidal or geo-thermal generators) the manufacturers' or commissioning data can be used until sufficient performance tracking data is available to verify generator or generation facilities lagging and leading reactive capabilities.

5.4.3 Multiple Generator Facilities Forming a Generation Facility

The verification of **Gross Reactive Power Capability** and **Net Reactive Power Capability** for multiple generator facilities when limited by common elements shall be based on the reactive power capability of the facility and not the sum of the capabilities of the individual generators.

5.4.4 Consideration of Other Limitations

The Generator Owner shall identify any equipment or other factor that will limit the capability of the generator or generation facility to meet its **Declared Gross Reactive Power Capability** and **Net Reactive Power Capability**.

5.4.5 If the generator or generation facility is unable to demonstrate its **Declared** lagging or leading seasonal **Gross Reactive Power** and **Net Reactive Power Capability** during testing or by use of performance data, the Transmission Operator and Generator Owner shall evaluate the cause of the limitation. The Transmission Operator shall document the reasons that prevented the generator or generation facility from achieving its **Declared Capability** and determine if retesting is required during that seasonal period.

5.5 Exemption of Generators or Generation Facilities from Verification Testing

5.5.1 The Generator Owner shall notify the Transmission Operator and request an exemption if it cannot conduct seasonal capability testing on a generator or generation facility for any of the reasons listed below. For existing generators, the Generator Owner shall submit certified generator operation records, manufacturer data, or performance tracking for the same previous seasonal verification period for this generator or generation facility. For new generators only, the Generator Owner shall submit commissioning data.

1. Adverse impact on transmission system reliability
2. Potential damage to transmission system or generator equipment

3. Governmental regulatory or operating license limitations
- 5.5.2 The Transmission Operator shall, within 30 days of receiving notification by a Generator Owner that it cannot perform verification testing for the required seasonal period, notify the Generator Owner that its generator shall be exempted from the seasonal capability testing and coordinate with the Generator Owner to reschedule the verification testing for the next seasonal verification period.
- 5.5.3 The generator or generation facility exempted from seasonal capability testing shall submit generator performance tracking records, manufacturers or commissioning data (for new generators only) from the previous applicable seasonal verification period. Engineering analysis may be used in conjunction with performance tracking data to justify any difference between a generator's or generation facility's declared capability and previous seasonal performance data.
- 5.6 Documenting and Reporting Verified Generator or Generation Facility Gross and Net Reactive Power Capabilities
 - 5.6.1 Each Generator Owner shall, as specified by the Transmission Operator:
 - 5.6.1.1 Provide generator or generation facility **Declared Gross Reactive Power Capability** and **Net Reactive Power Capability** to the Transmission Operator;
 - 5.6.1.2 Provide generator or generation facility **Verified Gross Reactive Power Capability** and **Net Reactive Power Capability** to the Transmission Operator.
 - 5.6.1.3 Report to the Transmission Operator any discrepancies between declared and **Verified Gross Reactive Power Capability** or **Net Reactive Power Capability** within time frame specified by the Transmission Operator as required in Section 5.2.2, and develop and implement a plan to resolve the discrepancies.
 - 5.6.1.4 Determine and report to the Transmission Operator the generator or generation facilities reactive power seasonal auxiliary **loads**.
 - 5.6.1.5 Retain **Gross Reactive Power** and **Net Reactive Power Capability** testing results, commissioning data or performance tracking data with any supplemental engineering analysis to support any of the data for the current and most recent prior verification period.

5.6.2 The Transmission Operator shall:

- 5.6.2.1 Document any discrepancies between system modeling and generator **Verified Capabilities** and the reason for such discrepancies.
- 5.6.2.2 Specify a time frame for the Generator Owner to address the discrepancy between the declared and **Verified Gross Reactive Power Capability** or **Net Reactive Power Capability** of its generators or generation facilities.
- 5.6.2.3 Report to NPCC annually any discrepancies between declared and **Verified Gross Reactive Power Capability** or **Net Reactive Power Capability**.

6.0 Measures and Assessments

None developed at this time.

7.0 Program Validation and Compliance Monitoring

The NPCC Task Force on Coordination of Operation shall annually validate that each Transmission Operator has implemented the **Gross Reactive Power Capability** and **Net Reactive Power Capability** verification program.

The NPCC Compliance Committee shall conduct periodic compliance audits to review the effectiveness of the Transmission Operator’s **Gross Reactive Power Capability** and **Net Reactive Power Capability** verification program, and ensure compliance to the criteria in this Directory by the responsibility entities.

Adherence to these criteria shall be reported by each responsible entity in a manner and form designated by the Compliance Committee.

Prepared by:	Task Force on Coordination of Operation / Task Force on Coordination of Planning
Review and Approval:	Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task

Forces for their recommendation to seek RCC approval.

Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast.

Revisions pertaining to the Appendices or any other portion of the document such as Links glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document.

This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

References: NPCC Glossary of Terms (Document A-7)

Appendix A Definition of Terms¹

Declared Capability (of a generator or generating facility) – The values submitted by the Generator Owner to the respective Transmission Operator.

Generation Facility – generating units, which are modeled as a single entity by the Transmission Operator.

Gross Reactive Power Capability (of a generator or generating facility) – The maximum lagging and leading reactive capability at the generator terminals and at a specified Gross Real Power output for a specific seasonal capability period.

Gross Real Power Capability (of a generator or generating facility) – The maximum megawatt output at the generator terminals, at the normally expected system conditions for that seasonal capability period.

Net Reactive Power Capability (of a generator or generating facility) – the **Gross Reactive Power Capability** adjusted for any applicable losses and auxiliary loads incurred up to the point of interconnection and at a specified Gross Real Power output for a specific seasonal capability period.

Net Real Power Capability (of a generator or generating facility) – The Gross Real Power Capability, less the auxiliary real power loads necessary to operate the generator at maximum real power output.

Load — The electric **power** used by devices connected to an electrical generating system. (IEEE Power Engineering). Also see **Demand**.

NPCC Specific Definitions:

Firm Load — Loads that are not **Interruptible Loads**.

Interruptible Load — Loads that are interruptible under the terms specified in a contract.

Power

Apparent Power — The product of the volts and amperes. It comprises both *real* and *reactive* power, usually expressed in kilovoltamperes (kVA) or megavoltamperes (MVA).

Reactive Power — The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied

¹ These terms will be moved and grouped under a separate Directory when all other Directories are developed.

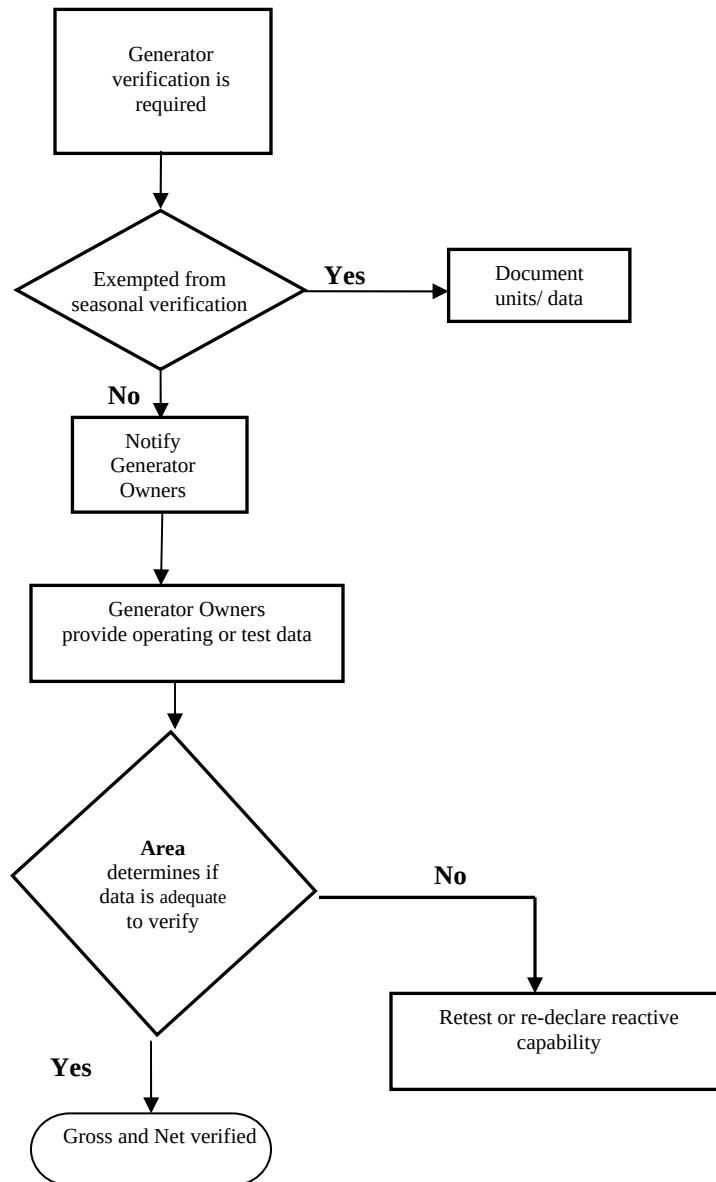
to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, **synchronous condensers**, or electrostatic equipment such as capacitors. Reactive power directly influences electric system voltage. It is usually expressed in kilovars (kVAr) or megavars (MVar).

Real Power — The rate of producing, transferring, or using electrical energy, usually expressed in kilowatts (kW) or megawatts (MW).

Verified Capability (of a generator or generating facility) – The capability as demonstrated by the methods specified in this Directory and accepted by the Transmission Operator.

APPENDIX B-1

Basic Flow Chart for Verification of Generator Gross and Net Reactive Power Capability



APPENDIX B-2 – Generator Reactive Capability Form

GENERATOR REACTIVE CAPABILITY DATA FORM												
1. Data Preparation Documentation*												
Generator Facility Name			Unit No.		Facility ID		Generator Owner			Primary Contact		
Big Generator Station			1		12234		Big Power			Jim Smith		
Prepared By			Date prepared:		Effective Date		Contact Tel			Contact e-mail		
John Doe			01/05/2007		01/10/2007		XXX-XXX-XXXX			john@bigpower.com		
Auxiliary Reactive Power Requirements				Summer MVAR				Winter MVAR				
				20				15				
Reactive Data*												
Seasonal Data		Declared Real and Reactive Capability					Verified Reactive Capability and Season			Verification Method (T, P, C** as applicable)	Date Verified	
		Summer			Winter			Winter				Date
		Gross MW	Gross MVAR	Net MVAR	Gross MW	Gross MVAR	Net MVAR	Gross MW	Gross MVAR	Net MVAR		
Lagging Capability		500	120	120	525	100	100	520	110	110	P	03/15/2007
Leading Capability		500	250	230	525	240	225	525	200 (1)	185(1)	T	01/25/2007
<i>*Data inputted for illustration purposes, ** T- Testing; P- Performance Tracking; C-Commissioning data</i>												
Notes and Limitations:		(1) Full MVAR capability could not be achieved because of system voltage restriction. Engineering analysis was provided to demonstrate unit was capable of declared values.										
Generating unit capability curve. <i>Please attach a .jpg image from the generating unit capability D curve</i>												

This document, when downloaded or printed, becomes UNCONTROLLED. Users should check the NPCC website for the current CONTROLLED version of this document.



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NPCC
Regional Reliability Reference Directory # 12
Under frequency Load Shedding Program Requirements

Task Force on Coordination of Operations Revision Review Record:
June 26th, 2009
March 3rd, 2010

Adopted by the Members of the Northeast Power Coordinating Council, Inc. June 26th, 2009 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	6/26/09	Effective Date	New
1	3/03/10	Sections 5.2.2 and 5.2.3 revised to consider small entity participation.	Revision

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Appendix A	

1.0 Introduction

1.1 Title Under frequency Load Shedding Program

1.2 Directory Number 12

1.3 Objective

This Directory presents the basic criteria for the design and implementation of under frequency **load shedding** programs to ensure that declining frequency is arrested and recovered in accordance with established NPCC performance requirements to prevent system collapse due to load-generation imbalance.

1.4 Effective Date **June 26th, 2009**

The effective date of this Directory also is the initial date of a six-year implementation plan for under frequency **load shedding** program in the portion of NPCC in the Eastern Interconnection and a two-year implementation plan in the Québec Interconnection.

1.5 Background

This Directory was developed from the automatic Under frequency **Load Shedding** requirements in NPCC Directory #2, Emergency Operations, and the recommendations and implementation plans provided in the study reports: 2006 Assessment of Under frequency Load Shedding Adequacy Part III – Assessment of Program Modifications and 2008 Assessment of Under frequency Load Shedding Adequacy – Québec Area, approved by the Reliability Coordinating Committee on November 19, 2008.

1.6 Applicability

1.6.1 Functional Entities

Balancing Authorities
Transmission Operators
Generator Owners

2.0 Terms Defined in this Directory

The definitions of terms found in this Directory appearing in bold typeface can be found in the Appendix A.

3.0 NERC ERO Reliability Standard Requirements

The NERC ERO Reliability Standards containing Requirements that are associated with this Directory include, but may not be limited to:

- 3.1 EOP-003: Load Shedding Plans
- 3.2 PRC-006: Development and Documentation of Regional UFLS Programs
- 3.3 PRC-007: Assuring Consistency with Regional UFLS Program Requirements

4.0 NPCC Regional Reliability Standard Requirements

None.

5.0 NPCC Full Member, More Stringent Criteria

These Criteria are in addition to, or more stringent or more specific than the NERC or any Regional Reliability standard requirements.

5.1 Under frequency Load Shedding Program – General Criteria

The intent of the NPCC automatic Under frequency **Load Shedding** program is to ensure that declining frequency is arrested and recovered in accordance with established NPCC performance requirements stipulated in this document, as follows:

- 5.1.1 Frequency decline is arrested at no less than 58.0 Hz for the portions of NPCC in the Eastern Interconnection and 56.0 Hz for the portion of NPCC in the Québec Interconnection.
- 5.1.2 Frequency does not remain below 58.5 Hz for greater than 10 seconds, and does not remain below 59.5 Hz for greater than 30 seconds, for a generation deficiency of up to 25% of the **load**.

5.2 Under frequency Load Shedding Program – Eastern Interconnection specific Requirements

Each Balancing Authority in the NPCC portion of the Eastern Interconnection shall develop an automatic Under frequency **Load Shedding** Program that meets the following requirements, unless an alternative plan is submitted by the Balancing Authority for review by the NPCC Task Forces on Coordination of Operation and System Studies and approved by the NPCC Reliability Coordinating Committee:

- 5.2.1 The program shall consist of five stages of **load shedding** to be provided by entities with 100 MW or more of end-use load connected to its facilities with the following attributes:

	Threshold Setting	Block Size	Total Operating Time ⁽¹⁾
Stage 1	59.5 Hz	7 percent	300 ms
Stage 2	59.3 Hz	7 percent	300 ms
Stage 3	59.1 Hz	7 percent	300 ms
Stage 4	58.9 Hz	7 percent	300 ms
Stage 5 (anti-stall)	59.5 Hz	2 percent	10 s

Notes:

- (1) Total operating time is the load-weighted average for all **load** within a Balancing Authority area, with maximum deviation for any load limited to ± 50 ms.

- 5.2.2 The program shall consist of two stages of **load shedding** to be provided by entities with 50 MW or more and less than 100 MW of end-use load connected to its facilities with the following attributes:

	Threshold Setting	Block Size	Total Operating Time ⁽¹⁾
Stage 1	59.5 Hz	14 percent	300 ms
Stage 2	59.1 Hz	14 percent	300 ms

Notes:

- (1) Total operating time is the load-weighted average for all **load** within a Balancing Authority area, with maximum deviation for any load limited to ± 50 ms.

- 5.2.3 The program shall consist of one stage of **load shedding** to be provided by entities with 25 MW or more and less than 50 MW of end-use load connected to its facilities with the following attributes:

	Threshold Setting	Block Size	Total Operating Time ⁽¹⁾
Stage 1	59.5 Hz	28 percent	300 ms

Notes:

- (1) Total operating time is the load-weighted average for all **load** within a Balancing Authority area, with maximum deviation for any load limited to ± 50 ms.

- 5.2.4 Entities with less than 25 MW of end-use load connected to its facilities are exempt from providing UFLS.
- 5.2.5 Entities with less than 100 MW of end-use load connected to its facilities may collectively implement by mutual agreement with one or more entities within the same island¹ identified an aggregated automatic UFLS program that sheds load based on the frequency thresholds in section 5.2.1 as an alternative to implementing the applicable program in section 5.2.2 or 5.2.3.
- 5.2.6 Under frequency threshold **relays** shall be set to a nominal total operating time of 300 ms, from the time when frequency passes through the set point to the time of circuit breaker contact opening (including any communications time delay), with a minimum relay operating time to be no less than 100 ms when the rate of frequency decay is 0.2 Hz per second.

5.3 Under frequency Load Shedding Program – Québec Interconnection Specific Requirements

The Balancing Authority in the Québec Interconnection shall develop an automatic Under frequency **Load Shedding** Program that meets the following requirements, unless an alternative plan is submitted by the Balancing Authority for review by the NPCC Task Forces on Coordination of Operation and System Studies and approved by the NPCC Reliability Coordinating Committee:

¹ BA shall identify the appropriate island for entities participating in the program.

5.3.1 The program shall consist of five threshold stages and four rate-of-change (slope) stages of **load shedding** as depicted in Table 2.

Table 2 – UFLS Parameters for the Québec Interconnection Portion of NPCC

	Rate	Frequency	MW at System Peak	Mvar at System Peak	Total Operating Time
Threshold Stage 1	—	58.5 Hz	1000 MW ⁽¹⁾	1000 Mvar	300 ms
Threshold Stage 2	—	58.0 Hz	800 MW ⁽¹⁾	800 Mvar	300 ms
Threshold Stage 3	—	57.5 Hz	800 MW	800 Mvar	300 ms
Threshold Stage 4	—	57.0 Hz	800 MW	800 Mvar	300 ms
Threshold Stage 5 (anti-stall)	—	59.0 Hz	500 MW	500 Mvar	20 s
Slope Stage 1	-0.3 Hz/s	58.5 Hz	400 MW	400 Mvar	300 ms
Slope Stage 2	-0.4 Hz/s	59.8 Hz	800 MW ⁽¹⁾	800 Mvar	300 ms
Slope Stage 3	-0.6 Hz/s	59.8 Hz	800 MW ⁽¹⁾	800 Mvar	300 ms
Slope Stage 4	-0.9 Hz/s	59.8 Hz	800 MW	800 Mvar	300 ms

Notes:

- (1) These stages shed fixed load independent of system load level.
- (2) The amount of load shedding in this table includes load shedding to compensate for generators that trip above the curve in Figure 1.

5.4 Generator Under frequency Protection Requirements

Generators shall not be tripped for under-frequency conditions in the area above the curve in Figure 1, except as provided for in Sections 5.4.1 and 5.4.2.

5.4.1 It is recognized that, in special cases, requirements may dictate generator trip in the region above the curve. In those cases, the Generator Owner shall so notify its Balancing Authority and shall ensure through alternate arrangements, that automatic **load shedding** additional to the amount set out in Section 5.2 and in Section 5.3, equivalent (+/- 5%) to the amount of **generation** to be

tripped, is provided. Such cases shall be reviewed by the Task Force on Coordination of Operation

- 5.4.2 Generator Owners shall not increase the under frequency trip settings or make other modifications to the existing exempt generators (that trip above the curve in Figure 1) that may cause these generators to, directly or indirectly, trip at a higher frequency.

5.5 UFLS Program Assessment Requirements

- 5.5.1 Studies shall be performed by the associated Transmission Operator to ensure satisfactory voltage and loading conditions after automatic **load shedding**.

- 5.5.2 The Task Force on System Studies shall conduct a triennial study to coordinate the Automatic Under frequency **Load Shedding** Program among the NPCC Balancing Authorities.

6.0 Measures and Assessments

None developed at this time.

7.0 Compliance Monitoring

Adherence to these Criteria shall be reported by the responsible entity in a manner and form designated by the Compliance Committee.

Prepared by: Task Force on System Studies

Review and Approval: Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval.

Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC Bylaws" in effect at the time the ballots are cast.

Revisions pertaining to the Appendices or any other portion of

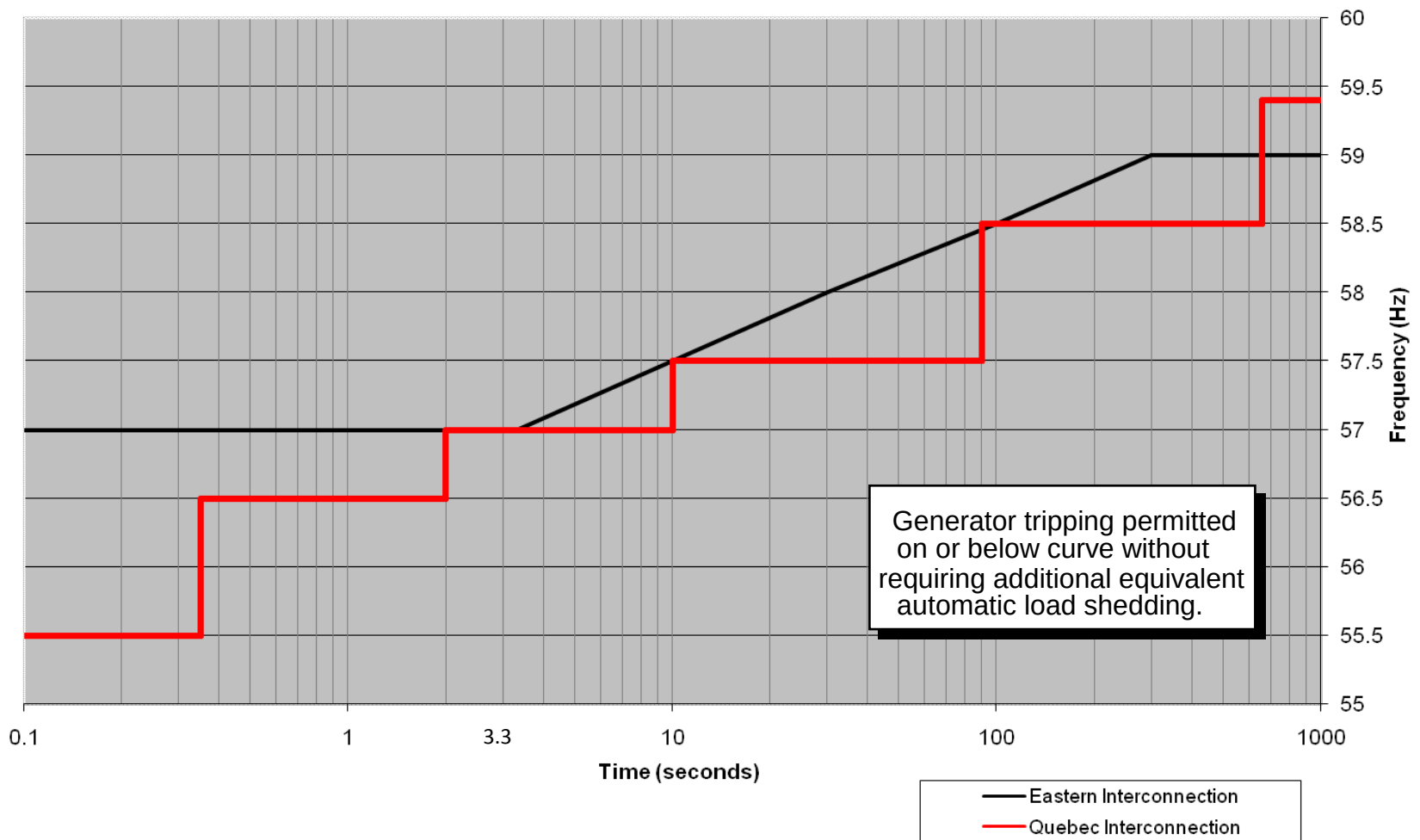
the document such as Links, glossary of terms, etc., will only require RCC Members' approval. Errata may be corrected by the Lead Task Force at any time and provide the appropriate notifications to the NPCC Inc. membership.

This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

References:

NPCC Directory #2 – Emergency Operations.

Figure 1
Standards for setting underfrequency trip protection for generators



Appendix A

Definition of Terms²

Bulk power system — The interconnected electrical systems within northeastern North America comprised of system **elements** on which **faults** or **disturbances** can have a **significant adverse impact** outside of the **local area**.

Island — A portion of a **power** system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission system **elements**.

Load — The electric **power** used by devices connected to an electrical generating system. (IEEE Power Engineering). Also see **Demand**.

NPCC Specific Definitions:

Firm Load — Loads that are not **Interruptible Loads**.

Interruptible Load — Loads that are interruptible under the terms specified in a contract.

Load Shedding — The process of deliberately removing (either manually or automatically) preselected customers' **load** from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.

Relay — An electrical device designed to respond to input conditions in a prescribed manner and after specified conditions are met to cause contact operation or similar abrupt change in associated electric control circuits. (Also: see **protective relay**).

² These terms will be moved and grouped under a separate Directory when all other Directories are developed.



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Operating Reserve Criteria

Adopted by the Members of the Northeast Power Coordinating Council March 30, 1972, based on recommendation by the Operating Procedure Coordinating Committee and the System Design Coordinating Committee, in accordance with paragraph IV, subheading (a), of NPCC's *Memorandum of Agreement* dated January 19, 1966 as amended to date.

Revised: September 24, 1976
Revised: May 18, 1979
Revised: May 14, 1980
Revised: November 5, 1982
Revised: December 30, 1986
Reviewed: October 10, 1990
Revised: August 26, 1992
Revised: February 14, 1996
Revised: September 1998
Revised: November 7, 2001
Revised: November 14, 2002
Revised: February 6, 2006
Revised: July 17, 2007
Revised: December 29, 2008

1.0 Purpose

In the continuous operation of electric power systems, **operating capacity** is required to meet forecast demand, including an allowance for error, to provide protection against equipment failure which has a reasonably high probability of occurrence, and to provide adequate regulation of frequency and **tie line** power flow. The **operating capacity** in excess of that required for actual load is commonly referred to as **operating reserve**.

This document establishes standard terminology and minimum requirements governing the amount, availability, distribution, and shared activation of **operating reserve**.

The objective is to facilitate a high level of **reliability** in the NPCC Region that is, as a minimum, consistent with the Operating Policies and Standards specified by the North American Electric Reliability Council (NERC).

2.0 Definitions

Please refer to the *NPCC Glossary of Terms* (NPCC Document A-07). Terms found in the Glossary are bolded here.

3.0 Minimum Requirements

3.1 Ten-Minute Reserve Requirement

The **ten-minute reserve** available to each **Area** shall at least equal **its first contingency loss** multiplied by the **Contingency Reserve Adjustment Factor** for the most recently completed quarter. **Ten-minute reserve** shall be sustainable as specified in section 3.7 below.

Each **Area** shall restore its **ten-minute reserve** within 105 minutes if it becomes deficient as a result of a contingency that is a **reportable event**, as described in NPCC Document C-09, *Monitoring Procedures For Operating Reserve Criteria*. Each **Area** shall restore its **ten-minute reserve** as soon as possible, and within 90 minutes if it becomes deficient and the deficiency is not a result of a contingency that is a **reportable event**. If an **Area** foresees that it cannot restore its **ten-minute reserve** within the times specified above, or extends beyond these times, a NERC Energy Emergency Alert of the appropriate level shall be declared. This requirement shall be maintained at all times, except as noted in NPCC Document C-20, *Procedures During Abnormal Operating Conditions*.

3.2 Thirty-Minute Reserve Requirement

The **thirty-minute reserve** available to each **Area** shall at least equal one-half its **second contingency loss**. **Thirty-minute reserve** shall be sustainable as specified in section 3.7 below.

Each **Area** shall restore its **thirty-minute reserve** within four hours if it becomes deficient. If an **Area** forecasts a deficiency in **thirty-minute reserve** for more than four hours into the future, the **Area** shall take corrective actions to eliminate the deficiency. This requirement shall be maintained at all times, except as noted in NPCC Document C-20, *Procedures During Abnormal Operating Conditions*.

3.3 Regulating Reserve Requirement

The **reserve** on **Automatic Generation Control** in each **Area** shall be sufficient to meet NERC control performance standards.

Except during significant frequency excursions as provided in *NPCC Regional Reliability Reference Directory #2 Emergency Operations*, **automatic generation control** equipment shall remain in service at all possible times to provide immediate response to sudden load changes or loss of generating equipment.

3.4 Synchronized Reserve Requirement

100 percent of an **Area's ten-minute reserve** requirement shall be **synchronized reserve** except as described below. An **Area** shall adjust its **synchronized reserve** requirement based on its ability to recover from **reportable events** within fifteen minutes.

This **synchronized reserve** requirement may be decreased to a minimum of 25 percent of the **ten-minute reserve** requirement based upon the **Area's** past performance in returning its **Area Control Error (ACE)** to precontingency values, or to zero, within fifteen minutes following loss of **resource**, in accordance with the following relationship:

The **synchronized reserve** requirement shall be decreased by 10 percent of the ten-minute requirement for every time a **control area** successfully returns its ACE to precontingency values, or to zero, following a **reportable event** where the **resource** loss is equal to or less than the magnitude of the **first contingency loss**. Successful recoveries that occur in the same month as a failure shall not be counted that month towards a reduced **synchronized reserve** requirement. However, successful recoveries subsequent to a failure can be counted in the next month provided there are no failures in that month.

The **synchronized reserve** requirement shall increase by 20 percent of the **ten-minute reserve** requirement for every time a **control area** fails to return its ACE to precontingency values or to zero within fifteen minutes following a **reportable event** where the **resource** loss is equal to or less than the magnitude of the **first contingency loss**. The maximum **synchronized reserve** requirement shall be 100 percent of the **Area's ten-minute reserve** requirement.

Changes in the **synchronized reserve** requirement shall be calculated at the end of each month and shall be applied at the beginning of the next month.

3.5 Compliance with NERC Disturbance Control Standard (DCS)

Areas within NPCC shall calculate and report compliance with the Disturbance Control Standard as stipulated in Document C-09, *Monitoring Procedures for Operating Reserve Criteria*. The evaluation of DCS compliance for an Area shall utilize the NERC Disturbance Recovery Period of fifteen minutes and shall meet the DCS requirement 100% of the time for reportable disturbances. Each Control Area not meeting the DCS during a given quarter shall increase its **ten-minute reserve** requirement for the calendar quarter (offset by a month) by the **Contingency Reserve Adjustment Factor**.

3.6 Distribution of Reserve

Operating reserve available to an **Area** shall be distributed so as to ensure that it can be utilized without exceeding individual **element** ratings or transfer limitations.

3.7 Sustainability of Reserve

“Synchronized Reserve, Ten Minute Reserve and Thirty Minute Reserve acquired by an Area, if activated, shall be sustainable for at least one hour from the time of activation. Areas shall determine their sustainability requirement for regulating reserve based on their ability to achieve compliance with relevant standards, with due consideration of their operating characteristics.”

3.8 Activation Of Inter-Area Reserve

When an **Area** acquires **operating reserve** from another **Area**, the provider of the **operating reserve** shall deliver an increase in energy equal to the amount of **operating reserve** acquired when the acquiring **Area** requests its activation. Unless the provider experiences its own contingency, the provider shall not initiate the curtailment of an existing or planned energy sale to any **Area** to support the activation of the **operating reserve** that was acquired until the contingent **Area** has recovered from the contingency. **Operating reserve** acquired from another **Area** shall be sustainable as specified in section 3.7 above.

3.9 Shared Activation Of Ten-Minute Reserve

Recovery from a sudden large loss of **generation** can be achieved faster by jointly activating **reserve** in several areas. NPCC and PJM have implemented such an arrangement in order to:

- more quickly relieve the initial stress placed on the interconnected transmission system following a large loss of **generation** or energy purchase
- effect an improvement in **reliability** achieved by the faster recovery
- assist in achieving compliance with the NERC Disturbance Control Standard (DCS)

Implementation of Shared Activation of **Ten-Minute Reserve** is described in NPCC document C-12, *Procedure for Shared Activation of Ten-Minute Reserve*. The provision for assistance via the Shared Activation Of Ten-Minute Reserve Procedure shall be a **reportable event**, except as noted in NPCC Document C-12. A portion of the energy being provided by assisting **Areas** as described in NPCC Document C-12 may be extended beyond the time limits specified therein as **Regional Reserve Sharing Energy**, as specified in NPCC Document C-38, *Procedure For Operating Reserve Assistance*.

3.10 Resource-Specific Requirements

- 3.10.1 **Synchronized Reserve, Ten Minute Reserve, and Thirty Minute Reserve** cannot be provided from loads where the same capacity is included in demand response programs and would result in double counting the same capacity.
- 3.10.2 Loads cannot provide **Synchronized Reserve** if the reduction in load is dependent on starting a generator to replace energy that is supplied from the grid.
- 3.10.3 To be eligible to provide **Synchronized Reserve, Ten Minute Reserve, or Thirty Minute Reserve**, the **Resource** shall meet the metering and testing requirements of the relevant **Area(s)**.
- 3.10.4 To be eligible to provide **Synchronized Reserve, Ten Minute reserve, or Thirty Minute Reserve**, the **Resource** shall continuously meet the dispatch instruction requirements of the relevant **Area(s)**.
- 3.10.5 To be eligible to provide **Synchronized Reserve, Ten Minute reserve, or Thirty Minute Reserve**, the **Resource** shall meet the requirements specified by the relevant **Area(s)** for operating limits and response rate, so that available reserve shall be computed accurately.

4.0 **Procedures**

4.1 Scheduling

- 4.1.1 Each **Area** shall ensure that sufficient **resources** are available such that its requirements for **operating reserve** are met at all times.
- 4.1.2 An **Area** shall meet its requirement for **operating reserve** using **resources** within the **Area** or obtain deliverable **capacity** from outside the **Area**.
- 4.1.3 Additional resources shall be made available to ensure the adequacy of operating reserve considering various sources of uncertainty such as, but not limited to, errors in the load forecast.

4.2 Daily Operation

- 4.2.1 Energy associated with **operating reserve** may be interchanged with the understanding that it is immediately recallable. The energy associated with reserve that is utilized to meet **AGC** requirements to provide satisfactory system regulation shall not be sold.

An **Area** acquiring energy sold out of the operating reserve of another **Area**:

- will not use this energy to augment its reserve. Resources displaced by the energy must remain available to cover for the curtailment of said energy at any time.
- must adjust its **ten-minute reserve** requirement to cover the larger of the **Area's first contingency loss**, or the largest sum of such energy purchases, which could be withdrawn at the same time due to a single contingency or event.

An **Area** acquiring energy not sold out of the **operating reserve** of another **Area** is the only **Area** that can use this energy to augment its reserve. The providing **Area** is obligated to advise the acquiring **Area** of any change in the surplus status of the energy.

- 4.2.2 When an **Area** foresees it will be unable to provide its **operating reserve** requirements, appropriate measures, as contained in NPCC Document C-20, *Procedures During Abnormal Operating Conditions*, shall be implemented.
- 4.2.3 When an **Area** experiences a **contingency** in excess of its **first contingency loss**, it may request other **Areas**, via the NYISO Shift Supervisor, to activate an appropriate amount of their **ten-minute reserve**.

4.2.4 When **ten-minute reserve** in NPCC is fully utilized, appropriate measures by the deficient **Area**, as contained in *NPCC Regional Reliability Reference Directory #2 Emergency Operations* shall be implemented.

5.0 **Responsibilities**

- 5.1 Each **Area** is responsible for observing the criteria and procedures contained herein, identifying a loss of **capacity** within its **Area** and activating **operating reserve** available to that **Area**.
- 5.2 Each **Area** is responsible for periodically auditing **operating reserve** status and availability to ensure proper response at all times.
- 5.3 The NPCC Task Force on Coordination of Operation (TFCO) is responsible for monitoring the application of these criteria.
- 5.4 The NPCC Control Performance Working Group (CO-1) shall monitor total NPCC reserves as part of the ongoing **Area** Trouble Report process detailed in Procedure C-09, *Monitoring Procedures for Operating Reserve Criteria*, and report to the TFCO if levels drop below the historical norms within the NPCC region.
- 5.5 The NPCC Control Performance Working Group (CO-1) shall monitor compliance with the Control Performance Standards on a monthly basis and report its findings to the TFCO and NERC.
- 5.6 For reportable frequency deviation events, the NPCC Control Performance Working Group (CO-1) shall initiate the required data collection and reporting as required by NPCC Procedure C-11, *Monitoring Procedures for Interconnected System Frequency Response* and NERC Frequency Response Characteristic Surveys.

Lead Task Force: Task Force on Coordination of Operation

Review frequency: 3 years

References: *NPCC Regional Reliability Reference Directory #2 Emergency Operations* (NPCC Directory D#2)

NPCC Glossary of Terms (NPCC Document A-07)

Monitoring Procedures for Operating Reserve Criteria (NPCC Document C-09)

Monitoring Procedures for Interconnected System Frequency Response (NPCC Document C-11)

Procedure for Shared Activation of Ten-Minute Reserve (NPCC

Document C-12)

Procedures During Abnormal Operating Conditions (NPCC Document C-20)

Procedure for Operating Reserve Assistance (NPCC Document C-38)

NERC Standard BAL-001-0a “Real Power Balancing Control Performance”

NERC Standard BAL-002 “Disturbance Control Performance”

NERC Standard BAL-003-0a “Frequency Response and Bias”

NERC Standard BAL-004-1 “Time Error Correction”

NERC Standard BAL-005-0b “Automatic Generation Control”

NERC Standard BAL-006-1 “Inadvertent Interchange”

NERC Performance Standard Reference Document



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NPCC Glossary of Terms

Adopted by the Members of the Northeast Power Coordinating Council in September 1998 based on recommendations by the Reliability Coordinating Committee, in accordance with paragraph IV, subheading (a), of NPCC's Memorandum of Agreement dated January 19, 1966 as amended to date.

Partially Revised:	November 1, 2002
Partially Revised	November 14, 2002
Partially Revised	February 6, 2006
Partially Revised	April 30, 2007
Partially Revised	July 17, 2007

1.0 Introduction

The *NPCC Glossary of Terms* (the Glossary) originated as Appendix A to the *Criteria for Review and Approval of Documents* (Document A-1). It includes terms from NPCC Criteria (A), Guideline (B) and Procedure (C) Documents, as well as the North American Electric Reliability Council (NERC) *Glossary of Terms*, August 1996. The IEEE *Standard Dictionary of Electrical and Electronics Terms*, Sixth Edition, has also been used as a source for some definitions.

In general, only one entry is presented for each term, and where applicable, the definition from the *NERC Glossary of Terms* is used. All entries are listed alphabetically, and related sub-definitions are listed in alphabetic order under a main definition. For example, listed under **Fault** are the sub-definitions for Permanent Fault and Transient Fault. In a number of cases, where the main definition originated in the *NERC Glossary of Terms*, NPCC Specific Definitions have been added.

1.1 Applicability

The terms in the Glossary should be used in NPCC Documents ONLY with the defined meaning, so as to avoid ambiguity and confusion.

1.2 Bolding

Terms that are defined in the Glossary have been bolded when they appear in other definitions. However, a defined term is not bolded in its own definition.

1.3 Source Identification

The source of each definition is indicated just above the dividing line between items. For example, the following notation indicates that the NERC definition is used, and that similar A-1 and C-1 definitions are available:

NERC (A-1, C-1)

2.0 The Glossary

Applicable emergency limits — These limits depend on the duration of the occurrence, and on the policy of the various member systems of NPCC regarding loss of life to equipment, voltage limitations, etc.

Emergency limits are those which can be utilized for the time required to take corrective action, but in no case less than five minutes.

The limiting condition for voltages should recognize that voltages should not drop below that required for suitable system **stability** performance, and should not adversely affect the operation of the **bulk power system**.

The limiting condition for equipment loadings should be such that cascading outages will not occur due to operation of protective devices upon the failure of facilities. (Various definitions of equipment **ratings** are found elsewhere in this glossary.)

A-1

Area — An **Area** (when capitalized) refers to one of the following: New England, New York, Ontario, Quebec or the Maritimes (New Brunswick, Nova Scotia and Prince Edward Island); or, as the situation requires, area (lower case) may mean a part of a system or more than a single system. Within NPCC, Areas (capitalized) operate as **control areas** as defined by the North American Electric Reliability Council (NERC) (the definition can be found on page 6 of this glossary).

A-1 (A-3, A-6, C-1)

Area Control Error — The instantaneous difference between actual and net **scheduled interchange**, taking into account the effects of frequency bias.

NERC (C-1)

Automatic Generation Control (AGC) — Equipment that automatically adjusts a **Control Area's generation** to maintain its **interchange schedule** plus its share of frequency regulation.

The following AGC modes are typically available:

- a. **Tie Line Bias** Control — Automatic generation control with both frequency and net **interchange** terms of **Area Control Error** considered.

Automatic Generation Control (AGC) – continued

- b. Constant Frequency (Flat Frequency) Control — Automatic generation control with the net **interchange** term of **Area Control Error** ignored. This Automatic Generation Control mode attempts to maintain the desired frequency without regard to **interchange**.
- c. Constant Net **Interchange** (Flat **Tie Line**) Control — Automatic generation control with the frequency term of **Area Control Error** ignored. This Automatic Generation Control mode attempts to maintain net **interchange** at the desired level without regard to frequency.

NERC (A-3, C-1)

Availability — A measure of time a generating unit, transmission line, or other facility is capable of providing service, whether or not it actually is in service. Typically, this measure is expressed as a percent available for the period under consideration.

NERC (C-1)

Basic Minimum Power System — Consists of one or more generating stations, transmission lines, and substations operating in the form of an **island**. Such a system can be restarted independently and later **synchronized** to other **islands** or the main grid. The transmission **elements** included in the basic minimum power system connect the units which have **blackstart capability** to those units without **blackstart capability** which have been designated in the restoration plan to be restarted in the first stages of the restoration process. Also included are selected tie lines and corresponding substations, which are considered essential to the formation of a larger power system. The intent is to focus on the ability to create smaller electrical systems or islands, which can be expanded and synchronized to other such islands and the main grid.

A-3

Bipolar — Operation of HVdc with two **poles** of opposite polarity with negligible ground current.

A-2

Blackstart Capability — The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering **power** without assistance from the electric system.

NERC (A-3, C-1)

Bottled Energy/Power/Capacity — Energy/Power/Capacity which is available at the source but which cannot be delivered to the point of use because of restrictions in the transmission system. Also referred to as Locked-In Energy/Power/Capacity.

A-10, (C-1)

Bulk power system — The interconnected electrical systems within northeastern North America comprised of system **elements** on which **faults** or **disturbances** can have a **significant adverse impact** outside of the **local area**.

A-1 (A-3, C-1, NERC)

Cable — An underground or underwater circuit.

C-13

Capability, Operating — The maximum load carrying ability of generating equipment or other electrical apparatus under specified conditions for a given time interval.

C-1

Capacity — The rated continuous load-carrying ability, expressed in megawatts (MW) or megavolt-amperes (MVA) of **generation**, transmission, or other electrical equipment.

Baseload Capacity — Capacity used to serve an essentially constant level of customer **demand**. Baseload generating units typically operate whenever they are available.

Firm Capacity — Capacity that is as firm as the seller's native **load** unless modified by contract. Associated energy may or may not be taken at option of purchaser. Supporting **reserve** is carried by the seller.

Intermediate Capacity — Capacity intended to operate fewer hours per year than **baseload capacity** but more than peaking capacity. Typically, such generating units have a capacity factor of 20% to 60%.

Net Capacity — The maximum capacity (or effective **rating**), modified for ambient limitations, that a generating unit, **power** plant, or electric system can sustain over a specified period, less the capacity used to supply the **demand** of station service or auxiliary needs.

Peaking Capacity — Capacity used to serve **peak demand**. Peaking generating units operate a limited number of hours per year, and their capacity factor is normally less than 20%.

NERC (C-1)

Capacity Benefit Margin (CBM) — See under **Transfer Capability**.

Commutation Failure — A fault in a thyristor valve group where the current transfer from one valve to the next is interrupted.

A-5, C-15

Component — refers to components of equipment or protection systems rather than **elements** of a **power** system. See **Element**.

A-5, B-11

Contingency — An event, usually involving the loss of one or more **elements**, which affects the **power** system at least momentarily.

NPCC Specific Definitions:

NPCC Emergency Criteria Contingencies — The set of contingencies to be observed when operating the **bulk power system** under **emergency** conditions. (C-1, also reference Document A-2, Section 6.2, Emergency Transfers.)

NPCC Normal Criteria Contingencies — The set of contingencies to be observed when operating the **bulk power system** under normal conditions. (C-1, also reference Document A-2, Section 6.1, Normal Transfers.)

Double Element Contingency — A **contingency** involving the loss of two **elements**.(C-1)

Single Contingency — A single event, which may result in the loss of one or more **elements**.

Single Element Contingency — A **contingency** involving the loss of one **element**.(C-1)

Limiting Contingency — The **contingency** which establishes the **transfer capability**. (C-1)

Contingency--continued

First Contingency Loss — The largest **capacity** outage including any assigned Ten-Minute Reserve which would result from the loss of a single **element** (A-6, C-1)

Second Contingency Loss — The largest **capacity** outage which would result from the loss of a single **element** after allowing for the First Contingency Loss. (A-6, C-1)

NERC (except as indicated)

Contingency Reserve Adjustment Factor — A factor used in determining the additional **ten-minute reserve** that each **Area**, not meeting the DCS requirement for a given quarter, must carry. It is calculated using the following formula:

$$\text{CRA}_{\text{quarter}} = 2 - \{\text{the average percentage DCS (expressed as a decimal) for the quarter of measurement}\}$$

A-6

Control Area — An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling **generation** to maintain its net **interchange schedule** with other Control Areas and contributing to frequency regulation of the **Interconnection**.

NERC (C-1)

Converter — An operative unit comprised of either a rectifier or inverter bridge connected to an ac system through transformers and switching devices with the associated control equipment.

A-5

Converter Transformer — A **power** transformer which transfers the energy from the thyristor valves to the connected ac system and vice-versa.

A-5

Critical Components — Equipment required for continued and proper operation of a **key facility** in the event of a total loss of AC supply. Critical components include but are not limited to blackstart generating units, substation backup power supplies, control center and telecommunication center backup power supplies and computer systems, control center and telecommunication center computer room air conditioning and telecommunication facilities backup power supplies.

A-3

Demand — The rate at which energy must be generated or otherwise provided to supply an electric **power** system. Types of Demand include:

Instantaneous Demand — The rate of energy delivered at a given instant.

Average Demand — The electric energy delivered over any interval of time as determined by dividing the total energy by the units of time in the interval.

Integrated Demand — The average of the instantaneous demands over the demand interval.

Demand Interval — The time period during which electric energy is measured, usually in 15-, 30-, or 60-minute increments.

Peak Demand — The highest electric **power** requirement occurring in a given period (e.g., an hour, a day, month, season, or year). For an electric system, it is equal to the sum of the metered net outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system.

Coincident Demand — The sum of two or more demands that occur in the same demand interval.

Noncoincident Demand — The sum of two or more demands that occur in different demand intervals.

Contract Demand — The amount of **capacity** that a supplier agrees to make available for delivery to a particular entity and which the entity agrees to purchase.

Firm Demand — That portion of the Contract Demand that a **power** supplier is obligated to provide except when system **reliability** is threatened or during **emergency** conditions.

Billing Demand — The demand upon which customer billing is based as specified in a rate schedule or contract. It may be based on the contract year, a contract minimum, or a previous maximum and, therefore, does not necessarily coincide with the actual measured demand of the billing period.

NERC (C-1)

Disturbance – Severe oscillations or severe step changes of current, voltage and/or frequency usually caused by **faults**.

Disturbance--continued

System Disturbance — An event characterized by one or more of the following phenomena: the loss of **power** system **stability**; cascading outages of circuits; oscillations; abnormal ranges of frequency or voltage or both.

A-3 (NERC, C-1)

Economic Dispatch — The optimization of the incremental cost of delivered **power** by allocating generating requirements among the on-control units with consideration of such factors as incremental generating costs and incremental transmission losses.

B-3, C-18 (IEEE definition PE 94-1991)

Element — Any electric device with terminals that may be connected to other electric devices, such as a generator, transformer, circuit, circuit breaker, or bus section.

Limiting Element — The element that is either operating at its appropriate **rating** or would be following a limiting **contingency** and, as a result, establishes a system limit.

NERC (slightly modified)

Emergency — Any abnormal system condition that requires automatic or manual action to prevent or limit loss of transmission facilities or **generation** supply that could adversely affect the **reliability** of the electric system.

NPCC Specific Definition:

Emergency — An **Emergency** is considered to exist in an Area if **firm load** may have to be shed. (TFCO)

C-38

Emergency Regional Reserve Redispatch — The regional coordination of actions to enhance **reliability** among **Areas** in response to a **Regional Reserve Deficiency**.

C-38

Emergency Regional Reserve Redispatch Energy — Electrical energy that is received and delivered among **Areas** in response to a **Regional Reserve Deficiency** to enhance regional **reliability**.

NERC (except as indicated)

Energize — To make a piece of equipment or circuit alive.

A-5 and B-1

Fault — An electrical **short circuit**.

Permanent Fault — A fault which prevents the affected **element** from being returned to service until physical actions are taken to effect repairs or to remove the cause of the fault.

Fault--continued

Transient Fault — A fault which occurs for a short or limited time, or which disappears when the faulted **element** is separated from all electrical sources and which does not require repairs to be made before the **element** can be returned to service either manually or automatically.

C-1 (NERC)

Fault Clearing

Delayed fault clearing — Fault clearing consistent with correct operation of a breaker failure **protection group** and its associated breakers, or of a backup **protection group** with an intentional time delay.

High speed fault clearing — Fault clearing consistent with correct operation of high-speed relays and the associated circuit breakers without intentional time delay.
Notes: The specified time for high-speed relays in present practice is 50 milliseconds (three cycles on a 60Hz basis) or less. [IEEE C37.100-1981]. For planning purposes, a total clearing time of six cycles or less is considered high speed.

Normal fault clearing — Fault clearing consistent with correct operation of the **protection system** and with the correct operation of all circuit breakers or other automatic switching devices intended to operate in conjunction with that **protection system**.

A-1 (C-1)

Generation (Electricity) — The process of producing electrical energy from other forms of energy; also, the amount of electric energy produced, usually expressed in kilowatthours (kWh) or megawatthours (MWh).

Gross Generation — The electrical output at the terminals of the generator, usually expressed in megawatts (MW).

Net Generation — Gross generation minus station service or unit service **power** requirements, usually expressed in megawatts (MW).

NERC (C-1)

Generation Rejection — The process of deliberately removing preselected **generation** from a **power** system, or initiating HVdc power runback, in response to a **contingency** or an abnormal condition in order to maintain the integrity of the system. Synonym: Generator Dropping.

A-3 (C-1)

Grounded — Connected to earth or some extended conducting body that serves instead of the earth, whether the connection is intentional or accidental.

A-5

Harmonic — A sinusoidal component of a periodic wave or quantity having a frequency that is an integral multiple of the fundamental frequency. Note: For example, a component, the frequency of which is twice the fundamental frequency, is called a second harmonic.

A-5

Harmonic current — A periodic component of current having a frequency that is an integral multiple of that current's fundamental frequency. Harmonic currents are normally measured in amperes or in percent of the fundamental frequency current, generally at specific frequencies, such as second and third harmonics. Harmonic currents can, for example, be generated by HVdc converters, **Static Var Compensators** (SVC) and geomagnetically induced currents (GIC).

C-15

HVdc Link — A high Voltage direct current connection between two **power** systems, often used to interconnect two asynchronous **power** systems.

A-5

Inadvertent Interchange — The difference between a **Control Area's** net **actual interchange** and net **scheduled interchange**.

NERC (C-1)

Interconnection — When capitalized, any one of the five major electric system networks in North America: Eastern, Western, ERCOT, Québec, and Alaska. When not capitalized, the facilities that connect two systems or **Control Areas**. Additionally, an interconnection refers to the facilities that connect a nonutility generator to a **Control Area** or system.

NERC

Interchange — Electric **power** or energy that flows from one entity to another.

Actual Interchange — Metered electric **power** that flows from one entity to another.

Interchange Schedule — An agreed-upon transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of **power** and energy between the contracting parties and the **Control Area(s)** involved in the transaction.

Interchange Scheduling — The actions taken by scheduling entities to arrange transfer of electric **power**. The schedule consists of an agreement on the amount, start and end times, ramp rate, and degree of firmness.

Scheduled Interchange — Electric **power** scheduled to flow between entities, usually the net of all sales, purchases, and **wheeling** transactions between those areas at a given time. .

NERC (C-1)

Interface — The specific set of transmission **elements** between two areas or between two areas comprising one or more electrical systems.

NERC (C-1)

Island — A portion of a **power** system or several power systems that is electrically separated from the interconnection due to the disconnection of transmission system **elements**.

NERC (A-3, C-1)

Key Facilities — Facilities required to establish a **basic minimum power system** following a system blackout. These facilities are essential to the restoration plan of the **Control Area** and include generating stations having blackstart units and other selected generating stations, transmission **elements** which are part of the **basic minimum power system**, control centers and telecommunication centers and telecommunication facilities which are necessary to support **protection** and control facilities, voice and data between and within control centers and voice and data between control centers and key generating / transmission substations.

A-3

Load — The electric **power** used by devices connected to an electrical generating system. (IEEE Power Engineering). Also see **Demand**.

NPCC Specific Definitions:

Firm Load — Loads that are not **Interruptible Loads**.

Interruptible Load — Loads that are interruptible under the terms specified in a contract.

(Referenced in A-3)

Load Cycle — The normal pattern of **demand** over a specified time period associated with a device or circuit.

NERC (C-1)

Load Relief — **Load** reduction accomplished by **voltage reduction** and/or **load shedding**.

A-3 (C-1)

Load Shedding — The process of deliberately removing (either manually or automatically) preselected customers' **load** from a power system in response to an abnormal condition to maintain the integrity of the system and minimize overall customer outages.

A-10

Local area — An electrically confined or radial portion of the system. The geographic size and number of system elements contained will vary based on system

characteristics. A local area may be relatively large geographically with relatively few buses in a sparse system, or be relatively small geographically with a relatively large number of buses in a densely networked system.

C-38

Negative Shared Activation Reserve Energy — Energy received by an assisting **Area** from a contingent **Area** for an eligible **resource** loss having a concurrent effective loss of demand that exceeds the loss of energy from the **resource** loss, and is implemented at a zero time ramp rate immediately following allocation notification, maintained until the Contingent **Area** requests a return to normal but not longer than thirty minutes, and ramped out at a ten-minute ramp rate following communications initiated by the Contingent **Area** which have resulted in mutually established **interchange schedules**.

NERC (A-3, C-1)

Operating Limit — The maximum value of the most critical system operation parameter(s) which meet(s): (a) pre-**contingency** criteria as determined by equipment loading capability and acceptable voltage conditions; (b) **stability** criteria; (c) post-**contingency** loading and voltage criteria.

A-3 (C-1)

Operating Capacity — The **capacity** claimed for any generating source recognizing any temporary deratings, governor load limits, proven maximum loading rates, starting times and equipment limitations including transmission **operating limits**.

A-6

Operating Procedures — A set of policies, practices, or system adjustments that may be automatically or manually implemented by the **system operator** within a specified time frame to maintain the operational integrity of the interconnected electric systems.

Automatic Operating Systems — **Special protection systems**, remedial action schemes, or other operating systems installed on the electric systems that require *no intervention* on the part of **system operators**.

Normal (Precontingency) Operating Procedures — Operating procedures that are normally invoked by the **system operator** to alleviate potential facility overloads or other potential system problems in anticipation of a **contingency**.

Postcontingency Operating Procedures — Operating procedures that may be invoked by the **system operator** to mitigate or alleviate system problems after a **contingency** has occurred.

NERC

Operator, System — Person responsible for operating control of the **bulk power system** in an **Area** of NPCC or an adjoining system interconnected with NPCC. This could be a Security Coordinator, a **Control Area** Operator or in some cases a bulk power utility operator (e.g. NYPA, Niagara Mohawk, etc)

A-3

Outage

Forced Outage — The removal from service of a generating unit, transmission line, or other facility for **emergency** reasons or a condition in which the equipment is unavailable due to unanticipated failure.

Forced Outage Rate — The hours a generating unit, transmission line, or other facility is forced out of service, divided by the sum of the hours it is removed from service, plus the total number of hours the facility was connected to the electricity system expressed as a percent.

Maintenance Outage — The removal of equipment from service **availability** to perform work on specific **elements** that can be deferred, but requires the equipment be removed from service before the next planned outage. Typically, a Maintenance Outage may occur anytime during the year, have a flexible start date, and may or may not have a predetermined duration.

Planned Outage — Removing the equipment from service **availability** for inspection and/or general overhaul of one or more major equipment groups. This outage usually is scheduled well in advance.

NERC (C-1)

Phase Shifting Transformer — A transformer that advances or retards the phase angle relationship of one circuit with respect to another to control **power** flow. Synonyms: Phase angle regulator, phase shifter.

A-2, C-25

Pole (of an ac switching device) — That portion of the device associated exclusively with one electrically separated conducting path of the main circuit of the device.

B-1 (IEEE definition C37.100-1992)

Pole (HVdc term) — A rectifier and an inverter, with associated filter banks and control equipment, tied together by a transmission line or bus.

A-2, A-6, C-20

Power

Apparent Power — The product of the volts and amperes. It comprises both *real* and *reactive* power, usually expressed in kilovoltamperes (kVA) or megavoltamperes (MVA).

Reactive Power — The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive power is provided by generators, **synchronous condensers**, or electrostatic equipment such as capacitors. Reactive power directly influences electric system voltage. It is usually expressed in kilovars (kVAr) or megavars (MVar).

Real Power — The rate of producing, transferring, or using electrical energy, usually expressed in kilowatts (kW) or megawatts (MW).

NERC (C-1)

Power Pool — Two or more interconnected electric systems operated and/or planned to supply **power** for their combined **demand** requirements.

NERC (slightly modified)

Power Swing — A transient change in the **power** flows on a system, usually of an oscillatory nature.

A-2 and A-5

Protected element — The power system **element** protected by the subject **protection system**.

Examples: Line, bus, transformer, generator.

A-1

Protection — The provisions for detecting power system **faults** or abnormal conditions and taking appropriate automatic corrective action.

Protection group — A fully integrated assembly of **protective relays** and associated equipment that is designed to perform the specified protective functions for a power system **element**, independent of other groups.

Protection--continued

Notes: _____

(a) Variously identified as Main Protection, Primary Protection, Breaker Failure Protection, Back-Up Protection, Alternate Protection, Secondary Protection, A Protection, B Protection, Group A, Group B, System 1 or System 2.

(b) Pilot protection is considered to be one protection group.

Protection system

Elem _____ent Basis

One or more protection groups; including all equipment such as instrument transformers, station wiring, circuit breakers and associated trip/close modules, and communication facilities; installed at all terminals of a power system **element** to provide the complete protection of that **element**.

Term _____inal Basis

One or more protection groups, as above, installed at one terminal of a power system **element**, typically a transmission line.

Pilot Protection — A form of line protection that uses a communication channel as a means to compare electrical conditions at the terminals of a line.

A-1

Protective relay — A **relay** that detects a power system **fault** or abnormal condition and initiates appropriate control system action.

A-1 (C-1)

Rating — The operational limits of an electric system, facility, or **element** under a set of specified conditions.

Continuous Rating — The rating – as defined by the equipment owner – that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or **element** can support or withstand indefinitely without loss of equipment life. (Normally not used in NPCC)

Rating--continued

Normal Rating — The rating – as defined by the equipment owner – that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or **element** can support or withstand through the daily **demand** cycles without loss of equipment life.

Emergency Rating — The rating – as defined by the equipment owner – that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units, that a system, facility, or **element** can support or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

NPCC Specific Definitions:

Long Time Emergency (LTE) Rating — The maximum rating of electrical equipment based on nominal ambient conditions and recognizing the nominal **load cycle** for a long period such as 24 hours. (C-1)

Short Time Emergency (STE) Rating — The maximum loading of electrical equipment which can be sustained for 15 minutes based on nominal ambient conditions and recognizing preloading conditions. (C-1)

NERC (except as indicated)

Reclosing

Autoreclosing — The automatic closing of a circuit breaker in order to restore an **element** to service following automatic tripping of the circuit breaker. Autoreclosing does not include automatic closing of capacitor or reactor circuit breakers.

High-speed autoreclosing — The autoreclosing of a circuit breaker after a necessary time delay (less than one second) to permit **fault** arc deionization with due regard to coordination with all **relay** protective systems. This type of autoreclosing is generally not supervised by voltage magnitude or phase angle.

Manual Reclosing — The closing of a circuit breaker by operator action after it has been tripped by **protective relays**. Operator initiated closing commands may originate from local control or from remote (supervisory) control. Either local or remote close commands may be supervised or unsupervised.

Supervision — A closing command is said to be supervised if closing is permitted to occur only if certain prerequisite conditions are met (e.g., **synchronism-check**).

Reclosing--continued

Synchronism-check — refers to the determination that acceptable voltages exist on the two sides of the breaker and the phase angle between them is within a specified limit for a specified time.

C-38

Regional Reserve Deficiency — When two or more **Areas** are deficient in **ten minute reserve** after all **Area** coordinated actions have been deployed, including acquiring emergency energy and/or capacity but excluding the shedding of firm load.

C-38

Regional Reserve Sharing — Procedure that allows participating **Areas** to reduce the requirement for **reserve** within its **Area** due to the availability and deliverability of **reserve** from other **Areas**.

A-6 and C-38

Regional Reserve Sharing Energy — Energy delivered to a contingent **Area** from assisting **Areas** that is converted from delivered **Shared Activation Reserve Energy** after the **Shared Activation Reserve Energy** has been delivered for 30 minutes; maintained until the Contingent **Area** requests a return to normal but not longer than sixty minutes, and ramped out at a ten-minute ramp rate following communications initiated by the Contingent **Area** which have resulted in mutually established **interchange schedules**.

B-1 and C-1

Relay — An electrical device designed to respond to input conditions in a prescribed manner and after specified conditions are met to cause contact operation or similar abrupt change in associated electric control circuits. (Also: see **protective relay**).

A-1

Reliability — The degree of performance of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired. Reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. Electric system reliability can be addressed by considering two basic and functional aspects of the electric system — **Adequacy** and **Security**.

Reliability-continued

Adequacy — The ability of the electric system to supply the aggregate electrical **demand** and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system **elements**.

Security — The ability of the electric system to withstand **disturbances** such as electric **short circuits** or unanticipated loss of system **elements**.

NERC (slightly modified)

Reportable Events — **System disturbances** involving losses of **load**, **generation** or transmission facilities within NPCC **Control Areas** which equal or exceed the following criteria are reportable events:

- (1) Actual net **interchange** deviations equal to or greater than 500 MW (Maritime: 300 MW).
- (2) Loss of **generation** or **load** equal to or greater than 500 MW (Maritime: 300 MW).
- (3) System frequency deviations equal to or greater than 0.03 Hz (Hydro-Quebec: 0.5 Hz). (System frequency deviations that occur for events outside of the NPCC are reported for analysis of frequency response, but are not included in the reporting for the NERC Disturbance Control Standard.)

A-6 (also see NERC DAWG *System Disturbances* Reports)

Reserve — In normal usage, reserve is the amount of **capacity** available in excess of the **demand**

Reserve Requirement — That capability above firm system **demand** required to provide for regulation, **load** forecasting error, equipment forced and scheduled outages, and local area supply **adequacy**.

NPCC Specific Definitions:

Non-Synchronized Reserve — That portion of **operating capacity** which is available by synchronizing a generator to the network, and that capacity which can be made available by reducing load that is dependent on starting a generator to replace energy that is supplied from the grid. Non-Synchronized Reserve also includes the capacity achieved through the implementation of **voltage reduction**. (A-6, C-1)

Reserve--continued

Operating Reserve — The sum of **ten-minute** and **thirty-minute reserve**. (A-3, A-6, C-1)

Reserve on **Automatic Generation Control (AGC)** — That portion of **synchronized reserve** which is under the command of an automatic controller to respond to **load demands** without need for manual action. (A-6, C-1)

Synchronized Reserve — The unused capacity from resources that are synchronized to the system and ready to achieve claimed capacity (A-6, C-1)

Ten-minute reserve — The sum of **synchronized** and **non-synchronized reserve** that is fully available in ten minutes. (A-6, C-1)

Thirty-Minute Reserve — The sum of **synchronized** and **non-synchronized reserve** that can be utilized within thirty minutes of receiving an activation request, excluding capacity assigned to **ten minute reserve**. (A-6, C-1)

Resource — Resource refers to the total contributions provided by supply-side and **demand-side** facilities and/or actions. Supply-side facilities include utility and non-utility **generation** and purchases from neighboring systems. **Demand-side** facilities include measures for reducing **load**, such as conservation, **demand** management, and **interruptible load**.

C-38

Shared Activation Reserve Energy — Energy delivered from an assisting **Area** to a contingent **Area** that is implemented at a zero time ramp rate immediately following allocation notification, maintained until the Contingent **Area** requests a return to normal but not longer than thirty minutes, and ramped out at a ten-minute ramp rate following communications initiated by the Contingent **Area** which have resulted in mutually established **interchange schedules**.

A-1

Short Circuit — An abnormal connection (including an arc) of relatively low impedance, whether made accidentally or intentionally, between two points of different potential. *Note:* The term **fault** or short-circuit **fault** is used to describe a short circuit.

A-10, IEEE C37.100-1981

Significant adverse impact — With due regard for the maximum operating capability of the affected systems, one or more of the following conditions arising from **faults** or **disturbances**, shall be deemed as having **significant adverse impact**:

- a. instability;
 - any instability that cannot be demonstrably contained to a well-defined local area.
 - any loss of synchronism of generators that cannot be demonstrably contained to a well-defined local area
- b. unacceptable system dynamic response;
 - an oscillatory response to a contingency that is not demonstrated to be clearly positively damped within 30 seconds of the initiating event.
- c. unacceptable equipment tripping
 - tripping of an un-faulted bulk power system element (element that has already been classified as bulk power system) under planned system configuration due to operation of a protection system in response to a stable power swing
 - operation of a Type I or Type II Special Protection System in response to a condition for which its operation is not required
- d. voltage levels in violation of applicable **emergency** limits;
- e. loadings on transmission facilities in violation of applicable **emergency** limits;

A-1

Special Protection System (SPS) – A **protection system** designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted **elements**. Such action may include changes in **load**, **generation**, or system configuration to maintain system **stability**, acceptable voltages or **power** flows. Automatic underfrequency **load shedding** as defined in the *Emergency Operation Criteria A-3*, is not considered an SPS. Conventionally switched, locally controlled shunt devices are not SPSs.

A-1

Stability — The ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or **disturbances**.

Small-Signal Stability — The ability of the electric system to withstand small changes or **disturbances** without the loss of synchronism among the synchronous machines in the system.

Transient Stability — The ability of an electric system to maintain synchronism between its parts when subjected to a **disturbance** and to regain a state of equilibrium following that disturbance.

NERC (slightly modified) (C-1)

Stability Limit — The maximum **power** flow possible through some particular point in the system while maintaining **stability** in the entire system or the part of the system to which the stability limit refers.

NERC (C-1)

Static Var Compensator (SVC) — A combination of controlled shunt reactors and switched capacitor banks, used to affect the **reactive power** flow of the system or to regulate the system voltage.

A-5, B-3, C-5 and C-18

Supervision — see **Reclosing**

Supervisory Control — A form of remote control comprising an arrangement for the selective control of remotely located facilities by an electrical means over one or more communications media.

NERC (C-1)

Surge — A transient variation of current, voltage, or **power** flow in an electric circuit or across an electric system.

NERC (C-1)

Synchronism-check — see **Reclosing**

Synchronism-check Relay — A verification **relay** whose function is to operate when two input voltages satisfy predetermined operating parameters.

B-1

Synchronize — The process of connecting two previously separated alternating current apparatuses or systems after matching frequency, voltage, phase angles, etc. (e.g., paralleling a generator to the electric system).

NERC (slightly modified) (C-1)

Synchronous Condenser — A synchronous machine which operates without mechanical load to supply or absorb **reactive power** for voltage control purposes.

B-3, C-15

Teleprotection — A form of **protection** that uses a communication channel.

A-1

Tie Line — A circuit connecting two or more **Control Areas** or systems of an electric system.

NERC A-3 (C-1)

Tie Line Bias — A mode of operation under automatic **generation** control in which the **area control error** is determined by the actual net **interchange** minus the biased scheduled net **interchange**.

NERC (C-1)

Transfer Capability — The measure of the ability of interconnected electric systems to move or transfer **power in a reliable manner** from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric **power**, generally expressed in megawatts (MW). In this context, "area" may be an individual electric system, **power pool**, **Control Area**, subregion, or NERC Region, or a portion of any of these. Transfer capability is directional in nature. That is, the transfer capability from "Area A" to "Area B" is *not* generally equal to the transfer capability from "Area B" to "Area A."

Available Transfer Capability (ATC) — A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. ATC is defined as the Total Transfer Capability (TTC), less the **Transmission Reliability Margin (TRM)**, less the sum of existing transmission commitments (which includes retail customer service) and the Capacity Benefit Margin (CBM).

Nonrecallable Available Transfer Capability (NATC) — Total Transmission Capability less the **Transmission Reliability Margin**, less nonrecallable reserved transmission service (including the Capacity Benefit Margin).

Recallable Available Transmission Capability (RATC) — Total Transmission Capability less the **Transmission Reliability Margin**, less recallable transmission service, less non-recallable transmission service (including the Capacity Benefit Margin).

Total Transfer Capability (TTC) — The amount of electric **power** that can be transferred over the interconnected transmission network in a *reliable* manner based on *all* of the following conditions:

1. For the existing or planned system configuration, and with normal (pre-**contingency**) **operating procedures** in effect, all facility

loadings are within normal **ratings** and all voltages are within normal limits.

2. The electric systems are capable of absorbing the dynamic **power swings**, and remaining stable, following a **disturbance** that results in the loss of any single electric system **element**, such as a transmission line, transformer, or generating unit.

3. After the dynamic **power swings** subside following a **disturbance** that results in the loss of any single electric system **element** as described in 2 above, and after the operation of any automatic operating systems, but before any post-**contingency** operator-initiated system adjustments are implemented, all transmission facility loadings are within **emergency ratings** and all voltages are within **emergency** limits.

4. With reference to condition 1 above, in the case where precontingency facility loadings reach normal thermal **ratings** at a transfer level below that at which any first **contingency** transfer limits are reached, the transfer capability is defined as that transfer level at which such normal **ratings** are reached.

5. In some cases, individual system, **power pool**, subregional, or Regional planning criteria or guides may require consideration of specified multiple contingencies, such as the outage of transmission circuits using common towers or rights-of-way, in the determination of transfer capability limits. If the resulting transfer limits for these multiple contingencies are more restrictive than the single **contingency** considerations described above, the more restrictive **reliability** criteria or guides must be observed. See Available Transfer Capability [shown above].

Capacity Benefit Margin (CBM) — CBM is defined as that amount of transmission transfer capability reserved by **load** serving entities to ensure access to **generation** from interconnected systems to meet **generation reliability** requirements.

Transmission Reliability Margin (TRM) — TRM is defined as that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

First Contingency Incremental Transfer Capability (FCITC) — The amount of **power**, incremental above normal base **power** transfers, that can be transferred over the transmission network in a reliable manner based on the following conditions:

First Contingency Incremental Transfer Capability--continued

1. For the existing or planned system configuration, and with normal (pre-**contingency**) **operating procedures** in effect, all facility loadings are within normal **ratings** and all voltages are within normal limits.
2. The electric systems are capable of absorbing the dynamic **power swings**, and remaining stable, following a **disturbance** that results in the loss of any single electric **element**, such as a transmission line, transformer, or generating unit.
3. After the dynamic **power swings** subside following a **disturbance** that results in the loss of any single electric system **element** as described in 2 above, and after the operation of automatic operating systems, but before any post-**contingency** operator-initiated system adjustments are implemented, all transmission facility loadings are within **emergency ratings** and all voltages are within **emergency** limits.

First Contingency Total Transfer Capability (FCTTC) — The algebraic sums of the FCITC values and the appropriate total interregional transfers assumed in the base load flow model used for the FCITC calculations.

Normal Incremental Transfer Capability (NITC) — The amount of electric **power**, incremental above normal base power transfers, that can be transferred between two areas of the interconnected transmission systems under conditions where pre-**contingency** loadings reach the normal thermal **rating** of a facility prior to any first **contingency** transfer limits being reached. When this occurs, NITC replaces FCITC as the most limiting transfer capability.

NPCC Specific Definitions:

Transfer Capability — An **operating limit** relating to the permissible **power** transfer between specified areas of the transmission system. (C-1)

Emergency Transfer Capability — The amount of **power** transfer allowed between Areas or within an Area when **operating** to meet NPCC **emergency** criteria contingencies [as defined in the *Basic Criteria for Design and Operation of Interconnected Power Systems* (Document A-2).] (A-3, C-1)

Normal Transfer Capability — The amount of **power** transfer allowed between Areas or within an Area when operating to meet NPCC normal criteria contingencies [as defined in Document A-2.] (A-3, C-1)

NERC (except as indicated)

Transmission Reliability Margin (TRM) — See under **Transfer Capability**

Voltage Reduction — A means to reduce the **demand** by lowering the customer's voltage.

NERC (C-1)

Voltage Regulating Transformer — A transformer that increases or decreases the voltage magnitude relationship of one circuit with respect to another, most often used to control voltage but also to control **reactive power** flow.

B-3

Wheeling — The contracted use of electrical facilities of one or more entities to transmit electricity for another entity.

NERC (C-1)

With due regard to reclosing — This phrase means that before any manual system adjustments, recognition will be given to the type of **reclosing** (i.e., manual or automatic) and the kind of **protection**.

A-1

Compiled by the Joint Glossary Working Group under the auspices of the Task Force on Coordination of Planning.

Reviewed for concurrence by: TFCO, TFEMT, TFSP and TFSS

Review frequency: 1 year

References: *Criteria for Review and Approval of Documents* (Document A-1)

Basic Criteria for Design and Operation of Interconnected Power Systems
(Document A-2)

Emergency Operation Criteria (Document A-3)

Bulk Power System Protection Criteria (Document A-5)

Operating Reserve Criteria (Document A-6)

Guide for the Application of Autoreclosing to the Bulk Power System
(Document B-1)

Guidelines for Inter-AREA Voltage Control (Document B-3)

Special Protection System Guideline (Document B-11)

Glossary of Standard Operating Terms (Document C-1)

Monitoring Procedures for Emergency Operation Criteria (Document C-5)

Operational Planning Coordination (Document C-13)

Procedures for Solar Magnetic Disturbances on Electrical Power Systems
(Document C-15)

Procedure for Testing and Analysis of Extreme Contingencies (Document
C-18)

Procedures During Abnormal Operating Conditions (Document C-20)

Procedure to Collect Real Time Data for Inter-Area Dynamic Analysis
(Document C-25)

The North American Electric Reliability Council (NERC) *Glossary of
Terms*, August 1996.

The IEEE *Standard Dictionary of Electrical and Electronics Terms*, Sixth
Edition.



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NPCC Inc. Reliability Compliance and Enforcement Program

Adopted by the Members of the Northeast Power Coordinating Council on mm, dd, yyyy, based on recommendation by the Reliability Coordinating Committee, in accordance with paragraph VIII, sub heading (a), of NPCC Inc. Bylaws dated May 18, 2006 as amended to date.

Revised: November 7, 2001
Revised: April 30, 2004
Revised: January 30, 2006
Revised: December 20, 2007

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Note:

Terms in bold typeface are defined in the *NPCC Inc. Glossary of Terms* (Document A-7)

1.0 Introduction

The purpose of the Northeast Power Coordinating Council Inc. is to promote the reliable and efficient operation of the interconnected **bulk power systems** in Northeastern North America through the establishment of criteria, coordination of system planning, design and operations, and assessment and enforcement of compliance with such criteria. In the development of reliability criteria, NPCC Inc., to the extent possible, facilitates attainment of fair, effective and efficient competitive electric markets.

The NPCC Inc. Reliability Compliance and Enforcement Program (the Program) described in this document is to be used to assess and enforce compliance with NPCC Inc. **reliability** criteria in such a way that the **reliability** objective stated above will be achieved. Actions taken by NPCC Inc. under the Program, including the imposition of sanctions, where applicable, shall in no way be construed as an acceptable alternative to the Member's continued obligation to comply with NPCC Inc. Criteria, Guides and Procedures. As such the Member, as stated in the NPCC Inc. Bylaws, remains responsible for providing its plan and schedule to achieve compliance. It is further noted that the Program requirements are applicable only to the elements of the **bulk power system** as defined by NPCC Inc. This definition can be found in the *NPCC Glossary of Terms* (Document A-7). The Program is applicable to all Full Members of the Council who have by virtue of their membership in NPCC Inc. agreed, under Section IX, Sub-section A (2) (f) of the NPCC Inc. Bylaws, to submit such data and reports as required and described in the Program.

The Program is designed to be consistent with the concept that compliance assessment and enforcement is most effectively accomplished by the entities that are closest to the complying party. The Program establishes the following assessment structure: NPCC Inc. will assess and enforce compliance to those standards and criteria for which the **Areas** have the reporting responsibilities, and the **Areas** will assess and enforce compliance to those standards and criteria for which the market participants have reporting responsibilities. It is expected that the **Areas** will have compliance processes in place that involve the market participants. The specific standards and criteria covered by this Program are described in Appendix A, which will be amended annually as required.

1.1 Non- member Facilities

A Member, through whose facilities a non-member connects with or proposes to connect with the NPCC Inc. **bulk power system** shall use its best efforts to assure that the arrangements for such connection are consistent with NPCC Inc. criteria in accordance with the provisions and requirements of the NPCC Inc. Bylaws.

2.0 **Reliability Criteria**

2.1 Development of Criteria

The criteria utilized in assessing compliance have been developed by NPCC Inc. consistent with the North American Electric Reliability Council broad-based standards. NPCC Inc. has implemented its Open Process as a means of assuring that the development and modification of these criteria are non-discriminatory. The process provides the opportunity for industry input into the establishment of such criteria.

2.2 Obligations of Members

Appendix A of this document sets forth the compliance requirements to which each Member has agreed for the current enforcement year.

2.3 Review of Appendix A Requirements

CMAS, in conjunction with the appropriate NPCC Inc. Task Forces, shall annually review the requirements included in Appendix A to assure that the effectiveness of the Reliability Compliance and Enforcement Program is maintained. Whenever an NPCC Inc. Criteria Document is due for a periodic review, the appropriate Task Force shall also review any associated compliance template in Appendix A to assure consistency of compliance implementation with the revised Criteria and shall inform the CMAS whether or not a template change is required.

The various NPCC Inc. Task Forces have a responsibility to make a recommendation for any additional requirements to be included in the RCEP or for the removal of an existing requirement from the RCEP. Such addition or removal of a requirement must be communicated to the CMAS as a proposed Amendment to Appendix A. Based on the Task Force's recommendation, CMAS submits the proposed Amendment for endorsement by the RCC and approval by the NPCC members.

3.0 **Reporting and Disclosure**

3.1 Area Reporting

Each **Area** furnishes to CMAS via the NPCC Inc. web-based Compliance Application, as per the established schedule, a compliance submittal for each of the requirements described in the annual NPCC Inc. Compliance Program Schedule.

NPCC Inc. has established a lateness policy with associated sanctions. The policy is detailed in Section 4.2 of A-8.

3.2 Area Disclosure

When an alleged violation is suspected, the name of the Area (not the individual party) will be reported to NPCC Inc. CMAS will track alleged violations and report to the RCC. Upon confirmation and completion of the due process within the Area, the Area shall disclose the name the participant responsible for the violation to the RCC if the participant is a member of NPCC Inc., or if a participant is not a member of NPCC Inc, the Area shall disclose the name of the participant responsible for the violation in accordance with the Area's disclosure procedure.

4.0 **Compliance Assessment and Enforcement Process**

The compliance assessment and enforcement process is described below in terms of the functional entities that will be responsible for the process. In addition, the *Guidelines for the Implementation of the NPCC Inc. Compliance Program* (Document B-22) diagrams and describes in detail the processes utilized by the Program and other pertinent details related to the Program.

4.1 **Compliance Monitoring and Assessment Subcommittee (CMAS)**

CMAS, as a standing subcommittee of the Reliability Coordinating Committee (RCC), has the responsibility to perform independent compliance monitoring and assessment functions and to recommend the appropriate compliance violation sanctions to the RCC.

CMAS establishes the Program requirements and schedule and submits them to the RCC for approval. Once approved, CMAS is responsible for managing the Program, making periodic reports to the RCC, and seeking RCC approvals when necessary.

NPCC Inc. Task Forces are utilized to develop compliance templates and to perform many of the technical assessments required in the Program. The results of these assessments are forwarded to CMAS for compliance review.

CMAS employs, whenever practical, the use of self-certification forms as a means of streamlining the reporting process. The *Review Process for NPCC Inc. Reliability Compliance Assessment and Enforcement Program*

(Document C-32) will be utilized to verify compliance reporting. The review process, which requires selected **Areas** to present detailed information related to selected requirements, assures accurate and efficient execution of the Program. CMAS establishes an annual schedule for the review process that is approved by the RCC.

CMAS conducts its compliance assessment and submits its report to the RCC for review and approval. CMAS will also provide a sanction recommendation for compliance violations where appropriate.

4.2 Reliability Coordinating Committee (RCC)

The RCC, a standing committee of NPCC Inc., reviews the compliance report submittals received from CMAS. Prior to a final compliance determination, the RCC may remand the report back to CMAS for clarification. Once the RCC has made a final compliance determination, any dispute regarding the technical compliance assessment will be submitted to the Enforcement Panel (EP).

The RCC also reviews any sanction recommendations received from CMAS. Prior to endorsing them, the RCC may remand the sanction recommendations back to CMAS for further clarification before forwarding them to the EP.

4.3 Enforcement Panel (EP)

The NPCC Inc. EP members shall adhere to the *Enforcement Panel Code of Conduct* and the *NPCC Administrative Procedures for Conducting an Enforcement Panel Hearing*.

The NPCC Inc. EP will receive either an undisputed RCC determination of a compliance violation including a sanction recommendation, an undisputed RCC determination with a disputed sanction recommendation or a disputed compliance violation from the RCC. The EP has full discretion to implement sanctions.

The **Area** shall notify the EP as to whether it will accept or dispute the sanction. If the **Area** accepts the sanction, the EP issues the appropriate sanction letter.

If, however, the Area disputes the sanction or the EP receives a disputed compliance violation, an EP hearing will be held in accordance with the approved hearing procedures. Non-voting regulatory observers, who are members of NPCC Inc., are permitted at Enforcement Panel hearings and may offer comments as appropriate but may not participate in any deliberations. A

regulatory observer is not permitted to participate in an Enforcement Panel hearing involving an entity subject to the regulator's jurisdiction.

The EP, which consists of five-members, functions independently from the NPCC Inc. Board of Directors (BODs). The panel will be made up of two Transmission Provider representatives, two Transmission Customer representatives, and a NPCC Inc. Staff Member. In addition, one alternate Transmission Customer member and one alternate Transmission Provider member will be elected. The alternate member shall provide substitute for a sitting member when there is potential conflict of interest. The EP members will elect a Chair.

The BODs will solicit nominations for participation on the EP from the NPCC Inc. Membership. Members of the EP will be elected by the NPCC Inc. membership from a list of candidates proposed by the BODs. An EP member shall not be a member of the CMAS.

4.4 Board of Directors

The NPCC Inc. BODs will provide oversight to the assessment and enforcement process through administration of the Program. The BODs will monitor the RCC compliance-related activities, EP final reports including sanction determinations and the results of any cases resolved through the NPCC Inc. ADR process in order to determine the success of the Program and whether changes are desirable.

4.5 Arbitration

An **Area** ("Disputing Area") may only seek review of an EP Final Report by invoking the arbitration provision described below:

- a. Within 15 calendar days of submission for arbitration of any dispute related to a determination of non-compliance with a reliability criterion and/or the assessment of a sanction, the Chairman of the EP and the Disputing Area shall select a single arbitrator. If the Chairman of the EP and the Disputing Area are unable to agree on an arbitrator, they shall select an arbitrator from a list of qualified arbitrators maintained by the NPCC Inc. Each NPCC Inc. **Area** may submit one name of an arbitrator to be included on such list. All arbitrators included on such list are knowledgeable with respect to electric utility industry matters.

The EP and the Disputing Area shall select the arbitrator from such list by (a) agreement, or in the absence of agreement, (b) striking names

from the list in turn (beginning with the party requesting arbitration) until only the selected arbitrator remains. The arbitrator selected will not be an employee, director or officer of either the NPCC Inc. or the Disputing Area or any Affiliate thereof. Potential arbitrators who are employees, directors or officers of Members of the NPCC Inc., but who are not themselves officers of the NPCC Inc. or members of the EP, will not be considered to be employees, directors or officers of the NPCC Inc. The arbitrator must agree in writing to be bound by the confidentiality obligations applicable to the NPCC Inc. Staff.

- b. All arbitration proceedings shall be held in New York City, unless an alternate location is agreed to by the parties. The NPCC Inc. Staff will facilitate any such arbitration proceedings.
- c. The arbitrator shall provide the EP and the Disputing Area the opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association. The NPCC Inc. shall submit to the arbitrator evidences including reports provided by the CMAS to the RCC, the RCC Final Compliance Determination and the EP Final Report, and the data and information provided by the **Area** and by other **Areas** to the CMAS. The EP and the Disputing Area shall be afforded a reasonable opportunity to rebut any such evidence. The arbitrator shall create and maintain an evidentiary record of sufficient detail to render an informed decision.

During the arbitration process, the NPCC Inc. and the Disputing Area shall make funds available to the arbitrator as required by the arbitrator to pursue the arbitration. Such funds shall be shared equally by the NPCC Inc. and the Disputing Area, and at the conclusion of the arbitration shall be reimbursed as specified in (g) below.

- d. In any arbitration, either the EP or the Disputing Area may raise any issue regarding the technical assessment and or sanction determination, including the factual basis for the technical assessment and or sanction, or whether the procedures specified in this document were properly followed. Neither the EP nor the Disputing Area, however, may dispute the validity of the reliability criteria used in the RCEP.
- e. If an arbitrator hearing a dispute between the NPCC Inc. and the Disputing Area determines that data from another **Area** are relevant to the consideration of such dispute, the arbitrator shall so notify such other **Area**, and such other **Area** shall have 15 calendar days, or a mutually agreeable extension thereof, to provide the requested data.

- f. As soon as practicable, but no later than 90 calendar days after initial selection of the arbitrator, the arbitrator shall issue to the EP and the Disputing Area a written decision resolving the dispute and explaining the basis for the conclusion. Such decision shall include findings of fact to support the arbitrator's conclusion. Such decision shall be final and binding on the parties.

Any and all costs associated with the arbitration (not including attorney and expert witness fees which shall be borne by the respective parties) shall be borne by the party whose arbitration position was not selected by the arbitrator, unless the NPCC Inc. and the Disputing Area agree to an alternative method of allocating costs. If the arbitration decision differs from the positions of both the EP and the Disputing Area, the arbitrator shall specify how the costs are to be allocated. Such cost allocation shall include reimbursement of any funds provided to the arbitrator by the NPCC Inc. and the Disputing Area pursuant to the description contained in (c) above.

4.6 Appeal to Applicable Governmental Authority

Either the NPCC Inc. or the **Area** ("Disputing Area") may apply to applicable Governmental Authority to hear an appeal of any arbitrator's decision resulting from implementation of the NPCC Inc. ADR process. Such an appeal shall be filed at applicable Governmental Authority within fifteen (15) calendar days of the arbitrator's decision. The NPCC Inc. and the Disputing Area agree that in any appeal to applicable Governmental Authority either NPCC Inc. or the Disputing **Area** may address any issues raised in the arbitration or the EP proceeding, including the factual basis for the technical assessment or sanction or whether the procedures were properly followed. Neither NPCC Inc. nor the Disputing **Area**, however, may raise issues regarding the validity of the reliability standard and criteria in RCEP. Any appeal from an arbitrator's decision to the appropriate Governmental Authority shall be based solely upon the record assembled by the arbitrator, unless otherwise determined by appropriate Governmental Authority. Each of the NPCC Inc. and the Disputing **Area** in connection with such an appeal to appropriate Governmental Authority shall be solely responsible for its own cost incurred. Any initiation of a Governmental Authority appeal by the NPCC Inc. pursuant to this section 3.5 must be authorized by the NPCC Inc. Board of Directors.

5.0 **Sanctions**

5.1 Violations of Reliability Criteria

Table 1 defines the sanctions for violations to the criteria as described in the Compliance Templates shown in Appendix A. Not all Compliance Templates require all four levels of non-compliance. Except where noted, when there is an inconsistency between the template and the referenced criteria, the criteria shall prevail.

Table 1 - NPCC Inc. Non-Compliance Sanctions

Level of Non-Compliance	Sanctions
1	Letter to the relevant functional head (operations, planning) of the Area
2	Letter to the Chief Executive of the Area with copy to the relevant functional head, other NPCC Inc. Areas , the NPCC Inc. Task Force Chairs, the NPCC Inc. Reliability Coordinating Committee, the NPCC Inc. Board of Directors and NPCC Inc. Member Representatives.
3	Letter to the Board of Directors of the Area with copies to the Chief Executive of the Area , the relevant functional head of the Area , other NPCC Inc. Areas , the NPCC Inc. Task Force Chairs, the NPCC Inc. Reliability Coordinating Committee, the NPCC Inc. Board of Directors, NPCC Inc. Member Representatives, and Regional Managers of adjacent reliability Councils. Post on NPCC Inc. Web site
4	Same as Level 3 with copies to State/Provincial regulatory authorities, State Governor and Legislators

5.2 Policy on Lateness

All compliance reports are to be received by NPCC Inc. on time in accordance with the due dates established by CMAS. All reports are to be provided in easily readable electronic format.

Sanctions shall be applied if a complete report is not received by CMAS after a grace period of ten calendar days has expired. CMAS shall assess the following level of non-compliance for lateness:

Level 1	After 10 calendar day grace period
Level 2	After 30 calendar days following due date
Level 3	After 60 calendar days following due date
Level 4	After 90 calendar days following due date or report never received

Levels are defined in Table 1.

6.0 RCEP Data Retention Requirements

For the purposes of NPCC Inc. RCEP, a minimum of three years of data shall be retained that fully supports certification towards an NPCC Inc. criteria document or compliance template. This requirement may be superseded by data retention requirements where specified in other NPCC Inc. criteria documents or compliance templates.

Lead Subcommittee: Compliance Monitoring and Assessment Subcommittee

Reviewed for concurrence by: TFCP, TFCO, TFSP, TFSS, TFIST

Review frequency: Annually

References: *NPCC Inc. Bylaws*

NPCC Inc. Glossary of Terms (Document A-7)

Guidelines for Implementation of the NPCC Inc. Compliance Program (Document B-22)

Review Process for NPCC Inc. Reliability Compliance and Enforcement Program (Document C-32)

APPENDIX A

Compliance Templates and Monitoring

Compliance Template A2-1

Area Transmission Review

Standard: The interconnected transmission systems shall be planned, designed, and constructed to reliably meet projected customer electricity demand and energy requirements in accordance with NPCC Inc. *Basic Criteria for Design and Operation of Interconnected Power Systems* (Document A-2). Studies shall be conducted in accordance with NPCC Inc. *Guidelines for NPCC Area Transmission Reviews*, Document B-4

References: NPCC Inc. *Basic Criteria for Design and Operation of Interconnected Power Systems* (Document A-2) and NPCC Inc. *Guidelines for NPCC Inc. Area Transmission Reviews* (Document B-4)

<u>Responsibilities</u>	
Reporting Responsibility:	Areas
Frequency of Reporting:	Annually
Compliance Monitoring and Assessment Responsibility:	NPCC Inc.
Enforcement Responsibility:	NPCC Inc.

Full (100%) Compliance

An annual Area Transmission Review Report, including all supporting documentation in accordance with Document B-4 was submitted to TFSS and the Area's planned **bulk power system** meets the requirements of Document A-2. For an Annual or Interim or Intermediate Review, the Area must submit its report to TFSS no later than the end of the year in which the review was initiated. For a comprehensive Review, the Area must submit its report to TFSS no later than April 1st of the following year after which the review was initiated.

Non-Compliance

Level 1: An Area Transmission Review was submitted, but was incomplete in meeting the requirements of Document B-4.

Level 2: An Area Transmission Review was submitted. However, the Area's planned **bulk power system** was found to be noncompliant with the A-2 criteria in one or more instances. The Area submitted an acceptable plan and schedule for addressing the instances of noncompliance.

Level 3: An Area Transmission Review was submitted. However, the Area's planned **bulk power system** was found to be noncompliant with the A-2 criteria in one or more instances, and that either the Area failed to submit a plan and schedule to meet the requirements, or that the Area submitted such a plan, but it was found to be unacceptable.

Level 4: An Area Transmission Review was not submitted. Please refer to Section 5.2, Policy on Lateness.

Compliance Template A3-1

Underfrequency Load Shedding

Standard: Each NPCC Inc. **Area** shall plan and implement an Underfrequency Load Shedding Program as specified in section 4.6 of the NPCC Inc. *Emergency Operation Criteria* (Document A-3).

References: NPCC Inc. Documents A-3.

<u>Responsibilities</u>	
Reporting Responsibility:	Areas
Frequency of Reporting:	Annually
Compliance Monitoring and Assessment Responsibility:	NPCC Inc.
Enforcement Responsibility:	NPCC Inc.

Full (100%) Compliance

The Area load-shedding program fully complies with the requirements of the NPCC Inc. *Emergency Operation Criteria* (Document A-3), Section 4.6.

Non-Compliance

Level 1: Deficiencies in Area load shedding capability were reported and a plan was submitted by the Area to correct the deficiencies. Deficiencies were corrected within five (5) months of the end of the current reporting period, or

The implementation of the Area's UFLS program is incomplete or inconsistent in one or more requirements of Document A-3, Section 4.6 (4.6.1, 4.6.2, or 4.6.3), but is consistent with the required **total** amount of load shedding, or

The amount of load shedding is less than 100% but greater than 95% of the Area's requirement of any of the load steps.

Level 2: Deficiencies in Area load shedding capability were reported and a plan was submitted by the Area to correct the deficiencies. Deficiencies were corrected within twelve (12) months of the end of the current reporting period, or

The amount of load shedding is less than 95% but greater than 90% of the Area's requirement in any of the load steps

Level 3: Deficiencies in Area load shedding capability were reported with no plan for correction within twelve (12) months of the end of the current reporting period, or

deficiencies from the immediately previous reporting period were not corrected by the end of the current reporting period, or

The amount of load shedding is less than 90% but greater 85% of the Area's requirement in any of the load steps.

Level 4: An Area load shedding capability report was not submitted or deficiencies from more than one previous reporting period were not corrected by the end of the current reporting period. Please refer to Section 5.2, Policy on Lateness, or

The amount of load shedding is less than 85% of the Area's requirement in any of the load steps.

Compliance Template A3-3

Key Facility and Critical Components List

Standard: Each **Area** shall maintain an inventory of **key facilities** and their **critical components** required for the energization of the **basic minimum power system** to ensure a successful system restoration. (Section 4.11 of the NPCC Inc. *Emergency Operation Criteria*, Document A-3)

References: NPCC Inc. *Emergency Operation Criteria* (Document A-3)

<u>Responsibilities</u>	
Reporting Responsibility:	Areas
Frequency of Reporting:	Annually
Compliance Monitoring and Assessment Responsibility:	NPCC Inc.
Enforcement Responsibility:	NPCC Inc.

Full (100%) Compliance

Each **Area** shall provide to NPCC Inc. , on a confidential basis, their current **key facilities** and **critical components** list annually. The list shall identify **critical components** associated with the following applicable **key facility** categories:

1. Blackstart generating stations.
2. Underground transmission cables.
3. Substation and Telecommunication sites.
4. Control Center and Telecommunication Center facilities.

Non-Compliance

Level 1: None.

Level 2: A **key facility** and **critical component** list was provided but NPCC Inc. Inter-Area Restoration Coordination Working Group (CO-11) found that it did not fully support the energization of the **basic minimum power system**.

Level 3: The **Area** did not maintain a current **key facility** and **critical components** list.

Level 4: None.

A-4 Compliance

Bulk Power System Protection Minimum Maintenance

Standard: Protection system owners shall implement a protection system maintenance and testing program that fulfills the requirements of the NPCC *Maintenance Criteria for Bulk Power System Protection* (Document A-4).

References: Document A-4.

Responsibilities

Area shall enforce market participants' compliance to A-4 Criteria in accordance with the **Area's** policy and procedure.

Full (100%) Compliance

Exceptions to Document A-4 requirements are acceptable if the exceptions are completely removed within five (5) months of the end of the current reporting period.

Compliance Template A6-1

Ten-Minute Operating Reserve

Standard: Each **CONTROL AREA** shall operate its MW power **resources** to provide for a level of **OPERATING RESERVE**. Following loss of **resources**, a **CONTROL AREA** shall take appropriate steps to return its **AREA CONTROL ERROR (ACE)** to zero or its pre-disturbance level in accordance with the NPCC Inc. Operating Reserve Criteria (Document A-6). Each **CONTROL AREA** will maintain at all times sufficient **OPERATING RESERVE** to cover its **first contingency loss**.

Reference: NPCC Inc. *Operating Reserve Criteria* (Documents A-6)

<u>Responsibilities</u>	
Reporting Responsibility:	Control Areas
Frequency of Reporting:	Monthly by the end of the following month
Compliance Monitoring and Assessment Responsibility:	NPCC Inc.
Enforcement Responsibility:	NPCC Inc.

Full (100%) Compliance

Control Area meets the **Ten-Minute Reserve** requirement as described in Sections 3.1 and 3.4 of A-6, except during emergency operations resulting from a capacity deficiency.

Non-Compliance

Level 1: Failure to meet the **Ten-Minute Reserve** requirement as described above once during the past twelve (12) months.

Level 2: Failure to meet the **Ten-Minute Reserve** requirements as described above twice during the past twelve (12) months.

Level 3: Failure to meet the **Ten-Minute Reserve** requirements as described above three times during the past twelve (12) months.

Level 4: Failure to meet the **Ten-Minute Reserve** requirements as described above four or more times during the past twelve (12) months.



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Classification of Bulk Power System Elements

Adopted by the Members of the Northeast Power Coordinating Council Inc., this Dec. 1, 2009 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Inc. Bylaws dated May 18, 2006 as amended to date.

1.0 Introduction

NPCC defines specific requirements applicable to design, operation, and **protection** of the **bulk power system**. The object of this *Classification of Bulk Power System Elements* (Document A-10) is to provide the methodology to identify the **bulk power system elements**, or parts thereof, of the interconnected NPCC Region.

The methodology in this document is used to classify **elements** of the **bulk power system** and may result in **elements** being added to or removed from the NPCC **Bulk Power System List**. The methodology in this document is based on the following:

- Results of an analysis done on a bus basis can be applied to identify which **elements**, or portions thereof, connected to the bus are part of the **bulk power system**.
- **Elements** shall not automatically be included or excluded from the **bulk power system** based on voltage class. Application of this methodology may be omitted at buses that can be logically excluded from the **bulk power system** based on study results at other buses tested using this methodology. If a bus is determined to be **bulk power system**, all other buses with elements connected to that bus must be tested.
- **Elements** shall be evaluated based on this methodology when significant changes occur on the system that could change an **element's bulk power system** status; the evaluation may be limited to the affected part of the system.
- **Areas** and facility owners may adopt methodologies that exceed the requirements set forth in this document for their own purposes. However, only **elements** classified as **bulk power system** as a result of testing described in this document shall be included on the NPCC's list of **bulk power system elements**. NPCC criteria and compliance monitoring shall consider only the system **elements** listed on NPCC's list of **bulk power system elements**.

The Classification of **Bulk Power System Elements** is based on three defined terms: **bulk power system**, **local area** and **significant adverse impact**.

2.0 Definitions

Terms in *italics* in this document are defined in this section.

Terms in **bold** are defined in the *NPCC Glossary of Terms* (Document A-7).

2.1 *Bus*

Within this document the term *bus* refers to a junction with sensing or **protection** equipment within a substation or switching station at which the terminals of two or more **elements** are connected, regardless of whether circuit breakers are provided. In this context, *bus* may not have a direct correlation to the use of this term in substation design or a power flow data set.

In some configurations a *bus* may include more than one physical *bus*, such as in a breaker-and-a-half arrangement or a single-line-single-breaker arrangement in which two physical *buses* are connected through a *bus-tie* breaker. The examples in Figure 1 depict two of many possible configurations where two physical *buses* are tested as a single *bus*. *Buses* that are separated by normally open *bus-tie* breakers are considered as separate *buses*. The termination of line sections through switches should not be considered as a *bus* requiring testing unless the switches are activated as part of a **protection system** for the line which they sectionalize as part of normal **protection system** actions.

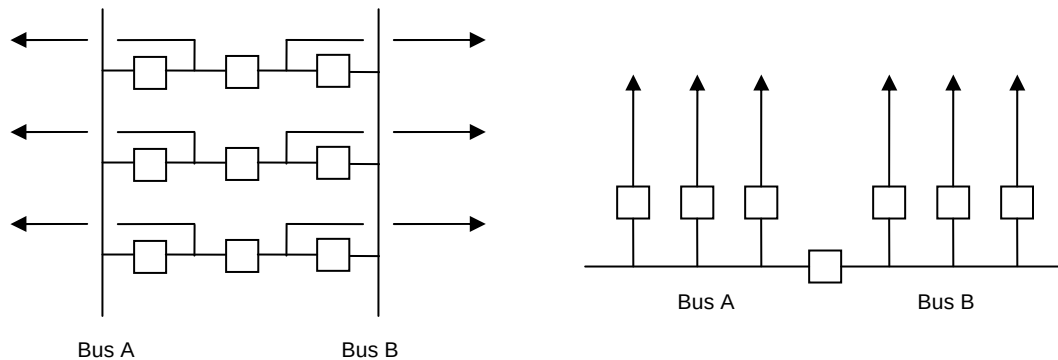


Figure 1 – Configurations where *Bus A* and *Bus B* are tested as one *bus*.

In some configurations **elements** may not be terminated to the *bus* through circuit breakers, such as the generator *bus* for a unit connected generator or a *bus* between a transmission line and transformer that are switched as a single circuit. The examples in Figure 2 depict two of many configurations where two physical *buses* are tested as separate *buses*.

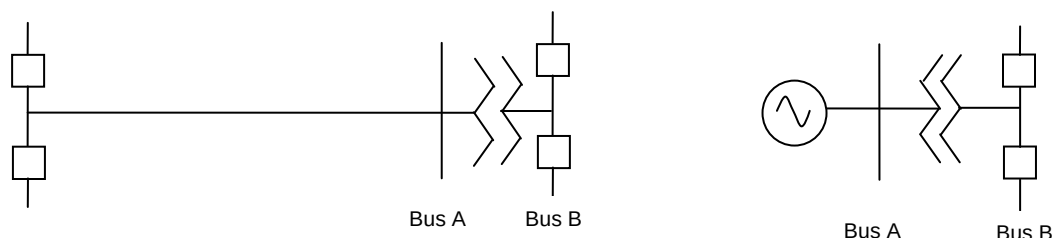


Figure 2 – Configurations where *Bus A* and *Bus B* are tested as two separate *buses*.

2.2 *Uncleared Locally*

Within this document the phrase *uncleared locally* is used to denote failure of the **protection** including **Special Protection Systems** for the *bus* under test to initiate tripping of all associated interrupting devices regardless of their location.

Protection located at other *buses* is assumed to operate as designed when that **protection** cannot be disabled by failure of a single component in common with the **protection** at the *bus* under test. For example, consider the case where the **protection** for **elements** connected to higher voltage level and lower voltage level *buses* in the same station share a dc source, and an independent dc source is provided for second **protection groups** associated with **elements** connected to the higher voltage level *bus*. In this case, it is acceptable when testing the lower voltage level *bus* to assume correct operation of any **protection groups** associated with **elements** connected to the higher voltage level *bus* capable of detecting the **fault** and supplied by the independent dc source.

In cases where circuit breakers are not provided at the terminals of the **element** at the *bus* under test (as shown in Figure 2, *bus A*), *uncleared locally* includes a failure to clear a **fault** by circuit breakers located at another *bus* within the same substation, unless back-up **protection** at that other *bus* using an independent dc source would detect the **fault** and initiate clearing.

3.0 Classification of Bulk Power System Elements

3.1 Testing Conditions and Assumptions

Studies conducted for the purpose of determining the **elements** of the **bulk power system** shall assume the following conditions:

- 3.1.1. Power flow transfers, **load** and **generation** patterns expected to exist for the period under study which stress the system in a manner critical to the classification of the *bus* to be tested. All **reclosing** facilities rendered inoperative.
- 3.1.2. Operation of **Special Protection Systems**, undervoltage **load shedding** and underfrequency **load shedding** modeled as designed.
- 3.1.3. Load models used in the **Transient Stability** Test are consistent with **Area** practices for the studies of rotor angle stability.
- 3.1.4. Load models used for steady state testing are either constant MVA or are based on actual system testing with LTC movement.
- 3.1.5. Stability simulation runs until the system response can be clearly determined.
- 3.1.6. Generic or detailed relay models to monitor, after tripping of remote terminals, the potential for tripping of un-faulted **elements**.

3.2 Test Methodology

Both **transient stability** and steady-state tests are used to determine the impact on system performance resulting from power system **faults**.

Testing is based on application of a *bus fault* at a single voltage level that is *uncleared locally*. Tripping of un-faulted **elements** associated with clearing the test **fault** does not constitute a **significant adverse impact**.

Depending on system configuration or topology, testing only **faults** at *buses* can fail to uncover **significant adverse impacts** arising from a design criteria contingency involving the loss of two adjacent transmission circuits on a common tower. Hence, specific tests in 1c and 2c below are designed to assess this contingency for its potential **significant adverse impact** outside of the **local area**.

A **transient stability** test may be done first to identify *buses* at which **faults** may cause a **significant adverse impact** outside of the **local area**.

For those *buses* which are not classified as **bulk power system** in the **transient stability** test, a steady-state test is used to identify *buses* at which **faults** may cause a **significant adverse impact** outside of the **local area**.

Step 1 - Transient Stability Test

Simulate the **transient stability** condition of a three-phase **fault** with delayed clearing at the *bus* under test (step 1a). If the test results in a positive **bulk power system** determination, more detailed testing (step 1b) may be applied to obtain a more precise determination.

- 1a. Apply a three-phase **fault** for at least 10 seconds at the *bus* that is being tested. Do not open any of the **elements** connected to the *bus* for the duration of the **fault**. After 10 seconds, simulate tripping of all terminals of each **element** connected to the *bus* under test. In cases where there is no **fault** interrupting device at the remote terminal of an **element**, open all terminals of all **elements** between the *bus* under test and the interrupting device(s) that will open to clear the **fault**. This test is performed as an efficient, but conservative method for evaluating the impacts of:

- *bus faults* which would result in faster clearing time, and
- **faults** off the *bus*.

It is recognized that due to the conservative nature of this test some **elements** could be classified unnecessarily as part of the **bulk power system**. If the above test results in a positive **bulk power system** determination, the following additional testing may be utilized to obtain a more precise determination. Subsequent testing utilizes design clearing times for the conditions being tested, as stated below.

- 1b. Apply a three-phase **fault** at the *bus*, which is *uncleared locally* and trip the remote terminals of all **elements** that will open to clear the **fault**. Remote clearing times shall be based on design **fault clearing** times, assuming no communications from the station under test to the remote terminals.

Transformers and other **elements** connected to the *bus* shall only be tripped by operation of independent remote **protection groups** capable of clearing a **fault** on the *bus* under test.

Some **protection groups** (e.g. directional comparison blocking) at remote terminals may provide high-speed **fault clearing** for faults at the *bus* under test. In order to test the effects of longer **fault clearing** times for fault conditions when these remote **protection**

groups would not provide high speed **fault clearing**, for either test (1a) or (1b) above:

- High-speed **fault clearing** at remote terminals must be ignored; or
- Testing must vary the placement of the 3-phase **fault** on the elements connected to the bus under test to include locations beyond the reach of the high-speed tripping relay element at the remote terminal.

However, the **protective relay** settings may be reviewed to determine whether the *bus* could be classified as not part of the **bulk power system** if faster remote **fault** clearing can be achieved. If **protective relay** settings are modified, an assessment shall be conducted to ensure that the faster clearing time does not compromise the security of the **protection system**. Until the **protective relay** settings are modified, the *bus* must be classified as **bulk power system**.

- 1c. The test above is meant to cover the majority of design criteria contingencies. However, the **elements** associated with the *bus* under test must be reviewed to ensure adverse consequences resulting from a design criteria contingency involving the loss of two adjacent transmission circuits on a common tower are not overlooked.

If a circuit terminating at the *bus* under test shares a multiple circuit tower with an adjacent circuit that does not terminate at the *bus* under test, the adjacent circuit design contingency must also be assessed. In such cases, simultaneous permanent phase to ground **faults** on different phases of each of two adjacent transmission circuits shall be applied at critical common tower locations. The **fault** on the circuit associated with the *bus* under test which is *uncleared locally*, shall be simulated with **normal fault clearing** at the remote terminal and on the adjacent circuit.

If the **fault** has a **significant adverse impact** outside of the **local area**, the *bus* is classified as part of the **bulk power system**.

For *buses* not classified as part of **bulk power system** in Step 1, continue with the Steady State Test in step 2.

Step 2 - Steady State Test

Simulate the post-**contingency** steady-state conditions based on one of the

following outcomes of the **fault** applied to the *bus* under test:

- 2a. If the **fault** was cleared based on design **fault clearing** times in the **Transient Stability** Test, open the same **elements** that were opened to clear the **fault** in the Transient Test. Post-**contingency** conditions shall reflect operation of all automatic devices.
- 2b. If the **fault** was not cleared based on design **fault clearing** times in the **Transient Stability** Test, assume that the **fault** propagates to the nearest location where it can be detected by independent **protection groups** and open the **elements** that would be opened by the **protection groups** to clear the **fault**. Note that because **fault clearing** will occur at interrupting devices capable of clearing the **fault**, it may be necessary to open multiple **elements** between the *bus* under test and the relevant interrupting devices, for example, a transmission line and transformer in series as shown in Figure 2.
- 2c. As in Step 1, the steady state test above is meant to cover the majority of design criteria contingencies. However, the **elements** associated with the *bus* under test must be reviewed to ensure adverse consequences resulting from a design criteria contingency involving the loss of two adjacent transmission circuits on a common tower are not overlooked. The post-contingency analysis must assess the loss of any adjacent circuit on common towers with a circuit terminating at the *bus* under test in addition to the **elements** associated with the *bus* under test.

Voltages and thermal loading will be assessed for **significant adverse impact** outside of the **local area** following automatic actions. In cases where a power flow solution is not obtained, other techniques shall be used to assess the impact of the event on the power system.

If the **fault** has a **significant adverse impact** outside of the **local area**, the *bus* is classified as part of the **bulk power system**.

Note that Step 2 can be done prior to Step 1. If a *bus* is classified as part of the **bulk power system** by the Steady State Test (Step 2), the **Transient Stability** Test (Step 1) need not be done for that *bus*.

3.3 Utilization of Test Results to Classify on an **Element-by-Element** Basis.

Classification of **bulk power system elements** is achieved by applying the results of the above tests to the **elements** connected to the tested *bus*.

An **element** with only one terminal such as a generator, shunt reactor, or capacitor bank, is classified as part of the **bulk power system** if the *bus* at which it is connected is classified as part of the **bulk power system**.

An **element** with multiple terminals such as a transformer or transmission line is classified as part of the **bulk power system** if any terminal of the **element** is connected to a *bus* that is classified as part of the **bulk power system**. The **bulk power system** classification may be limited to only a portion of the **element** if all of the following conditions are met:

- At least one terminal is connected to a *bus* that is not part of the **bulk power system**.
- The Steady State Test has been applied at the *buses* connected to all terminals of the **element** and none of these *buses* have been classified as part of the **bulk power system** based on results of the Steady State Test.
- The **Transient Stability** Test has been applied between the terminals of the **element** to identify those portions of the **element** for which the **Transient Stability** Test will not result in a **significant adverse impact** outside of the **local area**.

3.4 Documentation

Documentation for **Bulk Power System** classification shall include:

- 3.4.1 The rationale for the test conditions and assumptions used that are not listed above in 3.1.
- 3.4.2 The criteria used in evaluating the result of the testing including but not limited to stability, voltage, and thermal performance.
- 3.4.3 Detailed result of the testing shall be provided upon request.

4.0 Application and List Maintenance

Each **Area** shall be responsible for the application of the *Classification of Bulk Power System Elements* as described in this document and shall submit proposed changes and supporting documentation to the Task Force on System Studies (TFSS).

The “NPCC **Bulk Power System List**” will be maintained by the TFSS. Additions to and removals from the NPCC **Bulk Power System List** will be submitted by TFSS to the Reliability Coordinating Committee (RCC) for approval.

4.1 Addition of Elements to the Bulk Power System List

When application of this methodology identifies an **element** that was not part of the **bulk power system** should be classified as a **bulk power system element**, documentation of the analysis shall be presented to the TFSS. Once classification of the **element** is recommended by TFSS and approved by the RCC the **element** will be added to the NPCC **Bulk Power System List** with the appropriate comments and information. All task forces and the Compliance Committee will be notified once an **element** is approved by the RCC to be added to the **Bulk Power System List**. Within three months of an element being added to the **Bulk Power System List**, a plan and schedule for achieving compliance shall be provided to TFSP for review and acceptance. TFSP may require modifications to the proposed plan and schedule.

4.2 Re moval of Elements from the Bulk Power System List

When application of this methodology identifies a **bulk power system element** that no longer should be classified as a **bulk power system element**, documentation of the analysis shall be submitted to the TFSS. If reclassification of the **element** is recommended by TFSS and approved by the RCC, the **element** will be removed from the NPCC **Bulk Power System List**.

Lead Task Force:	Task Force on Coordination of Planning
Reviewed for concurrence by:	TFSS, TFCO, TFSP, and TFIST
Review frequency:	4 years
References:	<i>Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2)</i> <i>NPCC Glossary of Terms (Document A-7)</i>



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Disturbance Monitoring Equipment Criteria

Adopted by the Members of the Northeast Power Coordinating Council on August 23, 2007 based on recommendation by the Reliability Coordinating Committee, in accordance with paragraph IX, subheading (A), of the Amended and Restated Bylaws of Northeast Power Coordinating Council dated July 24, 2007 as amended to date.

Note:

Terms in bold typeface are defined in the *NPCC Glossary of Terms* (Document A-7)

1.0 Introduction

A prompt and accurate sequence of events must be established following a **disturbance** to provide timely analysis and reporting of the **disturbance**. The importance of Disturbance Monitoring Equipment (DME) in monitoring performance of **protection** equipment and validation of system simulation models has long been recognized in NPCC criteria. This document provides the application and functional requirements for NPCC DME, in accordance with NERC Reliability Standards PRC-002 and PRC-018.

2.0 General

The term Disturbance Monitoring Equipment (DME) is defined in the NERC Glossary, listed as Reference 1, and is repeated below for convenience:

Disturbance Monitoring Equipment (DME) - Devices capable of monitoring and recording system data pertaining to a Disturbance. Such devices include the following categories of recorders:

- Sequence of event (SOE) recorders which record equipment response to the event
- Fault recorders, which record actual waveform data replicating the system primary voltages and currents. This may include protective relays.
- Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions.

Footnote: Phasor Measurement Units (PMUs) and any other equipment that meets the functional requirements of DMEs may qualify as DMEs.

In this document, the terms DME, Sequence of Events Recorders, Fault Recorders, and DDRs all refer to functional capability and not to discrete devices.

All of the following applies to all new installations, and modifications to existing installations. Existing DMEs are required to be upgraded to meet these Criteria in accordance with the schedule called for in NERC Standard PRC-018-1.

This document shall be provided to the affected Reliability Coordinators (RCs), Transmission Owners (TOs), and Generator Owners (GOs) within 30 calendar days of its approval.

The TO and GO shall each install DMEs in accordance with these criteria. DMEs shall be provided to permit analysis and reporting of system protection performance,

monitoring of system protection performance, and validation of system simulation models.

3.0 **Sequence Of Event Recording**

- 3.1. Sequence of Event recording is the responsibility of transmission owners and **generation** owners. This capability can be provided as part of another device, such as a Supervisory Control And Data Acquisition (SCADA) Remote Terminal Unit (RTU), a generator plant Digital (or Distributed) Control System (DCS) or part of **fault** recording equipment.
- 3.2. Sequence of Event recorders shall be provided at all **bulk power system** substations and at generating units above 50 MW **capacity**, and at generating plants above 300 MW **capacity**
- 3.3. Sequence of Events recording shall monitor the following at each location:
 - Transmission and Generator circuit breaker positions
 - **Protective Relay** tripping for all **protection groups**
 - **Teleprotection** keying & receive

4.0 **Fault Recording**

- 4.1 **Fault** recording is the responsibility of transmission owners and **generation** owners. When adding or replacing a DFR at an existing BPS facility, the TO or GO should complete a notification in accordance with Document C-22.
- 4.2 **Fault** recording shall be provided by the TO to determine the current zero time for loss of **BPS** transmission **elements**. The current zero time shall be reported as the time of the final current zero on the last phase to interrupt.
- 4.3 **Fault** recording capability shall be provided by the GO for generating units above 200 MW **capacity**.
- 4.4 **Fault** recorders shall monitor the following **elements** at each location where **fault** recorders are installed:
 - All **BPS** Transmission Lines
 - Autotransformers or phase-shifters connected to **BPS** busses
 - Shunt capacitors 345 kV and above
 - Individual generator interconnections
 - Dynamic Var Devices
 - HVDC Terminals

- A Transmission Owner may optionally include the monitoring of transformers serving load from a **BPS** bus.
- 4.5 Electrical quantities to be recorded for each monitored **element** shall be sufficient to determine the following:
- Three phase-to-neutral voltages. (Common bus-side voltages may be used for lines.)
 - Three phase currents and neutral currents.
 - Polarizing currents and voltages, if used.
 - Frequency.
 - Active and reactive power.
- 4.6 **Fault** recorder record duration shall be a minimum of one (1) second.
- 4.7 **Fault** recorder minimum recording rate shall be 16 samples per cycle.
- 4.8 As a minimum, **fault** recorders shall be set to trigger for all the following functions:
- **Protective Relay** tripping for all **protection groups**
 - Neutral (residual) overcurrent set at 0.2 pu rated CT secondary current
 - Phase undervoltage set at 0.85 pu
- 4.9 When local conditions require different settings or additional functions, such situations shall be documented.

5.0 **Dynamic Disturbance Recording (DDR) Capability**

- 5.1 Where the DDR capability is deemed necessary by the Reliability Coordinator, the Reliability Coordinator shall provide guidance in setting triggers and shall monitor the performance of the DDR devices.
- 5.2 On an **Area** basis, there shall be at least ten (10) DDRs per 30,000 MW of peak **load**, distributed throughout the system, and installed at various types of locations, with consideration given to the following factors:
- Major **load** centers
 - Major **generation** clusters
 - Major voltage sensitive areas
 - Major transmission interfaces
 - Major transmission junctions
 - **Elements** associated with Interconnection Reliability Operating Limits (IROLs)

- Major EHV interconnections between control areas.
- 5.3 An evaluation of the need for a DDR should be made upon each new major **BPS** installation and upon each bulk power system station addition or expansion where a **fault** recorder replacement project is being made. (A field for this purpose will be included in the next revision of Document C-22.)
- 5.4 DDRs shall monitor the following **elements** at each location where dynamic recorders are installed:
- Most lines such that normal maintenance activities do not interfere with DDR requirements.
 - Bus voltages
- 5.5 As a minimum, DDRs shall monitor one phase current per monitored **element** and two phase-to-neutral voltages of different **elements**. One of the monitored voltages shall be of the same phase as the monitored current.
- 5.6 Electrical quantities to be recorded for each monitored **element** shall be sufficient to determine the following:
- Voltage, current, and frequency
 - Active and reactive power
- 5.7 DDRs installed after January 1, 2009 shall function as continuous recorders.
- 5.8 Each device shall sample data at a rate of at least 960 samples per second (16 samples per cycle and shall store the RMS value of electrical quantities at a rate of at least 6 data points per second.)
- 5.9 The following DDR triggers shall be considered where available based on manufacturers capability:
- Rate of change of Frequency
 - Rate of change of Power
 - Delta Frequency 20 mHz change
 - Oscillation of Frequency
- 5.10 When local conditions require different settings or additional functions, such situations shall be documented.
- 5.11 When DDR triggers are used, duration of triggered records shall be a minimum of sixty (60) seconds.

6.0 Data

- 6.1 Recorded **disturbance** data from DMEs shall be forwarded within 30 days of receipt of the request in each of the following cases:
- Request from NERC **Disturbance** Investigation Team
 - Request from NPCC **Disturbance** Investigation Team
 - Reliability Coordinator Request
- 6.2 Data forwarded shall be archived in its native format for a period of 3 years by the TO or GO.
- 6.3 **Disturbance** data files shall be provided in a format which is capable of being viewed, read, and analyzed with a generic COMTRADE analysis tool (8).
- 6.4 Disturbance Data files shall be named in conformance with IEEE C37.232 Recommended Practice for Naming Time Sequence Data Files.
- 6.5 **Fault** Recorder and DDR Files shall contain all monitored channels. SOE records shall contain station, date, time resolved to milliseconds, SOE point name, status.
- 6.6 Recorded data from each **disturbance** shall be retrievable for 10 calendar days. This requirement does not apply to **relays** unless those **relays** are designated as DME.
- 6.7 The TO and GO shall each maintain and be ready to report to NPCC on request the following data on the DMEs installed to meet this standard:
- Type of DME
 - Make and model of equipment
 - Installation location
 - Operational Status
 - Date last tested
 - Monitored **Elements**
 - Monitored Devices
 - Monitored Electrical Quantities

7.0 Time Synchronization

Internal clocks in DME devices shall be time synchronized to within 2 milliseconds or less of Coordinated Universal Time (UTC) scale. The time zone shall be clearly identified as either universal time zone or local time zone.

8.0 Maintenance And Testing

Each TO, and GO shall establish a maintenance and testing program for DME (guidance for maintenance and testing is provided in Document B-26) that includes:

- Maintenance and testing intervals and their basis.
- Summary of maintenance and testing procedures.

Prepared by: Task Force on System Protection

Review frequency: 3 years

References: *NERC "Glossary of Terms Used in Reliability Standards," November 1, 2006, available at www.nerc.com*

NERC Standard PRC-002-1, "Define Regional Disturbance Monitoring and Reporting Requirements," adopted by NERC BOT on 08/02/06 and effective on 05/-2/07, available at www.nerc.com.

NERC Standard PRC-018-1, "Disturbance Monitoring Equipment Installation and Data Reporting," adopted by NERC BOT on 08/02/06 with effective dates phased in over four year period beginning 08/02/06, available at www.nerc.com.

NPCC Glossary of Terms (Document A-07)

NPCC Guide to Time Synchronization of Substation Equipment (Document B-25)

NPCC Guide for Application of Disturbance Recording Equipment (Document B-26)

SP-6 Report

IEEE C37.111-1999, "IEEE Standard Common Format for Transient Data Exchange for Power Systems."

IEEE C37.232, "IEEE Recommended Practice for Naming Time Sequence Data Files." This document was submitted for publication in February 2007. Refer questions to TFSP.