August 10, 2006

To: NPCC Reference Manual Recipients

Subject: NPCC Reference Manual - Revision Number 17

Revision 17 to the NPCC Reference Manual includes nine revised Criteria, nine revised Guides and fifteen revised Procedure Documents. Also included are the revised scopes for Task Forces, Working Groups and for Compliance Monitoring and Assessment Subcommittee, CMAS.

Revisions to the NPCC Reference Manual are primarily distributed through the NPCC Web Site (http://www.npcc.org) and via e-mail upon requests to NPCC Staff. As was the case with recent Revisions, Reference Manual material will be distributed in Adobe format only, but copies of NPCC Documents in Word format can be obtained by request to NPCC staff.

For those of you that refer to the on-line versions of the Reference Manual located on the NPCC Web Site, the revised items have been updated. The files are in two locations:

1) The A, B and C Documents are found in the “NPCC Criteria Guides Procedures” folder, to which the direct link is: http://www.npcc.org/criteriaGuidesProcedures.asp Alternatively, go to the Web Site at http://www.npcc.org, click on “Reliability” and then on “NPCC Criteria Guides Procedures.”

2) The general section items are found at: https://www.npcc.org/documents.asp under publications. Alternatively, go to the Web Site, click on “Documents” and, under “Publications”, click on “Reference Manual – General Section & Revisions”

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Very truly yours,
Reza Rizvi
Engineer, Compliance
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Northeast Power Coordinating Council
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WHEREAS, reliable electric service is critical to the economic and social welfare of the millions of residents and businesses in Northeastern North America (as defined herein); and

WHEREAS, the reliable and efficient operation of bulk power systems in Northeastern North America is fundamental to achieving and maintaining reliability of power supply, requiring extensive coordination of system design and operations; and

WHEREAS, an open, inclusive process for assuring the establishment of, and compliance with regional design and operating criteria by all entities and industry sectors participating in the electricity market in Northeastern North America, in coordination with its members, including the ISO/Control Areas and sub-regional Councils within the region, is essential to assuring reliable service; and

WHEREAS, Northeast Power Coordinating Council is the appropriate authority to establish regional criteria, consistent with NERC/NAERO broad-based standards, and to assess and enforce mandatory compliance with such regional criteria in Northeastern North America.

NOW, THEREFORE, the members of Northeast Power Coordinating Council hereby agree as follows:
I. Purpose of Northeast Power Coordinating Council

The Full Members hereby agree to amend the Membership Agreement, which established the Northeast Power Coordinating Council (the "Council"), as provided herein effective November 9, 2000.

The purpose of the Council 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, to the extent possible, facilitates attainment of fair, effective and efficient competitive electric markets.

II. Membership of the Council

A. The members of the Council as of October 1, 2000 are listed on Schedule A hereto.

B. Upon suitable application describing the nature and activities of the applicant, additional entities shall be accepted by the Executive Committee as members in the appropriate categories, defined as follows:
(1) Full Membership shall be available to entities which participate in the interconnected electricity market in Northeastern North America.

(2) Public-Interest Membership shall be available to regulatory agencies with jurisdiction over participants in the electricity market in Northeastern North America and to public-interest organizations expressing interest in the reliability of electric service in Northeastern North America.

C. Independent System Operators ("ISO’s"), and Control Areas operating in Northeastern North America are expected to be Full Members of the Council. The New York State Reliability Council and any other sub-regional reliability councils which may be formed are also expected to be Full Members.

D. For purposes of this Agreement, two voting classes, each consisting of several sectors are hereby established. The two voting classes shall be composed solely of either Transmission Providers or Transmission Customers, defined as follows:

(1) A Transmission Provider means any entity operating in Northeastern North America which
owns, operates, or controls facilities used for the transmission of electric energy in international, interstate, or inter-provincial commerce; provided, however, that those facilities must be beyond the generator step-up transformers or radial generator leads and be employed in the interconnected bulk power system; or any sub-regional reliability council.

(2) A Transmission Customer means any entity not primarily a Transmission Provider operating in Northeastern North America which enters into a transmission service agreement with, or receives transmission service from, a Transmission Provider or an ISO within Northeastern North America.

E. (1) Upon acceptance of a new applicant for membership, the applicant shall indicate its voting class preference subject to Executive Committee approval.

(2) Executive Committee assignments of members to voting class shall be binding on the member and on the Council. Such assignments shall be subject to reevaluation and change upon request or at the discretion of the Executive Committee.
F. For purposes of this Agreement, the term "Northeastern North America" shall be deemed to comprise the geographical area within the perimeter border enclosing the State of New York, the six New England States of the United States, and the Canadian Provinces of Ontario, Quebec, Newfoundland, and the Maritime Provinces of New Brunswick, Nova Scotia and Prince Edward Island including any radial load or generation connecting to these systems.

III. Organization of the Council

A. Each Full Member shall designate a representative and an alternate representative with full authority to act for it in carrying out the work of the Council.

B. The Council shall have an Executive Committee to consist of the Council Chair, *ex officio*, who shall also be Chair of the Executive Committee, Vice Chair[s], the Executive Director, and the Secretary, all *ex officio*; and additional members to be selected by the two voting classes of Full Members, as follows:

(1) Transmission Providers:
Transmission Providers shall designate ten Executive Committee members as follows:

- ISO-New England 1
- New England Transmission Provider 1
- New York ISO 1
- New York State Reliability Council 1
- Independent Electricity Market Operator 1
- Ontario Transmission Provider 1
- Hydro-Quebec TransEnergie 2
- Maritime Provinces Transmission Providers 2

(2) Transmission Customers:

The Transmission Customers shall designate ten Executive Committee members, reflecting, insofar as practicable, the diversity of membership among the sectors in the voting class so as to distribute voting power equitably within the voting class.

The Council’s officers, when serving ex officio shall not have any vote on the Executive Committee.
The term of office of the voting members of the Executive Committee shall be three years. Initial terms of Committee members shall be staggered by the Committee so that members serve initial terms of one, two, or three years. There shall be no limit on the number of terms which may be served by any individual.

C. The officers of the Council shall consist of a Chair, one or more Vice Chairs, a Secretary and a Treasurer, with assistants as appropriate, and such additional officers as may be approved by both voting classes. Officers shall hold office for one year or until the next Annual Meeting of Members of the Council and until their successors are duly elected and qualified. In the temporary absence of the Chair, a Vice Chair designated by two-thirds vote of the individual Full Members represented on the Executive Committee shall perform the duties of the chair.

The Council shall also employ an Executive Director and Staff, as required to carry out the Council’s mission and to perform the functions of the Council.

D. In the event a vacancy occurs in the membership of the Executive Committee, or in the office of Vice
Chair, Secretary, or Treasurer in the interim between Annual Meetings of Members of the Council, the Chair may designate a person (from the same voting class when applicable) to fill such vacancy with the approval of two-thirds of the Full Members represented on the Executive Committee.

In the event a vacancy occurs in the Office of Chair in the interim between Annual Meetings of Members of the Council, the Executive Committee may fill such vacancy by approval of both voting classes. The term of office of the persons designated to fill any such vacancy shall expire on the date of the next subsequent Annual Meeting of Members of the Council. The authority and responsibilities of the Chair and of the Executive Director shall be defined by the Executive Committee.

E. Duties of the Executive Committee

The Executive Committee shall develop Council policies, direct the activities of the Council, accept additional entities as members, review and approve or modify the assignment of Full Members to their appropriate voting class, and make assignments to the committees of the Council. The Executive Committee shall oversee the Council's assessment and
enforcement of mandatory compliance with reliability criteria through administration of the NPCC Reliability Compliance and Enforcement Program. The duties of the Executive Committee shall also include consideration and resolution of all budgetary matters, including the levying of any special assessments, and determination of the annual membership fee for Full Members. However, the Executive Committee may not amend this Agreement or establish, modify or eliminate any of the Council’s reliability criteria, guides, programs or procedures; nor may the Executive Committee add, modify, or eliminate voting classes established pursuant to this Agreement.

To carry out the purposes of the Council, the Executive Committee, acting through the Executive Director and Council staff, shall enlist such personnel from members as may be necessary; and, within the limits of the annual budget, may employ such personnel, incur such administrative expenses, and retain such independent professional consulting services for the Council and the committees of the Council as it may deem desirable.
The Council shall also have a Standing Committees known as the Reliability Coordinating Committee (the Council’s principal technical committee), the Public Information Committee, and such other committees, subcommittees, task forces, and other such NPCC groups as the Executive Committee or the Standing Committee may deem appropriate. Standing Committee members shall be nominated by the Full Members and approved by the Executive Committee in accordance with guidelines established by the Executive Committee.

IV. Voting Rights

A. Class Voting by the General Membership.

(1) Each Full Member also shall have one vote when voting within its voting class on issues to be decided by the general membership by class voting in accordance with this Agreement.

(2) Issues related to the following matters, and any other issues expressly so designated by this Agreement, shall be resolved by the general membership by class voting:

- Establishment, modification, or elimination of any regional reliability criteria consistent with the North American Electric
Reliability Council/North American Electric Reliability Organization (NERC/NAERO) broad-based standards

- Establishment, modification, or elimination of the NPCC Reliability Compliance and Enforcement Program
- Election of Officers
- Selection of the members of the Council’s Executive Committee other than those serving ex officio
- Addition, modification, or deletion of voting classes
- Amendment of this Agreement

The resolution of such issues shall require the approval of both voting classes by two-thirds vote of the Full Members voting within each class when a quorum of the voting class has been obtained. Full Members may vote within a voting class by personal representative, by teleconference, by prior written consent, or by proxy. A majority of all Full Members in a voting class shall constitute a quorum sufficient to permit class voting by that voting class. A voting class failing to establish a quorum of the voting class through participation in person,
by teleconference, by prior written consent or by proxy may not vote; and, in that event, the issue shall be resolved by vote of the voting class which has established a quorum.

B. Class Voting by the Executive Committee and Standing Committee.

The resolution of all issues before the Executive Committee and the Standing Committee shall require the approval of both voting classes by two-thirds vote of the Full Members represented on each Committee voting within each voting class when a quorum of the voting class has been obtained.

Full Members may vote within a voting class by personal representative, by teleconference, by prior written consent, or by proxy. A majority of all Full Members in a voting class shall constitute a quorum sufficient to permit class voting by that voting class. A voting class failing to establish a quorum of the voting class through participation in person, by teleconference, by prior written consent or by proxy may not vote; and, in that event, the issue shall by resolved by the voting class which has established a quorum.
C. Subcommittee, task force, and other such NPCC groups procedures, including voting procedures, shall be established by the Standing Committee.

D. Any Full Member dissatisfied with the outcome of a vote at a meeting of a Standing Committee, task force, or other such NPCC group may bring the matter up for reconsideration by the Standing Committee or for consideration by the Executive Committee in accordance with procedures established by the Executive Committee which may include Alternate Dispute Resolution.

E. Public-Interest Members shall not have any voting rights.

V. Membership Rights and Obligations

A. Full Members shall have the following additional rights and obligations:

(1) Rights:

(a) Attendance at all meetings of the general membership of the Council; and, subject to procedures established by the Reliability Coordinating Committee and to the terms of applicable confidentiality agreements, attendance at meetings of the Council’s
committees, task forces and other such NPCC groups.

(b) Access to all committee, subcommittee, task force, and other such NPCC group’s minutes; and to reports and technical data developed by the Council’s staff, subject to procedures established by the Reliability Coordinating Committee and to the terms of applicable confidentiality agreements.

(2) Obligations:

(a) Each Full Member shall plan and design its bulk power system in compliance with Criteria, Guides, and Procedures established by the Council and applicable NERC/NAERO Standards.

(b) Each Full Member shall conduct its operations in compliance with Criteria, Guides, and Procedures established by the Council and applicable NERC/NAERO Standards.

(c) Each Full Member shall assure that, whenever it enters into arrangements with non-members which could have an impact on the reliability of the interconnected bulk
power systems in Northeastern North America, the arrangements accord with criteria established by the Council, the North American Electric Reliability Council, its successor, or the regional reliability councils established in areas in which the facilities used for such arrangements are located.

(d) Each Full Member shall notify the Council of its existing facilities and operating procedures and of its plans for major additions or modifications affecting the operation of the interconnected systems; and shall report to the Council any decision as to significant alterations or changes proposed for their respective electric systems, whether in generation, transmission, inter-system communication or control and protective equipment, or in operating procedures; such report to be submitted promptly and, except in cases of emergency, before final commitments are undertaken or changes in operating procedures become effective.
(e) Each Full Member shall promptly notify the Council and all other members in writing or electronically if its bulk power system is not being designed or operated, or its operations are not being conducted in compliance with Criteria, Guides, and Procedures established by the Council, stating its reasons, and providing its plan and schedule to achieve compliance.

(f) Each Full Member agrees to submit such data and reports as required by the Reliability Compliance and Enforcement Program and to abide by the compliance assessments and sanctions prescribed by the Council's enforcement procedures, subject to Alternate Dispute Resolution.

(g) Each Full Member shall undertake and perform the administrative and financial obligations described in Article X of this Agreement.

B. Public-Interest Members shall have the following rights:

(1) Attendance at all meetings of the general membership of the Council; and, subject to
procedures established by the Reliability Coordinating Committee and to the terms of applicable confidentiality agreements, attendance at meetings of the Council’s committees, task forces and other such NPCC groups.

(2) Access to all committee, subcommittee task force, and other such NPCC group’s minutes and reports, subject to procedures established by the Reliability Coordinating Committee and to the terms of applicable confidentiality agreements.

VI. Coordination of Design and Operations

Subject to approval by both of the voting classes of the general membership of the Council, the Reliability Coordinating Committee shall from time to time, through an open and inclusive process, establish or modify criteria for such elements of design as affect the operation of the interconnected bulk power systems of the members, and, through an open and inclusive process, establish or modify criteria for such elements of operating procedure as affect the operation of the interconnected systems. Such criteria, as a minimum, shall be consistent with applicable policies and criteria.
established by the North American Electric Reliability Council or its successor.

The Executive Director shall promptly inform the Reliability Coordinating Committee of any reports received from a member advising the Council of additions, modifications, alterations, and changes proposed for its bulk power system which have been submitted pursuant to Article V A(2)(d) of this Agreement. The Executive Director shall also promptly inform all members of the Council and the Reliability Coordinating Committee of reports of non-compliance with Council criteria submitted pursuant to Article V A(2)(e) of this Agreement.

On receipt of reports of proposals for additions, modifications, alterations, and changes or notification of noncompliance with Council Criteria, Guides, and Procedures received pursuant to Article V (2) (d) and (e) hereof, the Council, through its Reliability Coordinating Committee, shall proceed expeditiously to study and evaluate the proposed alterations or changes or non-compliance. Each member shall cooperate fully in the study and shall provide information requested by the Council concerning such proposals or reports of non-compliance.
Upon completion of such study and evaluation, the Executive Director shall report to each member the findings, conclusions, and recommendations of the Reliability Coordinating Committee with respect to such matters. If the Reliability Coordinating Committee determines that the proposals for alterations or changes, the reported non-compliance with Council criteria or instances of non-compliance identified following Council reviews could have a significant or persistent adverse impact upon the reliability of the interconnected bulk power systems, the Executive Committee may, and upon request of any member shall, call a special meeting of the members of the Council to consider further the effect of any such proposed additions, modifications, alterations, changes, or non-compliance on the interconnected systems and to consider the feasibility of any reasonable alternatives thereto.

In addition to its efforts to resolve issues arising out of such reports, the Executive Committee shall establish Alternate Dispute Resolution procedures pursuant to which Full Members may seek to voluntarily resolve disputes which could have a significant or persistent adverse impact on the reliability of the
interconnected bulk power systems in Northeastern North America.

VII. **Assessment and Enforcement of Mandatory Compliance**

Subject to approval by both of the voting classes of the general membership, the Council shall establish a Reliability Compliance and Enforcement Program, including matrices for measuring compliance, levying sanctions, and procedures for Alternate Dispute Resolution. Such program shall be administered by the NPCC Executive Committee. The Reliability Coordinating Committee, with the full cooperation of each member, shall expeditiously evaluate, as appropriate, alterations or measures designed to correct any assessed non-compliance and shall report such studies to the NPCC Executive Committee.

VIII. **Meetings**

Meetings of the Council may be held on such dates as the Chair from time to time determines and shall be held in such places as the Chair may from time to time designate. Special meetings may be called from time to time by the Chair, by the Executive Committee, or by three or more Full Members of the Council. Notice of all meetings, stating the time and place, shall be given by
the Council staff in writing to each member by issuing the notice at least one week prior to the date of the meeting. The Secretary, Assistant Secretary, or, in their absence, a secretary pro tempore, shall keep the records of Council meetings.

When appropriate, the general membership and the committees may use proxies or teleconference facilities. Such participation shall satisfy quorum requirements. The general membership, the Executive Committee, the Standing Committees, subcommittees, task forces and other such groups of the Council may take action without a meeting by unanimous written consent of all Full Members entitled to vote at a meeting.

IX. Budget

The Executive Committee, acting on behalf of the Council, shall adopt an administrative expense budget for each calendar year. Each Full Member shall be notified of the annual administrative expense budget and of its Membership Fee or assessment of its proportional share of expenses due on or before December 1st of the preceding year.
X. **Funding**

The Council’s annual administrative expenses, including any special assessments approved by the Executive Committee, shall be apportioned to and funded by the Full Members of the Council in fixed and variable components, as follows:

(A) Each Full Member, other than Full Members which are ISO/Control Areas, shall be assessed and pay an annual Membership Fee of $5,000 as established by the Executive Committee.

(B) A transition to ISO/CA Net Energy for Load based funding is outlined as follows:

(1) For the budget year 2001 - transitional year two, each ISO/Control Area shall be assessed and pay its proportional share of the remaining expenses of the Council in proportion to a .6667/.3333 weighted average of the ISO/CA percentages based upon the ratio of the Control Area’s 1999 Net Energy for Load to the aggregate Net Energy for Load within all Control Areas in Northeastern North America and the 1999 assessment percentages (NB 2.33%, NS 1.43%,
Ontario 19.22%, Quebec 17.88%, NE 24.17%, NY 34.97%.

(2) For Budget assessments starting in the year 2002 and thereafter, each ISO/Control Area shall be assessed and pay its proportional share of the remaining expenses of the Council in proportion to the ratio of the second previous year’s Net Energy for Load within the Control Area to the aggregate Net Energy for Load within all Control Areas in Northeastern North America.

(C) Public-Interest Members shall not be assessed any charge.

(D) Except in the event of dissolution of the Council, no member shall, without its consent, be responsible for administrative expenses of the Council in any one calendar year in excess of its Membership Fee or assessed portion of the amount budgeted for administrative expenses for that year, whichever is applicable; provided, however, that special assessments may be separately budgeted and their cost allocated by the Executive Committee to the Full Members which are ISO/Control Areas.
(E) The costs of dissolution of the Council shall be borne only by Full Members which are ISO/Control Areas in the same manner as that described in Article X (B)(2) of this Agreement.

XI. **Termination of Membership and Dissolution of the Council**

A. **Termination**

A Full Member may terminate its rights and obligations under this Agreement (other than its obligation to pay its (i) Membership Fee or (ii) its proportionate share of the administrative expenses of the Council, including special assessments or the costs of dissolution of the Council, if applicable, for the full calendar year within which such termination is effective) at any time upon one year’s written notice to the Executive Director; whereupon, it shall cease to be a member of the Council as of the date such termination is effective. The Executive Director shall promptly inform all members of receipt of any such notices. Public-Interest Members may terminate their membership in the Council at any time upon fifteen days written or electronic notice without liability to the Council.
B. Dissolution

The Council may be dissolved by vote of a majority of the Full Members which are ISO/Control Areas.

XII. General

A. This Agreement may be amended with the approval of both voting classes by vote of two-thirds of the Full Members in each voting class.

B. Notices to the Council pursuant to this Agreement may be written or electronic and shall be addressed to the Executive Director at the Council’s office in New York City, New York. Notices shall be effective upon receipt.

C. This Agreement shall be governed by, and construed in accordance with, the laws of the State of New York.

D. No member shall be liable for the failure of any other member to perform its obligations hereunder.

E. This Agreement shall not create any rights in non-members of the Council.

F. No NPCC officer, member of the Executive Committee or member of other such NPCC group, or employee of the Council shall be personally liable to NPCC or
any Member thereof, for damages for breach of any duty owed to NPCC or any Member, thereof, except for liabilities arising from breach of any duty based upon an act or omission (1) in breach of the duty of loyalty owed to NPCC or any individual Member, (2) not in good faith or involving a knowing violation of law, or (3) resulting in receipt of an improper personal benefit by such NPCC officer, member of the Executive committee or member of other such NPCC group, or employee of the Council. Neither the amendment nor repeal of this paragraph, nor the adoption of any provision of this Membership Agreement inconsistent with this paragraph, shall eliminate or reduce the protection offered by this paragraph to a NPCC officer, member of the Executive Committee or member of other such NPCC group, or employee of the Council in respect to any matter which occurred, or any cause of action, suit or claim which, but for this paragraph, would have accrued or arisen, prior to such amendment, repeal, or adoption.

G. Those entities listed as members on Schedule A and subsequent applicants granted membership in the Council
H. shall be deemed to have accepted and to be bound by all the terms and conditions of this Agreement, as adopted on November 9, 2000 and as subsequently amended, without the need to sign this Agreement.

I. The modifications of this Agreement, adopted on November 9, 2000 shall become effective on November 9, 2000.

Executed as of January 19, 1966

As amended to November 9, 2000
Schedule A

MEMBERS

on October 1, 2000

**FULL MEMBERS***

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<td>PG&amp;E Generating Company</td>
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**PUBLIC INTEREST MEMBERS**

New York State Department of Public Service
Office of Senator Henri S. Rauschenbach
Québec Energy Board

*Full Members vote within Transmission Provider (TP) or Transmission Customer (TC) voting classes.
Northeast Power Coordinating Council
Compliance Monitoring and Assessment Subcommittee

SCOPE & PROCEDURES

RESPONSIBILITIES

The Compliance Monitoring and Assessment Subcommittee (CMAS) is responsible for performing independent monitoring and assessment of compliance with the criteria and standards included in the NPCC Compliance Program. CMAS is charged to manage the on-going NPCC Compliance Program, which consists of the NPCC Reliability Compliance and Enforcement Program (RCEP), the compliance monitoring and surveys requirements in NPCC Reliability Assessment Program (NRAP) and NPCC participation in the NERC Compliance Program.

SCOPE OF ACTIVITIES

To carry out the above responsibilities, CMAS will:

1. Monitor and assess Area compliance with NPCC criteria including requirements in the NPCC RCEP, NRAP, and the NERC Compliance Program. Request technical inputs and reports from the NPCC Task Forces as needed.
2. Document results and provide appropriate reports (e.g. to RCC, to NERC, etc.)
3. For instances of identified non-compliance, provide a report fully explaining the reason for the non-compliance and recommend to the RCC the appropriate sanction and review any mitigation plan or action proposed to achieve compliance.
4. Develop and implement the necessary processes and procedures to efficiently execute the NPCC Compliance Program.
5. Provide information and feedback on compliance program to NPCC Members, RCC, Task Forces and participants in the program. Conduct workshops as necessary to communicate NPCC Compliance Program requirements and obtain feedback from the program participants.
6. Conduct compliance surveys as required.
7. Manage the Review Process for the NPCC RCEP.
8. Provide oversight review of Area compliance programs.
9. Review and propose changes to existing documents as required for the NPCC Compliance Program, and propose new documents as required.
PROCEDURES

The following procedures establish the rules and conducts of the Compliance Monitoring and Assessment Subcommittee (CMAS or the Subcommittee).

ORGANIZATION AND MEMBERSHIP

Representation on CMAS is open to all NPCC members. Membership on CMAS is subject to the approval of the NPCC Reliability Coordinating Committee as a body the CMAS reports to. The CMAS consists of the officers (the Chair, the Vice-Chair, and the Secretary) and members.

The term of office of the CMAS members shall be a minimum of one year.

OFFICERS:

The officers of the CMAS shall be a chair, a vice-chair, and a secretary. The chair and vice-chair are elected by the CMAS Members to serve a minimum term of one year. The term of office begins upon adjournment of the meeting in which the election was held. There is no limit on the number of terms that the chair or vice-chair may serve. The NPCC Staff shall appoint the secretary.

The Chairperson represents the Subcommittee, and provides reports, recommendations and technical advice to the RCC, as necessary, to carry out the assigned functions of the Subcommittee.

The Vice-Chairperson shall act in the Chairperson’s absence, and may provide other assistance to the Chairperson. The Vice-Chairperson would normally succeed the chairperson.

VOTING

CMAS shall conduct business on a consensus basis. In the event of disagreement among the participants on a report or recommendation to be submitted to the RCC, majority and minority opinions shall be reflected in the report.

QUORUM REQUIREMENTS

CMAS does not make final decisions; therefore there are no quorum requirements for this Subcommittee.

MEETINGS

Meetings of the Subcommittee may be held on such dates and places as CMAS from time to time determines at its meetings. Special meetings may be called from time to time by the Chair or by three or more members of the Subcommittee. Written notice of a meeting shall be given at least seven days in advance of the meeting date. Such notice of a meeting shall include the agenda of the topics to be discussed and any materials deemed by the Chair or the Secretary to be necessary for the CMAS to establish a position on the issues.
CMAS MEMBER’S RIGHTS

CMAS members shall have the rights to:

1. Attend all meetings of the CMAS and express views on any matter to be acted upon at any CMAS meeting, subject to the established meeting rules and procedures.

2. Make or second motions and vote on any action brought before the CMAS.

3. Receive access to all the Subcommittee’s minutes and reports, subject to procedures established by the CMAS and to the terms of applicable confidentiality agreements.

4. Participate in any sub-group activities established by the CMAS, subject to established procedures.

CMAS MEMBER’S OBLIGATIONS

1. CMAS member shall participate fully in all activities of the Subcommittee in support of the CMAS Responsibilities as defined above and the Northeast Power Coordinating Council’s purpose as defined in its Membership Agreement.

2. CMAS member shall inform the Chair and the Secretary of his or her inability to attend a meeting or if an alternate member will be attending the meeting on his or her behalf.

Revised and approved at November 4, 2003 RCC Meeting
Northeast Power Coordinating Council
Task Force on Coordination of Operation

SCOPE

Mandate

To promote, and provide a forum for, the active coordination of reliability and operation among the NPCC Areas and NERC Regions to enhance the reliability of the interconnected bulk power system. To operate under the direction of the Reliability Coordinating Committee. To accomplish this mandate, the Task Force on Coordination of Operation (TFCO) has the following specific responsibilities:

1. Coordinate development of operating criteria and procedures affecting the reliability and operability of interconnected power systems in coordination with, and as directed by, NERC and NPCC.

2. Establish standing working groups and ad hoc working groups to assist in carrying out the mandate of the TFCO. Monitor the progress of these Working Groups.

3. Conduct seasonal reviews of the overall reliability of the generation and transmission systems in NPCC. Review the operational readiness of NPCC and recommend possible actions to mitigate any potential problems identified for the coming operating period.

4. Review, and act upon, NERC Standards, actions, motions and recommendations. Formulate the position of the TFCO on NERC Standards and provide this position to the NPCC Working Group CP-09 as appropriate.

5. Ensure the effectiveness of NPCC operations through:
   • the review of operations and disturbances and by providing any necessary follow-up, including the recommendation of remedial or mitigating actions; and
   • the development of criteria and procedures.

6. Promote and sponsor inter-Area and interregional studies to enhance reliability and operational effectiveness through the development of common operating criteria, standards and procedures, on such matters as:
   • inter-Area operations;
   • the derivation, application and interpretation of operating limits;
   • operating reserve criteria;
   • recovery to a secure state following contingencies; and
• the principles of operator actions in emergencies as they affect inter-Area reliability.

7. Provide coordination of operating issues with NPCC Task Forces and other Regions.

8. Provide recommendations for the NPCC representation on the NERC Operating Committee and its Subcommittees.

9. Assist the NPCC Compliance Monitoring and Assessment Subcommittee to monitor and coordinate the compliance efforts of the Areas.

10. On an annual basis, develop a two year statement of measurable goals and specific action plans that will be presented to the Reliability Coordinating Committee.

November 29, 2005
Northeast Power Coordinating Council

Task Force on Coordination of Operation

Terms of Reference

The following Procedures define the composition and conduct of the NPCC Task Force on Coordination of Operation.

Participation

Participation is open to all NPCC Members, and they shall have a reasonable opportunity to express views on any matter to be acted upon at the meeting. Any NPCC Member may request membership to the NPCC Task Force on Coordination of Operation. All guests attending a meeting of the NPCC Task Force on Coordination of Operation shall be identified at the meeting to the members and alternates present.

Due to the commercially sensitive real time nature of some of the material discussed, only entities responsible for system operation, and having no market function responsibility, may be a party to such discussions. In the context of sharing information pertinent to maintaining reliability among the Areas of the Northeast Power Coordinating Council, it may be necessary for the members of the NPCC Task Force on Coordination of Operation to disclose to each other certain information and materials which are, or may be, confidential, proprietary, secret or protected by state, provincial and federal laws relating to trade secrets. Use of such confidential information is solely for the purpose of allowing the members of the NPCC Task Force on Coordination of Operation to discuss, assess and evaluate reliability within the Northeast Power Coordinating Council. Members and guests taking part in the activities of the NPCC Task Force on Coordination of Operation must not disclose to merchant entities any information concerning the transmission system obtained through his or her participation. Members and guests taking part in the activities of the NPCC Task Force on Coordination of Operation must not share market information acquired from their respective markets.

All attendees of a meeting of the NPCC Task Force on Coordination of Operation are asked to so advise the Chair and Secretary of the Task Force in advance to facilitate the logistics of the meeting.

Representation and Voting

Two voting representatives are selected by each of the five NPCC Areas, defined as Ontario, the New York ISO, the ISO New England Inc., the Maritimes Area and Québec, one of whom must be a representative of the Area’s Reliability Coordinator. The second voting representative for the Area should be a representative of a Transmission Operator from that Area. Voting representatives should serve a minimum
of two years. A vote may be cast in person by the voting representatives or the voting representative’s alternate, or by another person provided with a written designation or proxy dated not more than one month prior to the meeting and delivered by the member or alternate to the Secretary of the NPCC Task Force on Coordination of Operation at, or in advance of, the meeting at which the vote is cast. A member or alternate may revoke their designation of a proxy by delivering written notice of the revocation to the Secretary of the NPCC Task Force on Coordination of Operation.

A quorum of the NPCC Task Force on Coordination of Operation must be participating for any action to be taken by the Task Force other than adjournment of the meeting. Eight of the ten Area voting representatives must be present, and all NPCC Areas must be represented, to establish a quorum. When a quorum has been obtained, affirmative action of any issue submitted to the NPCC Task Force on Coordination of Operation for vote shall require approval by two-thirds vote of the voting representatives present but no less than six affirmative votes. The results of the vote conducted by the NPCC Task Force on Coordination of Operation will be recorded in the minutes of the Task Force.

The NPCC Task Force on Coordination of Operation elects a Chair and Vice Chair whose terms are not to exceed two years. Upon the completion of the term of the Chair, the current Vice Chair of the Task Force will normally succeed as Chair for a term not to exceed two years. A Secretary to the NPCC Task Force on Coordination of Operation is appointed by the Staff of the Northeast Power Coordinating Council.

Each member shall have the right to express views on any matter to be acted upon at any meeting of the TFCO (subject to the established meeting rules and procedures), make or second motions, request a special meeting, and, if a voting member, vote on any action properly brought before the Task Force on Coordination of Operation.

Meetings

The NPCC Task Force on Coordination of Operation shall normally meet six times per year.

Additional meetings, as requested by a member and approved by the Chair, shall be held as necessary to conclude issues before the Task Force.

Conference calls of the NPCC Task Force on Coordination of Operation, as requested by a member and approved by the Chair, shall be held as necessary to address urgent issues before the Task Force.

Members of the NPCC Task Force on Coordination of Operation may participate in a meeting of the Task Force in person, by telephone, or, as available, by means of conference telephone, electronic video screen communication, or other communications equipment by means of which all persons participating in the meeting can communicate
in real time with each other, and such participation in a meeting shall constitute presence in person at the meeting. To the extent that meetings are to be held in person, upon request and if practicable, provisions shall be made for a member or alternate to listen to the meeting by telephone and, if authorized, to vote at the meeting.

Notice of Meeting

Written or electronic notice of each meeting of the NPCC Task Force on Coordination of Operation shall be given to each member and alternate not less than seven days prior to the date of the meeting. Such notice of the meeting shall include the agenda of those topics to be addressed and all background materials available and deemed by the Chair or Secretary to be necessary for the TFCO to establish a position on all issues to be discussed. Background materials must be provided to the Secretary of the NPCC Task Force on Coordination of Operation prior to the date the notice of a meeting is required to be given to each member and alternate so that such background materials can reasonably be included with the notice. Notice shall be deemed to have been given if sent electronically to the member and alternate at his or her designated electronic mail address and when posted on the Web site of the Northeast Power Coordinating Council. As deemed necessary, the NPCC Task Force on Coordination of Operation may vote to waive the notification requirements.

November 29, 2005
Northeast Power Coordinating Council  
Task Force on Coordination of Planning  
SCOPE(RCC Approved 9/7/05)

General Statement
Promote reliability through the coordination of NPCC Area planning processes and activities.

Responsibilities
1. Initiate reviews of the Basic Criteria for the Design and Operation of Interconnected Power Systems (Document A-2), of other NPCC criteria, guidelines, and procedures related to planning, and of those documents which provide for the uniform implementation, interpretation and monitoring of compliance with criteria, guidelines and procedures related to planning. These reviews will be coordinated with the other Task Forces, based on a schedule set forth in the Reliability Assessment Program.

2. Initiate reviews of any documents in response to lessons learned from major system events.

3. Review the adequacy of the NPCC systems to supply load considering forecast demand, installed and planned supply and demand resources and required reserve margins in accordance with Guidelines for Area Review of Resource Adequacy (Document B-8) and Guidelines for Transmission Area Reviews (Document B-4), based on a schedule set forth in the Reliability Assessment Program.(review for consistency with Documents)

4. Coordinate the review of the future Area plans for compliance with the Basic Criteria including an analysis of resource and transmission system additions, and the potential inter-Area effects of special protection systems, based on a schedule set forth in the Reliability Assessment Program. Specific projects, which in the opinion of the task force could have an impact on the reliability of the NPCC bulk power system, may be reviewed outside of the set schedule.

5. Coordinate the review of proposed new or modified special protection systems in accordance with the Procedure for NPCC Review of New or Modified Bulk Power System Special Protection Systems (Document C-16).

6. Coordinate assessments related to new applications from entities requesting membership in NPCC in accordance with the Procedure for Review of an Entity’s Application for Membership.

7. Maintain close liaison with other task forces of NPCC and coordination with adjoining councils, with reference to system planning activities.

8. Review the implications of various reliability related issues and make recommendations to the Reliability Coordinating Committee as appropriate.

9. Encourage Area planning organizations to initiate inter-Area and interregional studies where improved reliability may be achievable through joint planning.

June 21, 2005
10. Establish working groups and initiate studies, including joint efforts with other task forces as appropriate, relative to the overall reliability of the planned bulk power system.

11. Assess requests by member systems for exclusions in accordance with the Guidelines for Requesting Exclusion to Section 5.1(B) of the NPCC Basic Criteria for Design and Operation of Interconnected Power Systems (Document B-10) and make recommendations to the Reliability Coordinating Committee regarding such requests.

12. Interface with and provide information to the North American Electric Reliability Council Reliability Assessment and Reliability Criteria Subcommittees, as required. Ensure NPCC Criteria are not inconsistent with the NERC requirements as set forth in their Reliability Standards.

13. Coordinate NPCC responses to related FERC and regulatory/governmental agencies. Ensure NPCC Criteria are reviewed with respect to approved governmental regulatory orders.

14. Promote use of emerging technologies that are not inconsistent with current best practices.

15. Review and modify documents to reflect prudent application of new technologies.

16. Report to the Reliability Coordinating Committee on the above and other matters as required.
Northeast Power Coordinating Council
Task Force on Infrastructure Security and Technology (TFIST)

SCOPE

General Statement

The mission of the NPCC Task Force on Infrastructure Security and Technology (TFIST) is to:

- advance the Physical and Cyber Security of the electricity infrastructure of Northeastern North America
- advance the technology of EMS, SCADA and their associated telecommunications for the reliable operation of the NPCC Bulk Power System

Responsibilities

It shall be considered within the scope of the activities of this task force to:

1. Provide a forum for NPCC review of proposed and posted documents from the NERC Critical Infrastructure Protection Committee (CIPC).

2. Provide recommendations to NPCC Committees, Task Forces and Working Groups to facilitate NPCC’s position regarding proposed NERC security guidelines/standards.

3. On an annual basis provide recommendations to RCC to enhance compliance with NERC Standards within TFIST’s General Statement.

4. Represent and advocate NPCC’s position in the activities of NERC groups involved in the development and/or implementation of Physical and Cyber Security, EMS, SCADA and Telecommunications. TFIST will focus on the activities of the NERC Critical Infrastructure Protection Committee (CIPC).

5. Participate in information sharing activities at national, regional, and interregional levels.

6. Coordinate and communicate with those responsible for both Physical and Cyber Security within all NPCC Members.


8. Address potential Security implications from Interdependencies with the electric utility industry, including telecommunications, Gas, Water, Coal, transportation industries.
9. Assess areas in which process improvements or sharing can improve the reliability of the NPCC Bulk Power System.

10. Provide guidance in areas such as corporate continuity, and disaster recovery.

11. Develop and maintain levels of expertise in those areas of concern to the task force through activities such as periodic workshops, seminars, and meetings, open to the general NPCC membership.


14. Provide coordination for the administration of inter-Area and inter-Regional data communications networks used to interconnect control centers.

15. Under policy direction of the Reliability Coordinating Committee provide assistance to the other NPCC Task Forces, and to NPCC staff.

16. TFIST will submit a workplan and a progress report to RCC, or concerned Task Force annually or when required and when necessary, attend meetings.

Membership

Membership on the TFIST is open to representatives from all NPCC members. Participants should have experience and responsibilities in the areas of cyber security, physical security, EMS, SCADA or Telecommunications.

May 25, 2005
Northeast Power Coordinating Council
Task Force on System Protection

SCOPE

Statement of Purpose

The purpose of the NPCC Task Force on System Protection (TFSP) is to promote the reliable and efficient operation of the interconnected bulk power systems in Northeastern North America through the establishment of criteria, guidelines, and procedures and coordination of design, relative to the protection associated with the bulk power systems. (Terms in bold typeface are defined in the NPCC Glossary of Terms (Document A-7)).

Responsibilities

1. Based upon the requirements set forth in the NPCC Reliability Assessment Program:

   A) Initiate, and coordinate with designated Task Forces, review of the:

      • Maintenance Criteria for Bulk Power System Protection (Document A-4)
      • Bulk Power System Protection Criteria (Document A-5)
      • Special Protection System Criteria (Document A-11)
      • Guide for the Application of Autoreclosing to the Bulk Power System (Document B-1)
      • Automatic Underfrequency Load Shedding Program Guideline (Document B-7)
      • Guide for Analysis and Reporting of Protection System Misoperations (Document B-21)
      • Guide for Maintenance of Microprocessor Based Protection Relays (Document B-23)
      • Security Guidelines for Protection Systems IEDs (Document B-24)
      • Procedure for Reporting and Reviewing Proposed Protection Systems for the Bulk Power System (Document C-22)
      • Procedures for Task Force on System Protection Review of Disturbances (Document C-30)

   Conduct other appropriate reviews, modify existing documents and submit reports as required.

   B) Review, in cooperation with the Task Force on Coordination of Planning, the Task Force on Coordination of Operation, and the Task Force on System Studies,
the *Basic Criteria for Design and Operation of Interconnected Power Systems* (Document A-2) and other NPCC Criteria, Guides and Procedures. Develop and recommend modifications as required.

C) Review and analyze the performance of protection systems following selected major power system disturbances and events, inside as well as outside NPCC in accordance with *Procedures for Task Force on System Protection Review of Disturbances* (Document C-30). Issue recommendations for changes to NPCC Documents, as appropriate.

D) Assess proposed protection systems and special protection systems in accordance with the *Procedure for Reporting and Reviewing Proposed Protection Systems for the Bulk Power System* (Document C-22).

2. On an as-needed basis:

A) Provide technical advice on protection issues to the Compliance Monitoring and Assessment Subcommittee (CMAS) and any other NPCC groups.

B) Coordinate with the Task Force on Infrastructure Security and Technology (TFIST) on application of Intelligent Electronic Devices (IEDs) that include functions related to energy management systems in addition to their protective functions, in order to safeguard the integrity of the protective functions.

3. Review and assess significant protection issues of common interest or informational value.

4. As required, review and assess regulatory and industry based documents as they relate to system protection. Provide technical representation to working groups for review of such documents.

5. Maintain an effective liaison with North America groups working in the protection areas, for example NERC System Protection & Control Task Force.

6. Exchange information with other power pools, Regional Reliability Councils, Regional Transmission Organizations and other industry groups on matters concerned with system protection.

7. Identify the need for special studies and new documents, recommend action to the Reliability Coordinating Committee, and perform special assignments and studies as directed or authorized.

8. Report to the Reliability Coordinating Committee on these and other matters as required.
Northeast Power Coordinating Council
Task Force on System Studies

SCOPE

General Statement

Provide for active overall coordination of system studies of the reliability of the interconnected bulk power system and for the review of certain NPCC documents, in accordance with the schedule set forth in the Reliability Assessment Program.

Responsibilities

1. Participate with the Task Force on Coordination of Planning, the Task Force on Coordination of Operation and the Task Force on System Protection in reviews of the "Basic Criteria for the Design and Operation of Interconnected Power Systems" and other NERC and NPCC criteria, guidelines, procedures and documents which provide for the uniform implementation, interpretation and monitoring of conformance to criteria, guidelines and procedures related to system studies.

2. Conduct Area Reviews, in accordance with the "Guidelines for NPCC Area Transmission Reviews (Document B-4)" based on material presented by the Areas. These reviews will assess the impact of planned transmission and resource additions or modifications, on system reliability and determine the Area's conformance with the Basic Criteria.

3. Review and classify new and modified Special Protection Systems, in accordance with the “Procedure for NPCC Review of New or Modified Bulk Power System Special Protection Systems (Document C-16).” Participate in the annual review and update of the NPCC SPS list and present it to the RCC.

4. Conduct such load flow, transient stability, and other studies as required to analyze the overall reliability of the planned bulk power transmission system of NPCC and the interconnections between NPCC and other regional councils. As a part of this effort, analyze potential inter-Area effects of Special Protection Systems.

5. Conduct analytical studies as appropriate to support the coordination of system planning, system operation and system protection in NPCC.
6. Maintain, through the SS-37 Working Group, a library of load flow base cases and associated dynamics data, for use in and support of Area Reviews, overall transmission assessments, operational studies, inter-Regional studies, etc.

7. Participate in ad hoc reviews of specific projects as requested by the Task Force on Coordination of Planning.

8. In conjunction with other Task Forces, review major system disturbances to ascertain the adequacy of the interconnected system. Also, review any associated recommendations for system modifications and consider the need for criteria changes.

9. Coordinate with the Compliance Monitoring and Assessment Subcommittee on compliance-related activities.

10. Identify and recommend improved system study techniques. This includes, but is not limited to, the following:

   (a) improved techniques and models for power system simulation;

   (b) improved techniques for power system reliability assessment;

11. Conduct a periodic review of the adequacy of the NPCC underfrequency load-shedding program.

12. Maintain a listing and monitor status of major transmission and generation projects within NPCC.

13. Maintain liaison with other NPCC Task Forces and report to the Reliability Coordinating Committee as required.

14. Monitor the work of industry research and development organizations such as the IEEE, Canadian Electricity Association, Electric Power Research Institute, CIGRE and other technical organizations.

   March 2003
Northeast Power Coordinating Council  
Operational Review, Coordination and Assessment Working Group  

SCOPE

Mandate

The objective of the Operational Review, Coordination and Assessment Working Group (CO-7) is to assess, coordinate and evaluate regional operational issues and reliability concerns as directed by the Task Force on the Coordination of Operations. The Working Group will be responsible for the periodic review of matters related to, but not limited to, NPCC’s Regional Reliability Plan and the Registration and Certification of entities to achieve conformance with the criteria and procedures of Northeast Power Coordinating Council (NPCC) and North American Electric Reliability Council (NERC) Standards.

1. Operate under the direction of the Task Force on Coordination of Operations (TFCO).

2. As requested by TFCO, review specific NERC Standards for consistency with applicable NPCC A, B and C documents.

3. Assist the NPCC Compliance Monitoring and Assessment Subcommittee to monitor and coordinate compliance efforts of the NPCC Areas as required.

4. Perform a periodic review of Functional Registration and Certification of NPCC entities.

5. Conduct an annual review or, as required, of the NPCC Regional Reliability Plan.

6. Coordinate with other NPCC Sub-Committees, Task Forces and Working Groups, as required.
Northeast Power Coordinating Council
Operational Review, Coordination and Assessment Working Group

Terms of Reference

The following Procedures define the composition and conduct of the NPCC Operational Review, Coordination and Assessment Working Group, CO-7.

Participation

Participation is open to all NPCC Members, and they shall have a reasonable opportunity to express views on any matter to be acted upon at the meeting. Any NPCC Member may request membership to the NPCC Operational Review Team WG. All guests attending a meeting of the NPCC Operational Review Team shall be identified at the meeting to the members and alternates present.

Due to the commercially sensitive real time nature of some of the material discussed, only entities responsible for system operation, and having no market function responsibility, may be a party to such discussions. In the context of sharing information pertinent to maintaining reliability among the Areas of the Northeast Power Coordinating Council, it may be necessary for the members of the NPCC Operational Review, Coordination and Assessment Working Group to disclose to each other certain information and materials which are, or may be, confidential, proprietary, secret or protected by state, provincial and federal laws relating to trade secrets. Use of such confidential information is solely for the purpose of allowing the members of the NPCC Operational Review, Coordination and Assessment Working Group to discuss, assess and evaluate reliability within the Northeast Power Coordinating Council. Members and guests taking part in the activities of the NPCC Operational Review, Coordination and Assessment working Group must not disclose to merchant entities any information concerning the transmission system obtained through his or her participation. Members and guests taking part in the activities of the NPCC Operational Review, Coordination and Assessment Working Group must not share market information acquired from their respective markets.

All members of the NPCC Operational Review, Coordination and Assessment Working Group intending to attend a meeting are requested to advise the Chair and secretary of the Working Group in advance to facilitate the logistics of the meeting.

Representation and Voting

Representatives for the NPCC Operational Review, Coordination and Assessment Working Group are selected by the five NPCC Areas, defined as the Independent Electricity System Operator for Ontario, the New York Independent System Operator, New England Independent System Operator, New Brunswick System Operator for the Maritimes Area and Hydro-Quebec TransEnergie for Québec, one of whom must have an in-depth technical knowledge of their defined Area of operations. Members of the NPCC Operational Review, Coordination and Assessment Working Group shall strive to reach
consensus on all issues. Should the members be unable to reach consensus, a majority and minority position shall be sent to the NPCC Task Force on Coordination of Operation.

A quorum of the NPCC Operational Review, Coordination and Assessment Working Group must be participating for any action to be taken by the Working Group other than adjournment of the meeting. Three of the five Area representatives must be present and four of NPCC Areas must be represented and participating to establish a quorum.

The NPCC Operational Review, Coordination and Assessment Working Group will elect a Chair and Vice Chair whose terms will be for two years. Upon the completion of the term of the Chair, the current Vice Chair of the Working Group will, under normal circumstances, succeed as Chair. The Chair position for 2006 will be filled by the IESO representative and the Vice-chair position by HQTE. The Vice-chair position beyond 2006 will be filled according to the following succession schedule:

1) NBSO  
2) ISO-NE  
3) NYISO  
4) IESO  
5) HQTE.

Each member shall have the right to express views on any matter to be acted upon at any meeting of the NPCC Operational Review, Coordination and Assessment Working Group

Meetings

The NPCC Operational Review, Coordination and Assessment Working Group shall normally meet six times per year.

Additional meetings, as requested by a member and approved by the Chair, shall be held as necessary to conclude issues before the Working Group.

Conference calls of the NPCC Operational Review, Coordination and Assessment Working Group, as requested by a member and approved by the Chair, shall be held as necessary to address urgent issues before the Task Force on Coordination of Operation.

Members of the NPCC Operational Review, Coordination and Assessment Working Group may participate in a meeting of the Working Group in person, by telephone, or, as available, by means of conference telephone, electronic video screen communication, or other communications equipment by means of which all persons participating in the meeting can communicate in real time with each other, and such participation in a meeting shall constitute presence in person at the meeting. To the extent that meetings are to be held in person, upon request and if practicable, provisions shall be made in advance for a member or alternate to listen to the meeting by telephone.
Notice of Meeting

Written or electronic notice of each meeting of the NPCC Operational Review, Coordination and Assessment Working Group shall be given to each member and alternate not less than seven days prior to the date of the meeting.

January 13, 2006
Northeast Power Coordinating Council
Task Force on Coordination of Operation
Working Group CO-8: System Operations Managers

Scope

Objective

Provide a forum for the Managers of the NPCC control centers to identify and discuss security concerns in the operation of the interconnected bulk power supply system, and specific concerns related to the integration of operation between and among the evolving control centers. The System Operations Managers Working Group (NPCC Working Group CO-8) will also assist the Task Force on Coordination of Operation in their work on issues related to system security and the operation of the control centers, and provide advice to the TFCO, as requested.

Activities

To meet the intent of the objective, the Working Group CO-8 will:

1. meet a minimum of four times a year, to identify and discuss evolving issues, share information, and reach agreements on needed processes. Critical issues will be identified and brought to the attention of the Task Force on Coordination of Operation. Regular meetings will be scheduled prior to the summer operating period (March and May) and the winter operating period (September and November)

2. initiate conference calls to provide management support in the event of situations that are causing or may cause severe stress to the interconnected bulk power supply system. The dissemination of information through this process will be restricted to control center staff and will be used for security reasons only

3. provide representation to the meetings of the Task Force on Coordination of Operation to review Working Group CO-8 initiatives, bring issues for resolution to the Task Force, and return assigned charges from the TFCO to the Working Group CO-8.

4. translate NPCC Criteria, Guides and Procedures, and NERC Operating Policies, into control room procedures, and coordinate among the Areas the implementation of these procedures
5. The System Operations Managers Working Group (Working Group CO-8) will further support the Working Group on Dispatcher Training (Working Group CO-2) in their work on issues related to training and seminars by:

- supporting the biannual seminars
- committing to a minimum number of dispatcher attendees by control area per seminar
- proposing, commenting and approving subjects or invited guests for seminars
- committing to obtain the financial support needed for the biannual seminars
- guaranteeing the participation in the CO-2 working group by maintaining a back up person for each of the CO-2 members.
- inviting schedulers to each seminar

6. Members of the CO-8 Working Group will guaranty their participation by maintaining an active alternate.

7. Joint meetings with Working Groups CO-2 and CO-8 will be held twice a year to prepare the seminars.

Approved by the NPCC Reliability Coordinating Committee
July 9, 2003
Northeast Power Coordinating Council
Task Force on Coordination of Operation
Working Group CO-9: Operational Policies Working Group

Scope

Objective

To coordinate the reformatting of the Northeast Power Coordinating Council (NPCC) operating criteria, guides and procedures and incorporate them into the NERC Operating Policies as regionally specific provisions.

Activities

1. Evaluate the conformance of the NPCC criteria, guides and procedures with the Operating Policies of the North American Electric Reliability Council (NERC) with a focus on correcting identified deficiencies and suggesting a course of remedial action to eliminate these deficiencies.”

2. Propose the primary Task Force responsibility for NPCC document maintenance, and, as appropriate, recommend secondary Task Force responsibility for concurrent document review.

3. Develop composite NPCC / NERC Operating Policies capturing NPCC specificity unique to each NERC Operating Policy and post the resulting drafts for NPCC Open Process review.

4. Coordinate and respond to all posted comments received through the NPCC Open Process.

5. Prepare a final draft submission of the consolidated NPCC / NERC Operating Policies for submittal to the Task Force on Coordination of Operation in accordance with the appended time line.
6. Finalize NPCC realizable Compliance Templates.

Task Force on
Coordination of Operation
January 18, 2000
<table>
<thead>
<tr>
<th>Proposed CO-9 Time Line</th>
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<tbody>
<tr>
<td>Release of Policies 2 and 4 to NPCC Open Process</td>
<td>February 18, 2000</td>
</tr>
<tr>
<td>Release of Policies 1, 5 and 6 to NPCC Open Process</td>
<td>April 14, 2000</td>
</tr>
<tr>
<td>Release of Policies 8 and 9 to Open Process</td>
<td>May 30, 2000</td>
</tr>
<tr>
<td>Submission of Complete Operating Policies (including Policies 3 and 7) to the TFCO</td>
<td>July 1, 2000</td>
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<tr>
<td>Release of Complete Operating Policies (including Policies 3 and 7) to Open Process</td>
<td>August 1, 2000</td>
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<tr>
<td>Final Review by the TFCO of Open Process Comments by the TFCO</td>
<td>September 27-28, 2000</td>
</tr>
<tr>
<td>RCC Submission</td>
<td>November 9, 2000</td>
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Purpose
The objective of the Inter-Control Area Restoration Coordination Working Group (IRCWG) is to achieve effective and coordinated power system restoration among the NPCC Control Areas and with adjacent jurisdictions.

Scope of Activities
1. Review the restoration plans of the NPCC Control Areas to identify in each individual plan:
   • general elements of the restoration plan
   • communication protocols employed
   • roles and responsibilities of the restoration participants
2. Recommend enhanced procedures for the coordination of inter-Area restoration.
3. Identify areas where mutual assistance can be provided and the extent to which each system can rely on its neighbors for assistance.
4. Review NPCC documentation, including, but not limited to, the following documents:
   • “Emergency Operation Criteria”
   • “NPCC Inter-Control Area Power System Restoration Reference Document”
5. Identify and recommend revisions to the Control Area training plans.
6. Review and maintain the NPCC list of Key Facilities and associated Critical Components.
7. Review relevant contingency events and system disturbances to determine findings and recommendations towards optimizing coordinated restoration.
8. Monitor evolving NERC activities relative to system restoration.
9. Assist the Compliance Monitoring and Assessment Subcommittee as appropriate.


NPCC Reliability Coordinating Committee
November 4, 2003
Mandate

To ensure sufficient resources in the event of extreme operating conditions, the Task Force on Coordination of Operations (TFCO) directs the Operations Planning Working Group (CO-12) to conduct overall assessments of the reliability of the generation and transmission system in the NPCC Region for the Summer and Winter operating periods. The assessment report for each Operating Period shall be available to TFCO prior to April 30 or November 30 of each year.

TFCO may request CO-12 to assess other operating periods on an ad hoc basis.

Terms of Reference

Participation

As a minimum, CO-12 membership shall be comprised of one member from each NPCC Area. To ensure co-ordination with external regions, assistance from adjacent regional reliability organizations will be requested on an as needed basis.

Due to the commercially sensitive nature of some of the material discussed during the development of assessment reports, only entities responsible for system operation, who have no market function responsibility, may be a party to discussions.

In the context of sharing information pertinent to maintaining reliability among the Areas of the Northeast Power Coordinating Council, it may be necessary for the CO-12 members to disclose to each other certain information and materials which are, or may be, confidential, proprietary, secret or protected by state, provincial and federal laws relating to trade secrets. Use of such confidential information is solely for the purpose of allowing the CO-12 members to discuss, assess and evaluate reliability within the Northeast Power Coordinating Council. Except as otherwise required for interim or final report presentations to TFCO or NPCC Reliability Coordinating Committee, CO-12 members shall not disclose to any merchant entity any information concerning the transmission system or market information acquired from the respective markets that was

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1 The Summer Operating Period includes the months May, June, July and August. The Winter Operating Period includes the months of December, January and February.
obtained through his or her participation in CO-12 activities. As necessary, CO-12 members and other participants shall sign a non-disclosure either annually or on a one-time basis, depending on the content of the agreement. NPCC staff will obtain the non-disclosure agreement developed by legal counsel.

Each NPCC Area shall provide a chair for CO-12 on a rotating basis. The chair shall oversee the report development for one consecutive Summer Operating Period and one Winter Operating Period. The order of the rotation shall be IMO, Trans Energie, Maritimes, ISO-New England and New York ISO.

Scope of Activities

For each operating period under consideration the CO-12 Working Group shall, for the report period under assessment:

1. Utilize single data standards for the reporting of Load and Capacity values to provide a uniform assessment between NPCC Areas.

2. Utilize Load and Capacity Values in the report and allow for consistent comparison of the results associated with other parallel pre-seasonal assessments such as the reports developed by the NERC Reliability Assessment Subcommittee.

3. Document the methodology each Area uses in its projection of load forecasts and in the Areas projection of unit unavailability rates.

4. Examine historical summer or winter operational experiences and assess their applicability.

5. Assess the extent to which the NPCC Areas may implement emergency operating procedures.

6. Report potential sensitivities on an Area basis, which may impact resource adequacy, including temperature deviations, merchant plant delays, load forecast uncertainties, fuel availability, load response measures and system voltage / generator reactive capability limits.

7. As appropriate, provide coordination with other parallel seasonal operational assessments.

On an annual basis, the CO-12 Working Group shall, as part of the assessment, review the Operational Readiness of each Area to deal with unforeseen operating conditions. This review of each Area’s Operational readiness shall be performed during the assessment of the Summer Operating Period and shall be applicable throughout the year.
including both the Summer and the following Winter operating periods. Specific items to be addressed include:

1. Impacts of Environmental constraints on Generation resources
2. Impacts of Geomagnetically Induced Currents on the Transmission system
3. The Operating Procedures in existence
4. Emergency Communications Systems with Customers
5. Ability of each Area to acquire Emergency Energy and confirm that necessary Agreements are in place
6. Training programs within each Area

A Pre-seasonal operations planning assessment forum will be arranged prior to each Summer and Winter operating period with the neighboring Regions to share results of each Region’s assessments. CO-12 will evaluate the Assessments from the neighboring Regions.

NPCC Reliability Coordinating Committee

November 16, 2004

Personnel

The CO-12 Operations Planning Working Group are listed in a separate roster.

| NPCC CO-12 Operations Planning Working Group E-mail List Server: | co12@npcc.org |
Background

The NERC Board of Trustees, at its May 13 and 14, 1996, meeting, approved the NERC Transmission Transfer Capability Task Force’s (TTCTF) report on Available Transfer Capability (ATC). In the covering letter to the Board of Trustees, the TTCTF recommended three distinct initiatives to effect a viable commercial electric power market while continuing to maintain electric system reliability via ATC calculation and posting. As part of this past report it was required that all Regions (or sub-Regions) should develop procedures for the determination and posting of available transfer capabilities and the allocation of transmission services (including reservations and scheduling), taking into account the ATC principles in the Task Force’s report.

Related to this recommendation, the basic principles stated in the framework document emphasize that ATC calculation must consider the points of electric power injection, extraction and parallel flow impacts, and use a Regional or wide-area approach to coordinate posted information and capture the interactions of electric power flows. It is recognized that within NPCC, ATCs will be calculated and posted on a Control Area/Reliability Authority basis and hence there is a need to establish/maintain processes to ensure Regional coordination of the ATC calculations and posted information. The Reliability Coordinating Council (RCC) has previously charged the Task Force on Coordination of Operation (TFCO) with this task.

The TFCO had formed this ATCWG as an “Ad Hoc” Working Group to address the implementation of ATC calculations and postings and to develop the required information, guideline and processes to ensure that the intent of the above mentioned ATC basic principles are met. This ATCWG has been meeting and will continue to meet on an ongoing basis to provide TFCO with expertise in ATC matters and address the issues pertaining to ATC in the new business and reliability standards currently being developed.

Terms of Reference

Participation

As a minimum, CO-13 membership shall be comprised of one member from each NPCC Area and this member should be directly involved with the actual TTC ATC calculations. To ensure co-ordination with external regions, assistance from adjacent regional reliability organizations will be requested on an as needed basis.
In the context of sharing information pertinent to maintaining reliability among the Areas of the Northeast Power Coordinating Council, the members of the Working Group CO-13 are subject to the provisions of the “NPCC Confidentiality Agreement.”

Each NPCC Area shall provide a chair for CO-13 on a rotating basis. The chair shall serve a period of two years. The order of the rotation shall be IESO, New York ISO, TransÉnergie, ISO-New England, and Maritimes and also shall include any other members of the group.

CO13 will continue to operate as a consensus based group with all the Areas represented.

Scope and Procedure

1. Review NERC Reliability Standards and proposed North American Energy Board (NAESB) Business Practice Standards as they pertain to TTC and ATC issues.

2. Review ATC calculation and posting processes that are to be adopted by each of the Control Areas/Reliability Authorities in NPCC.

3. Finalize and maintain a Regional white paper for the determination and posting of ATC.

4. Develop the necessary information and processes to assist NPCC Control Areas/Reliability Authorities in assuring that the implementation of ATC calculations and postings are consistent with the present NERC standards, and the existing and proposed market structures in the northeast.

5. Update and maintain the approach and mechanisms to make available the necessary information related to TTC calculations to all Control Areas/Reliability Authorities within NPCC on real-time and operational planning time frames.

6. Coordinate the above activities with those of adjacent Reliability Regions.

7. Coordinate with the other groups’ activities and exchange information regarding ATC/TTC issues.

8. Recommend to the TFCO any additional Regional work activities and/or facilities required to ensure adequate coordination of Regional and inter-Regional ATC calculation and posting.

9. Submit on-going updates and recommendations to the TFCO.
10. The group will meet at least once per year, and hold additional conference calls and meetings as required.

NPCC Reliability Coordinating Committee
June 1, 2005
Electronic Tagging Implementation Working Group of the NPCC Task Force on Coordination of Operation

Purpose

The Electronic Tagging Implementation Working Group (ETIWG) of the TFCO is the group responsible for overseeing the coordinated implementation of NERC's Electronic Tagging requirements and Constrained Path Methodology within the NPCC Region.

Scope of Activities

1. Review and comment on the technical aspects of the functional specifications for tagging systems, focusing on the identification of new tag requirements and critical issues, as developed by the NERC TISWG.

2. Develop plans that enable NPCC CA/TP's to meet the transition dates and functional requirements of Electronic Tagging and the NERC Constrained Path Methodology (CPM) resolution.

4. Provide a forum for NPCC members to exchange tagging system philosophies including both present and future electronic tagging capabilities.

5. Provide plans, schedules and guidance for the implementation and use of electronic tagging in accordance with NERC tagging policies, standards, and specifications.

6. Coordinate training programs on NERC electronic tagging mechanisms.

7. Coordinate the selection or development of electronic tagging systems by CA/TP/PSE's within NPCC that will enable compliance with NERC tagging policies, standards, and specifications.

Reporting

The ETIWG reports to the NPCC Task Force on Coordination of Operation. Either the ETIWG chairman or a designated ETIWG member shall attend all TFCO meetings.

Membership and Attendance

Chairman - Recommended by the ETIWG and approved by the TFCO
Area Representatives
Marketing Representatives
Others with specific expertise will be invited to attend as needed
Meeting Schedule

The working group will call meetings and conduct conference calls as necessary.

Approved by TFCO: March 3, 1999
Scheduled for Approval by the RCC: June 1999

Member Roster:

<table>
<thead>
<tr>
<th>Name</th>
<th>Position</th>
<th>Email</th>
</tr>
</thead>
<tbody>
<tr>
<td>K.C. Lotterhos</td>
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<tr>
<td>Rick Gonzales</td>
<td>NYPP (NYISO)</td>
<td><a href="mailto:rgonzales@nyiso.com">rgonzales@nyiso.com</a></td>
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Task Force on Coordination of Planning  
Scope of Work  
for  

NPCC Review of NERC Organization Standards  
OSWG, Organization Standards Working Group  
(CP-9)  

Objective  

The Working Group will be responsible for providing consolidated NPCC Regional review and comment to the existing NERC Planning Standards and participate in the NERC Organization Standards Development Process.  

Tasks  

1. Provide NPCC review and coordinate the submission of NPCC comments to existing NERC Planning Standards and the submission to the NERC of those comments to NERC Operating Standards prepared by the NPCC Task Force on Coordination of Operation when posted for NERC “Open Process Review”.  
2. Provide a forum for NPCC to participate, solicit, and provide Regional comments as new Standard Authorization Requests, SARs, and their respective Organization Standards, OS, are developed as part of the NERC Organization Standards Development process.  
3. Identify upcoming issues associated with new NERC Organization Standards and their potential impact to the NPCC Region, (i.e. Regional Difference). Propose solutions or guide the development of the Standards through effective and timely comments and soliciting NPCC participation on the SAR and OS drafting teams.  
4. Develop a Web-Based Database for tracking and scheduling Standards development activities from a Regional perspective.  
5. Target a broader range of participation in the commenting process. Develop databases and e-mail list servers to engage market participants and different perspectives.  
6. Develop an entire process for notification, solicitation, commenting on and revision to Standards.  
7. Follow up on the NERC Organization Standards Process evolution and provide NPCC members with basic information (or pointers to NERC website) for a common understanding of the process.  

Schedule  

The schedule for comments to the Standards associated with the various Phases of the NERC Compliance Program will be dictated by the NERC schedule. NPCC will develop its own internal review schedule to meet the NERC schedule.
Working Group

Members will be selected initially to represent NPCC Areas and the Task Forces on Coordination of Planning, System Protection, Coordination of Operations and System Studies. The Task Force on Coordination of Planning will be the lead Task Force.

Budget

A budget of $31,200 has been allocated for the working group in the 2002 NPCC budget.
Scope of Work
NPCC Collaborative Planning Initiative (CP-10)

Objective
Perform an NPCC system-wide review to identify potential reliability impacts of projected changes in system facilities associated with each Area’s respective transmission plans. This review, to be done on a triennial basis with annual updates, would examine a future year system (five years out), and would address the requirement, contained in the FERC 2000 RTO Notice, which deals with multi-Area planning and the assessment of expansion plans and utilize the efficiencies and synergies that coordinated planning could bring. This review would be done on a collaborative basis among the five Control Areas of NPCC and fully coordinated with neighboring Regions.

Study Process

1. Utilize NPCC working group structure under the Task Force on Coordination of Planning. NPCC Staff will chair the working group.

2. Select study year and develop a base case based on publicly known generation and transmission plans. (Utilize such resources as proposed generation listings or queues, NPCC Major Projects List, etc. which are part of each Area's planning and expansion process.)

3. Identify different scenarios that could have potential reliability impacts on the bulk power system. Examples of possibilities could be:
   • Unusual flows on the system leading to oscillatory problems;
   • Large wheel-outs/wheel-ins of NPCC impacting deliverability of total internal resources;
   • Major long term outages of critical facilities;
   • Combination of high loads and coincident maintenance;
   • Impacts of possible coal strike;
   • Low gas supply in New England;
   • Low water levels in Quebec;
   • Flow patterns generated based on prices;
   • Etc.

4. Utilize appropriate techniques (e.g. probabilistic, prospective analysis, risk analysis, etc.) to prioritize and review the scenarios postulated in #3.

5. Summarize results in report to Task Force on Coordination of Planning.

6. Present to other Task Forces and RCC for approval.
Scope of Work – CP-11


Objective

Perform a comprehensive review, as required by the NPCC Reliability Assessment Program, of the NPCC Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2) to update, where necessary, the document to assure that it is consistent with present industry reliability models, practices and market structures. Assure that document is consistent with other NPCC Criteria, Guidelines and Procedures.

Working Group Structure

A working group under the NPCC Task Force on Coordination of Planning will conduct this review. Membership on the Working Group will be solicited from the Task Forces on Coordination of Planning, Coordination of Operation, System Protection and System Studies. In addition other interested representatives of NPCC Member Companies are invited to participate.

Study Process


2. Review NPCC Criteria, Guidelines and Procedures that are referenced in Basic Criteria.

3. Review the adequacy of present assessment tools for evaluating compliance to NPCC Criteria in light of new technologies and current market structures.

4. Propose changes, if necessary, to the Basic Criteria.

5. Present revised document to TFCP for approval to post in NPCC Open Process. Allow internal Task Force review before initial posting to NPCC Open Process.

6. Respond to comments received during Open Process posting period.

7. Create revised version of document. Submit to TFCP who will determine if second posting to NPCC Open Process is necessary. TFCP will solicit other Task Forces in making this determination.

8. Upon Task Force acceptance of revised document, forward to NPCC RCC for review and approval. Interim status reports will be presented to the RCC.

9. Upon RCC approval, present to NPCC Executive Committee and NPCC Membership for approval.

Schedule

To be established by Working Group with a completion date of December 2002.
Criteria for Review
and
Approval of Documents

Adopted by the Members of the Northeast Power Coordinating Council October 28, 1986, 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: March 1997
Revised: March 2005
Introduction

This Criteria is intended to outline the review and approval procedures, (the NPCC Open Process), to be followed for all NPCC documents. All existing NPCC documents have been divided into three categories, Document Type "A", Type "B" and Type "C", and are listed in a separate document, (Document C-0) *Listing of NPCC Documents By Type*. (See Appendix A for Process Flow Diagram and detailed description of process steps)

**Document, Criteria-Type "A"**

**General Description**

Type "A" documents, with approval by the NPCC Full Member Representatives, describe the minimum criteria for Member Systems of NPCC functioning as part of the coordinated interconnected network.

**Review and Approval**

Type "A" documents are prepared and revised by the designated lead Task Force, specified in the *Listing of NPCC Documents By Type*, on a frequency, to be at least what is stipulated in the NPCC Reliability Assessment Program, NRAP. Drafts are distributed to other Task Forces for review, comments and/or concurrence. The document is also posted on the NPCC Open Process webpage for review for a period of 45 days, allowing industry comment. Notification is also given to neighboring Regions whose reliability might be impacted by NPCC’s Criteria, and their review of the proposed Criteria will be encouraged and comments analyzed and considered for inclusion. Acceptance is implied if no comments are received by NPCC. Comments are submitted through the 45-day period electronically through the NPCC web site “Forum”. Upon completion of the 45-day posting period, further comments will be rejected electronically by the “Forum”. The lead Task Force will discuss the comments submitted and post the responses to those comments on the NPCC Open Process webpage. If no substantive changes are developed, which would require additional posting(s), the draft Type "A" document is presented by the lead Task Force to the Reliability Coordinating Committee (RCC) for discussion, one meeting prior to seeking their final approval. This final approval will be conducted either at a scheduled RCC meeting or via email and electronic ballot.

In their review, the RCC will determine that proposed Criteria are neither inconsistent with nor less stringent than NERC industry-wide reliability standards and are not intended to result in any undue competitive advantage or disadvantage to any party or parties. The NPCC recognizes that the Area, Member system or local conditions may require criteria which are more stringent than those defined by NPCC Criteria.
Following the RCC’s approval, the document is submitted to the NPCC Full Member Representatives for vote, with a recommendation for its adoption. Approval of an NPCC Criteria requires a 2/3rd majority of both Transmission Provider and Transmission Customer voting classes. See Appendix A for further details on the entire NPCC Open Process.

For new or modified Type “A” documents, once approval has been obtained from the Member Representatives, the document is officially adopted, as noted on the document itself with the following statement:

"Adopted by the Members of the Northeast Power Coordinating Council (date), based on recommendation by the Reliability Coordinating Committee (or the Operating Procedure Coordinating Committee and the System Design Coordinating Committee, if adopted before November, 1994) in accordance with paragraph IV, subheading (a), of NPCC’s Memorandum of Agreement dated January 19, 1966 as amended to date."

The approved and adopted Type “A” document will then be posted, along with necessary additional documentation, if needed, such as an implementation plan or schedule for achieving full compliance with the requirements outlined in the document. This will be posted on the NPCC web site and distributed to the membership via a documented and maintained distribution list with the next Reference Manual Revision.

Members may request the lead Task Force, at any time, to review and revise the Criteria, or portions thereof, and have the right to enter into the NPCC “Appeals and Dispute Resolution Process” for non-compliance issues.

**Document, Guideline-Type "B"**

**General Description**

Type "B" documents, with approval by the Reliability Coordinating Committee, are the guides or guidelines for the achievement of acceptable system performance which implement criteria of Type "A" documents.

**Review and Approval**

Type "B" documents are prepared and revised by the designated lead Task Force, specified in the *Listing of NPCC Documents By Type*, on a frequency, to be at least what is stipulated in the Reliability Assessment Program, NRAP. Drafts are distributed to other Task Forces for review, comments and/or concurrence. The document is also posted on the NPCC Open Process webpage for review for a period of 45 days, allowing industry comment. Acceptance is implied if no comments are received by NPCC. Comments are submitted through the 45 day period electronically through the NPCC web site “Forum”. Upon completion of the 45-day posting period, further
comments will be rejected electronically by the “Forum”. The lead Task Force will
discuss the comments submitted and post the responses to those comments on the
NPCC Open Process webpage. If no substantive changes are developed, which would
require additional posting(s), the draft Type "B" document is presented by the lead Task
Force to the Reliability Coordinating Committee for approval either at a scheduled RCC
meeting or via email and electronic ballot. The document will then be posted on the
NPCC website and distributed to the membership via a documented and maintained
distribution list with the next Reference Manual Revision. See Appendix A for further
details on the entire NPCC Open Process.

Members may request the lead Task Force, at any time, to review and revise the
Guidelines, or portions thereof, and have the right to enter into the NPCC “Appeals and
Dispute Resolution Process” for outstanding issues.

**Document, Procedure-Type "C"**

**General Description**

Type "C" documents are procedures which provide for consistent implementation,
interpretation and monitoring of conformance with the general criteria, guides and
reporting requirements of Type "A" and "B" documents.

**Review and Approval**

Type "C" documents are prepared and revised by the designated lead Task Force,
specified in the *Listing of NPCC Documents By Type*, on a frequency, to be at least
what is stipulated in the NPCC Reliability Assessment Program, NRAP. Drafts are
distributed to other Task Forces for review, comments and/or concurrence. The
document is also posted on the NPCC Open Process webpage for review for a period of
45 days, allowing industry comment. Acceptance is implied if no comments are
received by NPCC. Comments are submitted through the 45-day period electronically
through the NPCC web site “Forum”. Upon completion of the 45-day posting period,
further comments will be rejected electronically by the “Forum”. The lead Task Force
will discuss the comments submitted and post the responses to those comments on the
NPCC Open Process webpage. If no substantive changes are developed, which would
require additional posting(s), the Type "C" document will be considered and voted on
for final approval by the lead task force and is then distributed for informational
purposes to the Reliability Coordinating Committee and the other Task Forces. (Formal
adoption by the Reliability Coordinating Committee or the NPCC Full Member
Representatives is not required for Type "C" documents).

The document will then be posted on the NPCC website and distributed to the
membership via a documented and maintained distribution list with the next Reference
Manual Revision. See Appendix A for further details on the entire NPCC Open
Process.
Members may request the lead Task Force, at any time, to review and revise the
Procedures or References, or portions thereof, and have the right to enter into the NPCC
“Appeals and Dispute Resolution Process” for outstanding issues.

Lead Task Force: Task Force on Coordination of Planning

Reviewed for concurrence by: TFCO, TFSP, TFSS, CMAS and TFIST

Review frequency: 4 years

Reference: Listing of NPCC Documents By Type (Document C-0)
Appendix A

NPCC OPEN PROCESS FOR REGIONAL RELIABILITY CRITERIA DEVELOPMENT AND REVIEW

Step 1 Initiation of the Open Process Review (Boxes 1, 2, 3, and 4)
(Ref. A-01 Flowchart)

The NPCC Open Process for Regional Reliability Criteria Development and Review can be initiated a number of ways:

- A comment is submitted through the Open Process Forum on the NPCC web site identifying an issue that could initiate a review. *(Box 1)* The Task Forces will review the comment and respond to it with a recommendation. *(Box 2)*
- An NPCC Member, Task Force, CMAS, or other party may identify a reliability need that is currently not addressed in the existing set of documents. *(Box 4)*
- The NPCC Reliability Assessment Program (NRAP) identifies the frequency of the updates, e.g. triennially *(Box 4)*.

Once a NPCC Open Process for Review is initiated for a Document, it is identified and tracked in the NRAP Report. *(Box 3)*

Step 2 Document Review and Revision (Boxes 5, and 6)

The designated Lead Task Force as identified in the NRAP or as charged by the Reliability Coordinating Committee (RCC) to draft a new document will develop it and build a consensus within the Task Force. *(Box 5)*

The document, once approved by the Lead Task Force for public release, will be posted on the NPCC Open Process Forum for a comment period and inclusion or revision of the NRAP. This comment period will begin once notification is made to the industry of the posting and comments will be accepted through a “web-based” forum for a period not to exceed 45 days. Notification will be given to neighboring Regions whose reliability might be impacted by NPCC’s Criteria, and their review of the proposed Criteria will be accommodated and submittal of their comments encouraged. *(Box 6)*

Step 3 Industry Comments on the Posted Document (Boxes 7, 8, 9, 10, 11, 12, 14, 15, 17, and 18)
The industry and neighboring Regions whose Reliability may be affected have 45 days to submit their comments to the proposed Document with no comment being understood to mean acceptance. (*Box 7*)

At the end of the comment period the Lead Task Force will review the comments and reach consensus on how to address the comment and whether further revision to the document is necessary. (*Box 8*) Also as part of this revision the Lead Task Force must ascertain if the revisions are substantive enough that another posting is required. (*Box 11*)

The lead Task Force will then post the responses to the comments received on the NPCC web based Open Process Forum for industry review. (*Box 9*)

The document is redrafted as necessary into a “final” draft. (*Box 10*)

If the document is a “C” (*a Procedure*), the document is voted on by the lead TF and if not approved further work is required and notification is posted. (*Box 14, 15, 17 and 18*)

*If the document is a “C” (*a Procedure*) (*Box 12*), and approved by the lead TF, jump to Step 6 (*Box 16*)

**Step 4 Gaining other Task Force and RCC Approval (Documents “A” and “B” Type-Criteria or Guidelines only) (Boxes 12a 13, 19-25)**

Following the posting of the Document, the remaining Task Forces will arrange to review the document and approve it or make specific recommendations for revisions that make it acceptable to them. (*Boxes 12a and 13*)

If the document is not acceptable as is and further revision is requested the document will be returned to the Lead Task Force with the specific recommended revisions. (*Box 19*)

This revision, if accepted by the Lead Task Force, may result in another Open Posting and notifications to neighboring Regions whose reliability might be impacted. (*Box 20*)

If the NPCC Task Forces have all signified their acceptance and approval of the document, it will be forwarded to the RCC for their review. (*Box 21*)

The RCC will vote on the document at their next scheduled meeting and if there are issues outstanding, the RCC will make specific recommendations to the Lead Task Force and request that further work be done. Notification is posted. (*Box 22, 23 and 24*)
If the document is approved by the RCC and is a “B” Type, (a Guideline Document) (Box 25), jump to Step 6 (Box 26)

**Step 5 Gaining Full Member Representative Approval (Document “A” Type-Criteria only) (Boxes 27, 28, 31, and 32)**

Upon approval of an “A Type” document by the RCC, the Document is submitted to the NPCC Full Member Representatives with a recommendation by the RCC to approve. (Box 27)

As outlined in the NPCC Membership Agreement the two voting classes of NPCC, the Transmission Providers and the Transmission Customers must each approve the document by a 2/3 majority vote. This vote can be conducted at an NPCC Annual Meeting or by email ballot. (Box 28)

If the document is not approved, any submitted comments by the Full Member Representatives will be forwarded along with the document back to the Lead Task Force for further work and notification is posted. (Box 31 and 32)

**Step 6 Document is Officially Adopted (All Documents) (Boxes 16, 26, 29, 30, 33, 34, and 35)**

Document is officially adopted along with any implementation plan for compliance and notifications are made to the NPCC Membership. (Boxes 16, 26, and 29)

Document is posted on the public portion of the NPCC website, replacing the old document if a revision is made, and distributed with the next Reference Manual Revision. NPCC Staff will also update the NRAP as required to show the next scheduled review date. (Box 30)

The requirements and procedures in the revised or new document are implemented, as stated in the implementation plan, or continued as required by the document. (Box 35)

At anytime during the process and prior to implementation the document is subject to the NPCC Dispute Resolution Process. (Box 33 and 34)
Basic Criteria for Design and Operation
Of Interconnected Power Systems

Adopted by the Members of the Northeast Power Coordinating Council September 20, 1967, 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: July 31, 1970
Revised: June 6, 1975
Revised: May 14, 1980
Revised: March 2, 1984
Revised: October 26, 1990
Revised: August 9, 1995
Revised: May 6, 2004
1.0 Introduction

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 5.1 and 5.2. 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 these criteria. 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. (Terms in bold typeface are defined in the Glossary located in Document A-7, the NPCC Glossary of Terms).

Criteria described in this document are to be used in the design and operation of the bulk power system. These criteria meet or exceed the North American Electric Reliability Council (NERC) policies and standards. These criteria are applicable to all entities which are part of or make use of the bulk power system. The Council member whose system is used to connect a non-member system to the bulk power system shall assure that, whenever it enters into arrangements or contractual agreements with non-members whose system could have a significant adverse impact on service reliability on the interconnected bulk power system in Northeastern North America, the terms of such arrangements or contractual agreements are consistent with criteria established by the Council, NERC, or the Regional Reliability Councils established in areas in which the facilities used for such arrangements are located.

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/baseload/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.

It is the responsibility of each Area to ascertain that its portion of the bulk power system is designed and operated in conformance with these criteria. The Council provides a forum for coordinating the design and operations of its five Areas.

Through committees, task forces, and working groups the Council shall conduct regional and interregional studies, and assess and monitor Area studies and operations to assure conformance to the criteria.

2.0 General Requirements

Area, Member system or local conditions may require 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 the Basic Criteria are not necessarily applicable to those elements that are not a part of the bulk power system or in the portions of a member system where instability or overloads will not jeopardize the reliability of the remaining bulk power system.

2.1 Design Criteria

The design criteria will be used in the assessment of the bulk power system of each of the NPCC member systems and each NPCC Area, and in the reliability testing at the member system, Area, 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.

A special protection system (SPS) shall be used judiciously and when employed, shall be installed, consistent with good system design and operating policy.

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. An SPS may also be applied to preserve system integrity in the event of severe facility outages and extreme contingencies. The decision to employ an 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 System Criteria, (Document A-11).

2.2 Operating Criteria

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

The operating criteria represent the application of the design criteria to inter-Area, intra-Area (inter-system) and intra-system operation.

The operating criteria define the minimum level of reliability that shall apply to inter-Area operation. Where inter-Area reliability is affected, each Area shall establish limits and operate so that the contingencies stated in Section 6.1 and 6.2 can be withstood without causing a significant adverse impact on other 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.

2.3 System Analysis and Modeling Data Exchange Requirements

It is the responsibility of NPCC, its Areas 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 operation and design. Also, any sharing of such information must not violate anti-trust laws.

For reliability purposes, Areas 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 member within an NPCC Area shall provide needed information to its Area representative 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.

Areas and member systems 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.

Areas shall install dynamic recording devices and provide recorded data necessary to enhance analysis of wide area system disturbances and validate system simulation models. These devices should be time synchronized and should have sufficient data storage to permit a few minutes of data to be collected. Information provided by these recordings would be used in tandem, when appropriate, with shorter time scale readings from fault recorders and sequence of events recorders (SER), as described in the Bulk Power System Protection Criteria (Document A-5), paragraph 2.7.2.

3.0 Resource Adequacy - Design Criteria

Each Area’s probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criteria 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 Areas and Regions, transmission transfer capabilities, and capacity and/or load relief from available operating procedures.
4.0 Resource Adequacy - Operating Criteria

Each Area 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 Area's forecasted load 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 Area on a regular basis.

5.0 Transmission Design Criteria

The portion of the bulk power system in each Area and of each member system shall be designed with sufficient transmission capability to serve forecasted loads under the conditions noted in Sections 5.1 and 5.2. 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 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 Area to another, as well as within Areas, shall be considered in the design of inter-Area and intra-Area transmission facilities. Transmission transfer capabilities shall be determined in accordance with the conditions noted in Sections 5.1 and 5.2.

5.1 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 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 an 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.

5.2 **Steady State Assessment**

a. Each **Area** shall design its system in accordance with these criteria and its own voltage control procedures and criteria, and coordinate these with adjacent **Areas** and **control areas**. Adequate reactive power resources and appropriate controls shall be installed in each **Area** to maintain voltages within normal limits for predisturbance conditions, and within **applicable emergency limits** for the system conditions that exist following the **contingencies** specified in 5.1.
b. Line and equipment loadings shall be within normal limits for predisturbance conditions and within applicable emergency limits for the system conditions that exist following the contingencies specified in 5.1.

5.3 Fault Current Assessment

Each Area 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 Areas and Regions.

6.0 Transmission Operating Criteria

Scheduled outages of facilities that affect inter-Area reliability shall be coordinated sufficiently in advance of the outage to permit the affected Areas to maintain reliability. Each Area shall notify adjacent Areas 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-Area reliability. Work on facilities which impact inter-Area reliability shall be expedited.

Individual Areas shall be operated in a manner such that the contingencies noted in Section 6.1 and 6.2 can be sustained and do not adversely affect other Areas.

Appropriate adjustments shall be made to 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.

6.1 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 an 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 Area in order to maintain voltages within normal limits for predisturbance conditions, and within applicable emergency limits for the system conditions that exist following the contingencies specified in the foregoing. Adjoining Areas shall mutually agree upon procedures of inter-Area voltage control.

Line and equipment loadings shall be within normal limits for predisturbance 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 Areas 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 Areas will not be subjected to the higher flows without prior agreement.

6.2 Emergency Transfers

When firm load cannot be supplied within normal limits in an Area, or a portion of an 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.
6.3 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 6.2 above.

6.4 Operation Under High Risk Conditions

Operating to the contingencies listed in Sections 6.1 and 6.2 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 an Area, consideration should be given to operating in a more conservative manner than that required by the provisions of Sections 6.1 and 6.2.

7.0 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 5.1. 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 widespread **bulk power system** shutdown. It is the responsibility of each **Area** to identify additional extreme contingencies, if any, to be assessed.

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

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 5.1.

h. The operation or partial operation of a special protection system for an event or condition for which it was not intended to operate.
8.0 Extreme System Conditions Assessment

The bulk power system can be subjected to a 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 adverse system response. Each Area has the responsibility to incorporate special simulation testing to assess the impact of extreme system conditions.

For example, 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.
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<thead>
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Emergency Operation

Criteria

Adopted by the Members of the Northeast Power Coordinating Council January 25, 1982, 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: March 8, 1985
Revised: July 3, 1989
Reviewed: October 10, 1990
Revised: August 6, 1993
Revised: October 1997
Reviewed: January 1999
Revised: November 1, 2002
Revised: August 31, 2004
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Figure 1- Standards for setting underfrequency trip protection for generators

Table 1-Standard test procedures for key facilities and associated critical components required for system restoration
1.0 Introduction

The purpose of these criteria 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. Objectives, principles and requirements are presented to assist the Area formulating plans and procedures to achieve desired results.

The definitions of terms in bold typeface can be found in the NPCC Reference Manual Document A-7, NPCC Glossary of Terms.

2.0 Objectives

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

2.1 To avoid, to the extent possible, the interruption of service to firm load.

2.2 To minimize the occurrence of system disturbances.

2.3 To contain any system disturbance and limit its effects to the Area initially affected.

2.4 To minimize the effects of any system disturbances on customers.

2.5 To avoid damage to system elements.

2.6 To avoid hazard to the public by maintaining safe transmission line conductor clearances.

2.7 To be prepared for system restoration following a system disturbance.

3.0 Principles

Principles of operation, based on the foregoing objectives, are as follows:

3.1 Bulk power system facilities must not be removed from service without prior notification and coordination with adjacent Areas, except in an emergency, when time does not permit such coordination, or when immediate action is required to prevent hazard to the public, sustained customer service interruption, or damage to facilities. In such cases adjacent Areas shall be informed as soon as practical.

3.2 Each Area shall make every effort to always maintain total net interchange schedules. Each Area shall change schedules as needed to maintain reliability.
3.3 Normal transfer capabilities shall be observed unless there is insufficient capacity or voltage support in an Area, in which case emergency transfer capabilities may be used prior to shedding firm load. Emergency transfer capabilities shall not be exceeded.

3.4 Each Area shall maintain automatic generation control equipment operational and in service except as stipulated in Section 4.5.

3.5 Operations during an emergency must recognize the requirements to balance load and generation, including support of system frequency, as well as the requirement to maintain system security, including thermal, voltage and stability limitations.

3.6 A trending of voltage through normal maximum or minimum values is an indication of insufficient real or reactive control in an Area. The affected Area must quickly restore the real and reactive power balance between load and source.

3.7 If an emergency is being caused in whole or in part by parallel power flows, the Area or Areas contributing to parallel power flows shall take all steps, including the shedding of firm load, to eliminate the circulating power flow contribution to the emergency and the Area experiencing the emergency shall implement all steps up to and including the shedding of firm load in accordance with local or NERC line loading relief procedures.

3.8 When an affected Area within NPCC is unable to correct a situation, a request for assistance from an Area or systems outside NPCC shall be made. Upon receiving a request for assistance to mitigate an emergency, an Area shall provide maximum reasonable assistance to any other Areas or systems outside of NPCC and shall act within the time frame that such assistance is required (Note: Neighboring Areas will ensure suitable arrangements with the generating resources and / or transmission provider(s) in the Area are in place to be able to provide reasonable assistance.)

3.9 Reasonable assistance shall be requested only after comparable action(s) has been implemented by the requesting Area(s). Reasonable assistance shall normally consist of, in no implied order of priority:

3.9.1 Redispetching generation (may be subject to agreements).

3.9.2 Curtailing non-firm energy transfers to non-affected Areas

3.9.3 Arming special protection systems.
3.9.4 Purchasing *capacity* and energy on behalf of the *Area* experiencing the *emergency*.

3.9.5 Redistribution or sharing of *operating reserve*.

3.9.6 Shedding *interruptible load* where permitted by a power system's internal policy.

3.9.7 Implementing *voltage reduction*.

3.9.8 Loading facilities to their *emergency transfer capabilities* provided that adverse weather conditions do not prevent such assistance.

Reasonable assistance shall not normally require the shedding of *firm load*.

4.0 **Requirements**

In order to effectively adhere to the foregoing principles, each *Area* shall meet the following requirements:

4.1 **Authority**

Reliability Coordinators, *control area* operators, and *system operators* shall have the responsibility and authority to implement *emergency* procedures including the curtailment of transactions and / or shedding of *firm load*.

4.2 **Metering & Indication**

Accurate and reliable metering and indication of system frequency, breaker status, voltage levels and power flows (real and reactive for all *tie lines* and other critical *elements*) shall be available to the appropriate *system operator(s)*.

4.3 **Communication**

Reliable inter-*Area* and intra-*Area* voice communications shall be available for the reliability coordinators, *control area* operators, and *system operators*, as appropriate to their accountabilities, with a reliability at least equivalent to that provided by a dedicated and redundant circuit.

4.4 **Operating Limits**

A comprehensive set of *operating limits* for inter-*Area* and critical intra-*Area interfaces*, recognizing both *normal* and *emergency transfer capabilities*, shall
be available to reliability coordinators, **control area** operators and **system operators** as appropriate to their accountabilities. The circumstances under which each of these transfer capabilities may be used shall be clearly indicated by written instructions.

For operation with facilities out of service, the comprehensive set of **operating limits** shall be supplemented by revised sets for planned outage conditions, by judgment of the reliability coordinators, **control area** operators and / or **system operator**, and by other studies as required.

4.5 **Disabling Automatic Generation Controls**

A sustained frequency excursion of ±0.2 Hertz is an indication of a major load-generation unbalance and possible formation of an **island**. It is important for the affected **Area** to reestablish a load-generation balance quickly, to restore frequency, and to allow **islands** to resynchronize as soon as possible. All **automatic generation controls** shall be removed from service at 59.8 Hertz on frequency decline and 60.2 Hertz on frequency increase.

4.6 **Automatic Underfrequency Load Shedding**

The intent of the Automatic Underfrequency Load Shedding program is to stabilize the system frequency in an **Area** during an event leading to declining frequency while recognizing the generation characteristics in each **Area**. The goal of the program is to arrest the system frequency decline and to return the frequency to at least 58.5 Hertz in ten seconds or less and to at least 59.5 Hertz in thirty seconds or less, for a generation deficiency of up to 25% of the load.

The Automatic Underfrequency Load Shedding Program must be coordinated among the NPCC Areas. Each Area is required to carry out the following unless an alternative plan is submitted by an Area for review by the NPCC Task Forces on Coordination of Operation and System Studies and approved by the NPCC Reliability Coordinating Committee:

4.6.1 Automatic **load shedding** of ten percent of its **load** at a nominal set point of 59.3 Hertz.

4.6.2 Automatic **load shedding** of an additional fifteen percent of its **load** at a nominal set point of 58.8 Hertz.

4.6.3 Underfrequency threshold **relays** shall be set to a nominal operating time of 0.30 second, from the time when frequency passes through the set point to the time of circuit breaker trip initiation (including any
communications time delay), when the rate of frequency decay is 0.2 Hertz per second.

Studies shall be performed by each Area to ensure satisfactory voltage and loading conditions after automatic load shedding.

4.7 Under-voltage

An Area may employ automatic under-voltage load shedding of selected loads to enhance power system security.

4.8 Manual Load Shedding

Each Area must be capable of manually shedding at least fifty percent of its load in ten minutes or less. Insofar as practical, the first half of the load shed manually should not include load which is part of any automatic load shedding plan (see Section 4.6).

Care should be taken that manual load shedding plans do not interrupt transmission paths. The plan should include the capability of shedding load proportionately over the whole system, but it must also recognize that operating requirements may limit shedding to one part of a system. An Area may require manual load shedding capability in excess of the minimum fifty percent.

Manual load shedding procedures should be reviewed at least annually by member companies, to ensure that the proper amount of load can be shed within the time limits prescribed.

Studies shall be performed by each Area to ensure that satisfactory voltage and loading conditions prevail after manual load shedding.

4.9 Generator Underfrequency Tripping

Generators should not be tripped for under-frequency conditions in the area above the curve in Figure 1.

It is recognized that, in special cases, requirements may dictate generator trip in the region above the curve. In those cases, automatic load shedding additional to the amount set out in Section 4.6, equivalent to the amount of generation to be tripped, must be provided. Such cases shall be reviewed by the Task Force on Coordination of Operation.

The intent of the added compensating load shedding is to preserve the stability of an island, if formed, and to avoid major underfrequency load shedding by the
Area, if it can be avoided. This can only be accomplished through a one to one correspondence of the generation lost and the immediate rejection of an equivalent neighboring load, at the frequency at which the given generator is tripped.

If the frequency decays below the curve shown in Figure 1, 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, actions such as those described in Sections 4.5 and 4.8 apply.

4.10 System Restoration

Each Area shall have a system restoration plan in accordance with NPCC Criteria, Guides and Procedures, and in conjunction with applicable NERC Operating Policies, Measures and Standards.

System operators shall be knowledgeable of the strategy, priorities and procedures for implementing their system restoration plan.

In addition, each Area shall maintain an inventory of key facilities and their critical components required for the energization of the basic minimum power system. Each Area shall include in the list of key facilities sufficient blackstart capability that is consistent with the strategy and priorities of their system restoration plan.

In the event of a system blackout or loss of AC supply, the prompt restoration of the power system depends on the successful operation 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 Section 4.10.1. The four categories of key facilities subject to testing are:

- Blackstart generating stations
- Underground transmission cables
- Substation and Telecommunication sites
- Control Center and Telecommunication Center facilities
A facility owner/operator may request the Area and/or NPCC to consider an actual event as a completed test for the applicable period, provided it can be demonstrated that the operation of the facility during the event met the test objectives and performance criteria.

4.10.1 Testing requirements for critical components associated with key facilities (Reference: Table 1)

4.10.1.1 Blackstart generating unit startup (Reference: Table 1; Test BS-1)

All facilities designated as having blackstart capability shall have this capability tested annually without dependencies on power sources not available during a partial or complete system blackout. Once the facility has been started, it shall continue to demonstrate the capability by operating in a stable condition while isolated from the power system for a minimum of ten minutes. The number of units within a facility that shall be blackstarted for this test is determined by the Area as needed by the Area’s system restoration plan.

All operating aids and auxiliary systems used in blackstarts, such as operations voice communications and system control and data acquisition (SCADA), shall be verified to operate adequately without dependency on the interconnected system or other unrelated unit support for any source of station service.

Transmission egress capability to deliver blackstart generation to the next substation shall be verified.

4.10.1.2 Backup pressurization system of underground transmission cables (Reference: Table 1; Test UG-1)

The back-up pressurization system of underground transmission cables that require a pressurized insulating medium to maintain dielectric strength shall be tested. 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. In all cases, the backup pressurizing system must be able to maintain required dielectric strength of the insulating medium for a time that is at least equal to the expected time required for restoration.
4.10.1.3 Substation and telecommunication backup power supplies—
Batteries and generators (Reference: Table 1; Tests ST-1 to ST-6)

Backup power supplies in substations and
telecommunication sites, which are deemed critical to
system restoration, shall be tested as specified below.
Where there are separate backup power arrangements at a
site for substation equipment and telecommunication
equipment they shall be separately identified in the critical
components listing and shall be inspected and tested
individually.

The required tests are as follows:

• Battery charger and batteries shall be inspected annually
  and meet owner / operator battery integrity standards.
  (Reference: Table 1; Test ST-1)

• Interruption of AC supply to a battery charger shall be
carried out annually for a duration of no less than thirty
  (30) minutes to ensure a battery picks up and carries load.
  (Reference: Table 1; Test ST-2)

• Confirmation that essential loads at substation and
telecommunication sites are supplied from battery
charger and batteries shall be performed at least once
every five (5) years for the time required to confirm
critical loads are supplied by battery charger and
batteries. (Reference: Table 1; Test ST-3)

• Performance testing of batteries in substations and
telecommunication sites shall be done at least once every
five (5) years. The test shall demonstrate that the
batteries meet their design capability. The design
capability of batteries must be consistent with the
strategy and priorities of Area restoration plans.
Discharge testing, or an equivalent procedure endorsed
by a recognized standard setting organization, is
acceptable. (Reference: Table 1; Test ST-4)

• 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. In order to 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; Tests ST-5 and ST-6)

4.10.1.4 Control center and telecommunication center facilities
(Reference: Table 1; Tests CC-1 to CC-7)

- Testing of facilities in control centers and telecommunication centers shall be performed in order to ensure the computer systems will be available when required for system restoration in blackstart situations. 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 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)

- Performance testing of batteries in control centers and telecommunication center facilities shall be done at least once every five (5) years. The test shall demonstrate that the batteries will provide a minimum support time compatible with battery design capabilities. Discharge testing, or an equivalent procedure endorsed by a recognized standard setting organization, is acceptable. (Reference: Table 1; Test CC-2)

- 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. In order to verify that the generators will pick up 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; Tests CC-3 and CC-4)

- Heating, Ventilation and Air Conditioning (HVAC) shall be assessed annually to demonstrate that ambient air temperature will be maintained within computer systems and telecommunication equipment working tolerances for at least the expected time required for restoration. If an
HVAC system relies on an external water supply for heat exchange purposes, the reliability of the external water supply during blackout conditions shall be considered. (Reference: Table 1; Test CC-5)

- Computer systems shall continue to function adequately during system disturbances, blackout and restoration conditions including situations where there are multiple status point changes and heavy alarm activities. Each Area shall test its computer redundancy features every six (6) months. Reliable computer system operation shall be confirmed by performing blackout like simulations and/or by verifying response to major system disturbances annually. (Reference: Table 1; Tests CC-6 and CC-7)

5.0 Operation During Abnormal Conditions

5.1 When an Area foresees, or is experiencing, abnormal operating conditions, appropriate measures, as stated in the NPCC Procedures During Abnormal Operating Conditions, shall be implemented.

5.2 Appropriate measures shall be taken to ensure that equipment critical to the security and restoration of the bulk power supply network is not affected by the interruption or degradation of the power system during abnormal conditions.

6.0 Responsibilities

6.1 All Reliability Coordinators, Control Area operators, facilities owners / operators and system operators are responsible for observing these criteria.

6.2 Each Area shall maintain records listing the identified key facilities and associated critical components. Each Area shall, annually, as scheduled by the NPCC Compliance Monitoring and Assessment Subcommittee, declare to NPCC that it has reviewed its list of key facilities and associated critical components and submit any revisions to NPCC.

6.3 Each facility owner / operator of key facilities containing critical components as identified by the Area shall complete the following:

6.3.1 Schedule and perform tests of critical components associated with key facilities in conformance with Area outage scheduling procedures and in accordance with Section 4.10.1.
6.3.2 Report to the Area as per the reporting and test procedures as prescribed in Table 1 and as scheduled by the NPCC Compliance Monitoring and Assessment Subcommittee. Within one month of the test completion, provide a written report outlining site location and date of test, test results, and, if required, list reasons for failure, remedial actions to be undertaken and date by which work is to be completed. Subsequent retesting is to be carried out within the originally prescribed test interval.

6.3.3 As noted on Table 1, the failure of a test, or the failure of critical components associated with key facilities encountered outside of normal testing as directed by NPCC Document A-03, shall be reported to the Area promptly, not to exceed 24 hours, to ensure the Area’s awareness of its exposure.

6.4 Each Area shall review reports submitted by its owner/operators and annually submit a declaration of compliance to NPCC, within sixty days of a request, for the previous calendar year. Each Area shall maintain records for the lesser of three years or the testing interval, to facilitate random audits and ensure compliance to the testing program.

6.5 The monitoring of automatic underfrequency load shedding requirements (Section 4.6), the monitoring of manual load shedding requirements (Section 4.8), the monitoring of the requirements of underfrequency generator tripping (Section 4.9), the monitoring of each Area’s system restoration plans (Section 4.10), the monitoring of each Area’s inventory of key facilities and associated critical components required for setting up a basic minimum power system and the monitoring of the testing of critical components associated with key facilities (Section 4.10.1) will be carried out by the NPCC Compliance Monitoring and Assessment Subcommittee.

Lead Task Force:       NPCC Task Force on Coordination of Operation

Review frequency:     3 Years

References:           NPCC Procedures During Abnormal Operating Conditions (NPCC Document C-20)

                        NPCC Glossary of Terms (NPCC Document A-07)
NERC Operating Policy 5.E, Emergency Operation-System Restoration

Figure 1 - Standards for setting underfrequency trip protection for generators

Generator tripping permitted on or below curve without requiring additional equivalent automatic load shedding.
<table>
<thead>
<tr>
<th>Test No.</th>
<th>Critical Component</th>
<th>Test</th>
<th>Test Frequency and Duration</th>
<th>Criteria for Successful Test</th>
<th>Report by Facilities Owner / Operator to Area</th>
</tr>
</thead>
<tbody>
<tr>
<td>BS-1</td>
<td>Blackstart</td>
<td>Startup test of generating unit blackstart capability without dependencies on the power system</td>
<td>Frequency: annually</td>
<td>-Successful startup and 10 minutes of stable operation -All operating aids and auxiliary systems are independent. -Transmission egress is verified</td>
<td>Refer to Section 6.3</td>
</tr>
<tr>
<td></td>
<td>Generating Units</td>
<td></td>
<td>Duration: 10 minutes of stable operation</td>
<td></td>
<td></td>
</tr>
<tr>
<td>UG-1</td>
<td>Backup pressurization system of underground transmission cables</td>
<td>Test backup pressurization system by switching from normal to backup pressurization scheme</td>
<td>Frequency: every 6 months Duration: minimum of 30 minutes; verify that backup pressurization system is able to maintain dielectric strength of insulating medium for the expected time required for restoration</td>
<td>- Backup maintains safe dielectric pressure for the minimum test period - Backup pressurization system can maintain dielectric of insulating medium for the expected time required for system restoration</td>
<td>Refer to Section 6.3</td>
</tr>
</tbody>
</table>

Refer to Section 6.3
<table>
<thead>
<tr>
<th>Test No.</th>
<th>Critical Component</th>
<th>Test</th>
<th>Test Frequency and Duration</th>
<th>Criteria for Successful Test</th>
<th>Report by Facilities Owner / Operator to Area</th>
</tr>
</thead>
<tbody>
<tr>
<td>ST-1</td>
<td>Battery charger and batteries in substation and telecommunication site</td>
<td>Check battery integrity as per owner / operator maintenance practices</td>
<td><strong>Frequency:</strong> annually</td>
<td>Meet owner / operator battery integrity standards</td>
<td>No need to report to Area.</td>
</tr>
</tbody>
</table>
| 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 | **Frequency:** annually  
**Duration:** for a test duration of no less than 30 minutes | Maintain acceptable voltage levels for the duration of the test | Refer to Section 6.3 |
| ST-3    | Battery charger and batteries in substation and telecommunication site | Confirm critical loads are supplied from battery charger and batteries  
If practicable, interruption of AC station service is preferred | **Frequency:** once every 5 years  
**Duration:** time required to confirm critical loads are connected and supplied from charger and batteries | All critical loads are supplied from battery charger and batteries | Refer to Section 6.3 |
<table>
<thead>
<tr>
<th>Test No.</th>
<th>Critical Component</th>
<th>Test</th>
<th>Test Frequency and Duration</th>
<th>Criteria for Successful Test</th>
<th>Report by Facilities Owner / Operator to Area</th>
</tr>
</thead>
</table>
| ST-4    | Batteries in substation and telecommunication site | Performance test of battery capacity | Frequency: at least once every five years  
Duration: Discharge testing, or an equivalent testing procedure endorsed by a recognized standard setting organization, is acceptable | Battery capacity is adequate | Refer to Section 6.3 |
| ST-5    | Backup generator in substation and telecommunication site | Startup and run test for backup generator | Frequency: monthly  
Duration: minimum of 15 minutes | Successful startup followed by 15 minutes of stable operation | No need to report to Area |
| ST-6    | Backup generator in substation and telecommunication site | Backup generator startup, transfer and run test to simulate loss of station service | Frequency: annually  
Duration: minimum of 30 minutes | - Successful startup  
- Transfer scheme operates correctly  
- 30 minutes of stable operation supplying critical loads | Refer to Section 6.3 |
<table>
<thead>
<tr>
<th>Test No.</th>
<th>Critical Component</th>
<th>Test</th>
<th>Test Frequency and Duration</th>
<th>Criteria for Successful Test</th>
<th>Report by Facilities Owner / Operator to Area</th>
</tr>
</thead>
</table>
| 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 | Frequency: annually  
Duration: 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 | Refer to Section 6.3 |
| CC-2    | Batteries in control center and telecommunication center                          | Performance test of battery capacity                                 | Frequency: at least once every five years  
Duration: for the time required to verify battery design capabilities  
Discharge testing, or an equivalent testing procedure endorsed by a recognized standard setting organization, is acceptable | Battery capacity is adequate | Refer to Section 6.3 |
<table>
<thead>
<tr>
<th>Test No.</th>
<th>Critical Component</th>
<th>Test</th>
<th>Test Frequency and Duration</th>
<th>Criteria for Successful Test</th>
<th>Report by Facilities Owner / Operator to Area</th>
</tr>
</thead>
<tbody>
<tr>
<td>CC-3</td>
<td>Backup generator in control center and telecommunication center</td>
<td>Startup and run test for backup generator</td>
<td>Frequency: monthly</td>
<td>Successful startup followed by 15 minutes of stable operation</td>
<td>No need to report to Area</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Duration: minimum of 15 minutes</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CC-4</td>
<td>Backup generator in control center and telecommunication center</td>
<td>Backup generator startup, transfer and run test to simulate loss of station service</td>
<td>Frequency: annually</td>
<td>- Successful startup</td>
<td>Refer to Section 6.3</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Duration: minimum of 30 minutes</td>
<td></td>
<td>- Transfer scheme operates correctly</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>- 30 minutes of stable operation supplying loads critical to system restoration</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td>- When HVAC system restarts, ambient temperature is in the range of equipment working temperature</td>
<td></td>
</tr>
<tr>
<td>Test No.</td>
<td>Critical Component</td>
<td>Test</td>
<td>Test Frequency and Duration</td>
<td>Criteria for Successful Test</td>
<td>Report by Facilities Owner / Operator to Area</td>
</tr>
<tr>
<td>---------</td>
<td>--------------------</td>
<td>------</td>
<td>-----------------------------</td>
<td>------------------------------</td>
<td>-----------------------------------------------</td>
</tr>
</tbody>
</table>
| CC-5    | Heating ventilation air conditioning (HVAC) system for control center and telecommunication center | Demonstrate that ambient air temperature will be maintained within computer system and telecommunication equipment tolerances for the expected duration of the restoration process | **Frequency:**  
- for air exchange systems no special testing is required, only regular maintenance  
- annually for water exchange systems  
**Duration:** the expected duration of the restoration process (water exchange systems only) | - For air exchange systems: anomalies detected by the maintenance program were corrected  
- For water exchange systems: water supply will remain viable and ambient temperature will be maintained in the range of equipment tolerances | For air exchange systems: written confirmation annual maintenance program was performed and that all anomalies detected were corrected  
For water exchange systems: Refer to Section 6.3 |
| CC-6    | 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. | Refer to Section 6.3 |
Table 1 - Standard Test Procedures for key facilities and associated critical components required for system restoration

<table>
<thead>
<tr>
<th>Test No.</th>
<th>Critical Component</th>
<th>Test Frequency and Duration</th>
<th>Criteria for Successful Test</th>
<th>Report by Facilities Owner / Operator to Area</th>
</tr>
</thead>
<tbody>
<tr>
<td>CC-7</td>
<td>Computer systems</td>
<td>Verify computer processing capacity during blackout-like simulation or multiple status point changes and heavy alarm activities such as in a major system disturbance or blackout</td>
<td>Perform blackout-like simulations and/or verify computer response to major system disturbances annually</td>
<td>Computer systems performed adequately</td>
</tr>
</tbody>
</table>
Maintenance Criteria for
Bulk Power System Protection

Adopted by the Members of the Northeast Power Coordinating Council April 22, 1969, based on recommendations by 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: July 13, 1971
Revised: May 18, 1979
Revised: August 2, 1982
Revised: April 21, 1986
Revised: August 19, 1991
Revised: November 8, 1995
Revised: March 1997
Revised: September 1998
Revised: December 2000
Revised: August 30, 2004
Note:

Terms in bold typeface are defined in the *NPCC Glossary of Terms* (Document A-7)
1.0 **Introduction**

This document establishes the minimum maintenance objectives and recommends maintenance practices for 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.

This Criteria is not intended to be a maintenance procedure, but rather a guide for member systems in developing their maintenance procedures. Adherence to this Criteria must be reported in a manner and form designated by the Compliance Monitoring and Assessment Subcommittee.

2.0 **General Maintenance Criteria**

Minimum periodic maintenance of each protection group shall consist of verifying that the protection group is capable of performing its intended protection function. This includes:

- making visual inspections,
- verifying inputs and outputs,
- confirming that the intended version of software is installed (microprocessor-based relays),
- verifying operating characteristics,
- verifying the integrity of current and voltage transformers and associated circuitry,
- verifying the proper performance of communications systems,
- verifying proper performance of auxiliary devices,
- performing trip or other operational tests required to assure satisfactory operation of the protective equipment as a system*.

All of the above shall be performed on a maintenance interval not exceeding that specified in Table 1 for [bulk power system protection groups](#).

* To assure satisfactory operation of the protective equipment as a system, test procedures and test facilities must ensure that related tests properly overlap.
3.0 Additional Maintenance

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.

It is the responsibility of each member system to evaluate its own particular circumstances and determine if any additional maintenance should be performed on its system. More extensive maintenance may be required:

- 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.

4.0 Underfrequency Load Shedding and Generator Tripping

Trip testing for protection required by the NPCC Automatic Underfrequency Load Shedding Program need not be performed more frequently than the trip test 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 Load Shedding Program requires the proper coordination of generator underfrequency tripping, as described in the NPCC Emergency Operation Criteria, Document A-3. 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.


TABLE 1
MAINTENANCE INTERVALS FOR PROTECTION GROUPS

<table>
<thead>
<tr>
<th>Protection Group</th>
<th>Electromechanical Protection Group Design</th>
<th>Solid-State Protection Group Design</th>
<th>Microprocessor-Based Protection Group Design¹</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission Line Protection Groups</td>
<td>2 years</td>
<td>2 years</td>
<td>6 years</td>
</tr>
<tr>
<td>Transformer, Bus, Shunt Reactor and Capacitor Protection Groups</td>
<td>4 years</td>
<td>4 years</td>
<td>6 years</td>
</tr>
<tr>
<td>Protection required for the NPCC Automatic Underfrequency Load Shedding Program*</td>
<td>2 years</td>
<td>2 years</td>
<td>6 years</td>
</tr>
<tr>
<td>Generator Underfrequency Tripping Relays*</td>
<td>2 years</td>
<td>2 years</td>
<td>6 years</td>
</tr>
<tr>
<td>All Other Protection Groups</td>
<td>2 years</td>
<td>2 years</td>
<td>6 years</td>
</tr>
</tbody>
</table>

*Calibration verification only - see Section 4.0

Note:

1. Microprocessor-based protection group design where the principal fault-sensing and logic components include extensive self monitoring or self checking. This must include checking or monitoring of:
   - power supplies
   - ac voltage and current inputs for reasonableness
   - calibration and functionality of analog data acquisition and conversion
   - integrity of programs (e.g., via checksums)
   - integrity of settings
   - execution of programs (e.g., via watchdog timers)

Lead Task Force: Task Force on System Protection

Review frequency: 3 years

References: NPCC Glossary of Terms (Document A-7)
            NPCC Guide for Maintenance of Microprocessor-based Protection Relays (Document B-23)
Bulk Power System
Protection Criteria

Adopted by the Members of the Northeast Power Coordinating Council August 31, 1970, 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: February 29, 1980
Revised: May 9, 1983
Revised: February 2, 1987
Revised: June 9, 1989
Revised: October 26, 1990
Revised: August 9, 1995
Revised: September 1998
Revised: November 14, 2002
Revised: January 30, 2006
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2.5 THIS SECTION IS INTENTIONALLY LEFT BLANK

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## 5.0 REPORTING OF PROTECTION SYSTEMS
Note:
Terms in bold typeface are defined in the *NPCC Glossary of Terms* (Document A-7)
1.0 Introduction

This document establishes the protection criteria and recommends minimum design objectives and practices for protection of the NPCC bulk power system. It is not intended to be a design specification, but a statement of protection objectives to be observed when developing design specifications.

It is recognized that certain Areas or member systems may choose to apply more rigid criteria because of local considerations.

1.1 Applicability

1.1.1 New Facilities

These criteria apply to all new Bulk Power System facilities.

1.1.2 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.

1.1.2.1 Planned Renewal or Upgrade to Existing Facilities

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, then these criteria apply to the extent practical.

1.1.2.2 Facility Classification Upgraded to Bulk Power System

These criteria apply to all existing facilities which become classified as bulk power system due to system changes. A mitigation plan is required to bring such a facility into compliance with these criteria.
1.1.2.3 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 1.1.2.1, Planned Renewal or Upgrade to Existing Facilities, these criteria apply to the protection systems for the new element.

1.1.2.4 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 in-service failure, then it is not required to upgrade the associated protection system to comply with these criteria.

If a bulk power system element (e.g., breaker, transformer, capacitor bank, reactor, etc.) or a protective relay is replaced as a result of a planned upgrade, then these criteria apply to the extent practical.

1.1.2.5 Revisions to These Criteria

As these criteria are revised, it is the responsibility of members to assess the protection systems at their facilities and to make modifications which, in their judgment, are required to meet the intent of these criteria.

1.2 **Responsibility**

Whenever significant changes are anticipated in generating sources, transmission facilities, or operating conditions, members shall review those protection system applications (i.e., settings, ac and dc supplies) which can reasonably be expected to be impacted by those changes. Close coordination shall be maintained among planning, design, operating, maintenance and protection functions with the intent that modifications or additions to the bulk power system will result in facilities that are adequately protected and can be operated and maintained reliably and safely.
2.0 General Criteria

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 intent of these criteria is to ensure that protection systems are designed to perform this function in accordance with the protection dependability and security levels implicit in the Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2).

The above 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.

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. 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.

For those protective relays responsible for removal of faults from the bulk power system, dependability is paramount, and the redundancy provisions of these criteria apply. For Protective relays installed for reasons other than fault sensing such as overload, etc., security is paramount, and the redundancy provisions of these criteria do not apply.

2.1 Issues Affecting Dependability

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

2.1.2 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.

2.1.3 Except as identified otherwise in these criteria, the protection system design shall not use components shared by the two protection groups.

2.1.4 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.

2.1.5 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.

2.1.6 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 shall 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 shall 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.

2.2 Issues Affecting Security

2.2.1 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.

2.2.2 For faults external to the protected zone, each protection group shall be designed either to not operate, or to operate selectively with other groups and with breaker failure protection.

2.2.3 For planned system conditions, protection systems should not operate to trip for stable power swings.
2.3 Issues Affecting Dependability and Security

2.3.1 Protection systems should be no more complex than required for any given application.

2.3.2 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.

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

2.3.4 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.

2.3.5 Protection systems, including intelligent electronic devices (IEDs) and communication systems used for protection, shall comply with applicable industry standards for utility grade protection service.

2.3.6 Communication link availability, critical switch positions, and trip circuit integrity, shall be annunciated or monitored.

2.3.7 Protection system circuitry and physical arrangements should be designed so as to minimize the possibility of incorrect operations due to personnel error.

2.3.8 Protection system automatic self-checking facilities shall be designed so as to not degrade the performance of the protection system.

2.3.9 Consideration should be given to the consequences of loss of instrument transformer voltage inputs to protection systems.

2.3.10 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.
2.3.11 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.

2.4 Operating Time

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

2.4.2 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 shall 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.

2.5 This section is intentionally left blank.

2.6 Protection System Testing and Maintenance

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

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

2.6.3 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.
2.6.4 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.

2.7 Analysis of Protection Performance

2.7.1 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.

2.7.2 Event and fault recording capability shall be provided to the extent required to permit analysis of system disturbances and protection system performance.

2.7.3 Event and fault recording equipment shall be time synchronized to Universal Coordinated Time with a time source accurate to within one millisecond. The time zone shall be clearly identified as either universal time zone or local time zone.

2.7.4 Each protective relay which trips Bulk Power System equipment shall provide separate target indication. Insofar as possible, each active protective function within a protective relay shall provide separate target information.

3.0 Equipment and Design Considerations

3.1 Current Transformers

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

3.1.1 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.

3.1.2 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.
3.1.3 For protection groups to be independent, they shall be supplied from separate current transformer secondary windings.

3.1.4 Interconnected current transformer secondary wiring shall be grounded at only one point.

3.1.5 Current transformers shall be connected so that adjacent protection zones overlap.

3.2 Voltage Transformers and Potential Devices

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

3.2.1 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.

3.2.2 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:

- Complete loss of one or more phase voltages does not prevent all tripping of the protected element;
- Each secondary winding has sufficient capacity to permit fuse protection of the circuit;
- Each secondary winding circuit is adequately fuse protected.

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

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

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

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

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

3.4 Microprocessor-Based Equipment and Software

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 shall be designed so as to not degrade the protection system functions.

3.5 Batteries and Direct Current (dc) Supply

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

3.5.1 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.

3.5.2 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.

3.5.3 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.

3.5.4 The circuitry between each battery and its first protective device cannot be protected and therefore shall be designed so as to minimize the possibility of electrical short circuit.

3.5.5 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.
3.5.6 The design for the regulation of the dc voltage shall 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.

3.5.7 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. Protection systems shall be continuously monitored or annunciated to detect abnormal power supply.

3.6 Station Service ac Supply

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.

3.7 Circuit Breakers

3.7.1 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.

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

3.8 Teleprotection

3.8.1 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:

3.8.1.1 Where each of the two protection groups protecting the same bulk power system element requires a communication channel, the equipment and channel for each group shall be separated physically and designed to minimize the risk of both protection
groups being disabled simultaneously by a single event or condition.

3.8.1.2 **Teleprotection** equipment shall be monitored in order to assess equipment and channel readiness.

3.8.1.3 **Teleprotection** systems shall be designed to assure adequate signal transmission during bulk power system disturbances, and shall be provided with means to verify proper signal performance.

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

3.8.1.5 Except as identified otherwise in these criteria, the teleprotection system design shall not use teleprotection components shared by the two protection groups protecting the same bulk power system element.

3.8.2 **Teleprotection** systems should be designed to prevent unwanted operations such as those caused by equipment or personnel.

3.8.3 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.

3.8.4 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.

3.9 **Control Cables and 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.
3.10 Environment

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

3.10.2 In addition to the physical separation as referenced in sections 2.1.4 and 3.8.8, each separate protection group protecting the same system element shall be on different non-adjacent vertical mounting assemblies or enclosures. In the event a common raceway is used, cabling for separate groups protecting the same system element shall be separated by a fire barrier.

3.11 Grounding

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:

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

4.0 Specific Application Considerations

4.1 Transmission Line Protection

4.1.1 The protection system shall be designed to limit the effects of faults and disturbances, while itself experiencing a single failure. For faults external to the protected zone, each protection group shall be designed either to not operate, or to operate selectively with other groups and with breaker failure protection.

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

4.1.3 Protection system settings should not normally constitute a loading limitation.
4.1.3.1 In the normal case, the tripping relay(s) should not operate at or below $I_{\text{Load}}$, assuming a 0.85 per unit voltage and a current phase angle of 30 degrees lagging.

4.1.3.2 $I_{\text{Load}}$ equals the highest seasonal ampere line or series elements rating, that most closely approximates a 4-hour rating (typically the winter seasonal rating), multiplied by a factor of 1.5, or; 1.15 times the 15-minute winter emergency ampere rating of the line.

4.1.3.3 In cases where the above criterion cannot be met, the limits thus imposed shall be documented and adhered to as a system operating constraint.

4.1.4 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.

4.2 Transmission Station Protection

4.2.1 Each protection system shall be designed to limit the effects of faults and disturbances, while itself experiencing a single failure. The protection systems should operate properly for the anticipated range of currents.

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

4.2.3 In particular, load responsive protective relays applied to transmission autotransformers should allow all possible loadability, consistent with equipment protection requirements. Any such relays settings that are identified in studies to be a possible limitation during normal or emergency conditions shall be documented and adhered to as a system operating constraint.

4.2.4 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.

4.3 Breaker Failure Protection
Means shall be provided to trip all necessary local and remote breakers in the event that a breaker fails to clear a fault.

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

4.3.2 Fault current detectors shall be used to determine if a breaker has failed to interrupt a fault. 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.

4.4 Generating Station Protection

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

4.4.2 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.

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

When a directional overcurrent 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.

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.
4.4.3 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.

4.4.4 Loss of excitation and out of step relays should be set with due regard to the performance of the excitation system.

4.4.5 It is recognized that the overall protection of a generator involves non-electrical considerations that have not been included as a part of these criteria.

4.4.6 All underfrequency protection systems designed to disconnect generators from the power system shall be coordinated with automatic underfrequency load shedding programs, in accordance with the Emergency Operation Criteria (Document A-3).

4.4.7 All overfrequency, overvoltage and undervoltage protection systems designed to disconnect generators from the power system should be coordinated with automatic underfrequency load shedding programs.

4.5 Automatic Underfrequency Load Shedding Protection Systems

Automatic underfrequency 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.

4.5.1 The criteria for the operation of these Protection Systems are detailed in the Emergency Operation Criteria (Document A-3) and the Automatic Underfrequency Load Shedding Program Relaying Guide (Document B-7).

4.5.2 Automatic underfrequency load shedding protection need not be duplicated.

4.6 HVdc Systems Protection
4.6.1 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.

4.6.2 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.

4.6.3 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 following 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.

4.6.4 The overall protection and control of an HVdc link may also involve the initiation of actions in response to abnormal conditions on the ac interconnected system. The control and protection systems associated with such conditions are not considered part of the HVdc systems protection.

4.7 Capacitor Bank Protection

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

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

4.7.3 **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 unit.

4.8 **Static Var Compensator (SVC) Protection**

4.8.1 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

**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.

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

5.0 **Reporting of Protection Systems**

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** facilities, or significant changes in the member’s existing **bulk power system protection** facilities. Each member shall also provide the TFSP with advance notification of non-member **protection** facilities as required per NPCC **Membership Agreement** Article V A(2) (c). Each new or revised **protection system** shall be reported to the TFSP in accordance with the
Procedure for Reporting and Reviewing Proposed Protection Systems for the Bulk Power System (Document C-22).

Prepared by: Task Force on System Protection

Review frequency: 3 years

References:
- Emergency Operation Criteria (Document A-3)
- Maintenance Criteria for Bulk Power System Protection (Document A-4)
- NPCC Glossary of Terms (Document A-7)
- Special Protection Systems Criteria (Document A-11)
- Automatic Underfrequency Load Shedding Program Relaying Guide (Document B-7)
- Procedure for Reporting and Reviewing Proposed Protection Systems for the Bulk Power System (Document C-22)
- Security Guidelines for Protection Systems IEDs (Document B-24)

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
1.0 Purpose

In the continuous operation of electric power systems, operating capacity is required to meet forecast load, 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 ensure 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 during operations, 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 Document A-3, *Emergency Operation Criteria*, **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 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

Operating reserve available to an Area, if activated, shall be sustainable for at least one hour from the time of activation.

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. Under normal conditions, the recovery time of the contingent Area should not exceed the DCS requirement. 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.

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 Document A-03, Emergency Operation Criteria, 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.

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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
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.)

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.

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.

C-1

**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.

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.
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.

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.
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)

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**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.

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**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.

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**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.

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**Pole (HVdc term)** — A rectifier and an inverter, with associated filter banks and control equipment, tied together by a transmission line or bus.
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:


(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.

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 for synchronizing to the network and that capacity which can be made available by applying load management techniques such as curtailing interruptible loads or implementing voltage reductions. (A-6, C-1)

Operating Reserve — The sum of ten-minute and thirty-minute reserve. (A-3, A-6, C-1)
Reserve--continued

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 portion of generating capacity which is synchronized to the system and ready to pick up load to claimed capacity and capacity which can be made available by curtailing pumping hydro units. (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 in thirty minutes, 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.
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. system instability;

b. unacceptable system dynamic response or equipment tripping;

c. voltage levels in violation of applicable **emergency** limits;

d. loadings on transmission facilities in violation of applicable **emergency** limits;

e. unacceptable loss of **load**.

**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.
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)


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.

NPCC
Reliability Compliance and Enforcement Program

Adopted by the Members of the Northeast Power Coordinating Council November 9, 2000, based on recommendation by the Reliability Coordinating Committee, in accordance with paragraph IV, subheading (A), of NPCC Membership Agreement dated November 9, 2000 as amended to date.

Revised: November 7, 2001
Revised: April 30, 2004
Revised: January 30, 2006
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Note:
Terms in bold typeface are defined in the *NPCC Glossary of Terms* (Document A-7)
1.0 Introduction

The purpose of the Northeast Power Coordinating Council 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, to the extent possible, facilitates attainment of fair, effective and efficient competitive electric markets.

The NPCC Reliability Compliance and Enforcement Program (the Program) described in this document is to be used to assess and enforce compliance with NPCC reliability criteria in such a way that the reliability objective stated above will be achieved. Actions taken by NPCC 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 Criteria, Guides and Procedures. As such the Member, as stated in the NPCC Membership Agreement, 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. 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 agreed, under Section V, Sub-section A (2) (f) of the NPCC Membership Agreement, 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 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 bulk power system shall use its best efforts to assure that the arrangements for such connection are consistent with NPCC criteria in accordance with the provisions and requirements of the NPCC Membership Agreement.
2.0  Reliability Criteria

2.1  Development of Criteria

The criteria utilized in assessing compliance have been developed by NPCC consistent with the North American Electric Reliability Council broad-based standards. NPCC 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 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 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 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 web-based Compliance Application, as per the established schedule, a compliance submittal for each of the requirements described in the annual Compliance Program. Where appropriate, submittals for the RCEP requirements and/or NRAP
requirements will be used to meet the NERC requirements, so that there will be no duplication of effort.

NPCC has established a lateness policy with associated sanctions. The policy is detailed in Section 4.2 of A-8.

3.2 Area Disclosure

The Area reports to CMAS and the NPCC Compliance Director within 48 hours of its awareness of a confirmed or alleged non-compliance to the NPCC criteria or NERC standards. These reports include information regarding the nature of the non-compliance that enables NPCC to meet its obligation to report to NERC.

3.3 NPCC’s Obligation to Report to NERC

In accordance with the approved NERC Guidelines for Reporting and Disclosure, NPCC has the obligation to report all instances of non-compliance within the Region to NERC within 48 hours from the time NPCC learns from the Area of the events as well as from the time NPCC become aware of the Area’s failure to comply with specific NPCC criteria or a NERC standard applicable to the Areas.

When an alleged violation is suspected, the name of the Area (not the individual party) will be reported, via the confidentiality provisions in the NERC Guidelines, to the NERC BOT, in accordance with the 48-hour window. CMAS will track alleged violations and report to NERC the final disposition.

In the case that the alleged compliance violation has been confirmed and the party in violation has had an opportunity to exhaust their rights to due process, the name of the party will be reported to NERC as required. The report will include the status and timetable of mitigation plan and the results of any investigation.

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 Reliability Compliance and Enforcement Program (RCEP) (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 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 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, 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 EP members shall adhere to the Enforcement Panel Code of Conduct and the NPCC Administrative Procedures for Conducting an Enforcement Panel Hearing.

The NPCC 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, 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 Executive Committee (EC). The panel will be made up of two Transmission Provider representatives, two Transmission Customer representatives, and a NPCC 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 EC will solicit nominations for participation on the EP from the NPCC Membership. Members of the EP will be elected by the NPCC membership from a list of candidates proposed by the EC. An EP member shall not be a member of the CMAS.

4.4 Executive Committee (EC)

The NPCC EC will provide oversight to the assessment and enforcement process through administration of the Program. The EC will monitor the RCC compliance-related activities, EP final reports including sanction determinations and the results of any cases resolved through the NPCC
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. Each NPCC 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 or the Disputing Area or any Affiliate thereof. Potential arbitrators who are employees, directors or officers of Members of the NPCC, but who are not themselves officers of the NPCC or members of the EP, will not be considered to be employees, directors or officers of the NPCC. The arbitrator must agree in writing to be bound by the confidentiality obligations applicable to the NPCC Staff.

b. All arbitration proceedings shall be held in New York City, unless an alternate location is agreed to by the parties. The NPCC 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 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 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 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 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 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 and the Disputing Area pursuant to the description contained in (c) above.

4.6 Appeal to FERC or Applicable Canadian Regulatory Authority

Either the NPCC or the Area ("Disputing Area") may apply to the FERC or applicable Canadian Regulatory Authority to hear an appeal of any
arbitrator’s decision resulting from implementation of the NPCC ADR process. Such an appeal shall be filed at FERC or applicable Canadian Regulatory Authority within fifteen (15) calendar days of the arbitrator’s decision. The NPCC and the Disputing Area agree that in any appeal to the FERC or applicable Canadian Regulatory Authority either NPCC 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 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 FERC or appropriate Canadian Regulatory Authority shall be based solely upon the record assembled by the arbitrator, unless otherwise determined by FERC or appropriate Canadian Regulatory Authority. All costs incurred by each of the NPCC and the Disputing Area in connection with such an appeal to FERC or appropriate Canadian Regulatory Authority shall be solely the responsibility of the party that incurred such costs. Any initiation of a FERC or appropriate Canadian Regulatory Authority appeal by the NPCC pursuant to this section 3.5 must be authorized by the NPCC Executive Committee.

5.0 Sanctions

5.1 Violations of Reliability Criteria

Table 1 defines the sanctions for violations to the standard and 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>
<thead>
<tr>
<th>Level of Non-Compliance</th>
<th>Sanctions</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Letter to the relevant functional head (operations, planning) of the Area</td>
</tr>
<tr>
<td>2</td>
<td>Letter to the Chief Executive of the Area with copy to the relevant functional head, other NPCC Areas, the NPCC Task Force Chairs, the NPCC Reliability Coordinating Committee, the NPCC Executive Committee and NPCC Member Representatives.</td>
</tr>
</tbody>
</table>
5.2 Policy on Lateness

All compliance reports are to be received by NPCC 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 RCEP, a minimum of three years of data shall be retained that fully supports certification towards an NPCC criteria document or compliance template. This requirement may be superseded by data retention requirements where specified in other NPCC 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 Membership Agreement

NPCC Glossary of Terms (Document A-7)

Guidelines for Implementation of the NPCC Compliance Program (Document B-22)

Review Process for NPCC Reliability Compliance and Enforcement Program (Document C-32)
APPENDIX A

FOR YEAR BEGINNING JANUARY 1, 2006
Compliance Template CPS1

Control Performance Standard 1 – CPS 1

**Standard:** Statistical measure of a Control Area’s Area Control Error (ACE) with respect to the interconnection’s short-term frequency error.

Each Control Area shall monitor its control performance on a continuous basis against CPS 1 as calculated in NERC Operating Manual, dated July 12, 2001, Policy 1, Section E, Control Performance Standard.

Over a year, the average of the clock-minute averages of a Control Area’s ACE divided by –10B (B is Control Area frequency bias) times the corresponding clock-minute averages of the Interconnection’s frequency error shall be less than a specific limit. This limit, e₁, is a constant derived from a targeted frequency bound reviewed and set as necessary by NERC.

**References:** NPCC Operating Reserve Criteria (Document A-6); NERC Operating Manual dated July 12, 2001, Policy 1, Section E, Control Performance Standard.

<table>
<thead>
<tr>
<th>Responsibilities</th>
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</thead>
<tbody>
<tr>
<td><strong>Reporting Responsibility:</strong></td>
</tr>
<tr>
<td><strong>Frequency of Reporting:</strong></td>
</tr>
<tr>
<td><strong>Compliance Monitoring and Assessment Responsibility:</strong></td>
</tr>
<tr>
<td><strong>Enforcement Responsibility:</strong></td>
</tr>
</tbody>
</table>

**Full (100%) Compliance**
- CPS 1 ≥ 100%

**Non-Compliance**
- **Level 1:** 95% ≤ CPS 1 < 100%
- **Level 2:** 90% ≤ CPS 1 < 95%
- **Level 3:** 85% ≤ CPS 1 < 90%
- **Level 4:** CPS 1 < 85%
For repeat occurrences of non-compliance with CPS 1, the equivalent level of non-compliance shall be determined as follows:

<table>
<thead>
<tr>
<th>CPS 1 Non-compliance</th>
<th>Occurrence (within the past twelve months)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Level 1</td>
<td>2nd time 3rd time 4th or more times</td>
</tr>
<tr>
<td>Level 2</td>
<td>2nd time 3rd or more times</td>
</tr>
<tr>
<td>Level 3</td>
<td>2nd or more times</td>
</tr>
<tr>
<td>Equivalent Level of Non-compliance</td>
<td>Level 2</td>
</tr>
</tbody>
</table>
Compliance Template CPS2

Control Performance Standard 2 – CPS 2

**Standard:** This is a surrogate measure of a Control Area’s Area Control Error (ACE) with the respect to the Interconnection’s long-term frequency error, and is designed to limit significant unscheduled adverse power flows.

The average ACE for each of the six ten-minute periods during the hour (i.e. for the ten-minute periods ending at 10, 20, 30, 40, 50, and 60 minutes past the hour) must be within specific limits, referred to as $L_{10}$ as referenced in NERC Operating Manual dated July 12, 2001, Policy 1, Section E, Control Performance Standard.

**References:** NPCC Operating Reserve Criteria (Document A-6); NERC Operating Manual dated July 12, 2001, Policy 1, Section E, Control Performance Standard

<table>
<thead>
<tr>
<th>Responsibilities</th>
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</thead>
<tbody>
<tr>
<td><strong>Reporting Responsibility:</strong></td>
</tr>
<tr>
<td><strong>Frequency of Reporting:</strong></td>
</tr>
<tr>
<td><strong>Compliance Monitoring and Assessment Responsibility:</strong></td>
</tr>
<tr>
<td><strong>Enforcement Responsibility:</strong></td>
</tr>
</tbody>
</table>

**Full (100%) Compliance**

CPS 2 ≥ 90%

**Non-Compliance**

- **Level 1:** 85% ≤ CPS 2 < 90%
- **Level 2:** 80% ≤ CPS 2 < 85%
- **Level 3:** 75% ≤ CPS 2 < 80%
- **Level 4:** CPS 2 < 75%
For repeat occurrences of non-compliance with CPS 2, the equivalent level of non-compliance shall be determined as follows:

<table>
<thead>
<tr>
<th>CPS 2 Non-compliance</th>
<th>Occurrence (within the past twelve months)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2\textsuperscript{nd} time</td>
</tr>
<tr>
<td>Level 1</td>
<td></td>
</tr>
<tr>
<td>Level 2</td>
<td>2\textsuperscript{nd} time</td>
</tr>
<tr>
<td>Level 3</td>
<td></td>
</tr>
<tr>
<td>Equivalent Level of Non-compliance</td>
<td>Level 2</td>
</tr>
</tbody>
</table>
Compliance Template DCS

Disturbance Control Standard - DCS

**Standard:** Area Control Error (ACE) must be returned to zero or to its pre-disturbance level within 15 minutes following the start of a NPCC reportable event.

**References:** NPCC Operating Reserve Criteria (Document A-6); NPCC Monitoring Procedures for Operating Reserve Criteria (Document C-9); NERC Operating Manual dated July 12, 2001, Policy 1, Section E, Control Performance Standard

<table>
<thead>
<tr>
<th>Responsibilities</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reporting Responsibility:</td>
</tr>
<tr>
<td>Frequency of Reporting:</td>
</tr>
<tr>
<td>Compliance Monitoring and Assessment Responsibility:</td>
</tr>
<tr>
<td>Enforcement Responsibility:</td>
</tr>
</tbody>
</table>

**Full (100%) Compliance**

Control Area and Reserve Sharing Group* returned the ACE to zero or its pre-disturbance level within 15 minutes following the start of all NPCC reportable events.

**Non-Compliance**

- **Level 1:** 95% ≤ DCS < 100%
- **Level 2:** 90% ≤ DCS < 95%
- **Level 3:** 85% ≤ DCS < 90%
- **Level 4:** DCS < 85%

---

* Reserve Sharing Group is defined in the referenced NERC Operating Manual.
For repeat occurrences of non-compliance with DCS, the equivalent level of non-compliance shall be determined as follows:

<table>
<thead>
<tr>
<th>DCS Non-compliance</th>
<th>Occurrence (within the past twelve months)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Level 1</td>
<td>2\textsuperscript{nd} time, 3\textsuperscript{rd} time, 4th or more times</td>
</tr>
<tr>
<td>Level 2</td>
<td>2\textsuperscript{nd} time, 3rd or more times</td>
</tr>
<tr>
<td>Level 3</td>
<td>2\textsuperscript{nd} or more times</td>
</tr>
<tr>
<td>Equivalent Level of Non-compliance</td>
<td>Level 2, Level 3, Level 4</td>
</tr>
</tbody>
</table>
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 Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2). Studies shall be conducted in accordance with NPCC Guidelines for NPCC Area Transmission Reviews, Document B-4

References: NPCC Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2) and NPCC Guidelines for NPCC Area Transmission Reviews (Document B-4)

<table>
<thead>
<tr>
<th>Reporting Responsibility:</th>
<th>Areas</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frequency of Reporting:</td>
<td>Annually</td>
</tr>
<tr>
<td>Compliance Monitoring and Assessment Responsibility:</td>
<td>NPCC</td>
</tr>
<tr>
<td>Enforcement Responsibility:</td>
<td>NPCC</td>
</tr>
</tbody>
</table>

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 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 Area shall plan and implement an Underfrequency Load Shedding Program as specified in section 4.6 of the NPCC Emergency Operation Criteria (Document A-3).

References: NPCC Documents A-3.

<table>
<thead>
<tr>
<th>Responsibilities</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reporting Responsibility: Areas</td>
</tr>
<tr>
<td>Frequency of Reporting: Annually</td>
</tr>
<tr>
<td>Compliance Monitoring and Assessment Responsibility: NPCC</td>
</tr>
<tr>
<td>Enforcement Responsibility: NPCC</td>
</tr>
</tbody>
</table>

Full (100%) Compliance
The Area load-shedding program fully complies with the requirements of the NPCC 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.

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.

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.

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.
Compliance Template A3-2

System Restoration Plan

**Standard:** Each Area shall have a system restoration plan to restore the Area’s power system following complete or partial system shut down. This plan shall have strategies, priorities and procedures in accordance with NPCC Criteria, Guides and Procedures, and NERC Standards (Section 4.10 of the NPCC Emergency Operation Criteria, Document A-3)

**References:**
- NPCC Emergency Operation Criteria (Document A-3)
- NERC Standard EOP-005-0 – System Restoration Plans

<table>
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<tr>
<th>Responsibilities</th>
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<tbody>
<tr>
<td>Reporting Responsibility:</td>
</tr>
<tr>
<td>Frequency of Reporting:</td>
</tr>
<tr>
<td>Compliance Monitoring and Assessment Responsibility:</td>
</tr>
<tr>
<td>Enforcement Responsibility:</td>
</tr>
</tbody>
</table>

Full (100%) Compliance

The Reporting Entity certifies that it has a System Restoration Plan to restore the Area’s power system following complete or partial system shut down, as required in Section 4.10 of NPCC Document A-03.

Non-Compliance

**Level 1:** The Reporting Entity has a plan, but it is not reviewed annually.

**Level 2:**

**Level 3:** None.

**Level 4:** The Reporting Entity does not have an Area System Restoration Plan in place as described above.
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 Emergency Operation Criteria, Document A-3)

**References:** NPCC Emergency Operation Criteria (Document A-3)

<table>
<thead>
<tr>
<th>Responsibilities</th>
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<tbody>
<tr>
<td>Reporting Responsibility:</td>
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<tr>
<td>Frequency of Reporting:</td>
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<tr>
<td>Compliance Monitoring and Assessment Responsibility:</td>
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<tr>
<td>Enforcement Responsibility:</td>
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</tbody>
</table>

**Full (100%) Compliance**

Each Area shall provide to NPCC, 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 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.
Compliance Template A4-1

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).


Responsibilities

<table>
<thead>
<tr>
<th>Reporting Responsibility:</th>
<th>Areas</th>
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<tr>
<td>Frequency of Reporting:</td>
<td>Annual, no later than six months after the end of the reporting period. At present, a reporting period is equal to the prior calendar year.</td>
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<tr>
<td>Information to be Reported:</td>
<td>Status of compliance for the reporting period, and status of any exceptions from previous reporting periods that had not already been reported as cleared.</td>
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</table>

| Compliance Monitoring and Assessment Responsibility: | NPCC |
| Enforcement Responsibility: | NPCC |
| Assessment and Enforcement Frequency: | Annual, six months after the end of the reporting period |
| Assessment and Enforcement Finding: | Either Full Compliance, the Level of Non-compliance that accounts for all outstanding exceptions or Non-compliance with extenuating circumstances demonstrated. (See guidelines for Implementation of the NPCC Compliance Program; Document B-22, annual compliance program schedule requirement for A4-1) |

Full (100%) Compliance

Area reports testing and maintenance of protection systems fully complies with the requirements of the NPCC Maintenance Criteria for Bulk Power System Protection (Document A-4). 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. For each reporting period, all exceptions from previous reporting periods must have been removed.

Non-Compliance

Level 1: None.

Level 2: Exceptions were reported, but not all exceptions were removed within five (5) months after the end of the current reporting period.

Level 3: Exceptions from the immediately previous reporting period were not removed by the end of the current reporting period.

Level 4: No maintenance report was provided by the Area or exceptions from more than one previous reporting period were not removed by the end of the current reporting period. Please refer to Section 5.2 (NPCC Document A-8), Policy on Lateness.
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 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 Operating Reserve Criteria (Documents A-6)

Responsibilities

<table>
<thead>
<tr>
<th>Reporting Responsibility:</th>
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<tbody>
<tr>
<td>Frequency of Reporting:</td>
<td>Monthly by the end of the following month</td>
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<tr>
<td>Compliance Monitoring and Assessment Responsibility:</td>
<td>NPCC</td>
</tr>
<tr>
<td>Enforcement Responsibility:</td>
<td>NPCC</td>
</tr>
</tbody>
</table>

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.
Special Protection System
Criteria

Adopted by the Members of the Northeast Power Coordinating Council November 14, 2002, based on recommendation by the Reliability Coordinating Committee, in accordance with paragraph IV, subheading (A), of NPCC Membership Agreement dated November 9, 2000 as amended to date.
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Note:

Terms in bold typeface are defined in the NPCC Glossary of Terms (Document A-7).
1.0 Introduction

1.0.1 This document establishes the protection criteria, and recommends minimum design objectives and practices, for Special Protection Systems. It is not intended to be a design specification. It is a statement of the objectives to be observed when developing design specifications for Special Protection Systems.

1.0.2 These criteria apply to all new Special Protection Systems (SPSs). It is recognized that SPSs existed prior to the establishment of these criteria and the predecessor Guideline. It is the responsibility of individual member systems to assess their existing SPSs and to ensure that modifications are made such that, in their judgment, the intent of these criteria are met. Similar judgment shall be used with respect to an SPS existing at the time of revision to these criteria.

1.0.3 Close coordination must 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.

1.0.4 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.

Type I An SPS 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 SPS along with the actions taken by other protection systems are intended to return power system parameters to a stable and recoverable state.

Type II An SPS 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. In the application of these systems, their security is the prime concern (see section 2.2 of this document). Since the SPS is installed at the discretion of the member systems,
sections 2.1, 2.6.1, 3.7 and 4.1 of this document do not apply.

Type III  An SPS 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  General Criteria

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.

An SPS must recognize or anticipate the specific power system conditions associated with the intended function. The relative effects on the bulk power system of a failure to operate when desired versus an unintended operation must 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.

2.1  Considerations Affecting Dependability

2.1.1  To enhance dependability, an SPS must be designed with sufficient redundancy such that the SPS is capable of performing its intended function while itself experiencing a single failure. This 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.

2.1.2  For an SPS which is composed of multiple protection groups, the risk of simultaneous failure of more than one protection group because of design deficiencies or equipment failure shall be considered, particularly if identical equipment is used in each protection group. The extent and nature of these failures shall
be recognized in the design and operation of the SPS.

2.1.3 The design of a Special Protection System which is composed of multiple protection groups for redundancy should avoid the use of components common to the groups. Areas of common exposure should be kept to a minimum to reduce the possibility of all groups being disabled by a single event or condition.

2.2 Considerations Affecting Security

2.2.1 An SPS shall be designed to avoid false operation while itself experiencing any credible failure.

2.2.2 An SPS should be designed to operate only for conditions which require its specific protective or control actions.

2.3 Considerations Common to Dependability and Security

2.3.1 Special Protection Systems should be no more complex than required for any given application.

2.3.2 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.

2.3.3 The thermal capability of all Special Protection System components must be adequate to withstand the maximum short time and continuous loading conditions to which the associated power system elements may be subjected.

2.3.4 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.

2.3.5 Critical features associated with the operability of Special Protection Systems, e.g. guard signals, critical control switch and test switch positions, and trip circuit integrity, should be annunciated or monitored.

2.3.6 Special Protection System circuitry and physical arrangements should be carefully designed so as to minimize the possibility of incorrect operations due to personnel error.
2.3.7 **Special Protection System** self-checking facilities should not degrade the performance of the **Special Protection System**.

2.3.8 Consideration should be given to the consequences of loss of ac voltage inputs to **Special Protection Systems**.

2.3.9 When remote access to **Special Protection Systems** is possible, the design should consider the consequences of unauthorized access to the **Special Protection Systems** on their overall security and dependability.

2.3.10 Consideration should be given to the effect of the means of arming on overall security and dependability of the SPS. Arming shall have a level of security and dependability commensurate with the requirements of the SPS.

2.4 **Operating Time**

An SPS shall take corrective action within times determined by studies. Adequate time margin should be provided taking into account study inaccuracies, differences in equipment, and **protection** operating times.

2.5 **Arming of an SPS**

Arming is the selection, which may be external to the SPS, of desired output action based on power system conditions and recognized **contingencies**. Arming requirements of an SPS 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 SPS, arming may be an on/off function. An SPS can be armed either automatically or manually.

2.5.1 Automatic arming is implemented without human intervention.

2.5.2 Arming is manual if the recognition, decision or implementation requires human intervention. Sufficient time with adequate margin for recognition, analysis and the taking of corrective action shall be allowed.

2.5.3 An SPS should be equipped with means to enable its arming to be independently verified.

2.6 **Special Protection System** Testing and Maintenance

2.6.1 Each SPS shall be maintained in accordance with the *Maintenance Criteria for Bulk Power System Protection*
2.6.2 The design of an SPS 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 an SPS 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.

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

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

2.6.5 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.

2.6.6 All positive combinations of input logic and significant negative combinations must be tested regardless of the maintenance strategy used. Negative combinations of input logic are those for which no SPS action should occur. Significant refers to combinations which could occur based on realistic system conditions and recognized system contingencies.

2.6.7 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.

2.6.8 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.

2.6.9 Whenever practicable, some of the maintenance testing requirements may be met by analyzing and documenting the detailed performance of the SPS 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.

2.7 Analysis of SPS Performance

2.7.1 **Bulk power system** automatic operations must 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.

2.7.2 Event recording capability should be provided to the maximum practical extent to permit analysis of system operations and **Special Protection System** performance. It is recommended that these devices be time synchronized.

3.0 Equipment and Design Considerations

3.1 Current Transformers

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

3.1.1 The output of each current transformer secondary winding must remain within acceptable limits for the connected burdens under all anticipated currents, including **fault** currents, to ensure correct operation of the **Special Protection System**.

3.1.2 The thermal and mechanical capabilities of the CT at the operating tap must be adequate to prevent damage under maximum **fault** conditions and normal or emergency system loading conditions.

3.1.3 For **protection groups** to be independent, they must be supplied from separate current transformer secondary windings.

3.1.4 Interconnected current transformer secondary wiring must be grounded at only one point.
3.2 Voltage Transformers and Potential Devices

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

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

3.2.2 If a Special Protection System is designed to have multiple protection groups at a single location for redundancy, each of the protection groups must 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 voltage does not prevent all operation of the redundant groups;
- Each secondary winding has sufficient capacity to permit fuse protection of the circuit;
- Each secondary winding circuit is adequately fuse protected.

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

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

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

3.3 Logic Systems

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

3.3.2 It should be recognized that timing is often critical in logic schemes. Operating times of different devices vary. Timing differences shall be recognized and accounted for in overall design.
3.4 Microprocessor-Based Equipment and Software

An SPS may incorporate microprocessor-based equipment. Information from this equipment may support other functions such as power system operations. In such cases care should be taken in the design of the software and the interface so that the support of the other functions does not degrade the SPS.

3.5 Batteries and Direct Current (dc) Supply

DC supplies associated with protection must have a high degree of dependability.

3.5.1 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 must be provided with its own charger.

3.5.2 Each battery should 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.

3.5.3 The circuitry between each battery and its first protective device cannot be protected and therefore must possess a high degree of integrity.

3.5.4 The battery chargers and all dc circuits must be protected against short circuits. All protective devices should be coordinated to minimize the number of dc circuits interrupted.

3.5.5 The regulation of the dc voltage should be such that, under all possible charging and loading conditions, voltage within acceptable limits will be supplied to all devices.

3.5.6 Dc systems shall be monitored to detect abnormal voltage levels (both high and low), dc grounds, and loss of ac to the battery chargers. Protection systems should be monitored to detect abnormal power supply.

3.5.7 Dc systems should be designed to minimize ac ripple and voltage transients.
3.6 **Station Service ac Supply**

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**.

3.7 **Circuit Breakers**

3.7.1 Where SPS 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.

3.7.2 If SPS redundancy is achieved by overarming, dual trip coils are not mandatory.

3.7.3 The indication of the circuit breaker position in **Special Protection Systems** should reliably mimic the main contact position.

3.8 **Teleprotection**

Communication facilities required for **teleprotection** must have a level of performance consistent with that required of the **Special Protection System**, such as:

3.8.1 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 should be separated physically and designed to minimize the risk of more than one **protection group** being disabled simultaneously by a single event or condition.

3.8.2 **Teleprotection** equipment should be monitored in order to assess equipment and channel readiness.

3.8.3 **Teleprotection** systems should be designed to assure adequate signal transmission during **bulk power system** disturbances, and should be provided with means to verify proper signal performance.

3.8.4 **Teleprotection** systems should be designed to prevent unwanted operations such as those caused by equipment or personnel.
3.8.5 **Teleprotection** equipment should be powered by the substation batteries or other sources independent from the power system.

3.9 **Control Cables and 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.

3.10 **Environment**

3.10.1 Means should be employed to maintain environmental conditions that are favorable to the correct performance of **Special Protection Systems**.

3.10.2 If a **Special Protection System** is designed to have multiple **protection groups** at a single location for redundancy, physical separation should be maintained between the **protection groups** in order to minimize the risk of more than one group being simultaneously disabled by fire or accidents.

3.11 **Grounding**

Station grounding is critical to the correct operation of **Special Protection Systems**. Consideration must be given to station ground grid design, cable shielding and equipment grounding to ensure proper **Special Protection System** operation and to minimize the risk of false operation from **fault** currents or transient voltages.

4.0 **Specific Application Considerations**

4.1 **Provision for Breaker Failure**

A Type I SPS shall include provision for breaker failure 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 the provision for breaker-failure include:

4.1.1 A design which recognizes that the breaker has not achieved or will not achieve the intended function required by the SPS and which takes independent action to achieve that function. This provision need not be duplicated and can be combined with
conventional breaker failure schemes if appropriate.

4.1.2 Overarming the SPS such that adequate action is taken even if a single breaker fails.

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

5.0 Reporting of Special Protection Systems

Each new or modified Special Protection System must be reported to NPCC in accordance with the Procedure for NPCC Review of New or Modified Special Protection Systems (SPS) (Document C-16). In addition, each new or modified Type I or Type II Special Protection System must be reported to the Task Force on System Protection in accordance with the Procedure for Reporting and Reviewing Proposed Protection Systems for the Bulk Power System (Document C-22).

Prepared by: Task Force on System Protection

Review frequency: 3 years

References:

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)

Procedure for NPCC Review of New or Modified Bulk Power System Special Protection Systems (Document C-16)

Procedure for Reporting and Reviewing Proposed Protection Systems for the Bulk Power System (Document C-22)
Guide for the Application of Autoreclosing to the Bulk Power System

Approved by the System Design Coordinating Committee and the Operating Procedure Coordinating Committee on January 29, 1979.

Revised: March 16, 1982
Revised: March 8, 1985
Revised: June 28, 1988
Reviewed: October 16, 1991
Revised: February 14, 1996
Revised: March 2, 1999
Reviewed: November 14, 2002
Revised: March 9, 2005
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Notes:
Terms in bold face type are defined in the NPCC Glossary of Terms (Document A-7). Italicized terms are defined in Section 3.0 of this Guideline.

The terms autoreclosing, high-speed autoreclosing and synchronism-check are defined in the Glossary (Document A-7). These terms are included in the definition list (Section 3.0) of this document for reference only, in order to make the document easier to read.
1.0 Objectives

The purpose of this document is to establish guidelines for the application of autoreclosing facilities to circuit breakers on the NPCC bulk power system. This document is not intended to provide guidance for the operation of the bulk power system in matters of reclosing, such as enabling or disabling autoreclosing or providing for manual closures following automatic tripping of an element.

2.0 Introduction

Autoreclosing should be applied for the purpose of restoring transmission lines to service subsequent to automatic tripping of their associated circuit breakers due to electrical faults. Experience of the NPCC member companies indicates that many faults on the bulk power overhead transmission system are temporary. In the absence of autoreclosing, longer duration outages could be experienced unnecessarily. Successful autoreclosing can enhance stability margins and overall system reliability. However, autoreclosing into a permanent fault may adversely affect system stability, hence due consideration must be given to this aspect of any application.

3.0 Definitions

3.1 Autoreclosing* is 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.

3.2 Breaker reclosing time is the elapsed time between the energizing of the breaker trip coil and the closing of the breaker contacts to reestablish the circuit by the breaker primary contacts on the reclose stroke.

3.3 High-speed autoreclosing* refers to 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.

* See note on Table of Contents Page
3.4 *Delayed autoreclosing* refers to the *autoreclosing* of a circuit breaker after a time delay which is intentionally longer than that for *high-speed autoreclosing*.

3.5 *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.

3.6 *Multiple-shot autoreclosing* refers to the *autoreclosing* of the circuit breaker(s) more than once within a predetermined reclosing sequence.

3.7 *Blocking* refers to the *automatic* prevention of an action following specific *relay* tripping operations.

3.8 *Single-pole autoreclosing* refers to the *autoreclosing* of one pole of a circuit breaker following a designed single-pole trip for single-phase-to-ground *faults*.

3.9 *Manual* refers to either local or remote switching operations that are initiated by an operator.

3.10 *Automatic* refers to either local or remote switching operations that are initiated by *relay* or control action without the direct intervention of an operator.

**4.0 Common Considerations to High-Speed and Delayed Autoreclosing**

4.1 *Blocking of Autoreclosing*

*Autoreclosing* should be blocked during the reception of a transferred trip signal. *Autoreclosing* should not be initiated following any *manual* operation of a circuit breaker.

4.2 *Turbine-Generator Considerations*

*Manual* closing or *autoreclosing* at line terminals that are in electrical proximity to turbine-generators may subject them to excessive shaft torques and winding stresses with resultant loss of life of the turbine-generator system. These effects should be studied and evaluated before *autoreclosing* is applied. It is preferable to re-energize a line at a terminal remote from the generator bus and then close at the generator end.

* See note on Table of Contents Page
4.3 Circuit Breaker Capability

*Autoreclosing* times and sequences should be selected with due regard to circuit breaker interrupting capability, derating, voltage withstand capability, resistor thermal capability, and overall breaker design.

4.4 Number of Operations

*Multiple-shot autoreclosing* systems should be designed considering available air or gas pressure for breaker operation.

4.5 Breaker Failure Operations

*Autoreclosing* following breaker failure operation is generally not recommended until the failed breaker is isolated.

4.6 Other System Elements

Risks versus benefits should be evaluated before applying *autoreclosing* following *faults* on transformers, busses, or *cables*. For these system *elements*, it is generally not advisable to *autoreclose* since the probability of a *fault* being permanent is high and the probability of aggravating equipment damage is increased. Under specific circumstances, however, the benefits of *autoreclosing* may justify its use.

4.7 Multiple Circuit Breaker Line Termination

The recommended mode of *autoreclosing* at a terminal with more than one breaker per line is to *autoreclose* with a preselected breaker. Following successful *autoreclose* operation, the other breaker(s) associated with the line at that terminal may be *autoreclosed*. Since simultaneous closing times are difficult to achieve, *autoreclosing* into a permanent *fault* by more than one breaker at the same line terminal could result in the *fault* being maintained on the system for a longer than intended period and may be followed by an incorrect breaker failure operation. In addition, the severity of the system *disturbance* may be increased.
5.0 High-Speed Autoreclosing Considerations

5.1 Tripping Requirements

High-speed autoreclosing should be initiated only if all terminals of the line are tripped without intentional time delay for line faults.

5.2 Stability Considerations

When high-speed autoreclosing is under consideration as a means for increasing the transient stability margin of a system, restoring service to critical loads, or restoring needed system interconnections, it should be recognized that there is a risk as well as a possible benefit attending its use. The risk is that stability may be endangered rather than benefited if a line is autoreclosed into a permanent fault. Stability studies should indicate whether or not the use of high-speed autoreclosing should be restricted.

5.3 Out-of-Step Conditions

High-speed autoreclosing should be blocked following an out-of-step relay operation.

5.4 Switching Surge Considerations

High-speed autoreclosing should not be used where transient voltage analysis studies indicate that high-speed autoreclosing may produce switching surge magnitudes exceeding the equipment design levels.

6.0 Delayed Autoreclosing Considerations

6.1 General Use

Delayed autoreclosing may be used, following design analysis, when restrictions such as in Section 5.0 exist.
6.2 Frequency, Phase Angle and Voltage Considerations

Synchronism-check relays should be used where analysis shows that for credible system conditions there may be harmful effects on the system due to excessive frequency differences, phase angles, or voltage magnitudes across the closing breaker. When applying synchronism-check relays appropriate consideration should be given to avoiding unnecessary restriction of breaker autoreclosing or manual closing following major system disturbances. It may be necessary to employ means to ensure undesired autoreclosing modes do not take place. For example, dead-line supervision of autoreclosing or manual closing may be used where harmful effects on the system would result from connection of energized facilities.

6.3 Autoreclosing Time Considerations

A time delay should be used, as determined by stability studies, to allow damping of system oscillations following a disturbance. If stability studies are not available, a 15-second time delay appears to be conservative for most systems.

Following the initiation of an autoreclosing sequence, autoreclosing attempts should be prevented after a predetermined time period. This time period should not prohibit completion of the autoreclosing sequence and must include circuit breaker fault clearing time, synchronism-check timing and protective relay and control system response times. To prevent unexpected operation, the autoreclosing sequence must be completed or go to a lockout state prior to the commencement of operator-initiated switching. Re-arming of the autoreclosing scheme may be achieved by automatic, manual or remote methods.

Prepared by: Task Force on System Protection.

Review frequency: 3 years

Reference: NPCC Glossary of Terms (Document A-7)
Guidelines for NPCC AREA
Transmission Reviews

Approved by the System Design Coordinating Committee and the Operating Procedure Coordinating Committee on February 10, 1976

Revised: June 14, 1982
August 26, 1985
December 13, 1988
December 10, 1991
December 14, 1993
August 7, 1996
November 7, 2001
September 7, 2005
1.0 General Requirement

NPCC has established a Reliability Assessment Program to bring together work done by the Council, its member systems and Areas 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 Area of NPCC and the transmission interconnections to other Areas. The purpose of these reviews is to determine whether each Area’s planned bulk power transmission system is in conformance with the NPCC Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2). Since it is NPCC’s intention that the Basic Criteria be consistent with the NERC Planning Standards, conformance with the NPCC Basic Criteria assures consistency with the NERC Planning Standards. Terms in bold typeface are defined in the NPCC Glossary of Terms (Document A-7).

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

NPCC's role in monitoring conformance with the NPCC Basic Criteria is limited to those instances where non-conformance could result in adverse consequences to more than one Area. If in the process of conducting the reliability review, problems of an intra-Area nature are identified, NPCC shall inform the affected systems and the Area within which the systems are located, but follow-up concerning resolution of the problem shall be the Area's responsibility and not that of NPCC. The affected Area will notify NPCC on a timely basis as to the resolution of the identified problem. If the problem is of an inter-Area nature, NPCC shall inform the affected systems and Areas 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 Area’s planned transmission system, based on its projection of available resources, is in conformance with the NPCC Basic Criteria. 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 (DCSs), which include Transmission Control Devices as defined in the NERC Planning Standards, should be addressed.

This review by the TFSS does not alter Area and/or Company responsibilities with respect to their system's conformity with the NPCC Basic Criteria.

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.

4.0 Types and Frequency of Reviews

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

In the years between Comprehensive Reviews, Areas may conduct either an Interim Review, or an Intermediate Review, depending on the extent of the Area’s system changes since its last Comprehensive Review. If the system changes are relatively minor, the Area may conduct an Interim Review. In an
Interim Review, the Area 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 Area’s system changes since its last Comprehensive Review are moderate or concentrated in a portion of the Area’s system, the Area 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 Area should conduct a Comprehensive Review.

In March of each year, each Area shall present to the TFSS a proposal for the type of review to be conducted that year. TFSS will consider each Area’s proposal and either indicate their concurrence, or require the Area to conduct a more extensive review if the Task Force feels that such is warranted based on the Area’s system changes since its last Comprehensive Review.

5.0 Format of Presentation

5.1 Comprehensive or Intermediate Review

5.1.1 Introduction

a) Reference the most recent Area Comprehensive Review and any subsequent Intermediate or Interim reviews as appropriate.

b) Describe the type and scope of this review.

c) For a Comprehensive Review, describe the bulk power system facilities included in this review.

d) Describe changes in system facilities, schedules and loads since the most recent Comprehensive Review.

e) Include maps and one-line diagrams of the system showing proposed changes as necessary.
5.1.2. Study results Demonstrating Conformance with Section 5.0 of the NPCC Basic Criteria entitled, "Transmission Design Criteria".

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 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.)

- 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 effect of major planned changes on the system.

- Discuss applicable transfer limit studies between contiguous areas.

- Discuss the adequacy of voltage performance and voltage control capability for the planned bulk power transmission system.

c) Stability Assessment

Discuss and/or refer to significant studies showing the effect on the system of contingencies as specified in Section 5.1 of the Basic Criteria, entitled "Stability Assessment" and report on the most severe contingencies in the following manner:

- 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.

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 Areas.

5.1.3. 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) 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 7.0 of the Basic Criteria, entitled "Extreme Contingency Assessment". Report on the most severe contingencies tested.

c) Discuss and/or refer to significant stability studies showing the effect on the system of contingencies as specified in Section 7.0 of the Basic Criteria. Report on the most severe contingencies tested.
d) In the case where contingency assessment concludes serious consequences, conduct an evaluation of implementing a change to address such contingencies.

5.1.4. 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 8.0 of the Basic Criteria, entitled "Extreme System Condition Assessment". Report on the most severe system conditions and contingencies tested.

c) Discuss and/or refer to significant stability studies showing the effect on the dynamic performance of extreme system conditions as specified in Section 8.0 of the Basic Criteria. Report on the most severe system conditions and contingencies tested.

d) In the case where extreme condition assessment concludes serious consequences, conduct an evaluation of implementing measures to mitigate such consequences.

5.1.5. 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-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 an SPS which was formerly considered to have only local consequences is identified as having the potential for inter-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) (Document C-16).

5.1.6. Review of Dynamic Control Systems (DCSs)

For those DCSs whose failure or misoperation may have an inter-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 impactive 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.

5.1.7. Review of Exclusions to the Basic Criteria.

Review any exclusions granted under the NPCC Guidelines for Requesting Exclusions to Sections 5.1(b) and 6.1(b) of the NPCC Basic Criteria for Design and Operation of Interconnected Power Systems (Document B-10). 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.

5.1.8. Overview Summary of System Performance for Year Studied

5.2. Interim Review

5.2.1. Introduction of Interim Review

Reference the most recent Comprehensive Review and any subsequent Intermediate or Interim Reviews as appropriate.
5.2.2. 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

5.2.3. Brief Impact Assessment and Overview Summary

The Area 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.

6.0 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 Area’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 Area or by utilities within the 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.
7.0 Task Force Follow-Up Procedures

1. Once an Area has presented its Review report to the TFSS, TFSS will review the Area’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 Area the specific areas of deficiency, and request the Area to address those deficiencies.
   
   b. Consider their concurrence with the results and conclusion(s) of the Area’s Review. If there is not concurrence, TFSS will indicate to the Area the specific areas of disagreement, and work with the Area 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 areas of disagreement.

2. If the results of the Area Review indicates that the Area’s planned bulk power transmission system is not in conformance with the NPCC Basic Criteria, TFSS will request the Area to develop a plan to achieve conformance with the Criteria.

3. If the Area Review indicates an overall bulk power system reliability concern (not specific to the Area’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.

4. Upon completion of an Area Review, TFSS will report the results of the review to the Task Force on Coordination of Planning, who in turn will report to the Reliability Coordinating Committee.
Coordinated by: Task Force on System Studies

Reviewed for concurrence by: TFCO and TFCP

Review frequency: 3 years

References:

- *Basic Criteria for Design and Operation of Interconnected Power Systems* (Document A-2)


- *NPCC Glossary of Terms* (Document A-7)

- *NPCC Reliability Compliance and Enforcement Program* (Document A-8)


- Procedure for Analysis and Classification of Dynamic Control Systems (Document C-33)

- *Guidelines for Requesting Exclusions to Sections 5.1(b) and 6.1(b) of the NPCC Basic Criteria for Design and Operation of Interconnected Power Systems* (Document B-10).

- Procedure for Testing and Analysis of Extreme Contingencies (Document C-18)
Automatic Underfrequency
Load Shedding Program
Relaying Guideline

Approved by the Reliability Coordinating Committee on March 2, 1999

Note: This Document supersedes the Automatic Load Shedding Employing
Underfrequency Threshold Relays (Document B-6) and the Application of
Underfrequency Protection (Document B-7), which were approved by the System
Design Coordinating Committee and the Operating Procedure Coordinating
Committee on November 25, 1983, and May 23, 1984, respectively.

Revised: November 14, 2002
Revised: March 9, 2005
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**Note:**
Terms in bold typeface are defined in the *NPCC Glossary of Terms* (Document A-7).
1.0 **Introduction**

The frequency of a power system will change when the load-generation equilibrium is disturbed. If the unbalance is caused by a deficiency of generation, the system frequency will decay to a value at which load-generation equilibrium is reestablished. If equilibrium cannot be established, system collapse will occur.

When the power system's self-regulation is insufficient to promote the establishment of a stable state, the system frequency will continue to decay unless some means is provided to force a load-generation balance. Automatic underfrequency load shedding is the accepted means of reestablishing this load-generation balance within the time constraints necessary to avoid system collapse.

The acceptable boundaries of frequency decay and the magnitude of the load to be shed by the automatic underfrequency load shedding program are determined by comprehensive tests on models of the system taking into account established load rejection practices.

The NPCC *Emergency Operation Criteria* (Document A-3) sets forth the requirements for automatic underfrequency load shedding and automatic underfrequency load shedding associated with generator underfrequency tripping. This guide presents relay application and testing requirements necessary to accomplish the objectives of Document A-3.

It is essential that sufficient generation remain in service so that the objective of the automatic underfrequency load shedding program is achieved. It must be recognized that generating units may trip during underfrequency conditions due to loss of plant auxiliary equipment. For example, the flow of coolant through a nuclear reactor of either the pressurized water or boiling water design may be affected by changes in reactor coolant pump or feedwater pump speed caused by underfrequency transients. The requirements for maintaining coolant flow must be considered when determining underfrequency trip setpoints for nuclear generating units.
2.0 Underfrequency Relay Application

In this guideline, underfrequency relays which operate at a discrete frequency value are called “underfrequency threshold relays.”

Selection of underfrequency sensing devices should be on a threshold basis. Alternatively, rate of change of frequency load shedding may be used when the requirements of the Area indicate that this method will achieve the intent of the load shedding program. Appropriate studies are necessary to determine the application and settings of the rate of change of frequency relays for a particular Area.

2.1 Uniform Response

In order for each Member System to shed approximately the same proportion of load, given the same frequency condition, all styles and manufacture of underfrequency relays must 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.

2.2 Additional Application Consideration

Where undesired underfrequency 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.

3.0 Setting and Maintenance Recommendations

3.1 Pickup & Time Delay Settings

Pickup and time delay settings of underfrequency threshold relays should be applied in accordance with the requirements of Section 4.6 and Section 4.9 of the Emergency Operation Criteria (Document A-3).

3.2 Relay Performance Requirements

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.

3.3 Maintenance

Protection required by the NPCC automatic underfrequency load shedding program has a direct effect on the operation of the bulk power system during major emergencies. As such, this protection must be maintained in compliance with the NPCC Maintenance Criteria for Bulk Power System Protection (Document A-4), even though the relays are usually located in non-bulk power system stations.

4.0 Annual Review & Documentation

The NPCC Reliability Compliance and Enforcement Program (Document A-8) requires periodic review by each NPCC Area of their automatic underfrequency load shedding capability and generator underfrequency tripping. This review shall be documented in a manner and form designated by the Compliance Monitoring and Assessment Subcommittee.

Background Information:

Minutes of the Task Force on System Protection, August 18, 19, 1982.
Restatement and clarification of "Coordination of Underfrequency Relay Settings" approved by the Joint Coordinating Committees, December 27, 1972.

"Coordination of Underfrequency Relay Settings" approved by the NPCC Joint Coordinating Committees, December 27, 1972.


Minutes of the Task Force on System Protection, October 22, 23, 1981.

"NPCC Reliability Assessment Program, Status Report" (latest update).
Prepared by: Task Force on System Protection

Review frequency: 3 years

References:  *Emergency Operation Criteria* (Document A-3)

  *Maintenance Criteria for Bulk Power System Protection* (Document A-4)

  *NPCC Glossary of Terms* (Document A-7)

  *NPCC Reliability Compliance and Enforcement Program* (Document A-8)
Guidelines for Area Review of Resource Adequacy

Approved by the System Design Coordinating Committee and the Operating Procedure Coordinating Committee on October 7, 1983

Revised: September 1, 1987
Revised: December 11, 1990
Revised: November 8, 1994
Revised: February 14, 1996
Revised: June 28, 2001
Revised: November 29, 2005
**Introduction**

NPCC has established a Reliability Assessment Program to bring together work done by the Council, its member systems and Areas relevant to the assessment of bulk power system reliability. As part of the Reliability Assessment Program, the Task Force on Coordination of Planning is charged, on an ongoing basis, with conducting reviews of resource adequacy of each Area of NPCC. (Terms in bold typeface are defined in the Glossary located in Document A-7, the NPCC Glossary of Terms).

**Resources** refer to the total contributions provided by supply-side and demand-side facilities and/or actions. Supply-side facilities include all generation sources within an Area and 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 (unmetered at control centers) generation.

The NPCC role in monitoring conformance with the NPCC Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2) is essential because, under this criterion, each Area determines its resource requirements by considering interconnection assistance from other Areas, on the basis that adequate resources will be available in those Areas. Because of this reliance on interconnection assistance, inadequate resources in one Area could result in adverse consequences in the other Areas.

It is recognized that all Areas may not necessarily express their own resource adequacy criterion as stated in the NPCC Basic Criteria. However, the NPCC Basic Criteria provides a reference point against which an Area’s resource adequacy criterion can be compared.

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

**Purpose of Presentation**

The purpose of the presentation associated with a resource adequacy review is to ascertain that each Area’s proposed resources are in accordance with the NPCC Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2). By such a presentation, the Task Force will satisfy itself that the proposed resources of each NPCC Area will meet the NPCC Resource Adequacy - Design Criteria (as defined in Section 3.0 of NPCC Document A-2) over the time period under consideration. This review by the Task Force on Coordination of Planning does not replace Area and/or company responsibility to assess their systems in conformity with the NPCC Basic Criteria.

**Time Period to be Considered**

The time period to be considered for an Area’s Comprehensive Resource Review will be five years and be undertaken every three years to focus on installed capacity requirements. In subsequent years, the Area 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 CP-8 Working Group may recommend to the TFCP that the Area conduct the next Comprehensive Review at a date earlier than specified above.

General Statement on Confidentiality

NPCC will respect the confidentiality requirements imposed within each Area and will not publish nor disclose commercially sensitive information without the consent of the information owner, unless such information is suitably aggregated with other data to mask the individual company information.

Format of Presentation and Report – Comprehensive Review

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

1.0 Executive Summary

1.1 Briefly illustrate the major findings of the review.

1.2 Provide a table format summary of major assumptions and results.

2.0 Table of Contents

2.1 Include listing of all tables and figures.

3.0 Introduction

3.1 Reference the previous NPCC Area review.

3.2 Compare the proposed resources and load forecast covered in this NPCC review with that covered in the previous review

4.0 Resource Adequacy Criterion

4.1 State the Area's resource adequacy criterion.

4.2 State how the Area criterion is applied; e.g., load relief steps.

4.3 Summarize resource requirements to meet the criteria for the time period under consideration. If interconnections to other Areas and regions are considered in determining this requirement, indicate the value of the interconnections in terms of megawatts.

4.4 If the Area 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.

4.5 Discuss resource adequacy studies conducted since the previous Area review, as appropriate.
5.0 **Resource Adequacy Assessment**

5.1 Evaluate proposed resources versus the requirement to reliably meet projected electricity demand assuming the Area’s most likely load forecast.

5.2 Evaluate proposed resources versus the requirement to reliably meet projected electricity demand assuming the Area’s high load growth scenario.

5.3 Discuss the impact of load and resource uncertainties on projected Area reliability and discuss any available mechanisms to mitigate potential reliability impacts.

6.0 **Proposed Resource Capacity Mix**

6.1 Discuss any reliability impacts resulting from the proposed resources fuel supply and transportation and/or environmental restrictions.

6.2 Describe available mechanisms to mitigate any potential reliability impacts of resource fuel supply and transportation issues and/or environmental restrictions.

**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 Area 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.

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

*******************************************************************************

APPENDIX - Sections A and B describe the reliability model and program used for the resource adequacy studies discussed in Section 4.5. Section C describes 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 Area that are not members of the 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 Resource Unit Representation

1.2.1 Unit Ratings

1.2.1.1 Definitions.


1.2.2 Unit 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 Areas and regions are considered, interconnection capacities assumed, and how expansion plans of other Areas and regions are considered.
1.4 Modeling of Limited Energy Sources.

1.5 Modeling of Demand Side Management 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 an Area, including references to applicable reports, summaries of reports, or submissions made to regulatory agencies.

C. Task Force Follow-Up Procedures

Once a specific Area 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. After the completion of the resource adequacy review, report on the Area's plans to the Reliability Coordinating Committee.

Coordinated by: Task Force on Coordination of Planning
Reviewed for Concurrence by: None
Review frequency: Every three years
References: NPCC Glossary of Terms (Document A-7)
Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2)

Guide for Rating Generating Capability (Document B-9)
Guidelines for Requesting Exclusions to Sections 5.1(B) and 6.1(B) of the NPCC

Basic Criteria for Design and Operation of Interconnected Power Systems

Approved by the System Design Coordinating Committee and the Operating Procedure Coordinating Committee on September 28, 1982

Created: September 28, 1982
Revised: February 8, 1994
Revised: June 26, 1998
Revised: November 14, 2002
Note:

Terms in bold typeface are defined in the *NPCC Glossary of Terms* (Document A-7)
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 Council 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* (the Basic Criteria -- Document A-2) 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 5.1(b), Bulk Power System - Transmission Design Criteria - Stability Assessment, and under Section 6.1(b), Bulk Power System - 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 define specific conditions for which a multiple circuit tower situation is an acceptable risk and, therefore, can be excluded.

The Basic Criteria also allows for requests for exclusion from this **contingency**, on the basis of acceptable risk, for other instances of multi-circuit tower construction. Each such request for exclusion must be specifically accepted by the Reliability Coordinating Committee (RCC). An acceptance of a request for an exclusion is dependent on the successful demonstration that such an exclusion is an acceptable risk. These guidelines describe the procedure to be followed and the supporting documentation required when requesting an 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 mileage and type of construction, geographic location, and connections to the rest of the interconnected power system;
2.2 design information pertinent to the assessment of acceptable risk, which might include: details of the construction of the facilities involved, 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 frequency of occurrence of impact outside the local area;

2.4 for existing facilities, the historical outage performance for multi-circuit contingencies on the specific facility(ies) 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 an exclusion to Sections 5.1(b) or 6.1(b) of the Basic Criteria:

3.1 The system or operating 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 sought within the Requestor’s own Area, if such process is applicable.

3.2 TFSS shall review the request, verify that the documentation requirements have been met, and determine its acceptance or non-acceptance 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. 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.

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 at the NPCC Offices.

4.0 Periodic Review of Exclusions of Record

Exclusions shall be reviewed within the Areas' transmission reviews as provided in Guidelines for NPCC Area Transmission Reviews (Document B-4). This review shall verify that the basis for each exclusion is still valid. TFSS shall notify TFCP, TFCO, TFSP, and the RCC when an Area’s transmission review has determined an exclusion is no longer applicable, and revise the exclusion summary list accordingly.

Coordinated by: Task Force on System Studies

Reviewed for concurrence by: TFCO and TFCP

Review frequency: 3 years

References: Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2)

NPCC Glossary of Terms (Document A-7)

Guidelines for NPCC Area Transmission Reviews (Document B-4)
Guide for Analysis and Reporting of Protection System Misoperations

Approved by the Reliability Coordinating Committee on March 21, 2001.

Revised: July 14, 2004
Note:

Terms in bold typeface are defined in the *NPCC Glossary of Terms* (Document A-7)
1.0 Introduction

Analysis of bulk power system protection operations shall be undertaken and the required information shall be supplied to the Area according to policies established in each Area.

Each NPCC Area is required to keep a record of all misoperations of protection systems and special protection systems on their bulk power systems. Included are misoperations of:

- protection systems for transmission lines, buses, transformers, generators, shunt or series compensating devices, and other bulk power system elements,
- protection systems for breaker failure,
- protection systems for the NPCC automatic underfrequency load shedding program, and
- special protection systems.

2.0 Definition of Misoperation

A misoperation is considered to be one in which one or more specified protective functions:

- did not occur as intended by the protection system design, or
- did not occur within the time intended by the protection system design, or
- occurred for an initiating event for which they were not intended by the protection system design to occur, or
- occurred for no initiating event.

Common examples of misoperations include:

- failures to trip,
- slow trips,
- incorrect tripping during a fault, or
- tripping for a non-fault condition.

The following are not considered misoperations:

- operations that are initiated by power plant, SVC, HVdc, circuit breaker, or other facility control systems (including autoreclosing),
- operations that occur during commissioning or testing, or
- operations that occur at a time when the affected or an associated element is out of service.
3.0 **Information to be Recorded and Reported**

All protection system and special protection system misoperations shall be analyzed in accordance with Area policies to determine the cause and the corrective action to be taken. The minimum information to be recorded for each misoperation includes:

- identification of the bulk power system elements affected,
- date and time of the event,
- cause of event, if known,
- identification of protection system(s) involved,
- identification of the protection systems that misoperated,
- identification of the cause(s) of the misoperation, if known,
- identification of the affected hardware/software components of the protection system(s) or special protection system(s) and/or the associated switching devices,
- the corrective action(s) taken or planned.

Each Area shall keep a record of the above information for each misoperation. Analyses should be undertaken and recorded within 60 days of the occurrence of the event in accordance with Area policies. The recorded information shall be maintained such that the Areas can report it to NPCC within thirty days from the date of a request.

If any analysis indicates that an addition, clarification, or modification to the NPCC Protection Criteria, Guides or Procedures should be considered, a report must be furnished to the Task Force on System Protection (TFSP) as soon as possible. In addition, any incident of general interest should be reported to the TFSP at its next scheduled meeting.

At each TFSP meeting, the Task Force will review all misoperations reported to it since the previous meeting. The minutes of the meeting shall record each misoperation reviewed and the action taken or planned. TFSP will follow up on the planned corrective action(s) through its Action Item List to ensure that the planned actions are implemented.

Prepared by: Task Force on System Protection

Review frequency: 3 years

References: NPCC Glossary of Terms (Document A-7)
Guidelines for
Implementation of the NPCC Compliance Program

Approved by the Reliability Coordinating Council on November 9, 2000

Revised: March 18, 2004
Revised: June 1, 2005
Note:

Terms in bold typeface are defined in the *NPCC Glossary of Terms* (Document A-7)
1.0 Introduction

This guideline describes the details of the processes used to implement the compliance programs in place at NPCC. The annual NPCC Compliance Program (the Program) includes the requirements of the NPCC Reliability Compliance and Enforcement Program (RCEP) and compliance monitoring requirements of the NPCC Reliability Assessment Program (NRAP). As part of the Program, NPCC annually adopts the NERC Compliance Enforcement Program (CEP).

The NPCC RCEP was established in 2000 in an effort to strengthen the Program by introducing enforcement and sanctions. NPCC Document A-8 defines the annual program, identifying specific NPCC criteria that will be measured against compliance templates and are subject to sanctions for non-compliance.

NRAP was established in 1977. It brings together works done by the Council, its members and the Areas relevant to the development of and compliance with NPCC Criteria and implementation of various items identified in the Guides and Procedures to assess the reliability of the NPCC bulk power system. NPCC continues to use NRAP to:

1. Review compliance of criteria currently not in RCEP, with examples such as:
   - Maintains schedules for periodic review and assessment of NPCC Area transmission system reliability and resource adequacy.
   - Review proposed new or modified protection systems and/or special protection systems for the bulk power system.
3. Provide budgeting report and status report on activities of the NPCC Subcommittee, Task Forces and Working Groups who are assigned specific responsibilities over areas of expertise in compliance, system planning, system operation, system protection, system modeling and studies, and system information, security, and technology.

The NPCC Criteria Guides and Procedures Documents used to support this Program are provided on the NPCC public web page at http://www.npcc.org/CriteriaGuidesProcedures.asp. These NPCC documents provide the foundation for ensuring the highest level of reliability within NPCC.

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1 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 Balancing Authority as defined by the North American Electric Reliability Council (NERC)
NPCC also utilizes the RCEP and NRAP to meet requirements defined by the annual NERC CEP. This ensures there is no duplication of effort required to report and to assess compliance on the requirements within each program.

NERC CEP was established in 1999. NERC annually select a set of standards for inclusion in the CEP to be monitored for compliance. The CEP requirements are adopted into the annual NPCC Compliance Program.

2.0 Annual Compliance Program Requirements, Responsibilities and Schedules

NPCC has established dedicated public web page at http://www.npcc.org/compliance.asp to document and to communicate the compliance responsibilities, schedules and other compliance materials about the annual NPCC Compliance Program.

2.1 Selection of Requirements

The annual NPCC Compliance Program comprises the requirements of the following programs:

- NPCC Reliability Compliance and Enforcement Program – RCEP
- NPCC Reliability Assessment Program – NRAP
- NERC Compliance Enforcement Program - CEP

Annually CMAS reviews the previous year’s compliance program and assesses if changes or modifications are required. The NPCC membership, through the various Task Forces annually review the criteria and, as necessary, make recommendations to add measures to the RCEP program. It is anticipated that the RCEP will grow to include templates for all NPCC criteria and these templates will rotate through the compliance program over the years.

CMAS submits, by June of each year, the additional RCEP requirements to the RCC for review and approval. The Reliability Coordinating Committee (RCC) seeks approval, from the Executive Committee (EC) and the NPCC membership, of the revised Appendix A of Document A-8 by the end of the year. Upon approval by the EC and NPCC membership, the amended RCEP is implemented the following January.

The NRAP Program is based on a long standing schedule set by NPCC. Criteria and due dates are assigned yearly by NPCC Staff and provided to the membership.

NPCC, through its representations on the NERC Compliance and Certification Committee and the NERC Compliance and Certification Managers Committee,
provide input into the development of the NERC Compliance and Enforcement Program including the selection of the annual NERC compliance program requirements.

2.2 Compliance Responsibilities

Consistent with the concept that compliance assessment and enforcement is most effectively accomplished by the entities that are closest to the complying party, NPCC compliance program establishes the following assessment structure for the compliance program: NERC assesses and enforces compliance to those standards for which the Regions have the reporting responsibilities. NPCC assesses and enforces compliance to those criteria and standards for which the Areas have the reporting responsibility and the Areas assess and enforce compliance to criteria and standards for which the Area participants have reporting responsibility. The diagram below illustrates how compliance is reported and assessed by various entities. This structure also establishes the oversight review responsibilities for NPCC over the Area compliance program and for NERC over the NPCC compliance program.

**Compliance Monitoring**

*Examples of Area participants are Transmission Owners, Generation Owners, Distribution Owners and Load Serving Entities*
2.3 Compliance Schedule

Based on the sets of requirements selected for the annual NPCC Compliance Program, CMAS publishes a table of the compliance reporting requirements, schedules and responsibilities on the compliance page of the NPCC web site at http://www.npcc.org/compliance.asp. This table is revised annually to capture the changes in the RCEP, NRAP and NERC CEP. For each requirement, the reporting entity, the compliance assessment and oversight review entity are identified. The due date to NPCC and the documentation requested for each requirement are specified by CMAS and included in the schedule. CMAS will inform the membership when new schedules are issued or when changes are made to the schedule. The Area will establish its own schedule for compliance reporting by participants under its purview consistent with the due dates to NPCC and NERC. NPCC reports to NERC in accordance with the established NERC compliance schedules.

2.4 Reporting Formats

Depending on the requirements, reporting is due to NPCC in one or more of the following forms:

Compliance Self-Certification Reporting: The reporting entity self-certifies compliance to the requirement, in lieu of submitting complete documentation, data or test results to demonstrate compliance.

Complete Documentation: The reporting entity submits complete documentation, data or test results for a specific requirement for review by the compliance monitoring entity.

Exception Reporting: The reporting entity submits a compliance report following an event that requires compliance/non-compliance reporting. The reporting entity completes an Exception Report Form.

NPCC has established a secure web-based application for compliance reporting on all the annual program requirements. The Areas submit all compliance requirements through this web-based application. A document must accompany each submission for a requirement. Submission via e-mail should only be used as backup when there is a failure to link up with the application through the web.
3.0 Compliance Processes

3.1 Compliance Assessment and Enforcement

NPCC Reliability Compliance and Enforcement Program Flow Diagram in Appendix A depicts the compliance assessment and enforcement process flow diagram. This process is also used to confirm non-compliance. An alleged non-compliance is confirmed when the Area accepts the RCC or EP determination of non-compliance.

3.1.1 Compliance Monitoring and Assessment Subcommittee (CMAS)

CMAS collects compliance reports as defined by the program schedules. CMAS reviews the submittals within 45 calendar days or at their next scheduled meeting and assesses them for compliance/non-compliance. CMAS may request the submission of reasonable supplemental or additional information to aid in the assessment.

Compliance report found to be in full compliance are collected and reported to the RCC on a quarterly basis. These results are also reported in the annual report.

In the event of a preliminary assessment of non-compliance CMAS notifies the Area and the Area has 45 calendar days from such notification to provide additional information or corrected data if it so desires. If the Area does not submit additional information or data in this time frame, CMAS will make its final determination and forward its compliance assessment to the Area and to the RCC. In the instance(s) of non-compliance, CMAS also provides a sanction recommendation to the RCC for their consideration. This sanction recommendation will be consistent with the NPCC Compliance Sanction Matrix contained in Section 4.1 and Appendix A of A-8.

Some compliance assessments may also depend on compliance status from previous reporting periods. In these cases, CMAS will notify the Area in writing if the compliance information the Area has provided for the current reporting period could influence compliance assessments in future reporting periods. This notification will detail the possible range of the outcomes of these future assessments, and the corrective actions the Area could be taking to mitigate any adverse future outcomes.
3.1.2 Reliability Coordinating Committee (RCC)

CMAS presents a technical assessment report to the RCC for review at least two weeks prior to an RCC meeting. The RCC may accept the report at its meeting or it may choose to remand the report to CMAS for clarification. In the event that the RCC remands the report to the Subcommittee, CMAS resolves the RCC concerns within 45 calendar days and resubmits its report to the RCC. The review of the re-submittal need not wait for the next RCC meeting and can be conducted via e-mail or conference call as per the desires of the RCC.

RCC then notifies the Area(s) of its Final Compliance Determination, which includes a technical assessment and, in instances of non-compliance, a sanction recommendation. The Area(s) has 45 calendar days to review and respond to the final RCC compliance determination. No response is considered acceptance of the RCC determination and the Final Compliance Determination is forwarded to the Enforcement Panel (EP) for sanction implementation. If the Area disputes the RCC compliance determination, the Final Compliance Determination and a copy of the Area’s response are forwarded to the EP for resolution.

3.1.3 Enforcement Panel (EP)

NPCC has established an Enforcement Panel to complete the compliance process. The processes followed by the EP are described below.

The EP receives either an undisputed RCC determination of a compliance violation, including a sanction recommendation or a disputed technical assessment from the RCC.

In the case of an undisputed RCC determination the EP reviews the RCC recommendation, determines the appropriate sanction, and notifies the Area within 45 calendar days. Upon receipt of such notice, the Area notifies the EP within 10 calendar days, whether it accepts the sanction or whether it will dispute the sanction. Sanctions are defined in Section 4.1 and Appendix A of Document A-8. If the Area notifies the EP that it disputes the sanction, the Area has 30 calendar days to provide the EP with relevant material in advance of the EP hearing. The EP will conduct the hearing and issue its Final Report within 15 calendar days.
In the instance of a disputed technical assessment an EP hearing will be held to resolve the technical dispute as well as determine the appropriate sanction if applicable.

The EP, whose members are bound by the NPCC Enforcement Panel Code of Conduct, conducts the hearing in accordance with the NPCC Administrative Procedures for Conducting an Enforcement Panel Hearing.

Should the Area seek to dispute the EP Final Report it may do so by notifying the EP, in writing, that it wishes to invoke the RCEP arbitration provision described in Section 3.5 of A-8. Requests for resolution of a dispute must be initiated within 15 calendar days after receipt of the EP Final Report.

Either the NPCC or the Area (“Disputing Area”) may apply to the FERC or applicable Canadian Regulatory Authority to hear an appeal of any arbitrator’s decision resulting from implementation of the RCEP Arbitration provision. Such an appeal is filed at FERC or applicable Canadian Regulatory Authority within 15 calendar days of the arbitrator’s decision in accordance with Section 3.6 of A-8.

3.2 Reporting and Disclosure

3.2.1 Area Reporting

Each Area furnishes to CMAS via the NPCC Compliance Application, as per the established schedule, a compliance submittal for each of the requirements described in the annual Compliance Program. Where appropriate, submittals for the RCEP requirements and/or NRAP requirements will be used to meet the NERC requirements so that there will be no duplication of effort.

NPCC has established a lateness policy with associated sanctions. The policy is detailed in Section 4.2 of A-8.

3.2.2 Area Disclosure

The Area reports to CMAS and the NPCC Compliance Director within 48 hours its awareness of a confirmed or alleged non-compliance to the NPCC criteria or NERC standards. Such reports include information regarding the nature of the non-compliance that enables NPCC to meet its obligation to report to NERC.
3.2.3 NPCC’s Obligation to Report to NERC

In accordance with the approved NERC Guidelines for Reporting and Disclosure, NPCC has the obligation to report all instances of non-compliance within the Region to NERC within 48 hours from the time NPCC learns from the Area of the events as well as from the time NPCC become aware of the Area’s failure to comply with specific NPCC criteria or a NERC standard applicable to the Areas.

When an alleged violation is suspected, the name of the Area (not the individual party) will be reported, via the confidentiality provisions in the NERC Guidelines, to the NERC BOT, in accordance with the 48-hour window. CMAS will track alleged violations and report to NERC the final disposition.

In the case that the alleged compliance violation has been confirmed and the party in violation has had an opportunity to exhaust their rights to due process, the name of the party will be reported to NERC as required. The report will include the status and timetable of mitigation plan and the results of any investigation.

4.0 Compliance Audit

In addition to reporting and assessing compliance to the above requirements, Area Compliance Audits are conducted as directed by CMAS, in accordance with the NPCC Review Process for the Reliability Compliance Program (Document C-32), twice a year such that each Area will be audited once every three years. The audit examines, in detail, an Area’s process and verifies documentation for selected NPCC criteria and NERC standards, which an Area has previously reported on. The audit is normally conducted during the spring and fall in order to minimize impacts on the operation of the bulk power system. The result of the audit is reported to the RCC and is used to assist the Areas and NPCC for feedback/process improvement.

NPCC annually publishes a compliance audit schedule and posts it on the NPCC website.
5.0 Readiness Audits

NPCC, in conjunction with NERC and with participation of personnel from the Areas and member companies, conduct Readiness Audits of Functional Entities on a periodic basis to identify best practices in performing the reliability functions and associated requirements. The results of these audits are shared in the industry to enhance reliability. NPCC, with input from the Areas, coordinates the readiness audit schedule with NERC and publishes the schedule and administer it through the Compliance Program. A Readiness Audit schedule is posted on the NPCC website.

6.0 Status Reporting

CMAS provides status reports on the NPCC Compliance Program at each RCC meeting. At the first RCC meeting of the year, CMAS includes a report on the Program for the previous year and any changes to the Program requirements in the current year.

CMAS also provides to NERC quarterly status report as well as the year-end summary report on the annual NPCC Compliance Program. These reports are also available on the NPCC website.

7.0 Workshop Presentation

Each year the Areas and/or CMAS may deem it necessary to sponsor a workshop that previews the requirements, including reporting instructions, for the coming year. Notification concerning the workshop will be disseminated via NPCC email and also posted on the NPCC web page.

Prepared by: Compliance Monitoring and Assessment Subcommittee (CMAS)

Review frequency: Annually

References: NPCC Reliability Compliance and Enforcement Program (Document A-8)

NPCC Glossary of Terms (Document A-7)

NPCC Review Process for the Reliability Compliance Program (Document C-32)
Figure 1: NPCC Reliability Compliance and Enforcement Process Flow Diagram

Notes:
* CMAS may request supplemental or additional information to aid in the assessment.
** RCC may remand Compliance / Non-compliance Report to CMAS for clarifications. CMAS then has 45 days to resolve issue and resubmits Report.
*** NPCC appeal must be authorized by the NPCC Executive Committee.
Guide for Maintenance of Microprocessor Based Protection Relays

Approved by the Reliability Coordinating Committee on July 14, 2004.
Note:

Terms in bold typeface are defined in the *NPCC Glossary of Terms* (Document A-7)
1.0 INTRODUCTION

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 2 of NPCC Maintenance Criteria for Bulk Power System Protection, Document A-4 on “verifying operating characteristics”, and in note 1 of Table 1 of Document A-4.

This document applies only to the protective relays. It does not include other protection maintenance that is still required, as outlined in Section 2 of A-4.

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

2.0 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:

1. Analog Input Section,
2. Digital Input/Output Section,
3. Processor Section, and
4. Power Supply Section

Each of the sections can be tested separately.

3.0 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.
4.0 **DIGITAL INPUT / OUTPUT SECTION**

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

4.1 **Inputs**

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

4.2 **Outputs**

Outputs of the IED should be verified either by:

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

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

5.0 **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. 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.

6.0 **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.
7.0 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.

7.1 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.
NPCC

SECURITY GUIDELINES FOR PROTECTION SYSTEM IEDS

Approved by the Reliability Coordinating Committee on July 14, 2004.
Note:

Terms in bold typeface are defined in the *NPCC Glossary of Terms* (Document A-7)
1.0 Introduction

This document establishes the NPCC’s guidelines for the application of remote access to protection system IEDs. It is intended as guidance in meeting the requirements of NPCC Bulk Power System Protection Criteria, Document A-5, Section 2.3.9 and Special Protection System Criteria, Document A-11, Section 2.3.9.

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

This is not intended to be a procedure, but rather a guide for members systems in designing and applying remote access for protective relays. The need for this guide has arisen due to the current, and wide-scale use of computer based protective relays and associated equipment that have remote access capabilities.

2.0 Scope

This guideline applies to protection group 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.

This guideline is applicable to NPCC bulk power system elements, for which these protection systems are applied.

3.0 Definitions

**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.

**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.

4.0 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.

5.0 Guidelines

5.1 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:

1) Something the user knows, such as passwords, or IP addresses.
2) Something the user has, such as a key, or cryptographic token.

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.

5.2 Substation IED Access Points

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.

5.3 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 described in Sections 5.2 and 5.3 be classified as confidential, and managed as such.

5.4 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.

5.5 Passwords

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

Default passwords should be changed when remote access is configured.

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.

5.6 **Logging/Alarming**

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

5.7 **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 Section 5.3 above, should have remote access capabilities.

5.8 **Disable Unused Functions**

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.

6.0 **Other Available Higher Level Authentication Factors and Some General Good Practices**

As stated in Section 5.1, 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.

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

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

6.3 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 IEDs 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.

6.4 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.

6.5 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.

Prepared by: Task Force on System Protection

Review frequency: 3 years

References:

NPCC Bulk Power System Protection Criteria, Document A5

NPCC Special Protection System Criteria, Document A11


NERC Urgent Action Standard 1200 Cyber Security
Listing of NPCC Documents by Type

Updated: January 2001
Note:
Terms in bold typeface are defined in the NPCC Glossary of Terms (Document A-7).
<table>
<thead>
<tr>
<th>Criteria – type &quot;A&quot; Documents</th>
<th>Latest Version</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>A-1 Criteria For Review and Approval of Documents</strong></td>
<td></td>
</tr>
<tr>
<td>Latest Version: March 1997</td>
<td></td>
</tr>
<tr>
<td>Description: This guide outlines the review and approval procedures to be followed for all NPCC documents.</td>
<td></td>
</tr>
<tr>
<td>Lead Task Force: Task Force on Coordination of Planning</td>
<td></td>
</tr>
<tr>
<td>Reviewed for concurrence by: TFCO, TFSP and TFSS</td>
<td></td>
</tr>
</tbody>
</table>

| **A-2 Basic Criteria for Design and Operation of Interconnected Power Systems** |
| Latest Version: August 9, 1995 |
| Description: Criteria are established for proper design and operation concerning Resource Adequacy and Transmission Capability. |
| Lead Task Force: Task Force on Coordination of Planning |
| Reviewed for concurrence by: TFCO, TFSP, TFSS and the TFEMT Chairman |

<p>| <strong>A-3 Emergency Operation Criteria</strong> |
| Latest Version: January 1999 |
| Description: Objectives, principles and requirements are presented to assist the NPCC Areas in formulating plans and procedures to be followed in an emergency or during conditions which could lead to an emergency. |
| Lead Task Force: Task Force on Coordination of Operation |
| Reviewed for concurrence by: TFCP, TFSP, and TFSS |</p>
<table>
<thead>
<tr>
<th>Criteria – type &quot;A&quot; Documents - continued</th>
<th>Latest Version</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>A-4</strong> Maintenance Criteria for Bulk Power System Protection</td>
<td>December 2000</td>
</tr>
<tr>
<td>Description: Establishes the maintenance intervals and practices which should result in dependable and secure <strong>protection system</strong> operation.</td>
<td></td>
</tr>
<tr>
<td>Lead Task Force: Task Force on System Protection</td>
<td></td>
</tr>
<tr>
<td>Reviewed for concurrence by: TFCO and TFSS</td>
<td></td>
</tr>
<tr>
<td><strong>A-5</strong> Bulk Power System Protection Criteria</td>
<td>September 1998</td>
</tr>
<tr>
<td>Description: This document establishes the minimum design objectives and recommends design practices to minimize the severity and extent of system disturbances and to minimize possible damage to system equipment.</td>
<td></td>
</tr>
<tr>
<td>Lead Task Force: Task Force on System Protection</td>
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</tr>
<tr>
<td>Reviewed for concurrence by: TFCO, TFCP and TFSS</td>
<td></td>
</tr>
<tr>
<td><strong>A-6</strong> Operating Reserve Criteria</td>
<td>September 1998</td>
</tr>
<tr>
<td>Description: This Criteria establishes standard terminology and minimum requirements governing the amount, availability and distribution of operating reserve.</td>
<td></td>
</tr>
<tr>
<td>Lead Task Force: Task Force on Coordination of Operation</td>
<td></td>
</tr>
<tr>
<td>Reviewed for concurrence by: TFCP and TFSS</td>
<td></td>
</tr>
<tr>
<td><strong>A-7</strong> NPCC Glossary of Terms</td>
<td>September 1998</td>
</tr>
<tr>
<td>Description: This Glossary includes terms from NPCC Criteria (A), Guideline (B) and Procedure (C) Documents, as well as from the North American Electric Reliability Council (NERC) <strong>Glossary of Terms</strong>, August 1996.</td>
<td></td>
</tr>
<tr>
<td>Lead Task Force: Task Force on Coordination of Planning</td>
<td></td>
</tr>
<tr>
<td>Reviewed for concurrence by: TFCO, TFEMT, TFSP and TFSS</td>
<td></td>
</tr>
</tbody>
</table>
Criteria – type "A" Documents - continued

A-8  NPCC Reliability Compliance and Enforcement Program

Description: This document describes the NPCC Reliability Compliance and Enforcement Program that is used to assess and enforce compliance with NPCC reliability criteria.

Lead Subcommittee: Compliance Monitoring and Assessment Subcommittee (CMAS)

Reviewed for concurrence by: TFCP, TFCO, TFEMT, TFSP and TFSS

Guides – type "B" Documents

B-1  Guide for the Application of Autoreclosing to the Bulk Power System

Description: This document establishes guidelines for the application of automatic reclosing facilities to circuit breakers on the NPCC bulk power system.

Lead Task Force: Task Force on System Protection
Reviewed for concurrence by: TFSS, TFCO and TFCP

B-2  Control Performance Guide During Normal Conditions

Description: Establishes a performance measure of NPCC Areas and systems within the Areas' ability to carry out their responsibilities regarding control performance.

Lead Task Force: Task Force on Coordination of Operation
Reviewed for concurrence by: TFCP, TFSS
B-3  **Guidelines for Inter-Area Voltage Control**

Description: This document establishes procedures and principles to be considered for occasions where a deficiency or an excess of reactive power can affect **bulk power system** voltage levels in a large portion of an **Area** or in two adjacent **Areas**.

Lead Task Force: Task Force on Coordination of Operation
Reviewed for concurrence by: TFCP, TFSS

B-4  **Guidelines for NPCC Area Transmission Reviews**

Description: Guidelines to help TFSS ascertain that each **Area**'s transmission expansion plan, based on its proposed generation additions, has been developed in accordance with the **NPCC Basic Criteria for Design and Operation of Interconnected Power Systems** (Document A-2).

Lead Task Force: Task Force on System Studies
Reviewed for comments by: TFCO and TFCP

B-5  Guideline B-5 was changed to Procedure C-22 as of February 8, 1994

B-6  The content of Guideline B-6 was incorporated into Guideline B-7 as of March 2, 1999
Guides – type "B" Documents - continued

**B-7  Automatic Underfrequency Load Shedding**
**Program Relaying Guideline**

Description: This guide presents relay application and testing requirements necessary to accomplish the objectives of the *Emergency Operation Criteria* (Document A-3) related to automatic underfrequency load shedding and automatic underfrequency load shedding associated with generator underfrequency tripping.

Lead Task Force: Task Force on System Protection
Reviewed for comments by: TFCO, TFSS and TFCP

**B-8  Guidelines for Area Review of Resource Adequacy**

Description: Guidelines to help TFCP ascertain that each Area's resource plan is in accordance with the NPCC *Basic Criteria for Design and Operation of Interconnected Power Systems* (Document A-2).

Lead Task Force: Task Force on Coordination of Planning
Reviewed for comments by: TFSS

**B-9  Guide for Rating Generating Capability**

Description: Establishes standards for rating and verifying Net Generating Capability.

Lead Task Force: Task Force on Coordination of Operation
Reviewed for comments by: TFCP
B-10  Guidelines for Requesting Exclusions to
   Section 5.1(B) and 6.1(B) of the NPCC
   Basic Criteria for Design and Operation
   of Interconnected Power Systems

   NOTE: Member Representatives shall be advised of
   approvals by the Reliability Coordinating
   Committee of applications for exclusions.

   Description: Establishes procedure for requesting
   exclusion from a certain contingency in the
   Basic Criteria (Document A-2).

   Lead Task Force: Task Force on System Studies
   Reviewed for concurrence by: TFCP, TFCO

B-11  Special Protection System Guideline

   Description: This guideline categorizes a special
   protection system (SPS) according to the
   criteria fault for which it is designed and
   the impact its failure would have on the
   network. It further provides guidelines for
   the design, testing and operation of the
   SPS.

   Lead Task Force: Task Force on System Protection
   Reviewed for concurrence: TFCO, TFSS

B-12  Guidelines for On-Line Computer System Performance
   During Disturbances

   Description: Establishes guidelines for the performance
   of NPCC Area on-line computer systems
   during a power system disturbance.

   Lead Task Force: Task Force on Energy Management Technology
   Reviewed for concurrence: TFCO
B-13  Guide for Reporting System Disturbances

Description: This document establishes the Task Force on Coordination of Operation's (TFCO) requirements and guidelines for reporting system disturbances to enable the TFCO to review, with emphasis on inter-
.Area implications, disturbances which affect a significant part of one Area. (This Guide was formerly known as Procedure C-2).

Lead Task Force: Task Force on Coordination of Operation

B-20  Guidelines for Identifying Key Facilities and Their Critical Components for System Restoration

Description: This document establishes requirements and guidelines for the identification of Key Facilities and their Critical Components that are required for restoration of the power system following a partial or total system blackout.

Lead Task Force: Task Force on Coordination of Operation

B-22  NPCC Guidelines for the Implementation of the Reliability Compliance and Enforcement Program (RCEP)

Description: This document describes the various NPCC functional entities that are utilized to implement the compliance assessment and enforcement process, described in the Reliability Compliance and Enforcement Program (Document A-8).

Lead Subcommittee: Compliance Monitoring and Assessment Subcommittee (CMAS)
Procedures – type "C" Documents

C-0  Listing of NPCC Documents by Type

Description: This listing describes all existing NPCC Criterion (type "A"), Guide (type "B") and Procedure (type "C") Documents.

C-1  Procedure C-1, the former Glossary of Standard Operating Terms, was discontinued in September 1998 with the approval of the NPCC Glossary of Terms (Document A-7).

C-2  Procedure C-2 was elevated to Guideline B-13 as of June 25, 1997

C-3  Procedures for Communications During Emergencies

Description: This Procedure addresses three separate but related areas of emergency of communications: 1) Operators’ communication during an emergency, 2) Communications with external agencies during extended Emergencies, and 3) Collection of data during or following a major system event. (The Procedure is a combination of three former Procedures: C-3, C23 and C-24).

Lead Task Force: Task Force on Coordination of Operation

C-4  Monitoring Procedures for Guidelines for Inter-Area Voltage Control

Description: This procedural document establishes TFCO's monitoring and reporting requirements for conformance with NPCC's Guidelines for Inter-AREA Voltage Control (Document B-3).

Lead Task Force: Task Force on Coordination of Operation
Procedures – type "C" Documents - continued

C-5 Monitoring Procedures for *Emergency Operation Criteria*

**Description:** This procedural document establishes TFCO's monitoring and reporting requirements for conformance with NPCC’s *Emergency Operation Criteria* (Document A-3).

Lead Task Force: Task Force on Coordination of Operation

C-6 Procedure C-6 has been discontinued as of February 8, 1994.

The sections that were under TFSS’s responsibility have been incorporated in Guide B-10.

The sections that were under TFCO’s responsibility have been incorporated in the new Procedure C-21.

C-7 Monitoring Procedures for *Guide for Rating Generating Capability*

**Description:** This procedural document establishes the TFCO's monitoring and reporting requirements for conformance with the NPCC, *Guide for Rating Generating Capability* (Document B-9).

Lead Task Force: Task Force on Coordination of Operation

C-8 Monitoring Procedures for *Control Performance Guide During Normal Conditions*

**Description:** This procedural document establishes a performance measure for NPCC Areas and systems and outlines the reporting function for NPCC *Control Performance Guide During Normal Conditions* (Document B-2)

Lead Task Force: Task Force on Coordination of Operation
C-9 Monitoring Procedures for Operating Reserve Criteria

Description: This procedural document establishes the TFCO's monitoring and reporting requirements for conformance with the NPCC Operating Reserve Criteria (Document A-6)

Lead Task Force: Task Force on Coordination of Operation

Latest Version: January 8, 2001

C-10 Procedure C-10 was discontinued as of July 11, 1991

C-11 Monitoring Procedures for Interconnected System Frequency Response

Description: This procedural document defines procedures for monitoring frequency responses to large generation losses.

Lead Task Force: Task Force on Coordination of Operation

Latest Version: March 25, 1998

C-12 Procedures for Shared Activation of Ten Minute Reserve

Description: This procedural document outlines procedures to share the activation of ten minute reserve on an Area basis.

Lead Task Force: Task Force on Coordination of Operation

Latest Version: March 25, 1998

C-13 Operational Planning Coordination

Appendix D - NPCC Critical Facilities List

Description: This document coordinates the notification of planned facility outages among the Areas. It also establishes formal procedures for Area communications in advance of a period of likely capacity shortages as well as for weekly and emergency NPCC conference call among the Areas.

Lead Task Force: Task Force on Coordination of Operation

Latest Version: May 15, 1997

Appendix D - NPCC Critical Facilities List November 1998
Procedures – type "C" Documents - continued

C-14 Procedure C-14 was incorporated in Procedure C-13 as of May 15, 1997

C-15 Procedures for Solar Magnetic Disturbances on Electrical Power Systems

Description: This procedural document clarifies the reporting channels and information available to the operator during solar alerts and suggests measures that may be taken to mitigate the impact of a solar magnetic disturbance.

Lead Task Force: Task Force on Coordination of Operation

C-16 Procedure for NPCC Review of New or Modified Bulk Power System Special Protection Systems (SPS)

Description: This document outlines procedures for reporting new or modified bulk power system special protection systems.

Lead Task Force: Task Force on Coordination of Planning

C-17 Monitoring Procedures for Guidelines for On-Line Computer System Performance During Disturbances

Description: This document establishes TFEMT's monitoring and reporting procedures for conformance with NPCC's Guidelines for Computer System Performance During Disturbances (Document B-12).

<table>
<thead>
<tr>
<th>Document</th>
<th>Title</th>
<th>Latest Version</th>
</tr>
</thead>
<tbody>
<tr>
<td>C-18</td>
<td>Procedure For Testing and Analysis of Extreme Contingencies</td>
<td>January 29, 1999</td>
</tr>
<tr>
<td></td>
<td>Description: This document establishes a procedure for the testing and analysis of Extreme Contingencies.</td>
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<tr>
<td></td>
<td>Lead Task Force: Task Force on System Studies</td>
<td></td>
</tr>
<tr>
<td>C-19</td>
<td>Procedures During Shortages of Operating Reserve</td>
<td>January 18, 2000</td>
</tr>
<tr>
<td></td>
<td>Description: This procedure is intended to provide specific instructions for the redistribution of Operating Reserve among the Areas when one or more Area(s) are experiencing an Operating Reserve deficiency.</td>
<td></td>
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<tr>
<td></td>
<td>Lead Task Force: Task Force on Coordination of Operation</td>
<td></td>
</tr>
<tr>
<td>C-20</td>
<td>Procedures During Abnormal Operating Conditions</td>
<td>March 3, 1999</td>
</tr>
<tr>
<td></td>
<td>Description: This procedure is intended to complement the Emergency Operation Criteria (Document A-3) by providing specific instructions to the System Operator during such conditions in an NPCC Area or Areas.</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Lead Task Force: Task Force on Coordination of Operation</td>
<td></td>
</tr>
<tr>
<td>C-21</td>
<td>Monitoring Procedures for Conformance with Normal and Emergency Transfer Limits</td>
<td>January 21, 1997</td>
</tr>
<tr>
<td></td>
<td>Description: This procedural document establishes TFCO monitoring and reporting requirements for transfer limits during normal and emergency operations as stipulated in the Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2).</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Lead Task Force: Task Force on Coordination of Operation</td>
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</tbody>
</table>
Procedures – type "C" Documents - continued

**C-22  Procedure for Reporting and Reviewing Proposed Protection Systems for the Bulk Power System**

Description: This procedure ensures that new facilities or modifications to existing facilities are presented to the TFSP in order to ascertain conformance with the principles of the *Bulk Power System Protection Criteria* (Document A-5). (This Procedure was formerly known as Guide B-5).

Lead Task Force: Task Force on System Protection

**C-23**  Procedure C-23 was incorporated in Procedure C-3 as of January 21, 1997

**C-24**  Procedure C-24 was incorporated in Procedure C-3 as of January 21, 1997

**C-25  Procedure to Collect Real Time Data for Inter-Area Dynamic Analysis**

Description: This procedure provides a mechanism to collect real time data following a power system disturbance for the purpose of analyzing the dynamic performance of the NPCC bulk power system.

Lead Task Force: Task Force on System Studies

**C-26  Procedures for Task Force on System Protection Compliance Monitoring and Surveys**

Description: This procedure documents the TFSP's procedures for compliance monitoring and surveys.

Lead Task Force: Task Force on System Protection
C-30  Procedure for Task Force on System Protection
Review of Disturbances

Description:  This procedure documents the TFSP's procedures for review of disturbances that have occurred both inside and outside NPCC.

Lead Task Force:  Task Force on System Protection

C-32  Review Process for NPCC Reliability Compliance Program

Description:  This Procedure describes the process required to review Area compliance to the standards that comprise the NPCC Reliability Compliance Program (RCP) or its successor program.

Lead Subcommittee:  Compliance Monitoring and Assessment Subcommittee
DOCUMENT C-03 WAS REPLACED BY DOCUMENT C-36 ON AUGUST 18, 2005.
Monitoring Procedures
for
Operating Reserve Criteria

Approved by the Task Force on Coordination of Operation on December 3, 1984

Revised: January 25, 1988
Reviewed: September 29, 1993
Reviewed: July 18, 1995
Reviewed: March 25, 1998
Revised: January 16, 2001
Revised: January 29, 2004
Note:

Terms in bold typeface are defined in the *NPCC Glossary of Terms* (Document A-7)
1.0 Introduction

NPCC Operating Reserve Criteria (Document A-6) as amended to date, "establishes standard terminology and minimum requirements governing the amount, availability and distribution of operating reserve". More specifically, the criteria establish Area synchronized reserve requirements based on an Area’s performance in responding to the loss of generation.

This Operating Instruction establishes the monitoring and reporting procedures to be used by the NPCC Control Performance Working Group (CO-1) for the NPCC Operating Reserve Criteria (Document A-6). Definitions for the terms used in the following sections may be found in the above referenced document.

NPCC-specific reporting requirements, beyond those required for meeting the NERC Disturbance Control Standard (DCS), are specified in this document. The reporting methodology is designed to meet both NERC and NPCC reporting requirements with a single reporting mechanism.

The evaluation of DCS compliance for an Area should utilize the NERC Disturbance Recovery Period applicable at the time of the reportable event (15 minutes). The evaluation of compliance for the purpose of determining Area synchronized reserve requirements should utilize a recovery period established by the NPCC (15 minutes).

2.0 Monitoring Criteria

As an indication of the adequacy in Operating Reserve, the monitoring and reporting criteria for Areas within NPCC should focus on the performance results following reportable events where the supply side resource loss is equal to or less than the first contingency loss.

To determine adjustments to synchronized reserve requirements, the NPCC should use a 500 MW supply side resource loss reporting threshold for all Areas except for the Maritimes. The Maritimes Area should use a 300 MW supply side resource loss reporting threshold for determining its adjustments to synchronized reserve requirements.

NPCC Areas should use 80% of their first contingency loss for the NERC DCS reporting threshold.
All supply side resource losses that resulted in the utilization of Procedures for Shared Activation of Ten Minute Reserve (SAR) or reserve sharing procedures should be reported to and reviewed by CO-1.

3.0 Monitoring Procedures: Month-by-Month

For each reportable event not utilizing SAR, an NPCC Area Trouble Report should be completed by the Area experiencing the contingency. The NPCC Area Trouble Report should be completed using the appropriate form.

At the conclusion of each calendar month, NPCC Areas should review all of their reportable events (including those utilizing the SAR procedure) to determine if any adjustment to its synchronized reserve requirement is necessary. Each Area should send an electronic copy of the report completed for each reportable event within a month to the Chair of CO-1. All reports for all the reportable events in a month are due by the tenth business day of the following month.

3.1 Performance for events in excess of the first contingency loss should be identified separately, and should not be used in calculating an Area’s required synchronized reserve component unless recovery occurs within the period specified for adjustments to synchronized reserve requirements.

3.2 The Chair (or his or her designee) of CO-1 should compile all monthly submissions at the end of each quarter to determine DCS compliance. The DCS results should be forwarded to the NERC office, the NPCC Compliance Monitoring and Assessment Subcommittee, and to CO-1. The detailed reports for all reportable events should be forwarded to CO-1 members for final review, and to the NPCC office for archiving.

4.0 Monitoring Procedures: Annually

4.1 The CPWG should prepare an annual summary for all Task Force on Coordination of Operation (TFCO) members indicating, for each Area and for NPCC as a whole, the number of violations and the percentage of events for which performance was successful. The summary report should also compare this past year’s performance with the performance of the five previous years. Comments and recommendations, as may be appropriate, should also be included in this summary.
4.2 The TFCO should review the annual summary prepared by the NPCC Control Performance Working Group (CO-1) and make any necessary modifications. The TFCO Chair should forward this report to the Chair of the NPCC Reliability Coordinating Committee and the Chair of the NPCC Compliance Monitoring and Assessment Subcommittee.

Prepared by: Task Force on Coordination of Operation

Review frequency: 3 years

References: *Criteria for Review and Approval of Documents* (Document A-1)

*Operating Reserve Criteria* (Document A-6)

*NPC Glossary of Terms* (Document A-7)
Procedures for
Shared Activation of
Ten Minute Reserve

Approved by the Task Force on Coordination of Operation on June 6, 1985

Revised:  July 1, 1989
           September 29, 1993
           May 8, 1996
           January 29, 2004

Reviewed: March 25, 1998
           January 18, 2000
           August 1, 2000
           March 12, 2001
           May 8, 2001
           January 15, 2002
Note: Terms in **bold typeface** are defined in NPCC Document A-07, *Glossary of Terms*. 
1.0 Introduction

NPCC Operating Reserve Criteria (Document A-6) "establishes standard terminology and minimum requirements governing the amount, availability and distribution of operating reserve." This Operating Procedure describes the implementation of inter-Area shared activation of ten-minute reserve.

2.0 Objectives

(1) To more quickly relieve the initial stress placed on the interconnected transmission system following a large loss of generation or energy purchase.

(2) To effect an improvement in reliability achieved by the faster recovery.

(3) To assist in achieving compliance with the NERC Disturbance Control Standard (DCS).

(4) To sustain assistance for a minimum of ten minutes unless reliability is affected adversely.

(5) To provide relief for transmission overloads, low voltage, or other abnormal conditions which might not otherwise be relieved by normal reserve pickup response.

NPCC and PJM require that losses of generation be recovered within fifteen (15) minutes. It is intended that by implementing this procedure, recovery will be achieved faster than it would otherwise have been achieved. This procedure recognizes that a large sudden loss of generation or energy purchase often results in revisions to economy / recallable interchange schedules between several Areas. Joint activation of reserve is intended to ensure that generation or energy purchases that are lost are quickly replaced by having several areas simultaneously loading generation in the few minutes immediately following a loss.

3.0 General

The participating Areas in this procedure to jointly activate reserves are ISO-New England (ISO-NE), New York ISO (NYISO), the Maritimes, and Independent Electricity Market Operator (IMO) in the NPCC, and PJM. The procedure may be implemented whenever a participating Area experiences a sudden loss of generation or energy purchase equal to or greater than 500 MW.
for IMO, ISO-NE, NYISO, and PJM, and 300 MW for the Maritimes. This procedure may be used if two or more resource losses below the reportable event threshold occur within one hour of each other, and the sum of those losses exceeds the reportable event threshold.

Areas are expected to respond to normal condition mismatches of load and generation via their internal generation control or with scheduled purchases.

The NPCC Operating Reserve Criteria (Document A-6) and the Operating Reserve Criteria of all NPCC Areas and of PJM Members are not changed by any of the provisions of this procedure. Each NPCC Area and PJM must continue to maintain operating reserve in accordance with existing requirements. Each Area maintains the ability to recover from its own loss of generation or energy purchase by deploying ten minute reserve within fifteen (15) minutes. In the event there is a shortage of operating reserve within NPCC, available reserve is shared in accordance with the provisions of the NPCC Document C-19, Procedures During Shortages Of Operating Reserve.

The term "Contingent Area" as used in this procedure is defined as the Area experiencing the loss of generation, energy purchase, or one or more conditions stated in objective (5) of section 2.0 above. The term "Assisting Areas" is defined as the other participating Areas. Unless precluded by transmission constraints prevailing at the time of a sudden loss, the following are applicable for the allocation of reserve pick-up to achieve recovery:

1. At least fifty percent (50%) of a loss is allocated to the Contingent Area.

2. The remainder of a loss is normally allocated among the Assisting Areas.

3. No Area should be requested to provide more assistance during a reserve pickup than is required to meet its own largest contingency.

4. Within the constraints noted in items 1-3 above, the NYISO Shift Supervisor assigns allocations to Assisting Areas at the time an applicable contingency or condition occurs.

5. The contingent Area should sustain its request for assistance for a minimum of ten minutes unless reliability is affected adversely.

The procedure provides for the shared recovery of sudden losses of generation or energy purchases by loading and sharing of ten (10) minute reserve and/or
revising economy / recallable interchange schedules. Each Area is responsible for the security monitoring of its own system and for the determination of the amount of assistance that it is able to provide, receive or transfer. Transmission limits or other internal constraints that preclude the normal implementation of this procedure are communicated immediately to the NYISO Shift Supervisor. Whenever normal implementation of the procedure is precluded, the NYISO notifies Maritimes, ISO-NE, IMO, and PJM.

The NYISO, being centrally located and equipped with telecommunication facilities to the other participating Areas, acts as the coordinator for this procedure. NYISO, with due consideration of conditions in other Areas, ensures that allocations assigned to Assisting Systems are within their response capability. Within the constraints noted above, the following recovery guidelines are applicable:

1. Time zero (T+0) is the time immediately following the loss of generation or energy purchase. Time (T-0) is the time immediately prior to the time of the loss. NYISO coordinates the time that scheduled changes resulting from reserve pick-up allocations are to be implemented and terminated.

2. Assistance by Assisting Areas activating ten (10) minute reserve will be by interchange schedules that are:
   a. Implemented at a zero time ramp rate immediately following allocation notification.
   b. Maintained until the Contingent Area requests a return to normal, but not longer than thirty minutes.
   c. Ramped out at a ten-minute ramp rate following communications initiated by the Contingent Area which have resulted in mutually established interchange schedules. (Ramping procedures for second contingencies are set out in (4.6).)

3. The Contingent Area purchases energy in accordance with applicable policies and agreements covering interchange and emergency assistance if a deficiency is caused by a withdrawal of assistance when the limit of 2b above is encountered. Such purchases are independent of the provisions of this procedure.

4. Assistance provided by Assisting Areas revising economy / recallable interchange schedules are treated the same as activating ten (10) minute reserve, and the interchange schedules will be:
a. Implemented at a zero time ramp rate immediately following allocation notification.

b. Maintained in effect until the sudden loss has been fully recovered by the Contingent Area and all assistance by shared activation of reserve has been terminated.

c. Maintained in effect until after actions in item 4b above are completed and until revised interchange schedules are mutually established.

d. Factored into the appropriate hourly economy / recallable interchange schedule.

5. Inadvertent interchange is caused by the implementation of this procedure. Inadvertent will be calculated by multiplying an Assisting Area's allocation by the duration of the assistance in minutes divided by 60. The NPCC Control Performance Working Group (CO-1) will monitor the net inadvertent interchange caused by the use of this procedure on an annual basis and report the results to the NPCC Task Force on Coordinated Operation (TFCO).

4.0 Procedure

4.1 Preliminary Reserve Assignment

On a continuing basis, Maritimes, ISO-NE, IMO, and PJM dispatchers keep the NYISO informed of the largest, single generation or energy purchase contingency on its system and changes thereof.

Information pertaining to an Area's inability to participate, reserve limitations (such as "bottled" reserve or reserves used to deliver economy energy sales), and transmission limitations are reported to Maritimes, ISO-NE, IMO, and PJM by the NYISO Shift Supervisor as those conditions arise.

4.2 Notification of Contingency

Immediately following a sudden loss of generation or energy purchase in the Maritimes, ISO-NE, NYISO, IMO, or PJM, the Contingent Area reports the following information to the NYISO via the interpool direct telephone lines:
4.3 Activation of Reserve

After receiving notification of the contingency, the NYISO Shift Supervisor:

a. Determines each Area’s reserve allocation

b. By the direct inter-Area telephone lines, immediately informs each Area of its reserve allocation, the time that the schedule change is effective, and the time that the contingency occurred.

The reserve allocation becomes part of the interchange schedule and is implemented at a zero ramp rate immediately following notification.

4.4 Provision Of Reserve Assistance

The contingent Area should request SAR assistance as soon as possible to provide Assisting Areas with a response window that is as long as possible. Assisting Areas respond as quickly as possible, assuming the same obligation as if the contingency occurred within its Area. Assisting Areas complete a report that documents the Reserve Assistance provided. Instructions and forms for reporting are provided on the NPCC Web Site. To access the Shared Activation of Reserve forms do the following:

Log on to the NPCC Member Site.
Select Working Groups then select CO-1. Select Archived Documents.
The forms are listed by Areas as SAR.

The Contingent Area initiates immediate action to provide its share of reserve to recover from the generation or energy purchase loss, prepare for the replacement of the reserve assistance assigned to assisting Areas, and proceed to re-establish ten (10) minute reserve at least equal to its next largest contingency.
4.5 Termination of Shared Reserve

As soon as the Contingent Area has provided its reserve allocation, it notifies the NYISO. The NYISO establishes a conference call between all participating Areas and confirms the time that the assistance is terminated. Revised interchange schedules are mutually established as required to ensure that the Assisting Areas properly recall assistance. The Contingent Area replaces the reserve assistance assigned to assisting Areas in a manner consistent with mutually established interchange schedules.

In the event that a Contingent Area is not prepared to replace the remaining portion of its reserve obligation within time zero + 30 minutes, the Contingent Area arranges for additional assistance in accordance with applicable policies and agreements covering interchange and emergency assistance.

In the event that the security of an Assisting Area becomes jeopardized, that Area may cancel all or part of its allocation by notifying the NYISO, which then requests the Contingent Area to pick up the required additional amounts of reserve. The Contingent Area completes a report that documents the recovery provided for the contingency. Instructions and forms for reporting are provided on the NPCC Web Site. To access the Shared Activation of Reserve-Assistance forms do the following:

Log on to the NPCC Member Site.
Select Working Groups then select CO-1. Select Archived Documents.
The forms are listed by Areas as ASAR.

4.6 Subsequent Contingencies

In the event that a subsequent loss of generation or energy purchase occurs during the period when a reserve pick-up is in progress, regardless of the size of the contingency, the second Contingent Area may, at its discretion, withdraw assistance and request the NYISO to reallocate the assistance in accordance with the provisions of this procedure. Upon such notification, the NYISO notifies the first Contingent Area of the amount of withdrawal. Both Contingent Areas immediately enter new interchange schedules that reflect the loss of the assistance, using a zero time ramp.

In the event that the second Contingent Area experiences a contingency that qualifies for shared activation of reserve, the NYISO allocates
assistance from the remaining Assisting Areas in accordance with this procedure, upon the request of that Area.

If the second contingency occurs in the Area that has incurred the first contingency, that Area may request additional assistance, in accordance with this procedure, regardless of the size of the contingency.

4.7 Reporting of Shared Activation Reserve Events

The evaluation of Disturbance Control Standard (DCS) compliance for an Area utilizes the NERC Disturbance Recovery Period applicable at the time of the reportable event. The evaluation of compliance for the purpose of determining Area synchronized reserve requirements utilizes a recovery period established by the NPCC.

The reportable event thresholds for the Contingent Area for DCS compliance and adjustments to Area synchronized reserve requirements are specified in NPCC Document C-09, Monitoring Procedures for Operating Reserve Criteria.

4.7.1 To determine compliance for Shared Activation Reserve events a group ACE is calculated from the algebraic summation of the ACE values of all Areas participating in the Shared Activation Reserve procedure. For compliance, the group ACE must cross zero (or return to the pre-contingency group ACE value if the initial group ACE value was negative just prior to the contingency) within the time(s) specified above from the start of the contingency, and, after all schedule changes have been implemented.

4.7.2 A Shared Activation Reserve event exceeding either Reportable Event threshold is a reportable event for all participants in the procedure if the NYISO Shift Supervisor declares implementation of assistance in five minutes or less from the start of the contingency.

4.7.3 A Shared Activation Reserve event exceeding either Reportable Event threshold is a reportable event only for the Contingent Area if the NYISO Shift Supervisor declares implementation of assistance after five minutes of the start of the contingency.

4.7.4 When the group ACE is found to be compliant (per 4.7.1) and all participants shall report (per 4.7.2), all participating Areas are credited with a fully compliant reportable event.
4.7.5 When the group ACE is found to be non-compliant (per 4.7.1) and all participants shall report (per 4.7.2), the computed DCS compliance factor (and/or adjustment to the Area synchronized reserve requirement) is assigned to all participants that are found to be non-compliant (see 4.7.7 and 4.7.8). Compliant Areas (per 4.7.7 and 4.7.8) are credited with a fully compliant reportable event.

4.7.6 When the group ACE is found to be non-compliant (per 4.7.1), all participants report (per 4.7.2), but all participants are compliant individually (i.e., non-coincident ACE behavior caused the compliance failure), the computed DCS compliance factor (and/or adjustment to the Area synchronized reserve requirement) is assigned to the contingent Area and all Assisting Areas report a fully compliant reportable event.

4.7.7 When the group ACE is found to be non-compliant (per 4.7.1) and all participants report (per 4.7.2), Assisting Areas are compliant when their ACE crosses zero (or returns to the ACE value just prior to its schedule change if it was negative) after the schedule change and within of the time(s) specified above from the start of the contingency.

4.7.8 When the group ACE is found to be non-compliant (per 4.7.1), Contingent Areas are compliant if their ACE crosses zero (or returns to its own pre-contingency ACE value if its own initial ACE value was negative just prior to the contingency) within the time(s) specified above from the start of the contingency and after their schedule change has been implemented.

5.0 Handling of Radial Source Contingencies with Several Areas Receiving Energy

Radial source tie lines crossing Area boundaries (i.e. from HQ to NYISO, ISO-NE, and the Maritimes) may have energy delivered over these lines to more than one Area. Handling of large contingencies on radial sources crossing Area boundaries is described in Appendix A. The methodology presented in Appendix A is generic and should be used for allocation of SAR assistance whenever single, multiple, or overlapping single contingencies occur.

6.0 Radial Source Contingencies with Counterflow Transactions
Coincident with energy transactions delivered out of the Area on radial source tie lines, countervailing transactions may be scheduled simultaneously into the Area. The contingency loss of one of these lines when it is carrying counterflow transactions may be a relatively small net energy loss to the interconnection. However, the size of the individual counterflow transactions could be quite large. The methodology presented in Appendix A may be used for allocation of SAR assistance whenever radial line contingencies with counterflow transactions occur. In instances when the net of the scheduled transactions is less than the reportable event threshold, the net interchange schedules may be ramped out instead of using the SAR procedure. The NYISO Shift Supervisor and the Areas party to the transactions may agree to this action and the duration of the ramp.
APPENDIX A

Handling of Radial Source Contingencies With Several Areas Receiving Energy

This Appendix describes the handling of large contingencies on radial sources crossing Area boundaries, such as Hydro-Quebec (HQ) to NYISO. At times, these flows may be composed of simultaneous energy deliveries to the directly connected Area and one or more other Areas. It allows for the use of the SAR procedure to allocate the portion of energy not designated for the directly connected receiving Area to other Areas participating in the Shared Activation of Ten Minute Reserve Procedure.

This same methodology can be applied for scenarios with simultaneous imports and exports of energy (counterflow transactions) by one or more Areas on radial sources crossing Area boundaries. The Area losing its ability to deliver energy may receive negative assistance shares from other Areas. In these scenarios, affected Areas should require smaller generation changes to restore ACE while the procedure is in effect and should have a longer period to adjust fully after the contingency. The use of negative assistance is illustrated in examples 5 and 6.

Background

Some of the radial source tie lines crossing Area boundaries from HQ to NYISO, ISO-NE, and the Maritimes have maximum transfer capabilities in excess of the Area’s single largest internal capacity contingency. Energy may be sold over these lines to more than one Area, with transmission service being provided by the Area to which the respective line is directly connected. An Area may limit the flow such that the loss would not exceed an Area’s largest single contingency to maintain Reserve requirements at reasonable levels. Transmission restrictions in other Areas may also limit these flows.

As the delivering entity, HQ has no practical means to provide reserves from its own system in the event of the loss of a tie. When only the directly connected Area receives the delivery, it can treat the energy as an internal source and carry reserve to cover the sudden loss. However, when the energy is delivered to more than one Area, the responsibility for the directly connected Area to carry all of the reserve can become overly burdensome.

Modification to the SAR Procedure

The SAR procedure is modified to allocate portions of the total delivery to Areas in addition to the directly connected Area during an ordinary shared activation of reserve. When the tie line trips, the directly connected Area may choose to activate the SAR procedure, and then each recipient’s share will be allocated to other participants based
on the principle of mutual assistance, according to share allocation rules in the SAR procedure.

Each Area receiving a portion of energy from the tie line through the directly connected Area will contribute energy to and receive assistance for their portion of the contingency. The Areas supplying this assistance would not have this energy replaced by the directly connected Area when the directly connected Area picks up its reserve to cover its purchase from HQ. Thus, the directly connected Area’s reserve requirement remains the greater of the largest internal contingency or its share of the respective tie line flow.

When MSC 7040 in NYISO, Sandy Pond in ISO-NE, or Eel River in the Maritimes and/or Madawaska in HQ trips, the directly connected Area may initiate the SAR procedure. In order to have each Area receiving energy from HQ prior to the contingency be presented with the correct ACE, all Areas that were receiving energy set their HQ interchange schedules to zero as soon as possible.

Initially, SAR shares would be calculated based on energy scheduled to each Area receiving energy from the tripped element. Initial shares would be allocated to each energy recipient according to the ordinary share allocation rules in the SAR procedure. Thus each energy recipient is assigned one half the energy received initially. An Area would then receive additional allocations to provide assistance to each other Area, until the total amount of the contingency is balanced.

Once the group ACE is restored, the contingent and recipient Areas shall proceed to pick-up the remainder of their respective reserve obligations. A recipient Area shall use its own generation to replace the energy initially received (unless additional alternative arrangements are made) after SAR assistance is withdrawn.

The methodology is iterative. One pass is required to allocate shares for each Area requiring assistance. Key features of the method are demonstrated in the examples below. Maritimes participation is excluded from these examples for simplicity. The values shown are rounded to whole numbers.
Example 1. PJM Buys 400 MW from HQ on MSC 7040, NYISO Buys 1200 MW:

MSC 7040 flow = 1600 MW
HQ – NYISO transaction = 1200 MW
HQ – PJM transaction = 400 MW

<table>
<thead>
<tr>
<th>Area</th>
<th>Initial Share/ Assistance Sought</th>
<th>First Pass</th>
<th>Second Pass</th>
<th>Total Generation Picked Up When SAR Energy Is Supplied Fully</th>
<th>Total Gen. Picked Up After SAR Is Canceled And All ACEs = 0</th>
</tr>
</thead>
<tbody>
<tr>
<td>IMO</td>
<td>200</td>
<td>67</td>
<td>267</td>
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</tr>
<tr>
<td>ISO-NE</td>
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<td>267</td>
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<td></td>
</tr>
<tr>
<td>NYISO</td>
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<td>67</td>
<td>667</td>
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<td>PJM</td>
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</tr>
<tr>
<td>Sum</td>
<td>800</td>
<td>600</td>
<td>200</td>
<td>1600</td>
<td>1600</td>
</tr>
</tbody>
</table>

Initial Shares – NYISO and PJM are initially assigned one half of their respective purchases from HQ. Consequently, under the ordinary SAR rules, they would be “seeking” assistance for an equal amount. The total assistance sought is 800 MW for the entire contingency amount.

First Pass – NYISO is provided 600 MW of assistance. These shares are allocated equally, 200 MW each, among the other three participants – including PJM.

Second Pass – PJM is provided 200 MW of assistance. These shares are allocated equally, 67 MW each, among the other three participants – including NYISO.

Total Generation Picked up – The additional generation in each Area, after all Areas provided their shares, and the composite NPCC/PJM ACE is restored, and the SAR procedure is about to be canceled, is shown in the next to last column of the table above. The additional generation after the SAR procedure is canceled and each Area returns it ACE to zero is shown in the last column.
The table below summarizes the changes in schedule and ACE from just prior to the contingency, through the cancellation of assistance and full recovery by both Areas losing energy due to the contingency (Note that the HVDC schedule is not shown, as it is modeled as an internal generator for NYISO).

<table>
<thead>
<tr>
<th>Time</th>
<th>IMO Sch</th>
<th>IMO ACE</th>
<th>NE Sch</th>
<th>NE ACE</th>
<th>PJM Sch</th>
<th>PJM ACE</th>
<th>NY Sch</th>
<th>NY ACE</th>
<th>Tot Sch</th>
<th>Tot ACE</th>
</tr>
</thead>
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<tr>
<td>Pre-contingency</td>
<td>0</td>
<td>0</td>
<td>0</td>
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<td>0</td>
<td>0</td>
<td>-400</td>
<td>0</td>
<td>+400</td>
<td>-1600</td>
<td>0</td>
<td>-1600</td>
</tr>
<tr>
<td>PJM/NY schedule change</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>-400</td>
<td>0</td>
<td>-1200</td>
<td>0</td>
<td>-1600</td>
</tr>
<tr>
<td>No response, SAR entries</td>
<td>+267</td>
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<td>+267</td>
<td>-267</td>
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<td>+200</td>
<td>0</td>
<td>-400</td>
<td>-600</td>
<td>-667</td>
</tr>
<tr>
<td>Full response, SAR not canceled</td>
<td>+267</td>
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<td>+267</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>-533</td>
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<td>0</td>
</tr>
<tr>
<td>SAR just canceled</td>
<td>0</td>
<td>+267</td>
<td>0</td>
<td>+267</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>-533</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>All get back to ACE = 0</td>
<td>0</td>
<td>0</td>
<td>0</td>
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<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>
Example 2. PJM Buys 1200 MW from HQ on MSC 7040, NYISO Buys 400 MW:

MSC 7040 flow = 1600 MW
HQ – NYISO transaction = 400 MW
HQ – PJM transaction = 1200 MW

<table>
<thead>
<tr>
<th>Area</th>
<th>Initial Share/Assistance Sought</th>
<th>First Pass</th>
<th>Second Pass</th>
<th>Total Generation Picked Up When SAR Energy Is Supplied Fully</th>
<th>Total Gen. Picked Up After SAR Is Canceled and All ACEs = 0</th>
</tr>
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<tbody>
<tr>
<td>IMO</td>
<td>67</td>
<td>200</td>
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<tr>
<td>ISO-NE</td>
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<td>67</td>
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<td>NYISO</td>
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<td>PJM</td>
<td>600</td>
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<td>667</td>
<td>1200</td>
<td></td>
</tr>
<tr>
<td>Sum</td>
<td>800</td>
<td>200</td>
<td>600</td>
<td>1600</td>
<td></td>
</tr>
</tbody>
</table>

Initial Shares – NYISO and PJM are initially assigned one half of their respective purchases from HQ. Consequently, under the ordinary SAR rules, they would be ‘seeking’ assistance for an equal amount. The total assistance sought is 800 MW for the entire contingency amount.

First Pass – NYISO is provided 200 MW of assistance. These shares are allocated equally, 67 MW each, among the other three participants – including PJM.

Second Pass – PJM is provided 600 MW of assistance. These shares are allocated equally, 200 MW each, among the other three participants – including NYISO.

Total Generation Picked up – The additional generation in each Area, after all Areas provided their shares, and the composite NPCC/PJM ACE is restored, is shown in the next to last column of the table above. The additional generation after the SAR procedure is canceled and each Area returns it ACE to zero is shown in the last column.

The table below summarizes the changes in schedule and ACE from just prior to the contingency, through the cancellation of assistance and full recovery by both Areas losing energy due to the contingency (Note that the HVDC schedule is not shown, as it is modeled as an internal generator for NYISO).
<table>
<thead>
<tr>
<th>Time</th>
<th>IMO Sch</th>
<th>IMO ACE</th>
<th>NE Sch</th>
<th>NE ACE</th>
<th>PJM Sch</th>
<th>PJM ACE</th>
<th>NY Sch</th>
<th>NY ACE</th>
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<th>Tot ACE</th>
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<tr>
<td>Contingency</td>
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<td>PJM/NY schedule change</td>
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<tr>
<td>No response, SAR entries</td>
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<td>+267</td>
<td>-267</td>
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<td>-533</td>
<td>-667</td>
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<tr>
<td>Full response, SAR not canceled</td>
<td>+267</td>
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<td>+267</td>
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<tr>
<td>SAR just canceled</td>
<td>0</td>
<td>+267</td>
<td>0</td>
<td>+267</td>
<td>0</td>
<td>-533</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>All get back to ACE = 0</td>
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<td>0</td>
<td>0</td>
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</tr>
</tbody>
</table>
Example 3. PJM and NYISO Buy 200 MW from Quebec on Sandy Pond, NE Buys 1200 MW:

<table>
<thead>
<tr>
<th>Area</th>
<th>Initial Share/Assistance Sought</th>
<th>First Pass</th>
<th>Second Pass</th>
<th>Third Pass</th>
<th>Total Generation Picked Up When SAR Energy Is Supplied Fully</th>
<th>Total Gen. Picked Up After SAR Is Canceled And All ACEs = 0</th>
</tr>
</thead>
<tbody>
<tr>
<td>IMO</td>
<td>200</td>
<td>33</td>
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<tr>
<td>ISO-NE</td>
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<tr>
<td>NYISO</td>
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<td>PJM</td>
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<td>Sum</td>
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<td>600</td>
<td>100</td>
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<td></td>
<td>1600</td>
</tr>
</tbody>
</table>

Initial Shares – ISO-NE, NYISO and PJM are initially assigned one half of their respective purchases from HQ. Consequently, under the ordinary SAR rules, they would be ‘seeking’ assistance for an equal amount. The total assistance sought is 800 MW for the entire contingency amount.

First Pass – ISO-NE is provided with 600 MW of assistance. These shares are allocated equally, 200 MW each, among the other three participants.

Second Pass – NYISO is provided 100 MW of assistance. These shares are allocated equally, 33 MW each, among the other three participants.

Third Pass – A third pass is now required to allocate assistance shares to the third component of the contingency. PJM is provided 100 MW of assistance. These shares are allocated equally, 33 MW each, among the other three participants.

Total Generation Picked up – The additional generation in each Area, after all Areas provided their shares, and the composite NPCC/PJM ACE is restored, and the SAR procedure is about to be canceled, is shown in the next to last column of the table above. The additional generation after the SAR procedure is canceled and each Area returns it ACE to zero is shown in the last column.

The table below summarizes the changes in schedule and ACE from just prior to the contingency, through the cancellation of assistance and full recovery by both Areas.
losing energy due to the contingency (Note that the HVDC schedule is not shown, as it is modeled as an internal generator for ISO-NE).

<table>
<thead>
<tr>
<th>Time</th>
<th>IMO Sch</th>
<th>IMO</th>
<th>NE Sch</th>
<th>NE ACE</th>
<th>PJM Sch</th>
<th>PJM ACE</th>
<th>NY Sch</th>
<th>NY ACE</th>
<th>Tot Sch</th>
<th>Tot ACE</th>
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<tr>
<td>Pre-contingency</td>
<td>0</td>
<td>0</td>
<td>+400</td>
<td>0</td>
<td>-200</td>
<td>0</td>
<td>-200</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Contingency</td>
<td>0</td>
<td>0</td>
<td>+400</td>
<td>-1600</td>
<td>-200</td>
<td>0</td>
<td>-200</td>
<td>0</td>
<td>0</td>
<td>-1600</td>
</tr>
<tr>
<td>PJM/NY/NE schedule change</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>-1200</td>
<td>0</td>
<td>-200</td>
<td>0</td>
<td>-200</td>
<td>0</td>
<td>-1600</td>
</tr>
<tr>
<td>No response, SAR entries</td>
<td>+267</td>
<td>-267</td>
<td>-600</td>
<td>+33</td>
<td>-667</td>
<td>-100 +200</td>
<td>+33</td>
<td>-333</td>
<td>+133</td>
<td>-333</td>
</tr>
<tr>
<td>Full response, SAR not canceled</td>
<td>+267</td>
<td>0</td>
<td>-533</td>
<td>0</td>
<td>+133</td>
<td>0</td>
<td>+133</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>SAR just canceled</td>
<td>0</td>
<td>+267</td>
<td>0</td>
<td>-533</td>
<td>0</td>
<td>+133</td>
<td>0</td>
<td>+133</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>All get back to ACE = 0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>
Example 4. ISO-NE, PJM and NYISO Purchase 700 MW each from Quebec on Sandy Pond:

\[
\begin{align*}
\text{Sandy Pond flow} &= 2100 \text{ MW} \\
\text{HQ – NYISO transaction} &= 700 \text{ MW} \\
\text{HQ – ISONE transaction} &= 700 \text{ MW} \\
\text{HQ – PJM transaction} &= 700 \text{ MW}
\end{align*}
\]

<table>
<thead>
<tr>
<th>Area</th>
<th>Initial Share/ Assistance Sought</th>
<th>First Pass</th>
<th>Second Pass</th>
<th>Third Pass</th>
<th>Total Generation Picked Up When SAR Energy Is Supplied Fully</th>
<th>Total Gen. Picked Up After SAR Is Canceled And All ACEs = 0</th>
</tr>
</thead>
<tbody>
<tr>
<td>IMO</td>
<td>117</td>
<td>117</td>
<td>117</td>
<td>350</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>ISO-NE</td>
<td>350</td>
<td>117</td>
<td>117</td>
<td>584</td>
<td>700</td>
<td></td>
</tr>
<tr>
<td>NYISO</td>
<td>350</td>
<td>117</td>
<td>117</td>
<td>584</td>
<td>700</td>
<td></td>
</tr>
<tr>
<td>PJM</td>
<td>350</td>
<td>117</td>
<td>117</td>
<td>584</td>
<td>700</td>
<td></td>
</tr>
<tr>
<td>Sum</td>
<td>1050</td>
<td>350</td>
<td>350</td>
<td>350</td>
<td>2100</td>
<td>2100</td>
</tr>
</tbody>
</table>

Initial Shares – ISO-NE, NYISO, and PJM are initially assigned one half of their respective purchases from HQ. Consequently, under the ordinary SAR rules, they would be ‘seeking’ assistance for an equal amount. The total assistance sought is 1050 MW for the entire contingency amount.

First Pass – ISO-NE is provided 350 MW of assistance. These shares are allocated equally, 117 MW each, among the other three participants.

Second Pass – NYISO is provided 350 MW of assistance. These shares are allocated equally, 117 MW each, among the other three participants.

Third Pass – PJM is provided 350 MW of assistance. These shares are allocated equally, 117 MW each, among the other three participants.

Total Generation Picked up – The additional generation in each Area after all Areas provided their shares, and the composite NPCC/PJM ACE is restored, and the SAR procedure is about to be canceled, is shown in the next to last column of the table above. The additional generation after the SAR procedure is canceled and each Area returns it ACE to zero is shown in the last column.

The table below summarizes the changes in schedule and ACE from just prior to the contingency, through the cancellation of assistance and full recovery by both Areas.
losing energy due to the contingency (Note that the HVDC schedule is not shown, as it is modeled as an internal generator for ISO-NE).

<table>
<thead>
<tr>
<th>Time</th>
<th>IMO Sch</th>
<th>IMO ACE</th>
<th>NE Sch</th>
<th>NE ACE</th>
<th>PJM Sch</th>
<th>PJM ACE</th>
<th>NY Sch</th>
<th>NY ACE</th>
<th>Tot Sch</th>
<th>Tot ACE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pre-contingency</td>
<td>0</td>
<td>0</td>
<td>+1400</td>
<td>0</td>
<td>-700</td>
<td>0</td>
<td>-700</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Contingency</td>
<td>0</td>
<td>0</td>
<td>+1400</td>
<td>-2100</td>
<td>-700</td>
<td>0</td>
<td>-700</td>
<td>0</td>
<td>0</td>
<td>-2100</td>
</tr>
<tr>
<td>PJM/NY/NE schedule change</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>-700</td>
<td>0</td>
<td>-700</td>
<td>0</td>
<td>-700</td>
<td>0</td>
<td>-2100</td>
</tr>
<tr>
<td>No response, SAR entries</td>
<td>+350</td>
<td>-350</td>
<td>-117</td>
<td>-583</td>
<td>-117</td>
<td>-583</td>
<td>-117</td>
<td>-583</td>
<td>0</td>
<td>-2100</td>
</tr>
<tr>
<td>Full response, SAR not canceled</td>
<td>+350</td>
<td>0</td>
<td>-117</td>
<td>0</td>
<td>-117</td>
<td>0</td>
<td>-117</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>SAR just canceled</td>
<td>0</td>
<td>+350</td>
<td>0</td>
<td>-117</td>
<td>0</td>
<td>-117</td>
<td>0</td>
<td>-117</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>All get back to ACE = 0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>
Radial Source Contingencies With Counterflow Transactions

Example 5. Counterflow Transactions on MSC 7040
PJM Exports 400 MW to HQ on MSC 7040, NYISO Imports 1200 MW:

MSC 7040 flow = 800 MW
HQ – NYISO transaction = 1200 MW
HQ – PJM transaction = -400 MW (flow is PJM to HQ)

<table>
<thead>
<tr>
<th>Area</th>
<th>Initial Share/ Assistance Sought</th>
<th>First Pass</th>
<th>Second Pass</th>
<th>Total Generation Picked Up When SAR Energy Is Supplied Fully</th>
<th>Total Gen. Picked Up After SAR Is Canceled And All ACEs = 0</th>
</tr>
</thead>
<tbody>
<tr>
<td>IMO</td>
<td>200</td>
<td>-67</td>
<td>133</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>ISO-NE</td>
<td>200</td>
<td>-67</td>
<td>133</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>NYISO</td>
<td>600</td>
<td>-67</td>
<td>533</td>
<td>1200</td>
<td></td>
</tr>
<tr>
<td>PJM</td>
<td>-200</td>
<td>200</td>
<td>0</td>
<td>-400</td>
<td></td>
</tr>
<tr>
<td>Sum</td>
<td>400</td>
<td>600</td>
<td>-200</td>
<td>400</td>
<td>800</td>
</tr>
</tbody>
</table>

Initial Shares – NYISO and PJM are initially assigned one half of their respective purchase from and delivery to HQ. Consequently, under the ordinary SAR rules, they would be ‘seeking’ assistance for both flows into and out of Quebec. The total net assistance sought is 400 MW for the net contingency amount.

First Pass – NYISO is provided 600 MW of assistance. These shares are allocated equally, 200 MW each, among the other three participants – including PJM.

Second Pass – PJM is provided -200 MW of assistance. These shares are allocated equally, -67 MW each, among the other three participants – including NYISO. These negative shares reduce the net pick-ups required of the assisting Areas.

Total Generation Picked up – The additional generation in each Area, after all Areas provided their shares, and the composite NPCC/PJM ACE is restored, and the SAR procedure is about to be canceled, is shown in the next to last column of the table above. The additional generation after the SAR procedure is canceled and each Area returns it ACE to zero is shown in the last column.
Example 6. ISO-NE Purchase 2000 MW from HQ, PJM and NYISO Deliver 500 MW each to Quebec on Sandy Pond:

- Sandy Pond flow = 1000 MW
- NYISO - HQ transaction = -500 MW (flow is NY to HQ)
- HQ – ISONE transaction = 2000 MW
- PJM – HQ transaction = -500 MW (flow is PJM to HQ)

<table>
<thead>
<tr>
<th>Area</th>
<th>Initial Share/Assistance Sought</th>
<th>First Pass</th>
<th>Second Pass</th>
<th>Third Pass</th>
<th>Total Generation Picked Up When SAR Energy Is Supplied Fully</th>
<th>Total Gen. Picked Up After SAR Is Canceled And All ACEs = 0</th>
</tr>
</thead>
<tbody>
<tr>
<td>IMO</td>
<td></td>
<td>333</td>
<td>-83</td>
<td>-83</td>
<td>167</td>
<td>0</td>
</tr>
<tr>
<td>ISO-NE</td>
<td>1000</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>2000</td>
</tr>
<tr>
<td>NYISO</td>
<td>-250</td>
<td>333</td>
<td>-83</td>
<td>-83</td>
<td>834</td>
<td>2000</td>
</tr>
<tr>
<td>PJM</td>
<td>-250</td>
<td>333</td>
<td>-83</td>
<td>0</td>
<td>0</td>
<td>-500</td>
</tr>
<tr>
<td>Sum</td>
<td>500</td>
<td>1000</td>
<td>-250</td>
<td>-250</td>
<td>1000</td>
<td>1000</td>
</tr>
</tbody>
</table>

**Initial Shares** – ISO-NE, NYISO and PJM are initially assigned one half of their respective purchase from and delivery to Quebec. Consequently, under the ordinary SAR rules, they would be ‘seeking’ assistance for flows into and out of Quebec. The total assistance sought is 1000 MW for the net contingency amount.

**First Pass** – ISO-NE is provided 1000 MW of assistance. These shares are allocated equally, 333 MW each, among the other three participants.

**Second Pass** – NYISO is provided -250 MW of assistance. These shares are allocated equally, -83 MW each, among the other three participants.

**Third Pass** – PJM is provided -250 MW of assistance. These shares are allocated equally, -83 MW each, among the other three participants.

**Total Generation Picked up** – The additional generation in each Area after all Areas provided their shares, and the composite NPCC/PJM ACE is restored, and the SAR procedure is about to be canceled, is shown in the next to last column of the table above. The additional generation after the SAR procedure is canceled and each Area returns it ACE to zero is shown in the last column.

Prepared by: Task Force on Coordination of Operation

Review frequency: 3 years
References:  

*Operating Reserve Criteria* (Document A-6)  

Monitoring Procedures for Operating Reserve Criteria (Document C-09)  

*NPCC Glossary of Terms* (Document A-7)  

Procedures During Shortages of Operating Reserve (Document C-19)
Procedures for Solar Magnetic Disturbances
Which Affect Electric Power Systems

Approved by the Task Force on Coordination of Operation on April 10, 1989
Re-designated as Document C-15 on August 18, 2005—Formerly Document RD-09

Revised: May 23, 1989
Revised: September 1, 1989
Revised: February 10, 1993
Revised: January 21, 1997
Reviewed: March 25, 1998
Revised: November 7, 2000
Revised: October 15, 2003
Reviewed: August 18, 2005
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   2.1 General Effects

3.0 NPCC Alerts of Solar Magnetic Disturbances

4.0 Recommended Procedures
   4.1 Operational Planning
   4.2 Operator Actions with the Onset of an SMD

5.0 Back-Up Communications
   5.1 Communications Failure
   5.2 Conflicting Data

APPENDICES

A Communication Paths
B Solar Alerts Issued by the Solar Terrestrial Dispatch
C Solar Alerts Issued by the Space Environment Services of the National Oceanic and Atmospheric Administration (Boulder, Colorado)
D Solar Alerts Issued by the Geological Survey of Canada, Department of Natural Resources Canada (Ottowa, Ontario)
E Time Conversion Reference Document
F Description of Solar Magnetic Disturbances

Note: Terms in bold typeface are defined in the NPCC Glossary of Terms (NPCC Document A-07).
1.0 Introduction

Solar Magnetic Disturbances (SMD) are events that occur on the sun which can ultimately affect man-made systems on earth, including power systems. Voltage potentials are induced in the earth's crust which in turn cause geomagnetically induced currents (GIC) to flow in transmission lines. The resulting GICs are predominantly direct currents in nature and are typically more prevalent in the more northerly latitudes and in those regions in which the resistivity of the earth’s crust is high to a considerable depth. This is notably the case in areas of igneous rock deposits.

Those utilities most affected by solar activity since 1989 have developed procedures which establish a safe operating posture and which are initiated by criteria for their respective systems.

A detailed technical description of SMDs may be found Appendix F.

2.0 Impacts on Power Systems

The flow of GICs in the transmission system may affect the following equipment:

2.1 General Effects

2.1.1 Power Transformers

The presence of GIC produces off-setting dc excitation in a transformer, resulting in some degree of core saturation. This can cause the production of harmonic currents which can distort system voltages and cause protective relay operation due to the flow of neutral current to ground. Core saturation can also result in internal localized heating of the core and windings, and degradation of winding insulation. Saturated transformers are reactive power sinks, using up system reactive capacity, resulting in voltage depression.

2.1.2 Instrument Transformers

The effects described in power transformers can also occur in other magnetic equipment such as potential and current transformers, resulting in the misoperation of protective relaying.

2.1.3 HVdc Systems and Static VAR Compensators
Operations at or near the minimum or maximum current rating of HVdc circuits increases the potential for commutation failures, jeopardizing continuity of service.

These systems require a sinusoidal voltage to properly commutate current transmission. Voltage distorted by harmonics may be severe enough to cause commutation failures and result in shutdown of such systems.

Filter banks, including capacitor banks, associated with these systems will tend to overload due to harmonic current and may result in tripping.

2.1.4 Shunt Capacitor Banks

Shunt capacitor banks will tend to overload due to harmonic current, typically the third harmonic.

2.1.5 Generators

Automatic voltage regulators (AVR) associated with generators require representative voltage signals to control the dc field current on generators. Distorted ac voltage input to the AVR may result in uncertain translation of the ac signals for control, possibly resulting in a cyclical level of excitation on the generator, and hence real and reactive power output may vary in an abnormal manner.

Overheating may occur in large generators due to imbalances in phase currents and harmonic distortion in voltages which result from the saturation of power transformers. Turbine mechanical vibration may be excited by the presence of increased harmonic rotor current.

2.1.6 Transmission Lines

Harmonic frequencies in the system voltage can increase the magnitude of the voltage required to be switched by circuit breakers. Harmonics increase transmission losses and cause interference to communications systems.

2.1.7 Overall System Impact


Transformer saturation results in increased VAR consumption and harmonic injection into the system. These harmonic currents can result in capacitor bank overloading and their tripping, generator tripping and misoperation of static VAR compensators. This could further deplete the system of reactive VAR support and impact the overall system performance and security. The power systems are becoming more vulnerable to GIC effects due to longer transmission lines, decreased reactive margins and greater dependence on static VAR compensators and high voltage dc control.

3.0 NPCC Alerts of Solar Magnetic Disturbances

The NPCC Areas receive, on a continual twenty-four by seven basis, the status of solar activity and geomagnetic storm alerts from the Solar Terrestrial Dispatch (STD). The primary mechanism for notification to the NPCC Areas is the Solar Terrestrial Dispatch’s Geomagnetic Storm Mitigation System (GSMS), an active communications software package installed on the operator’s console. Upon receipt of a geomagnetic storm alert from Solar Terrestrial Dispatch of level Kp 6 or higher, the GSMS simultaneously displays:

- a flashing dialog box advising the operator of a “Major or Severe Geomagnetic Storm Warning.” At the discretion of the Area, audible warnings will also accompany the flashing dialog box. Both the flashing indicator and the audible warning (if utilized) will continue until the “Confirm Receipt” button is clicked in the dialog box. This sends a verification to Solar Terrestrial Dispatch that the storm alert was received by the NPCC Areas. After acknowledging receipt of the geomagnetic storm alert, the GSMS will immediately prompt the operator to specify any GIC activity that has been observed on the power grid. The operator responds by clicking one of the following four buttons, as applicable:

  “No GIC activity has been observed yet.”
  “Yes. Weak GIC activity has been observed.”
  “Yes. Moderately strong GIC activity has been observed.”
  “Yes. Strong GIC activity has been observed.”

- a main screen providing the operator with all information currently known about possible solar activity. The following information is presented:
• the time of the notification in both Universal Time and the Area’s local time in twenty-four hour format

• the history of actual hourly Kp readings for the previous seven hours

• the Kp prediction, together with the predicted time of its onset, and the predicted peak Kp reading for the next twenty-four, forty-eight and seventy-two hours periods

• the maximum Kp prediction for both the auroral and sub-auroral zones

• the probability of occurrence of the predicted Kp level

• the probable duration of the geomagnetic storm

• a graphical presentation over time of both current historical Kp observations and projected Kp values

• the status of the receipt of the notification by all NPCC Areas.

After reviewing the available data, the operator may choose to enact protective measures. Such protective measures taken are to be promptly reported as soon as possible. This is done by clicking on the “Submit Notifications” tab and filling in the box labeled “ Specify new actions being taken.” Then click on the red arrow to record the actions that are being taken. This permanently records the action taken on the GSMS display and transmits the action to all NPCC Areas. Upon the halting of a previous action taken, the operator is to similarly report these steps using the same interface.

In the event that an Area observes GIC activity absent the notification of a geomagnetic storm alert, the operator is to use the “Submit Notifications” feature of the Geomagnetic Storm Mitigation System to automatically notify the other NPCC Areas and the Solar Terrestrial Dispatch of the activity.

All time alerts issued by the Solar Terrestrial Dispatch are disseminated in Universal Time (Greenwich Mean Time), a constant scientific time reference. All references to Universal Time may be converted to the prevailing Eastern Time or Atlantic Time as described in Appendix E.
A summary of the levels of solar activity that are made available to the NPCC Areas by the STD are shown in Appendix B. Further details can be obtained through the Web site of Solar Terrestrial Dispatch at:

http://www.spacew.com/

4.0 Recommended Procedures

4.1 Operational Planning

On receiving from the Solar Terrestrial Dispatch a forecast of SMD activity expected to result in Kp levels 7, 8 or 9, operations should be reviewed for vulnerability to such storms. Actions should be considered which include, but are not limited to, those listed in Section 4.2.

4.2 Operator Action With the Onset of an SMD

On receiving from the Solar Terrestrial Dispatch a geomagnetic storm alert predicting at least a 40% probability of activity at levels of Kp 7, Kp 8 or Kp 9, or notification of significant GIC activity, system operators may evaluate the situation and implement the following actions as appropriate for their power system.

4.2.1 Discontinue maintenance work and restore out of service high voltage transmission lines to service. Avoid taking long lines out of service.

4.2.2 Maintain the system voltage within an acceptable operating range to protect against voltage swings.

4.2.3 Adjust the loading on HVdc circuits to be within the 40% to 90% range of their nominal rating.

4.2.4 Reduce the loading on interconnections, critical transmission facilities, and critical transmission interfaces to 90%, or less, of their agreed limits.

4.2.5 Reduce the loading on generators operating at full load to provide reserve power and reactive capacity.

4.2.6 Consider the impact of tripping large shunt capacitor banks and static VAR compensators.
4.2.7 Dispatch generation to manage system voltage, tie line loading and to distribute operating reserve.

4.2.8 Bring equipment capable of synchronous condenser operation on line to provide reactive power reserve.

4.2.9 Ensure with personnel at those locations where SMD measurements are to be taken that the monitoring equipment is in service.

5.0 **Back-Up Communications**

5.1 **Communications Failure**

Although significant redundancy is incorporated in the dissemination of the solar alerts provided by the Solar Terrestrial Dispatch, in the event that all communication is lost with STD, the NPCC will, in the interim, rely on the solar forecasts and alerts issued by the governmental agencies of the United States and Canada. These are, respectively, the Space Environment Center (SEC) of the National Oceanic and Atmospheric Administration (NOAA), located in Boulder, Colorado, referenced in Appendix C, and the Geological Survey of Canada, Department of Natural Resources Canada (NRCAN), located in Ottawa, Ontario, referenced in Appendix D. These communication paths are summarized in Appendix A.

5.2 **Conflicting Data**

All actions to be considered in section 4.2 are to be based on the forecasts and alerts disseminated by the STD. This data is tailored for the power system in general, and for the geographic subauroral region in which the NPCC transmission system is located. It is therefore unlikely that the STD would predict less solar activity than either the SEC or the NRCAN. However, should the forecasts or alerts of either the SEC or the NRCAN predict higher solar activity than those of Solar Terrestrial Dispatch, each NPCC Area will communicate this discrepancy with the STD through the “Submit Notifications” tab of the GSMS and request clarification.

Prepared by: Task Force on Coordination of Operation
Review frequency: 3 years

References: NPCC Glossary of Terms (NPCC Document A-07)
Appendix A

Communication Paths

**Primary NPCC Notification:**

<table>
<thead>
<tr>
<th>Primary NPCC Notifications</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>On a continual basis, through the Solar Terrestrial Dispatch Geomagnetic Storm Mitigation System (GSMS), solar activity is available to:</td>
<td>all NPCC Areas (IESO, ISO-NE, NBSO, NYISO and TE)</td>
</tr>
<tr>
<td>Upon the prediction of a geomagnetic storm alert of level Kp 6 or higher, the Solar Terrestrial Dispatch GSMS automatically provides alarms to:</td>
<td>all NPCC Areas (IESO, ISO-NE, NBSO, NYISO and TE)</td>
</tr>
<tr>
<td>For a prediction of Kp 7 or higher, the Solar Terrestrial Dispatch notifies by telephone:</td>
<td>the NYISO; the NYISO in turn notifies the IESO, the ISO-NE, NBSO, and TE.</td>
</tr>
</tbody>
</table>

**Back-up NPCC Notification:**

<table>
<thead>
<tr>
<th>SEC (Boulder, Colorado) Forecasts and Alerts</th>
</tr>
</thead>
<tbody>
<tr>
<td>SEC-Boulder notifies:</td>
</tr>
<tr>
<td>New Brunswick System Operator notifies:</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>NRCAN (Ottawa) Forecasts and Alerts</th>
</tr>
</thead>
<tbody>
<tr>
<td>NRCAN-Ottawa notifies:</td>
</tr>
<tr>
<td>IESO notifies:</td>
</tr>
<tr>
<td>New Brunswick System Operator notifies:</td>
</tr>
</tbody>
</table>

**Note:** The North American Electric Reliability Council (NERC) also receives solar alerts from the Space Environment Center and transmits these alerts to the NERC Reliability Coordinators through the Reliability Coordinator Information System (RCIS).
Appendix B
Solar Activity Reporting Form

The predictive measure of solar activity reported by the Solar Terrestrial Dispatch is the Kp index, a scale divided into 27 zones of solar activity. A description of these zones and the relationship between the observed Kp index and typically observed GIC activity follows:

<table>
<thead>
<tr>
<th>Kp Index</th>
<th>Solar Activity</th>
<th>GIC Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>0o</td>
<td>Quiet</td>
<td>No GICs</td>
</tr>
<tr>
<td>1-</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1o</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1+</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2-</td>
<td>Unsettled</td>
<td></td>
</tr>
<tr>
<td>2o</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2+</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3-</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3o</td>
<td></td>
<td></td>
</tr>
<tr>
<td>3+</td>
<td></td>
<td></td>
</tr>
<tr>
<td>4-</td>
<td>Active</td>
<td></td>
</tr>
<tr>
<td>4o</td>
<td></td>
<td></td>
</tr>
<tr>
<td>4+</td>
<td></td>
<td></td>
</tr>
<tr>
<td>5-</td>
<td></td>
<td></td>
</tr>
<tr>
<td>5o</td>
<td>Minor Storm</td>
<td>Low Level GICs</td>
</tr>
<tr>
<td>5+</td>
<td></td>
<td></td>
</tr>
<tr>
<td>6-</td>
<td>Major Storm</td>
<td></td>
</tr>
<tr>
<td>6o</td>
<td></td>
<td></td>
</tr>
<tr>
<td>6+</td>
<td></td>
<td></td>
</tr>
<tr>
<td>7-</td>
<td>Severe Storm</td>
<td>Moderate GICs</td>
</tr>
<tr>
<td>7o</td>
<td></td>
<td></td>
</tr>
<tr>
<td>7+</td>
<td></td>
<td></td>
</tr>
<tr>
<td>8-</td>
<td>Very Severe Storm</td>
<td>Strong GICs</td>
</tr>
<tr>
<td>8o</td>
<td></td>
<td></td>
</tr>
<tr>
<td>8+</td>
<td></td>
<td></td>
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<tr>
<td>9-</td>
<td></td>
<td></td>
</tr>
<tr>
<td>9o</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Appendix C

Solar Alerts Issued by the Space Environment Services (SEC–Boulder, Colorado)

The Space Environment Center (SEC) of the National Oceanic and Atmospheric Administration (NOAA) is located in Boulder, Colorado, and provides warnings and alerts of geomagnetic activity to the New York ISO. The NYISO subsequently disseminates this information to the other operating Areas within NPCC.

SEC warnings and alerts are issued in the form of a daily "A" index up to three days in advance. The "A" index is a measure of the expected geomagnetic activity, based on solar observations, for Fredericksburg, Virginia. The classification of Major Storm (A index of 50 and above) is transmitted to the NPCC Areas. The SEC also includes a probability for “Major Storm” conditions to help users assess the confidence level of the forecast.

SEC warnings and alerts are also issued in the form of the Kp index, which is based on the maximum deviation of the horizontal magnetic field components of the earth relative to a quiet day, within a three hour time period. The Boulder Kp index is based on measurements from the Boulder magnetometer, and it is used at the SEC to define the alert thresholds. A warning or alert is issued for a Kp index of Kp 5 or greater. Most electrical power systems, however, are not affected until the Kp index reaches a level of 7 or higher.

The forecasts and warnings that are made available to system control centers follow:

**Warnings**

The following Warnings are issued by telephone from the SEC to the NYISO. Warnings are predictions for a certain period in the future. That is, warnings come before the specified period.

A Index = 30
A Index = 50
Kp Index = 5
Kp Index = 6
Kp Index = 7 or above
Alerts

The following Alerts are issued by telephone from the SEC to the NYISO. Alerts are observations of activity that has already occurred. Generally, alerts are issued at the end of the specified period.

A Index = 30
A Index = 50
Kp Index = 5
Kp Index = 6
Kp Index = 7
Kp Index = 8

Rapid Alerts

The following Rapid Alerts are issued by telephone from the SEC to the NYISO. Rapid Alerts are observations of activity that has occurred, but they are issued immediately, without waiting for the end of the period.

Kp Index = 7
Kp Index = 8

Note: The SEC in some cases speaks of all of these messages, including warnings, alerts and rapid alerts, as “alerts,” and thus all of the messages can carry an alert code.

All time alerts issued by the SEC are disseminated in Universal Time (Greenwich Mean Time), a constant scientific time reference. All references to Universal Time may be converted to the prevailing Eastern Time or Atlantic Time as described in Appendix E.

Further information can be obtained at:

http://www.sec.noaa.gov/today.html
Appendix D
Solar Alerts Issued by the Department of Natural Resources Canada (NRCAN–Ottawa, Ontario)

The Geological Survey of Canada, Department of Natural Resources Canada (NRCAN), located in Ottawa, Ontario, Canada, issues forecasts and warnings, based on magnetometer data from 12 observatories using the Canadian Automatic Magnetometer Observatory System (CANMOS) and on solar data received from sources around the world.

GSC forecasts are updated and issued every hour. They are based on hourly range predictions of geomagnetic activity for up to two days in the future for the subauroral zone, the geographic region in which most of the NPCC Areas are located. The classifications which are of concern to the NPCC Areas are "Stormy" (corresponding to an approximate Kp index of 5 or 6), and "Major Storm" (corresponding to an approximate Kp index of 7, 8, or 9). Several key observatories are continually monitored, and, when events are found that meet predefined criteria, a warning and updated forecast are issued. The forecasts and warnings that are made available to system control centers follow:

**Warnings**

Warnings issued by the NRCAN are based on actual conditions which have occurred and been observed:

<table>
<thead>
<tr>
<th>Kp Index</th>
<th>Hourly Range in nano Teslas (nT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0</td>
<td>0 to 7</td>
</tr>
<tr>
<td>1</td>
<td>8 to 14</td>
</tr>
<tr>
<td>2</td>
<td>15 to 29</td>
</tr>
<tr>
<td>3</td>
<td>30 to 59</td>
</tr>
<tr>
<td>4</td>
<td>60 to 104</td>
</tr>
<tr>
<td>5</td>
<td>105 to 179</td>
</tr>
<tr>
<td>6</td>
<td>180 to 299</td>
</tr>
<tr>
<td>7</td>
<td>300 to 499</td>
</tr>
<tr>
<td>8</td>
<td>500 to 749</td>
</tr>
<tr>
<td>9</td>
<td>750 and above</td>
</tr>
</tbody>
</table>
Forecasts

Forecasts issued by the NRCAN are projections for expected conditions:

<table>
<thead>
<tr>
<th>Activity Level</th>
<th>Kp Levels</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stormy</td>
<td>5 and 6</td>
</tr>
<tr>
<td>Major Storm</td>
<td>7, 8 and 9</td>
</tr>
</tbody>
</table>

**NOTE:** NRCAN data is measured at Ottawa, Ontario, Canada; forecasts are projections of conditions expected to occur in the subauroral zone in which most of NPCC is physically located.

All time alerts issued by the NRCAN are disseminated in Universal Time (Greenwich Mean Time), a constant scientific time reference. All references to Universal Time may be converted to the prevailing Eastern Time or Atlantic Time as described in Appendix E.

Further information can be obtained at:

forecast@geolab.nrcan.gc.ca
http://www.geolab.nrcan.gc.ca/geomag
Appendix E
Time Conversion Reference Document

The time reference used in the solar alerts disseminated by the Solar Terrestrial Dispatch, as well as the Department of Natural Resources Canada and the Space Environment Services, is the scientifically accepted Universal Time (UT), which is also equivalent to Greenwich Mean Time (GMT). The prevailing Eastern Time lags Universal Time / Greenwich Mean Time by five hours in the autumn and winter. The prevailing Eastern Time lags Universal Time / Greenwich Mean Time by four hours in the spring and summer. The prevailing Atlantic Time lags Universal Time / Greenwich Mean Time by four hours in the autumn and winter. The prevailing Atlantic Time lags Universal Time / Greenwich Mean Time by three hours in the spring and summer. The Universal Time / Greenwich Mean Time is a constant time reference and does not convert to accommodate daylight savings in the spring and summer. Conversion examples for the Eastern and Atlantic time zones follow:

<table>
<thead>
<tr>
<th>Eastern Standard Time (EST)</th>
<th>Universal Time (GMT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>12:00 hour</td>
<td>17:00 hour</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Eastern Daylight Time (EDT)</th>
<th>Universal Time (GMT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>13:00 hour</td>
<td>17:00 hour</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Atlantic Standard Time (AST)</th>
<th>Universal Time (GMT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>13:00 hour</td>
<td>17:00 hour</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Atlantic Daylight Time (ADT)</th>
<th>Universal Time (GMT)</th>
</tr>
</thead>
<tbody>
<tr>
<td>14:00 hour</td>
<td>17:00 hour</td>
</tr>
</tbody>
</table>
Appendix F

Description of Solar Magnetic Disturbances

Solar Magnetic Disturbances (SMDs) are events that occur on the sun that can ultimately affect man-made systems on Earth, including power systems. The sun emits a stream of charged particles known as the solar wind that continuously moves outward from the sun past the Earth. Solar activity (solar flares, disappearing filaments and coronal holes) affects the intensity of the solar wind, varying from very quiet levels to very active levels during major storms. Extremely fast coronal mass ejection (CME) events associated with unusually energetic solar flares (known as Fast Transit Events [FTEs]) can reach the earth in as little as fourteen hours. However, most CMEs (including disappearing filament eruptions) require approximately two to three days to travel to the Earth. Coronal hole based disturbances typically take two to four days to reach the Earth. The quiet solar wind can take up to six days to reach the Earth.

The Earth has a magnetic field that is generated by a liquid metal core. This magnetic field penetrates the surface of the Earth and expands outward a large distance into space, effectively creating a cocoon or shield around the Earth that protects the Earth from harmful effects of the solar wind. The domain of the Earth's magnetic field is known as the magnetosphere. Pressure from the solar wind shapes the magnetosphere into a comet-like appearance with a “head” surrounding the Earth and a “tail” (known as the magnetotail) that extends a great distance in a direction that is opposite to the Sun (behind the Earth).

Strong magnetic fields on the Sun are dragged out toward the Earth by the solar wind. As these magnetic fields flow past the Earth, they can interact with the Earth's magnetic field. When the magnetic field lines in the solar wind are oriented in a direction that is opposite to the magnetic field lines from the Earth, the magnetic field lines from the Earth can reconnect with the magnetic fields in the solar wind. This opens up a conduit that allows solar wind momentum energy and particles to directly enter and energize the Earth's magnetosphere. The reconnected field lines are then convected across the Earth's polar regions and are dragged by the solar wind into the magnetotail region of the Earth's magnetosphere. The build-up of additional magnetic flux in the magnetotail can eventually trigger powerful magnetic field reconnection events in the Earth's magnetotail that both energize and accelerate particles and plasma from the magnetotail toward the Earth. Beams of energized particles are guided by the Earth's magnetic field into the ionosphere where they collide with atmospheric constituents and fluoresce as aurora (northern lights). The aurora are produced within a ring of activity that encircles the earth's geomagnetic poles, usually over the higher latitudes. This ring is known as the auroral zone.
Within the auroral zone ionosphere, powerful electrical currents (auroral electrojets) are forced to flow to help dissipate the tremendous energy that is released during the magnetotail reconnection events. Currents in the dusk regions flow eastward while currents in the dawn regions flow westward. These current systems converge near local midnight. The region where these currents converge is known as the Harang discontinuity region. Although the intensity of these currents can rapidly change during a geomagnetic storm, the most significant and hazardous changes typically occur near the midnight Harang discontinuity region where eastward-directed currents may suddenly change direction to westward directed currents. Significant changes in the intensity and/or the direction of these current systems can induce ground-based voltage (potential) differentials between locations spaced some distance apart. These ground potential differences can cause currents to flow through the grounded connections of transmission lines if the resistivity of the ground to a respectable depth is higher than the resistivity of the transmission line. This condition occurs more frequently and with greater magnitude in areas that overlie igneous rock.

The flow of these currents into transmission lines is known as geomagnetically induced currents (GICs). They are ostensibly direct currents in nature and are most often located toward the higher latitudes within the auroral zone during quiet to modestly active geomagnetic conditions. However, as geomagnetic storm activity intensifies, the size of the auroral zone expands. This expansion causes the equatorward boundary of the auroral electrojets (the southern-most location of the intense ionospheric electrical current systems) to migrate toward lower latitudes. During extreme events, the auroral electrojets can move at least into the central United States. This equatorward motion and the concurrent intensification of the ionospheric electrical currents during significant geomagnetic storms can therefore expose a considerable portion of the North American power grid to GICs that may be considerably stronger than those observed over the higher latitudes or during quieter geomagnetic intervals.
Procedure for NPCC Review of New or Modified Bulk Power System Special Protection Systems (SPS)

Approved by the Task Force on Coordination of Planning on April 5, 1988.

Revised:    April 14, 1992
Revised:    September 28, 1995
Revised:    August 10, 2005
Procedure for NPCC Review of New or Modified Bulk Power System Special Protection Systems (SPS)

If an entity concludes that a new SPS or a modification of an existing SPS will be required which affects the bulk power system, the following procedure is to be followed to obtain concurrence from NPCC. The procedure is also shown on the attached flow chart. (Terms in bold type face are defined in the NPCC Glossary of Terms (Document A-7).

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 SPS or modify an existing SPS. The entity will send copies of the complete notification to the Task Force on Coordination of Operation (TFCO) and the Task Force on System Protection (TFSP). This notification will include statements that describe possible failure modes and whether misoperation, unintended operation or failure of the SPS would have local, inter-
Area or inter-Regional consequences, when the SPS 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 SPS will be designed according to the NPCC Bulk Power System Protection Criteria (Document A-5) and the Special Protection System Criteria (Document A-11).

2. If the SPS 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. Each of the Task Forces may require a presentation from the proposing entity.

a. TFSP will be notified of the proposed SPS. TFSP will advise TFCP of any concerns.

b. TFSS will review the analyses that the proposing entity has performed. 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 SPS to operate when and how it is required or an inadvertent or unintended operation of the SPS. If necessary, TFSS will request that the proposing entity conduct additional analyses.

c. If the TFSS review confirms the SPS 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 SPS has only local consequences. TFCP will also notify the Reliability Coordinating
Committee (RCC), all the Task Forces, the Compliance Monitoring and Assessment Subcommittee (CMAS), the proposing entity and other Member Systems that concurrence has been given to the proposing entity to modify an existing SPS or install a new SPS, at which time, the SPS may be deployed.

d. If the TFSS review concludes that the SPS 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 SPS could have inter-Area or inter-Regional consequences, TFCP will arrange for an overall NPCC review as detailed in Step 3.

e. The TFSS will then update the NPCC SPS list/database.

3. If the proposing entity expects the SPS 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 TFCO, TFSP and TFSS to review it. Each of the Task Forces may require a presentation from the proposing entity.

a) TFSP will confirm the failure modes of the SPS, including actions of back-up protection, and whether or not the SPS complies with NPCC system protection standards. TFSP will review whether the new or modified SPS is in conformance with the NPCC Bulk Power System Protection Criteria (Document A-5) and the Special Protection System Criteria (Document A-11) and forward a summary of their findings to TFCO, TFCP and TFSS. This summary will include a statement as to whether the SPS is in conformance with the Bulk Power System Protection Criteria (Document A-5) and the Special Protection System Criteria (Document A-11) and whether the Task Force has any objections to its modification or installation.

b) TFSS will review the analysis that the proposing entity has performed. The purpose of the review will be to assess the SPS 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 SPS to operate when and how it is required or an inadvertent or unintended operation of the SPS. 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 SPS is in
conformance with the *Basic Criteria* (A-2) and whether the Task Force has any objections to its modification or installation.

c. TFCO will review the operability of the SPS 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.

d. 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 SPS or the installation of the new SPS and as a minimum, include the following information:

  - Function, i.e. GR-generation rejection etc.
  - Identification
  - Initiating condition
  - Action(s) resulting
  - Name of the SPS, and owner, identification number
  - Arming, i.e. percentage of time, system conditions for which it’s needed, manual vs. automatic, etc.
  - Reason for 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
  - Determinations of the Task Forces’ analyses
  - Consequences of operation, misoperation and failure to operate
  - Approximate amount of load or generation rejected by SPS operation
  - Proposed date of deployment
  - Proposed date of retirement/deactivation

e. The RCC will review the summary report and act on the proposal to modify an existing SPS or install a new SPS. The RCC may also remand the review of the SPS back to the TFCP if further analyses are determined to be needed.

f. The TFCP will notify the RCC, all the Task Forces, the CMAS, the proposing entity and other member systems of the outcome of the review. Upon NPCC approval of the type and compliance with Criteria, the SPS may be deployed.
g. The TFSS will then update the NPCC SPS list/database.

Prepared by: Task Force on Coordination of Planning

References:

Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2)

Bulk Power System Protection Criteria (Document A-5)

Special Protection System Criteria (Document A-11)

NPCC Glossary of Terms (Document A-7)
PROCEDURE FOR NPCC REVIEW OF NEW OR MODIFIED BULK POWER SYSTEM
SPECIAL PROTECTION SYSTEMS (SPS)

SPS Proposal Submitted to TFCP Chair:

TFSS Reviews the SPS and Confirms Type

TFSS Reviews the SPS and Failure Modes

TFCO Reviews for Operating Impacts

TFSP Notified of the SPS

TFCP Reviews the SPS and Confirms Type

TFCP Evaluates Reviews and Forwards Recommendation to RCC

RCC Approves

YES

NO

Remanded Back to TFCP for Further Review(s) or Information

TFCP Notifies all Task Forces, CMAS, RCC, Proposing Entity and Member Systems

TFSS updates the NPCC SPS List/Database
Procedure for Testing and Analysis of Extreme Contingencies

Approved by the Task Force on System Studies on October 16, 1991.

Revised: January 19, 1995
Revised: January 29, 1999
Revised: July 23, 2003
Note:

Terms in bold typeface are defined in the *NPCC Glossary of Terms* (Document A-7)
1.0 **Introduction**

The NPCC *Basic Criteria for Design and Operation of Interconnected Power Systems* (Document A-2) calls for testing of Extreme Contingencies (ECs) "as a measure of system strength", in order to identify potential patterns of weakness in the bulk power transmission system. The NERC *Planning Standards* also calls for assessment of ECs. This document establishes a procedure for the testing and analysis of ECs. This procedure 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 *Areas*. It principally applies to Council-wide studies of the bulk power transmission system, and generally does not apply to studies normally conducted by NPCC member systems 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 *Areas*, and even to individual facility investigations, where such studies and investigations consider the overall performance of the interconnected systems of the NPCC *Areas*. Certain segments of the Council 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 NPCC's *Basic Criteria for Design and Operation of Interconnected Power Systems* (Document A-2) and in the NERC *Planning Standards*. Testing should focus on those ECs expected to have the greatest potential effect on the interconnected system. In considering specific contingencies to be investigated in an NPCC *reliability* study, all relevant testing done at the *Area* level should first be reviewed.

In general, a contingency in a particular *Area* should be studied, if requested by any other *Area*, based on a reasonable surmise that the requesting *Area* 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-
.Area, inter-
.Area, and, where appropriate, inter-regional transfers should be simulated at a level of at least 75\% of the historical or expected maximum transfer on a flow duration basis up to the maximum operating limit for the interfaces being tested. It is not NPCC’s intent to test the worst imaginable extreme, but EC tests should be severe.

Each Area shall specify the appropriate Area load representation (e.g. P and Q as a function of voltage) for use in NPCC reliability studies. This applies to long term stability test or post-transient loadflow 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,
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 initiated by SPS, or any other defined system separation,
8. identification of the Area(s) involved for any indicated instability or islanding (the extent of any indicated island, especially in terms of involvement of more than one 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 a 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 severe 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, facilities involved), and the extent of potential impact on other Areas, etc., should be reported.

5.0 Evaluating the Results of a Program of EC Testing

NPCC's Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2) 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 Areas 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 pool 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 Areas 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 Area or Areas for further and more detailed investigation with subsequent reporting to NPCC.

Prepared by: Task Force on System Studies

Review frequency: 3 years

References:

Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2)

NPCC Glossary of Terms (Document A-7)

NERC Planning Standards
Procedures During Abnormal Operating Conditions

Approved by the Task Force on Coordination of Operation on May 19, 2005
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**Note:**

Terms in bold typeface are defined in the NPCC Glossary of Terms (NPCC Document A-07)
1.0 Introduction

The Emergency Operation Criteria (NPCC Document A-3) state the essential principles for operations personnel in anticipating and dealing with abnormal operating conditions. This procedure is intended to complement the Emergency Operation Criteria (NPCC Document A-3) by providing specific instructions to the system operator during such conditions in an NPCC Area or Areas.

This procedure is also intended to provide specific instructions for the redistribution of operating reserve among the Areas when any Area is forecasting or experiencing an operating reserve deficiency. NPCC Operating Criteria [Emergency Operation Criteria (Document A-3) and Operating Reserve Criteria (Document A-6)] provide objectives for operations personnel in dealing with emergencies and procedures for maintaining operating reserve.

The Areas participating in this procedure are the five NPCC Areas: New England, New York, Ontario, Québec and the Maritimes.

2.0 Objectives

2.1 To minimize, when possible, the impact of an evolving event.

2.2 To prevent, contain and control an emergency.

2.3 To alert other Areas when any Area is deficient, or anticipates being deficient, in operating reserve.

2.4 To maximize reliability within NPCC through the sharing of resources when any Area becomes deficient in operating reserve.

2.5 To return to normal operating conditions as soon as possible.

3.0 Action to Mitigate Operating Reserve Shortages

Procedures to address shortages of the synchronized portion of ten-minute reserve, thirty-minute reserve, and ten-minute reserve that arise or are foreseen during actual operations are provided in this section. Areas are expected to commit adequate resources during the resource scheduling horizon (e.g., day-ahead Unit Commitment) to meet these requirements.

When an Area becomes deficient or forecasts a deficiency in either the synchronized portion of ten-minute reserve, thirty-minute reserve, and ten-minute reserve, and, the Area cannot meet the corresponding restoration requirements specified in NPCC Document Operating Reserve Criteria (A-06), it should:
• Inform the senior shift authority in each of the other Areas of the NPCC.

• Initiate, or request NPCC Staff to initiate, an NPCC Emergency Preparedness Conference Call, as defined in NPCC Reference Document C-01, *NPCC Emergency Preparedness Conference Call Procedures-NPCC Security Conference Call Procedures*.

These actions should be repeated whenever there is a change in the status of the available reserve with respect to their corresponding restoration requirements specified in NPCC Document *Operating Reserve Criteria* (A-06). For the sole purpose of these notification actions, the restoration requirements specified in NPCC Document *Operating Reserve Criteria* (A-06) for ten-minute reserve shall apply to the synchronized portion of ten-minute reserve as well.

Although the procedures in Sections 3.1 through 3.4 are presented in order of increasing severity, shortages of operating reserve during actual operations might not evolve in the presented order.

3.1 Deficiencies of the Synchronized Portion of Ten-minute Reserve

When an Area becomes deficient in the synchronized portion of ten-minute reserve but is not deficient in ten-minute reserve, the deficient Area should consider any or all of the following actions in no implied order to eliminate or minimize the deficiency as soon as practical:

• Activate off-line generation to increase the supply of the synchronized portion of ten-minute reserve.

• Re-dispatch online generation to increase the supply of the synchronized portion of ten-minute reserve.

• Obtain additional resources from outside the Area in accordance with regional and local practices. These resources should not be from the portion of another Area’s operating reserve that is needed to meet the other Area’s operating reserve requirements (current or anticipated).

• Disconnect interruptible loads, which are not contributing to the synchronized portion of ten-minute reserve due to implementation delays in excess of ten minutes, if permitted by market and other applicable rules.
3.2 **Deficiencies of Thirty-minute Reserve**

If an Area experiences a deficiency in **thirty-minute reserve** as specified in NPCC Document *Operating Reserve Criteria* (A-06) and cannot meet its restoration requirements specified therein with its current and planned deployment of **resources** available to it, the Area should implement any or all of the following actions in no implied order to meet the restoration requirements or to minimize the magnitude and duration of the deficiency:

- Obtain additional **resources** from outside the Area in accordance with regional and local practices. These additional **resources** should not be from the portion of another Area’s **operating reserve** that is needed to meet the other Area’s **operating reserve** requirements (current or anticipated).

- Recall planned generator and transmission outages that will increase **operating reserve** or **transfer capability**, if it can reasonably be expected that additional purchases are available to assist in reducing or eliminating the shortage.

- Recall applicable exports or convert applicable exports to a recallable product and include this energy and/or capacity in its **thirty-minute reserve**, while respecting Area operating procedures. The source Area of the applicable exports should give proper notification to the sink Area.

- Include interruptible customer load that can be interrupted within thirty minutes in its **thirty-minute reserve**, if not already included.

- Include voltage reduction that can be implemented within thirty minutes in its **thirty-minute reserve**, if not already included.

3.3 **Deficiencies of Ten-minute Reserve within an Area**

If an Area is either currently unable to meet its **ten-minute reserve** requirement or a deficiency is forecasted, and the Area does not expect to restore its **ten-minute reserve** within the time specified in NPCC Document *Operating Reserve Criteria* (A-06) without utilizing either **voltage reduction**, curtailment of interruptible load that are not part of normal operations, or public appeals, 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*. 
Also, the **Area** should implement any or all of the following actions in no implied order to either restore **ten-minute reserve** within the time specified in NPCC Document A-06 *Operating Reserve Criteria* if possible, or to minimize the magnitude and duration of the persisting deficiency:

- Commit sufficient off-line supply-side **resources** to create additional **ten-minute reserve** within the restoration period specified in NPCC Document A-06 *Operating Reserve Criteria*.

- Recall applicable exports respecting **Area** operating procedures. The source **Area** of the applicable exports should give proper notification to the sink **Area**.

- Obtain additional **resources** from outside the **Area** in accordance with regional and local practices. These additional **resources** should not be from the portion of another **Area’s operating reserve** that is needed to meet the other **Area’s operating reserve** requirements (current or anticipated).

- Recall planned generator and transmission outages that will increase **operating reserve** or **transfer capability**, if it can reasonably be expected that additional purchases are available to assist in reducing or eliminating the shortage.

- Include interruptible customer load that can be interrupted within ten minutes in its **ten-minute reserve**, if not already included.

- Include voltage reduction that can be implemented within ten minutes in its **ten-minute reserve**, if not already included.

- Consider the use of Public Appeals if sufficient time exists to activate them, or if the shortage is expected to last for an extended period.

If an **Area** remains deficient after implementing all of the applicable actions stated above, the **Area** should:

- Request that the NPCC Staff survey each **Area** to complete the information in Appendix A, providing each **Area’s first contingency loss**, **ten-minute reserve** and its requirement, **thirty-minute reserve** and its requirement, and each **Area’s Total Transfer Capability (TTC)** to and from other **Areas**.

- Update NPCC Reliability Coordinators with any change to the NERC Energy Emergency Alert Level.
• Coordinate the transfer of emergency energy between Areas so that the deficient Area will ultimately increase the ten-minute reserve available to it.

• Consider requesting that other Areas activate off-line resources if the activation promotes greater transfer of energy to the deficient Area to ultimately increase its ten-minute reserve. Assisting Areas choose how to supply the energy in a manner that is consistent with its own polices and procedures.

3.4 Regional Deficiency of Ten-minute Reserve

When two or more NPCC Areas are deficient in ten-minute reserve and all off line generation that could contribute to alleviating the shortages in the deficient Areas has been activated, then a Regional Reserve Deficiency is declared. During a Regional Reserve Deficiency, the NYISO Shift Supervisor will perform a manual Emergency Regional Reserve Redispatch, allocating Emergency Regional Reserve Dispatch Energy (as energy or capacity) optimally among NPCC Areas, coordinating available resources within or between Areas:

• To provide for maximum transfer capability between the Areas.

• To free bottled energy and/or bottled capacity.

• To allocate the remaining ten-minute reserve among the Areas in a manner which will provide maximum reliability and security considering each Area’s ability to control schedules at its electrical boundaries and the Area’s ability to sustain its first contingency loss.

During a Regional Reserve Deficiency, the NYISO Shift Supervisor will also:

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

• Advise all Areas to review their responsibilities should a contingency occur within the NPCC. These responsibilities should be expressed in terms of the acceptable post-contingency transfer levels between all Areas and the maximum time allowed to return transfers to those levels.

4.0 Action to Mitigate Abnormal Operating Conditions
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 required that the power system be operated in a prescribed manner to withstand these contingencies.

The following is a summary of methods that can minimize the impact of an event through proper pre-event operation and can result in recovery from abnormal loading or voltage conditions:

4.1 **Scheduling**

When planning for near term forecast conditions, each Area should develop operating strategies that provide for sufficient generation and transmission to meet the following:

4.1.1 **Operating reserve** requirements.

4.1.2 **Automatic generation control** requirement.

4.1.3 Line/tie line loadings within applicable normal operating limits.

4.1.4 **Bulk power system** voltage within normal limits.

4.1.5 Reactive reserve requirements.

4.2 **Correction of Transmission Loading if Exceeding Limits**

When an Area is experiencing internal circuit or tie line loading in excess of applicable operating limits, the following steps should be implemented as required and appropriate based on industry-wide and/or local procedures:

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

- adjust internal generation,
- transfer load,
- adjust phase angle regulators (phase shifters), and
- redeployment of reactive resources.

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

4.2.3 Recall generation and transmission element outages.
4.2.4 Discontinue generation and transmission element commissioning.

4.2.5 Activate/implement voltage reduction.

4.2.6 Utilize the NERC TLR process.

4.2.7 Operate to emergency condition limits.

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

4.2.9 All Areas in a position to assist must take any available action, excluding load shedding, to keep loading from exceeding applicable operating limits. Assistance should normally only be requested after similar action has been implemented by the requesting Area or Areas.

4.2.10 The Area or Areas causing the overload (if identifiable) must adjust generation or perform actions up to and including load shedding to keep loading below applicable operating limits.

4.2.11 The Area experiencing the overload must, when effective, open circuits or implement load shedding to return the load on elements to within applicable operating limits.

4.3 Correction of Voltage Conditions

If an Area is experiencing abnormal voltage conditions, it should implement the steps provided in NPCC Document B - 3, Guidelines for Inter-AREA Voltage Control.

If the abnormal voltage is caused by conditions external to NPCC, the following steps should be implemented by the NPCC Area experiencing abnormal voltage conditions as required and appropriate:

4.3.1 Using available voltage and reactive power flow information, determine which system is causing the abnormal voltage or the trend toward abnormal voltage.

4.3.2 Establish communication with the system causing the abnormal voltage.

4.3.3 All NPCC Areas in a position to assist must 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 Area or Areas.

4.3.4 If the action in 4.3.3 above is insufficient, the Area experiencing the difficulty shall promptly take all steps necessary to relieve the abnormal voltage condition, including **shedding firm load** and/or opening transmission circuits.

4.4 **Light Load Conditions**

When an Area is anticipating or actually experiencing a Light Load Condition, the Area should:


To ensure that reliability is maintained and that actual interchange flow is regulated to scheduled values, an Area that is anticipating or actually experiencing a Light Load Condition should consider implementing any of the following applicable steps (that are applicable to all supply-side resources in its Area).

4.4.1 Maximize the benefits to be obtained from schedule adjustments.

4.4.2 If permitted by applicable market rules and/or operating policies, increase load by scheduling available pumped storage facilities in the pumping mode.

4.4.3 Arrange for bilateral inadvertent payback.

4.4.4 If permitted by applicable market rules and/or operating policies, request that an appropriate amount of supply-side resources be reduced to the absolute minimum.

4.4.5 Review all supply-side resource “must-run” requirements. Determine if any may be temporarily removed or if other supply-side resources with lower limits could be brought on in place of normal “must-run” supply-side resources.

4.4.6 Review all supply-side resource “low-limits.” Any supply-side resource’s “low-limit” that can be reduced should be temporarily reduced as low as possible.
4.4.7 Obtain maximum reasonable assistance from Areas within or outside NPCC.

5.0 **Action to Contain an Emergency**

If preventative measures as outlined under sections 3.0 and/or 4.0 have not been adequate, actions to contain the emergency should then be taken. These actions should apply to both the Area or Areas causing the emergency (if identifiable) and the Area or Areas experiencing the emergency. The following is thus a continuation of the preventative measures implemented in section 3.0 and/or 4.0 above. Sections 5.1 and 5.2 apply to scenarios in which one Area is having an adverse impact on the reliability of another Area.

5.1 **Action of an Area Experiencing the Emergency**

If an Area is in an emergency because of conditions in another Area, it should implement any of the following actions that removes or lessens the threat to its reliability:

5.1.1 Attempt to identify the specific cause(s) and communicate with relevant Areas. Request assistance if required.

5.1.2 **Shed firm load** or reject generation as appropriate.

5.1.3 Communicate (if time permits) to the adjacent Area that the tie lines will be opened if immediate action is not taken to alleviate the emergency.

5.1.4 Open tie lines to prevent damage to equipment, if necessary.

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

5.2 **Action of an Area Causing the Emergency**

If an Area is having an adverse reliability impact in another Area, it is required by NERC and NPCC Operating Policies to respond to requests for assistance from the Area in difficulty that remove or lessen the threat to its reliability, including:

5.2.1 Attempt to identify the specific cause(s) and communicate with relevant Areas. Request assistance if required.

5.2.2 Manually shed load until transmission loading and voltage return to acceptable values at all known problem locations.
5.2.3 Open or close tie lines as required.

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

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

If an 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 Area is burdening other Areas or Interconnection frequency, then the Area should implement load shedding sufficient to return ACE to zero and perform the following notifications:

- Inform the senior shift authority in each of the other Areas of the NPCC.

Prepared by: NPCC Task Force on Coordination of Operation

References: *Emergency Operation Criteria* (NPCC Document A-03)

*Operating Reserve Criteria* (NPCC Document A-06)

*NPCC Glossary of Terms* (NPCC Document A-07)

*Guidelines for Inter-AREA Voltage Control* (NPCC Document B-03)

*NERC Version 0 Reliability Standards*
APPENDIX A

Reserve Summary

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<th>Area</th>
<th>First Contingency Loss</th>
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Procedure for Reporting and Reviewing
Proposed Protection Systems for the Bulk Power System

Approved by the Task Force on System Protection on February 8, 1994.

Note: Originally approved as Document B-5 by the System Design Coordinating Committee and the Operating Procedure Coordinating Committee on April 13, 1977

B-5   Revised:   July 19, 1983
     Revised:   May 5, 1986
     Revised:   April, 1990

C-22  Converted from B-5:  February 8, 1994
     Revised:   September 25, 1996
     Revised:   April 14, 1999
     Revised:   November 14, 2002
     Revised:   June 28, 2005
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Note:

Terms in bold typeface are defined in the *NPCC Glossary of Terms* (Document A-7)
1.0 Introduction and Requirement to Notify

In accordance with the concluding paragraph of the Bulk Power System Protection Criteria (Document A-5) and the Special Protection System Criteria (Document A-11) the member system shall provide the Task Force on System Protection (TFSP) with advance notification of any of its new bulk power system protection facilities, or significant changes in its existing bulk power system protection facilities. The member system shall also provide the TFSP with advance notification of non-member protection facilities as required per NPCC Membership Agreement Article V A(2) (c). Notification will be made to the TFSP early in the engineering design stage.

2.0 Additional Requirements for Presentation and Review

2.1 A presentation will be made to the TFSP on new facilities or a modification to an existing facility when requested by either a member system or the TFSP.

2.2 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).

2.3 A presentation will be made to the TFSP when a member system is in doubt as to whether a design meets the Protection Criteria.

3.0 Data Required for Presentation and Review of Proposed Protection Facilities

3.1 The member system 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.

3.2 The proposed protection system will be explained with due emphasis on any special conditions or design restrictions existing on the particular power system.
4.0 Procedures for Presentation

4.1 The member system will arrange to have a technical presentation made to the TFSP.

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

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

5.0 TFSP Procedures

5.1 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:

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

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

5.1.3 Acceptance of the submitted proposal.

5.1.4* Conditional acceptance of the submitted proposal.

5.1.5* Rejection of the submitted proposal.

* Position Statements 5.1.4 and 5.1.5 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.
5.2 The results of the TFSP review will be documented in the following manner.

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

5.2.2 If necessary, a letter outlining areas of nonconformance with the NPCC Protection Criteria and recommendations for correction will be submitted to the member system.

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

Prepared by: Task Force on System Protection

Review frequency: 3 years

References: NPCC Membership Agreement executed as of January 19, 1966 as amended to date

- Bulk Power System Protection Criteria (Document A-5)
- NPCC Glossary of Terms (Document A-7)
- NPCC TFSP Reviewed Facilities List
Review Process
for
NPCC Reliability Compliance Enforcement Program

Approved by the Compliance Monitoring and Assessment Subcommittee on
June 23, 2000

Revised: November 19, 2004
Note:

Terms in bold typeface are defined in the *NPCC Glossary of Terms* (Document A-07)
1.0 Introduction

As part of the NPCC Reliability Compliance Enforcement Program (RCEP), Document A-8 or its successor program, a process is required to review Area compliance to the criteria and standards that comprise the program.

The principles in this process have been adapted from other NPCC review processes and peer review processes used in comparable industries for continuous quality improvement.

2.0 Objectives

The purpose of this Review process is to ensure that NPCC is meeting its obligations in the following areas:

a) Compliance assessment of criteria and standards where the Area has the reporting obligation,

b) Verification of compliance self-certification

c) Oversight of Area compliance assessment and Area compliance programs.

The establishment of a Review process does not reduce or replace the obligation of an Area to meet NPCC RCEP reporting requirements, nor will the Review alter a previous compliance assessment.

3.0 Review Process

3.1 Standards to be reviewed – Criteria and Standards included in the RCEP plus two other selected standards requiring periodic review will be evaluated at each Review.

3.2 Frequency -

3.2.1 At the end of each calendar year, NPCC/CMAS will target to schedule Reviews for the following calendar year such that each Area would be reviewed at least once every 3 years. The schedule will identify only the Areas to be reviewed and the timeframe upon which they will be reviewed but not the specific standards that will be included in the Reviews. The Review will take place on a mutually agreed upon date(s). The Area shall be notified of the specific standards a minimum of 30 calendar days prior to the Review as described in Section 3.4.
3.2.2 CMAS may also trigger a Review following instances of non-compliance to the Reliability Compliance Enforcement Program criteria/standards. If an Area being reviewed in this situation has not been reviewed as part of the current three-year cycle, this Review would be counted as that routine Review. If the Area has already been reviewed for the current three-year cycle, this Review would be in addition to the routine Review requirements. If an Area is scheduled for a Review as part of the regular three-year cycle within the same calendar year as a Review that is triggered by non-compliance, CMAS may conduct both reviews concurrently. All Reviews carried out for non-compliance reasons shall follow the same format and criteria as routine Reviews.

3.3 **Review Team** - Each Review Team will be made up of an NPCC staff member as facilitator and at least two members from the Areas not being reviewed. Each Area will be requested to participate in performing the Review on a rotational basis. CMAS will direct Areas performing the Review to supply the appropriate personnel. The minimum credentials and core competencies of the candidates for the Review Team will be commensurate with the expertise deemed necessary based on the Review requirements. NPCC staff may request CMAS for additional team members as deemed appropriate. CMAS member shall not participate as a member of the Review Team.

The Area may file with CMAS 90 calendar days in advance of the Review the appropriate confidentiality agreement which will be reviewed by CMAS. Prior to the Review, the Team members will sign the appropriate confidentiality agreement on file with CMAS and a copy of this signed confidentiality agreement will be sent to the Area.

3.4 **Notification** – Review Team shall notify the Area of the specific standards to be reviewed. This notification will include a list of questions and documentations the Area may be required to produce. Review Team shall provide this notification a minimum of 30 calendar days prior to a regularly scheduled Review or a specially scheduled Review that was triggered following instances of non-compliance. See outline notification letter in Appendix I.

The Area will provide written response to the questionnaire and furnish requested documentations as appropriate 7 calendar days before the established onsite review date.

3.5 **Review Site** - The Review will take place at a mutually agreed upon location.
3.6 *Consistency of Reviews* - To ensure consistency in application and carrying out the Reviews, standard notification formats, report formats, criteria and question lists will be employed. This information will be made available on the NPCC website.

3.7 *Other Reviews* - To ensure efficiencies and avoid duplication of effort, reviews carried out for other purposes, e.g. regulatory requirements, will be given recognition in the CMAS Review.

3.8 *Reporting* -

3.8.1 The Review team shall produce a preliminary report within 15 calendar days of the date of the Review completion following the general outline shown in Appendix II. A copy of the preliminary report will first be made available to the *Area* being reviewed. The *Area* shall have 7 calendar days, following receipt of the preliminary report, to provide comments to the Review Team. The Review Team final report, together with the *Area’s* comments, will be provided to CMAS at the next meeting.

3.8.2 Following completion of an *Area* compliance review, CMAS will discuss any administrative problems or concerns identified in the Report with the *Area* that was reviewed. The intent is to improve future reporting and to facilitate process/reporting quality improvement.

CMAS will provide a Report to the NPCC Reliability Coordinating Committee (RCC) at its next meeting based on CMAS’s assessment of the Review. If the result of the Review indicates there is inadequate documentation to support prior compliance reporting, CMAS may conduct further investigation into the matter. If the evidence of inadequate documentation does exist, CMAS shall recommend to the RCC the appropriate actions to be taken.

3.8.3 The Review material, including the report, the comments if any from the *Area*, and the Review Team’s notes and records, will be maintained by NPCC/CMAS and will not be distributed further.

4.0 Appeals
Should the Area seek to dispute any findings of the Review Team’s final report or the actions that it is required to take as a result of the Review, the Area may write to the NPCC Enforcement Panel to request that a hearing be held. The Area may also invoke the arbitration provision as described in Section 3.5 of the NPCC Reliability Compliance and Enforcement Program, Document A-8 if the Area does not agree with the EP’s determination or final report.

Prepared by: Compliance Monitoring and Assessment Subcommittee
Review frequency: 3 years

References: Criteria for Review and Approval of Documents (Document A-01)
NPCC Reliability Compliance and Enforcement Program (Document A-08)
NPCC Glossary of Terms (Document A-07)
Guidelines for the Implementation of the Reliability Compliance and Enforcement Program (Document B-22)
Appendix I

Notification Letter Outline

Identification of
a. Date and location of Review
b. Selected Requirements

List of documentation to be provided in advance

List of questions on each requirement

List of required personnel to be interviewed as appropriate
Appendix II

Review Report Outline

1.0 Introduction

2.0 Objective

3.0 Review
   3.1 Review team members
   3.2 Standard(s) under review
   3.3 Information list provided in advance
   3.4 Assessment

4.0 Recommendations

5.0 Conclusions
Appendix III
Review Process for NPCC Reliability Compliance and Enforcement Program

CMAS develops annual Review schedule or sets non-compliance triggered Review schedule

CMAS selects criteria and forms Review Team to perform Scheduled Review

Review Team meets to develop Notification Letter (See Appendix I for Notification Letter outline)

Team conducts Onsite Review

Staff sends the Area notification letter of upcoming Review

Minimum 23 calendar days

Within 7 calendar days of receiving the information, Team reviews the Area's written response and documentation

Area submits written response to questions and provides advance documents as requested in notification letter

7 calendar days

Comments accepted?

No

Report and comments presented to CMAS at next meeting

Yes

Final Report presented to CMAS at next meeting

CMAS reviews Report and follow-up with Area to discuss any administrative problems or concerns identified in Report

Does result of Review supports prior compliance reporting?

No

CMAS recommends appropriate actions be taken

Yes

CMAS presents its assessment of the Review or recommended actions to RCG at next meeting
Procedure for Analysis and Classification of Dynamic Control Systems

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APPENDICES
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B) SUGGESTED TESTS FOR CLASSIFYING DYNAMIC CONTROL SYSTEMS IN NPCC
C) SUGGESTED DESIGN CONSIDERATIONS FOR DYNAMIC CONTROL SYSTEMS
1 INTRODUCTION

1.1 Scope

The NPCC Guidelines for NPCC AREA Transmission Reviews (Document B-4) calls for testing Dynamic Control Systems in order to classify them in terms of their impact on the NPCC Bulk Power System (BPS). The purpose of this procedure is to provide a set of objectives and procedures applicable to the analysis and classification of Dynamic Control Systems on the NPCC Bulk Power System. This procedure should be used when testing Dynamic Control Systems for NPCC studies or studies submitted for NPCC review. (Terms in bold typeface are defined in the Glossary located in Document A-7, the NPCC Glossary of Terms.)

1.2 Definitions

A Dynamic Control System is defined as a continuously-acting control system which responds to normal and abnormal system conditions or events so as to enhance Bulk Power System stability by acting upon one or more power system quantities such as voltage, current, or power as determined by measurement of one or more power system parameters. Dynamic Control Systems include, for example, Static Var Compensators, Synchronous Condensers, and other Flexible AC Transmission System (FACTS) devices, and the following portions of high voltage direct current (HVdc) systems, generator excitation systems, and turbine governor systems:

**HVdc Systems**: Converter Control (including any disturbance recovery auxiliary features); Voltage-Dependent Current Order Limit (VDCOL); ac Network Frequency Control; Power Modulation; Reactive Power Control; Fast dc Power Change; Subsynchronous resonance (SSR) damping; and any related measurement devices.

**Generator Excitation Systems**: Automatic Voltage Regulator (AVR); Power System Stabilizer (PSS); Under-excitation limiter; and any related measurement devices.

**Turbine Governor Systems**: Early valve actuation or “fast-valving” systems are assumed to come under the definition of an SPS. Although governors come under a strict interpretation of the Dynamic Control System definition above, they are considered to be too slow in response to significantly influence BPS performance.

Note, for example, that mechanically-switched reactive compensation, fixed compensation, tap changing transformers, phase angle regulators, and over-excitation limiters on generators are not considered to be Dynamic Control Systems.

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1 The NERC Planning Standards III.B Transmission Control Devices Measure M1 proposes that “When planning new or substantially modified transmission control devices, transmission owners shall evaluate the impact of such devices on the reliability of the interconnected transmission systems”. The NERC Planning Standards III.C Generation Control and Protection also calls for assessment of generator controls.
Subsystems are defined as portions of a Dynamic Control System which are functionally related, may be geographically separate, and together serve to perform the overall function of that Dynamic Control System.  

1.3 Classification

Dynamic Control 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 Contingencies” are described in Sections 5.0 and 6.0 and “Extreme Contingencies” are described in Section 7.0.

**Type I** Those Dynamic Control Systems whose incorrect operation or failure to operate following a Design Contingency would have **significant adverse impact** outside the local area. The correct response delivered by these Dynamic Control Systems is intended to return power system parameters to a stable and recoverable state.

The design practices contained in Appendix C should be considered for Type I Dynamic Control Systems.

**Type II** Those Dynamic Control Systems, installed for the purpose of mitigating the impact outside the local area of Extreme Contingencies. In the application of these Dynamic Control Systems, security is the prime concern. The design considerations relating to dependability in Appendix C do not necessarily apply.

**Type III** Those Dynamic Control Systems whose incorrect operation or failure to operate results in no **significant adverse impact** outside the local area. The design practices contained in Appendix C may or may not be considered for Type III Dynamic Control Systems. It should be recognized that Type III Dynamic Control Systems may, due to system changes, become Type I or Type II.

1.4 Coordination

With Dynamic Control Systems, it is imperative that system planning, design and engineering, protection, operating, and maintenance functions closely coordinate, since initially and throughout their life cycle, Dynamic Control Systems are a multi-discipline concern. Dynamic Control System and protection functional settings and operational procedures should be reviewed whenever significant changes in generating sources, transmission facilities, or operating conditions are anticipated.

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2 Except where they form a subsystem of a larger Dynamic Control System.

3 Note that NPCC’s definition of Dynamic Control Systems above includes generator controls, whereas NERC’s definition of Transmission Control Devices does not. Conversely, NERC’s definition of Transmission Control Devices includes the consideration of mechanically-switched shunt capacitors and reactors, whereas NPCC’s definition of Dynamic Control Systems does not.
2 PERFORMANCE CONSIDERATIONS

Potential failure of a single component that could affect operation of multiple Dynamic Control Systems at one location should be assessed in the testing procedure by failing at least two Dynamic Control Systems simultaneously.

Stability of the BPS should be maintained during and after the most severe of the Design Contingencies listed in Section 5.1 of the Basic Criteria, while any single Dynamic Control System is experiencing a single undetected failure. As stated in Section 5.2 of the Basic Criteria, voltages and 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 Section 5.1 of the Basic Criteria.

Pre-contingency load flows chosen for this analysis should reflect reasonably stressed power transfer conditions within Areas, or Area to Area; these are expected to be similar to conditions used to demonstrate compliance to the Basic Criteria under the guidelines in Document B-4.

3 PROCEDURE FOR CLASSIFICATION

A flow chart describing the procedure for classifying a Dynamic Control System as Type I or III is provided in Appendix A.

Note that for the purpose of classification, these tests generally fix the device at the pre-contingency operating point, restricting the dynamic response.

For example, for AVRs, the test considers a fixed field voltage $E_{fd}$ with a design contingency fault. For failure modes other than those that result in a fixed $E_{fd}$, it is assumed that either existing protection systems would remove the generator from service, or operators would recognize an abnormal condition and place the excitation system on manual control.

Appendix B shows a list of suggested tests for different Dynamic Control Systems in NPCC.

3.1 Testing for Type I Classification

A single undetected failure should not result in significant adverse impact outside the local area.

If any undetected failure of a single Dynamic Control System component or subsystem during and after any of the Design Contingencies listed in Section 5.1 of the Basic Criteria results in significant adverse impact outside the local area, that Dynamic Control System is classified as Type I.

3.2 Testing for Type II Classification

If any undetected failure of a single Dynamic Control System component or subsystem during and after any of the Extreme Contingencies listed in Section 7.0 of the Basic
Criteria results in significant adverse impact outside the local area, that Dynamic Control System is classified as Type II.

In general, Type II Dynamic Control Systems do not need to include redundancy provided that their design is secure.

3.3 Testing for Type III Classification

If any undetected failure of a single Dynamic Control System component or subsystem during and after the most severe of the Design Contingencies listed in Section 5.1 of the Basic Criteria results in no significant adverse impact outside the local area, that Dynamic Control System is classified as Type III.
Appendix A

Classifying Dynamic Control Systems as Type I or Type III

Does a Dynamic Control System failure have the potential for **significant adverse impact** outside the local area?

- **YES**
  - Type III Dynamic Control System

- **NO**
  - Is Testing to be performed?
    - **YES**
      - Assume, for the purpose of the test, that a Dynamic Control System does not have self-diagnostics or the first level of redundancy (even though it may actually exist). Test most severe design contingency event(s) assuming Dynamic Control System response as described in Appendix B.
    - **YES**
      - Type III Dynamic Control System
    - **NO**
      - How does the Dynamic Control System satisfy the Guideline?
        - Redundancy
        - Full coverage self diagnostic
      - Pass the test?
        - **YES**
          - Type III Dynamic Control System
        - **NO**
          - Assumed Type I
Appendix B

SUGGESTED TESTS FOR CLASSIFYING DYNAMIC CONTROL SYSTEMS IN NORTHEAST POWER COORDINATING COUNCIL

1. Generator Excitation AVRs
   Design contingency fault with fixed field voltage, \( E_{fd} \)

2. Power System Stabilizers (PSS)
   Design contingency fault with inoperative PSS

3. Static Var Compensator, Synchronous Condenser, and other FACTS device
   Design contingency fault with fixed pre-disturbance operating point at fault clearing

4. HVdc
   Design contingency fault with the worst single failure of the following:
   a. fixed converter firing angle
   b. inoperative VDCOL
   c. fixed frequency control
   d. fixed power modulation
   e. fixed reactive power control
   f. inoperative fast dc power change
   g. inoperative SSR damping
Appendix C

SUGGESTED DESIGN CONSIDERATIONS FOR DYNAMIC CONTROL SYSTEMS

Introduction

The general objective for any Dynamic Control System is to perform its intended function (for example, field current control of a generator, rapid voltage regulation and var production, power swing damping, etc.) in a dependable and secure manner. For Dynamic Control Systems, dependability is that facet of reliability that relates to the degree of certainty that the system will function correctly. Security is that facet of reliability which relates to the degree of certainty that the system will not operate incorrectly.

Dynamic Control Systems are intended to operate in response to measured power system conditions. The relative effects on the BPS of the failure to operate when desired or an incorrect operation versus an unintended operation should be weighed carefully in selecting design parameters as described further below.

The general objective can only be met if the Dynamic Control System can reliably respond to the specific conditions for which it is intended to operate and exhibit an acceptable response for other system conditions.

Dependability and Security

To enhance dependability, Type I Dynamic Control Systems should be designed such that the Dynamic Control System is capable of performing its intended function under the specified design contingencies, while itself experiencing a single undetected failure. This implies that failures which are not detectable by specific sub-systems designed for that purpose, or by operator observation, should be covered by functional redundancy. To enhance security, Type I and Type II Dynamic Control Systems should be designed such that the Dynamic Control System itself does not cause BPS significant adverse impact, while the Dynamic Control System is experiencing a single failure independent of any design contingency condition. These considerations are reflected in the performance considerations described in Section 2 of this procedure.

In achieving the above goal, duplication, as a means of achieving functional redundancy, should be used with caution and thorough design evaluation. For example, the choice of duplication as a means of providing functional redundancy improves the dependability of a properly designed and tested Dynamic Control System but, since it may increase the probability of an unintended operation, it can also jeopardize security. In addition, design weaknesses which go undetected during the planning, design, and commissioning phases of a Dynamic Control System may degrade the dependability afforded by duplication. This is because the design weakness may also be duplicated and may result in
inappropriate control action from both redundant systems. Finally, simple duplicate control systems may result in an inability to decide which of the two is giving the correct response.

Duplication of Dynamic Control Systems may not be necessary or appropriate if the performance considerations Section 2 of this procedure can be achieved through functional redundancy. For example, in the case of Dynamic Control System with microprocessor-based controls, duplication may be unnecessary if any failure within the microprocessor-based control can be detected and reported by self-diagnostic features, and appropriate action can be taken.

In any case, whether functional redundancy is achieved by means of physical duplication, backup subsystems, or fail-safe design with operator alarms, all Type I and Type II Dynamic Control Systems should be subjected to a design evaluation by the member system.

The dependability considerations for a Dynamic Control System apply only with respect to its response to the system conditions to which it is designed to respond. However, the security considerations for a Dynamic Control System apply with respect to its performance under normal BPS conditions as well as its response to any design or extreme contingency.

The above considerations imply the necessity to avoid the use of components common to redundant Dynamic Control Systems or subsystems of a Dynamic Control System. Areas of common exposure should be kept to a minimum to reduce the possibility of any physically or functionally redundant subsystems being disabled by a single contingency.

All of the provisions of the section of the NPCC Bulk Power System Protection Criteria entitled "Considerations Common to Dependability and Security" should apply to all subsystems of Dynamic Control Systems having prime purpose of protection, control, or measurement.

**Dynamic Control System Testing and Maintenance**

The design of Dynamic Control Systems, both in terms of circuitry and physical arrangement, should facilitate periodic testing and maintenance in a manner that mitigates the risk of significant adverse impact. As Dynamic Control Systems may be complex and may interface with other Dynamic Control Systems and/or protection systems, special attention should be placed on ensuring that test devices and test interfaces properly support a clearly defined maintenance strategy.

Sufficient testing should be employed on commissioning, when modifications are made, and periodically, to ensure that Dynamic Control System settings are as specified and that response characteristics are within design limits.

Type I Dynamic Control Systems that have been in service beyond the break-in period should be maintained at least every 2 years. This suggestion is based on the experience
and judgement of NPCC members. This maintenance interval should result in dependable and secure Dynamic Control System operation. There are reasons peculiar to many individual situations which will justify more frequent maintenance intervals. Each member system should evaluate its own particular circumstances and determine if any additional maintenance should be performed on the Dynamic Control Systems on its system.

Minimum maintenance of Dynamic Control Systems includes verifying inputs and outputs, making visual inspections, and performing other operational tests to assure satisfactory operation of the equipment as a system.

It is also recommended that the operation of a Dynamic Control System as a system be periodically checked between maintenance intervals by monitoring its response to a natural change in the power system or to a small perturbation initiated by a test.

Sufficient checks should be made periodically to ensure that instrument transformers, control batteries, and chargers are in proper operating condition.

Each time the Dynamic Control System is maintained, the Dynamic Control System hardware should be tested as a system to ensure compatibility and correct operation.

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

Wherever practical, the testing objectives of maintenance may be met by documenting actual events. Such an approach can reduce the probability of incorrect operation during maintenance while effectively reducing the extent of planned maintenance.

Test facilities or test procedures should be designed such that they do not compromise the independence of redundant Dynamic Control Systems or Dynamic Control System subsystems.

**Analysis of Dynamic Control System Performance**

To ensure the design parameters have been selected properly and that Dynamic Control System performance is correct, analysis of Dynamic Control System operation should be performed as outlined below.

Dynamic Control System response to significant BPS events should be analyzed for proper Dynamic Control System performance. Corrective measures should be taken promptly if a Dynamic Control System or one or more of its subsystems fail to operate or operate incorrectly.

Sequence-of-events recorders, oscillographs, disturbance monitors, etc., should be provided to the maximum practicable extent to permit analysis of system disturbances and
Dynamic Control System performance. Criteria for these types of devices are described in Document A-2, paragraph 2.3.
NPCC Inter-Area
Power System Restoration Procedure

Approved by the Task Force on Coordination of Operation on March 14, 2006
# NPCC Inter-Area Power System Restoration Procedure

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D Ontario Area Restoration Overview  
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H-7  External Power Systems-PJM Communications-Main and Alternate Paths

**Note:** Terms in **bold typeface** are defined in the *NPCC Glossary of Terms* (NPCC Document A-07).
1.0 Content Summary

The purpose of the “NPCC Inter-Area Power System Restoration Procedure” is to provide guidance and training material to the system operator to manage system restoration events that affect the NPCC Areas and adjoining control areas. This Procedure does not prescribe or supplant the specific restoration plans within each NPCC Area. This Procedure is structured to stipulate restoration actions on the part of an NPCC Area and includes the following broad categories:

- A quick reference of Area restoration plans;
- Area to Area voice communication overview (Appendix H details each Area’s communication links);
- Actions to stabilize remaining electrical islands;
- Assessment of conditions prior to interconnecting;
- Establishing interconnections;
- Actions to remain stable following an interconnection; and
- Training and testing to validate plans.

Although the risk of a complete power system shutdown in North America is minimized by operating to reliability criteria specified by NERC, NPCC and Area authorities, there remains a requirement to be prepared for the worst case scenario. NERC and NPCC require that all Areas maintain viable system restoration plans and restoration capabilities.

The Areas within NPCC have detailed individual restoration plans which 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 Area restoration plans recognize that it is impossible to predict the extent to which each individual control 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 Areas and neighboring areas. Instead, it provides technical guidelines for system operators to reconnect the 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 Restoration Plan Overview Table

The NPCC Area restoration plans are in accordance with all relevant NPCC Criteria and NERC Standards and reflect the best practices of the industry concerning power system restoration. Area 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:

- Establish the basic minimum power system within the Area;
- Provide AC supply to nuclear generating units and non-blackstart generating units;
- Restore enough load to stabilize generating units and transmission conditions; and
- Establish Area tie lines.

Table 2-1 below summarizes, at a very high level, the restoration plans of each NPCC Area; Table 2-2 following similarly summarizes the restoration plans of adjoining control areas. Appendices A through G provide a detailed overview of the restoration plans of each of these entities.

<table>
<thead>
<tr>
<th>Control Area</th>
<th>Type of Restoration Plan</th>
<th>Primary Priority</th>
<th>Secondary Priority</th>
<th>Priority in Restoring Interconnections</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maritimes Area (New Brunswick System Operator)</td>
<td>Detailed switching plans and duties of the control centers are documented using defined and / or alternate paths.</td>
<td>Restore AC station service to nuclear generating site.</td>
<td>Restore AC supply to station service to all other plants and transmission substations.</td>
<td>At the earliest opportunity in a controlled fashion.</td>
</tr>
<tr>
<td>New England Area (ISO-NE)</td>
<td>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.</td>
<td>Restore AC Station Service to nuclear generation sites.</td>
<td>Restore AC Supply to generating stations, transmission stations and control centers.</td>
<td>Interconnections are made when technically viable. Procedures advocate interconnecting early.</td>
</tr>
</tbody>
</table>
Table 2-1 NPCC Control Areas (continued)

<table>
<thead>
<tr>
<th>Control Area</th>
<th>Type of Restoration Plan</th>
<th>Primary Priority</th>
<th>Secondary Priority</th>
<th>Priority in Restoring Interconnections</th>
</tr>
</thead>
<tbody>
<tr>
<td>New York Area (NYISO)</td>
<td>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.</td>
<td>Restore the basic minimum power system to expedite restoration of AC station service to nuclear generating sites.</td>
<td>Load restoration, but when limited energy is available within the NY system, preference is given to generating station start-up.</td>
<td>High priority given to establishment of tie line operation.</td>
</tr>
<tr>
<td>Ontario Area (IESO)</td>
<td>Strategies for restoration 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.</td>
<td>Restore AC station service to nuclear generating sites.</td>
<td>Restore AC Supply to Critical Loads (AC &amp; DC station service) for Switchyards, Substations, Generating Stations, Control Centers and interdependent infrastructure (i.e. telecommunication s).</td>
<td>At the earliest opportunity in a controlled fashion.</td>
</tr>
<tr>
<td>Québec Area (HQTE)</td>
<td>The available restoration paths allow for the partition of the main system into five basic minimum power systems.</td>
<td>Restore AC station service to nuclear plant and critical facilities of the five basic minimum power systems.</td>
<td>Restore AC station service to all other facilities.</td>
<td>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.</td>
</tr>
<tr>
<td>Control Area</td>
<td>Type of Restoration Plan</td>
<td>Primary Priority</td>
<td>Secondary Priority</td>
<td>Priority in Restoring Interconnections</td>
</tr>
<tr>
<td>-------------------</td>
<td>------------------------------------------------------------------------------------------</td>
<td>----------------------------------------------------------------------------------</td>
<td>-------------------------------------------------------------------------------------</td>
<td>----------------------------------------</td>
</tr>
<tr>
<td>MISO (Manitoba)</td>
<td>Manitoba uses a defined path approach for system restoration applied over two restoration areas, the Northern collector system and the remainder of the <strong>bulk power system</strong>. The <strong>bulk power system</strong> is further subdivided into two areas that are paralleled at predefined locations.</td>
<td>The primary priority for restoration is to restore station service to the valve group on the Southern system.</td>
<td>Secondary priorities are to restore station service to the specified <strong>HVdc bipolar pole</strong> within time limits and to restore station service to the remainder of plants in the Southern system and in the Northern system to the <strong>HVdc</strong> collector plants.</td>
<td>There are no specified priority tie lines, but any available tie lines are used as an anchor for the system.</td>
</tr>
<tr>
<td>MISO (Michigan)</td>
<td>The portion of Michigan adjacent to Ontario uses a defined path approach for system restoration. Alternate paths are also defined.</td>
<td>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.</td>
<td>A secondary priority is to return the City of Detroit to normal power.</td>
<td>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.</td>
</tr>
<tr>
<td>MISO (Minnesota)</td>
<td>Minnesota uses a defined path approach utilizing the 115 kV system.</td>
<td>The primary priority for restoration is to provide start up power to major generating plants.</td>
<td>The secondary priority is to provide station light and power to remaining stations.</td>
<td>Interconnected operation is reestablished with neighboring jurisdictions as soon as tie lines become available, with tie lines to Manitoba being the priority.</td>
</tr>
<tr>
<td>PJM</td>
<td>Each member company of PJM has its own restoration plan. PJM will coordinate and direct all transmission tie connections to external control areas.</td>
<td>Restore off site power supply to nuclear plants.</td>
<td>Restore AC supply to switchyards, hydroelectric and fossil sites.</td>
<td>The restoration of tie lines will be evaluated as the facilities become available.</td>
</tr>
</tbody>
</table>
3.0 Voice Communications Overview

The ability to communicate is essential to the restoration process. The options for direct voice communications between control centers include the following:

- Public Switched Telephone Networks (PSTN)
- NERC Hot Line
- Cellular Telephones
- Direct Ring Down Circuits
- Utility Owned Voice Channels
- Satellite Telephones

Appendix H-1 shows the various communication media that are available in addition to the Public Switched Telephone Networks. Alternative means of communication to the PSTN can include direct ring down circuits and satellite telephones. All NPCC Areas are Reliability Coordinators, 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 Areas, although they have proven to be unreliable during major events due to excessive phone traffic.

Communication paths directly between NPCC control areas (referred to as primary paths) contain multiple communications media options. In the improbable event that all primary paths between two control areas are interrupted, alternate communication paths, where possible, have been identified and are shown along with the primary paths in Appendices H-2 through H-6. If available, a communication media on the direct or primary path between control areas should be used at all times unless otherwise directed by the control area to control area coordination.

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 at the control area or local dispatch level 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, area control centers may have to suspend use of economic dispatch signals and change over to manual dispatch orders.
4.3 **Tie Line Regulation**

_Area_ control centers should appropriately select flat frequency or _tie line_ bias control to stabilize frequency depending on the status of their _tie lines_. If a _control area_ is electrically isolated, the flat frequency control mode should be implemented. If two or more _control 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**

_Area_ control centers 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. Transmission switching authorities within _control areas_ should recognize and address this potential inadvertent automatic _reclosing_. Furthermore, switching authorities 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, _system operators_ should consider blocking the circuit breaker automatic _reclosure_.

5.0 **Assessment of Conditions Prior to Interconnecting**

When assistance is required from an external _control area_, communications between _control areas_ must ensure that there is a sufficient level of understanding of:

- existing system conditions after stabilization, and;
- types of assistance that may be sought after synchronization.

The existing system conditions to be assessed include, but are not limited to, the following:

- **Load**;
- **Synchronized Generation**;
- Prevailing Voltage and Frequency;
- System Topology;
- System Operating **Reserves**;
• System Reactive Reserves; and
• First Contingency Loss.

The types of assistance may include, but are not limited to, the following:

• Start-up for Generation;
• Frequency Control;
• Tie Line Regulation; and
• 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 Area (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 must be met in conjunction with implementing the actions offered in this document.

It must be understood that any assistance agreed to between the Areas is based on acceptable conditions identified by the system operators and agreed to by the system operators.

Once the assessment of conditions prior to interconnecting is completed, and if resources are available, the assisting Area must 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 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.
**Area 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, “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 **control 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:

- What is the largest single **contingency** loss?
- Are operating **reserves** adequate to cover the loss?
- What is the amount of spinning **reserve**?
- Is a **load shedding** plan being utilized for **reserve**?
- If **reserves** are activated, will any transmission facilities be overloaded?
- 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 **control areas**.

### 5.4 Frequency Control

The energy management systems of the NPCC **Areas** utilize the following control mechanisms to perform interconnected regulation using **Automatic Generation Control (AGC)** applications:

- **Flat Tie Line**

  Only the **tie line** mismatch between **scheduled interchange** and **actual interchange** flow is used to determine **area control error (ACE)**.
• **Flat Frequency**

Only frequency deviation is used to determine the ACE.

• **Tie Line Bias**

Both frequency deviation and tie line mismatch are used to determine the ACE.

Following a major system disturbance, system operators 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 control areas, the smaller island can more readily adjust its frequency to match that of the larger island. Once synchronized, Area control centers 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 control 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 Area.

For instance, if the larger of the control areas was in flat frequency control (as it should be), and the adjacent smaller control 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 Area, and tie line bias control by other smaller connected control areas should produce the best frequency regulation.

The control area system operator must determine if economic dispatch continues to be accurate and / or effective, and if it is determined that it is no longer viable, the system operator should switch to manual dispatch of generation.

The system operator must determine if tie line regulation continues to be accurate and / or effective by determining the following:

• the external Areas(s) to which the control area is connected
• the relative sizes of the Areas(s) to which the control area is connected

If it is determined that the control area remains tied to the massive Eastern Interconnection, the system operator may use normal tie line regulation (tie line bias). However, if only two control areas, or a few control areas, remain tied together, the system operators in the respective control areas should:
• Use flat frequency control in the largest control area
• Use tie line bias control in the smaller control area(s)

5.5 Synchronization or Paralleling of Electrical Islands

It is desirable to synchronize electrical islands between 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:

• Determining which circuit and circuit breaker to use to synchronize the electrical islands, then apply the guidelines of Section 7.1, “Synchronous Ties”; and
• 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 Areas as outlined in Section 5.6 following.

If a major system disturbance has completely separated two control areas, the reclosing of their first synchronous interconnection will require synchronization of the two control areas. If the two control areas have already synchronized and established a tie line, before energizing any additional tie lines, system operators must 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-Control Area Ties Lines,” must be followed.

5.6 Provision of External Restoration Service

External restoration service may be provided to an adjacent blacked-out 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:

- 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.)?
- In energizing transmission lines to generating stations, will customer loads be restored, and, if so, what will be their expected MWs?
- Will long transmission lines or high voltage cables be energized? If so, what is the expected charging current in MVAR?
- State any restrictions on the MW or MVAR flow on the Area’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 Area to supply generating stations, substations and customer load in an adjacent 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:

- Determine the current load expected to be supplied.
- Determine the expected peak load.
- Determine the generation available.
- Identify real or reactive restrictions (MW and / or MVAR) on the interconnected circuit(s) used to provide the assistance.
- If sourced from an Area’s electrical island, then the considerations of Section 5.6 are applicable.
- Determine the expected duration of this arrangement, if known, until the assisted Area is in a position to return its Area to its 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 system operator to determine the best location and voltage level to govern the interconnection.

6.1 Synchronous Tie Lines

When synchronizing control areas, the following guidelines should be followed:

Synchronize at locations where:

- Synchronism-check relays and / or manual synchroscopes are available;
- Voltage control resources are at, or in close proximity to, the open points;
• **Generation** sources are easily manipulated or controlled; and
• Good multi-party communications are available between the personnel directing the **synchronization**, the **system operators** controlling the **synchronizing** breaker, and the **system operators** 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 must 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 ± 20º (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. **System operators** 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 **Area’s system operators**.

### 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:

• **AC / HVdc commutation**;
• short circuit requirements; and
• 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 Area 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.

Areas should consider situations where non-synchronous tie lines have remained in service following the event. System operators need to 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:

\[
\left\{ \left( \text{the MW size of the islanded generation contingency} \right) \times \left( \text{the MW size of the island} \right) \right\} \div \left\{ \text{the MW size of the combined synchronized system} \right\}
\]

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., will help system operators establish secure flows on tie lines.

7.1 Frequency Considerations

In general, once Areas are tied together and receiving or supplying assistance, system operators 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, system operators 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

System operators 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

System operators should be aware of three key parameters noted below. The specific amounts for each facility need to be communicated between the
interconnecting Areas. These amounts may be revised as system condition change.

• **Maximum Tie Line Interface Export Loading**

  the maximum tie-line or interface loadings possible based on equipment ratings and operation to provide contingency coverage.

  Some control 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:

  • The normal continuous rating of any single facility making up the interface; or;
  • the appropriate emergency rating of any facility, as a result of the worst contingency impacting the interface.

• **Maximum Tie Line Interface Loading Rate**

  the maximum loading rate of a tie line or interface as allowed by the assisting 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.

• **Maximum Tie Line Interface Deviation for Step Changes in Load or Generation**

  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:

  • 5% of the synchronized capacity, or
  • the cumulative effect of the loading rates of generation within the control 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 system operator 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 Area,
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 system operators working together from more than one NPCC Area, or with jurisdictions external to the NPCC, inter-Area coordination of the emergency response of the system operators is greatly enhanced.

Each individual NPCC Area conducts regular system restoration exercises for their system operators and support staff. These Area exercises focus primarily on procedures specific to the given 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 system operators from multiple NPCC Areas and therefore can help to also evaluate the coordination of Area restoration plans.

Exercises may include:

- simulated emergency response activities;
- table top simulations;
- exercise participants participating from their normal work headquarters;
- minimal to zero coaching by exercise coordinators; and
- 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 system operator critiques. Coordinated inter-Area exercises should be considered as an additional step when an Area is scheduling its own internal restoration exercise in order to foster and sustain inter-Area coordination in performing system restoration.

In general, both Area and NPCC exercises should include experiences and lessons learned from actual restoration events.
Prepared by: NPCC Task Force on Coordination of Operation

Review frequency: 3 years

References: 
NPCC Glossary of Terms (NPCC Document A-07)
Emergency Operation Criteria (NPCC Document A-03)
Appendix A

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.
Appendix B
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 send system operators to the Local Control Centers to assist 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.
Appendix C
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.

• 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.

• 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.
Appendix D

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:

- Operational;
- Testing;
- Training; and
• Administration.

The primary objective of the Ontario Power System Restoration Plan (OPSRP) is to restore the 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:

• recovery of generation;
• energizing transmission lines;
• load restoration (initially to lower voltage), and
• 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:

• maintain the availability of generators post disturbance;
• shed load on underfrequency;
• open circuit breakers that are off potential in preparation for system restoration;
• restore station service at step-down transformer stations; and
• 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 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.
Appendix E
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:

- Basic plan;
- Regular follow-up;
- Personnel and material required; and
- 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 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:

- **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.

- **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.

- **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:

- Backup teams are called in;
- Other **system operators** are called in;
- An operator is dispatched to every unattended key facility;
- 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;
- 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;
- 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;
- Voltage and frequency profiles are the preferred monitoring indicators to speed up or to slow down the **load** restoration;
- **Synchronization** of the different BMPSs is coordinated by the **system operator**. **Load** restoration is stopped during **synchronization** of the BMPS;
- **Synchronization** of the different subsystems is coordinated by the **system operator**;
- The next step is to continue **load** restoration until all the **load** is back on the system;
- 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:

- Tripped equipment;
- **Energized** or in service equipment;
- Breakers which have remained closed;
- Unavailable equipment;
- Proceed with emergency procedures; and
- 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.
Appendix F
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 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 system 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 (Reliability Coordinator to Reliability Coordinator, Reliability Coordinator to control area, control area to control area, etc.), island operation, and interconnections.
Appendix G

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 control 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:

- PJM will coordinate all interchange schedules with external control areas.
- PJM will coordinate and direct all restoration of the 500 kV transmission system.
- PJM will develop and calculate area control error (ACE) as required when appropriate data is available to perform this calculation.
- PJM will coordinate and direct all transmission tie connections to external control areas.
- PJM will identify opportunities for interconnection between PJM internal Transmission Owners and / or neighboring control areas.
- PJM will collect system status information and provide status updates to members on system restoration status.
- PJM will conduct periodic System Operations Subcommittee (SOS) conference calls, as appropriate.
The following table presents the general steps that are performed to restore the PJM RTO following separation:

<table>
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<th>Step</th>
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<td>Determine Restoration Process</td>
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<td>Disseminate Information on System Status</td>
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<td>Member Interconnection</td>
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<tr>
<td>PJM Assumes Frequency Control</td>
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**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
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
Inter-Control Area Restoration

ISO-NE Communications Main and Alternate Paths

REMVEC
HQ TransÉnergie
VELCO
Maritimes (NBSO)

NYISO
ISO-NE
PSNH
Maine

CONVEX

Legend
Primary Path
Alternate Path
NPCC C/A Operator
ISONE Sub Area Restoration Coordinator (Optional)

Appendix H-3
IESO Communications Paths for Inter-Control Area Restoration

Legend

- Reliability Coordinator
- Transmission Owner / External Sub Region Restoration Coordinator

IESO West

Manitoba Hydro

Minnesota Power

MECS

ITC

MISO East

Hydro One

HQ TransÉnergie

MISO East

Reliability Coordinator Communications

direct operations

NYISO

National Grid USA

NYP A

Appendix H-5
Inter-Control Area Restoration

HQ TransÉnergie Communications Main and Alternate Paths

Legend
- Primary Path
- Alternate Path
- NPCC C/A Operator
- HQ Sub Area Restoration Coordinator (Optional)

IESO

Maritimes (NBSO)

IEO

St. Jerome (Lower Ottawa)

Rouyn (Upper Ottawa)

Québec

ISO-NE

Brascan

Montréal (St Lawrence)

Trois-Rivieres

Appendix H-6
Procedures for Communications During Emergencies

Approved by the Task Force on Coordination of Operation on January 21, 1997 as Reference Document RD-03
Re-designated as Procedure Document C-36 on August 18, 2005

Revised: March 8, 2000
Revised: September 18, 2001
Reviewed: August 18, 2005
1.0 Introduction

Communication among control areas is essential to maintain the reliability of the interconnected systems and permit the implementation of appropriate NPCC Criteria, Guidelines and Procedures. Proper and effective communication is particularly critical during an emergency, or as an emergency situation evolves in order to mitigate the consequences of the event.

Each Area is required to ensure that operational situations of an unusual nature are communicated promptly even though the situation may not appear to have an adverse impact on interconnected operations. Follow-up reports should be provided as deemed appropriate.

This Procedure addresses three separate but related areas of emergency communications:

- Operators’ communication during an emergency.
- Communications with external agencies during extended emergencies.
- Collection of data during or following an emergency.

2.0 Operators’ Communication During an Emergency

2.1 Control Room Communications

It is the responsibility of the operator of any system or Area to inform the appropriate Reliability Coordinator and other systems and Areas whenever it anticipates or experiences an emergency. The Reliability Coordinator will assist the operator in dissemination of the information if requested. Prompt notice of such conditions should be communicated to:

a) the Interconnection through the NERC Interregional Emergency Telephone Networks as outlined in NERC Operating Policy 7, Telecommunications, Appendix 7A,” Regional and Interregional Telecommunications”.

b) neighboring utilities via the Reliability Coordinator Information System (RCIS).

2.2 Description of Emergency Conditions

The following are examples of conditions that warrant the use of the NERC Interregional Emergency Telephone Network:

a sudden and unexplained change in frequency of at least 0.03 Hz from normally acceptable levels (0.5 Hz within the TransÉnergie system)
b gradual, unexplained decay in frequency leading to frequency levels below 59.95 Hz (59.5 Hz within the TransÉnergie system)

c sudden frequency changes sufficiently large to threaten an interconnection

d unexplained transmission loadings in a region

e sudden transmission loadings sufficiently large to threaten an interconnection

f Energy Emergency Alerts requiring the sudden need to import emergency power or energy from other Areas or regions

g supplemental communications following a partial or major interconnection blackout

h failure of other communications systems, either partially or totally

i electromagnetic storms in progress

It is the responsibility of any system or Area to inform the appropriate Reliability Coordinators, other systems and Areas whenever it is not able to operate within the NPCC operating criteria or its status is burdening or reducing the reliability of the Eastern Interconnection.

2.3 Disseminating Information

Reliability Coordinators will disseminate information and provide coordination with other Reliability Coordinators via the NERC Interregional Emergency Telephone Network (Hotline) and relay appropriate information to the Control Areas within their Security Areas.

The ISO-NE Security Coordinator will relay messages to New Brunswick Power and New Brunswick Power will coordinate with Nova Scotia Power. Conversely, the ISO-NE Reliability Coordinator will place messages requested by the Maritimes Area to other Regions, (see Appendix A).
3.0 Communications with external agencies during extended Emergencies.

During extended emergencies, it is critical to effectively communicate with external agencies including the media, government and regulatory bodies to provide public awareness of the problem and effect cooperation from them and the public.

The essential elements required within the NPCC Areas to ensure timely and effective communications with the Interconnection and with the appropriate organizations outside of the industry are outlined below.

3.1 Communications Logistics

3.1.1 Communications Personnel

A crisis management team shall be designated by each control area and be accessible at all times. As appropriate, the crisis management team can be composed of operating room personnel, operations management and/or public relations personnel. The crisis management team must have an identified team leader and a designated media spokesperson.

The team leader is responsible for coordinating communication with his counterparts in other systems.

3.1.2 Communications Center

The crisis management team shall have access at all times to a communications center capable of acquiring and disseminating information to appropriate organizations. The communications center should be equipped with adequate communications facilities, e.g., telephone listings, telephones, telexcopy machines and access to electronic bulletin boards to enable immediate access at all times to:

- other control areas
- the police, fire and emergency authorities
- the appropriate regulatory and government bodies
- the media
3.1.3 Media Interface

The media shall not be permitted in the control room during an emergency. A designated presentation area should be available for periodic presentations by the team.

3.2 Communications Requirements to other Areas

3.2.1 Operations Management

In crisis conditions, it is the responsibility of the Area’s operations manager or, if he/she is not available, the Control Area Operator to advise his/her counterpart in the other Areas of its situation and solicit assistance as directed in NPCC Document C-13, Operational Planning Coordination.

3.2.2 Crisis Management Team Communications

The crisis management team shall provide frequent status reports to other Areas (and to the press/media as required) of conditions throughout the course of an emergency.

If incidents of terrorism are suspected, the crisis management team should also be in communication with the Federal Bureau of Investigation (FBI) or the Royal Canadian Mounted Police (RCMP).

3.2.3 Examples of Crisis Reporting

Examples of Crisis Reporting are shown in NERC Appendices 5F and 9B.

3.2.4 Notice of Termination

The crisis management team shall immediately inform all parties with whom it has been communicating emergency information of the end of a system emergency and a return to normal operating conditions.

3.3 Training

All communication paths and crisis management team procedures should be tested on a routine basis.
4.0 Collection of Data During or Following a Major System Event

In the aftermath of a widespread system disturbance, it is essential that an accurate assessment of the interconnected bulk power system be available in a timely fashion. This requested data is necessary for initial reports to the appropriate regulatory agencies. Furthermore, it is important for the users of the transmission network to have access to this data so that they may begin an analysis of the events and establish lessons learned.

The North American Electric Reliability Council (NERC) has established a procedure to permit rapid data collection utilizing the Regional representatives. In this way NERC can quickly achieve an overview of the interconnection. The Regions shall ensure that all pertinent data is maintained and updated, including the original data disseminated to NERC.

4.1 Procedures

The request for an event data collection will be initiated by the NERC Operating Committee. Each Regional representative to the OC is responsible for the collection of that Region’s data.

Within NPCC, the NERC/OC representative will direct the request to the NPCC Staff. The NPCC Staff will, in turn, request the designated contact or alternate in each NPCC Area to supply the requested information. The request will be made simultaneously via direct telephone, telecopy and e-mail within one working day.

4.2 Contacts

The list of data collection contacts and alternates is included as Appendix B. This list will be reviewed by the TFCO on a yearly basis.

4.3 Data

Data sheets to be completed by each Area will be distributed by the NERC office together with each request. The data sheets will be self contained and include all necessary definitions of the required data items.

The completed sheets will be sent to the NPCC office, which will consolidate the information and forward it to the NERC office within two working days from the time NERC issued the initial request.
Prepared by: Task Force on Coordination of Operation

References:  *NPCC Glossary of Terms* (NPCC Document A-07)

*Operational Planning Coordination* (NPCC Document C-13)
Operating Procedures
for
Ace Diversity Interchange (ADI)

Approved by the Task Force on Coordination of Operation on August 14, 2002
as Reference Document RD-04
Re-designated as Procedure Document C-37 on August 18, 2005

Reviewed: August 18, 2005
1.0 Introduction

ACE Diversity Interchange (ADI) is a method of regional regulation among participating Areas that can achieve a mutual reduction in regulation requirements and generator output adjustments. ADI uses the sign diversity of the Area Control Error (ACE) values of the participating Areas to achieve this mutual reduction. This procedure is in conformance with NERC control policy.

2.0 General

The NPCC and PJM Areas agree to exchange ACE under this procedure. (Initial participating Areas are ISO-New England (ISO-NE), New York ISO (NYISO), and the Maritimes). Participating Areas can reduce their respective regulation burdens in real time while gaining an improvement in Control Performance Standard (CPS1 and CPS2) compliance. Areas will be able to participate in ADI once they establish the appropriate data exchange and apply the ADI term to their respective ACE in AGC.

Each Area shall be responsible for the security monitoring of its own system and for the determination of the amount of ACE diversity that it is able to provide, receive or transfer. Areas are expected to respond to normal condition mismatches of load and generation via their internal generation control or with scheduled purchases. Transmission limits or other internal constraints that preclude the normal implementation of ADI shall be communicated immediately to the NYISO Shift Supervisor. Whenever normal implementation of the procedure is precluded, the NYISO shall notify the other participants.

The industry sign standard for ACE is used, i.e., a negative ACE indicates under generation. The ADI sign convention is such that a positive ADI allocation will make the adjusted ACE of the Area less negative with respect to the unadjusted ACE. The positive ADI limit will restrict the amount of positive ADI that can be allocated to make an Area’s adjusted ACE less negative with respect to a negative unadjusted ACE. The converse is applied to positive ACE values and negative ADI allocation and limits.

Inadvertent interchange is affected by the implementation of ADI. In general the unadjusted ACE values have equal likelihood over an hour to be positive or negative. As long as the tendency to create inadvertent in a particular direction is not large and sustained then the Monthly inadvertent accounts will remain unchanged by the ADI process. ADI allocations will be monitored carefully for inequitable or inordinately large accumulations of inadvertent. These issues will be addressed and remedied promptly.
ADI may be used to drive inadvertent among participants that have accumulated balances that are opposite in sign. Two or more ADI participants may engage in this activity. At least one participant’s accumulated inadvertent balance must be opposite in sign to the other’s.

3.0 Procedure

Changes to the ADI states (enable/disable) and parameters will be coordinated through the Central Controller. The Central Controller will have the authority to globally disable ADI. Following this action, all participants must be notified (via Hotline conference). Changes to individual Satellites parameters can be communicated electronically and viewed by all participants, presuming all the participants have displayed a full complement of data.

The Satellite Areas shall have the authority to disable their respective participation in ADI. The Central Controller will have the capability to disable any individual Satellite, but should only do so at the Satellite’s request, unless there are under extenuating circumstances. Ordinarily the Central Controller would direct a Satellite to disable its ADI participation.

3.1 NYISO is established as the Central Controller. As such, the NYISO Shift Supervisor will coordinate and notify all participating Areas of any changes in a Satellite’s ADI state.

3.2 The Central Controller shall have the authority to enable or disable ADI exchange and/or related parameters if:
   - Control Performance is adversely affected by the ADI
   - ADI contributes to inordinately large or inequitable accumulations of inadvertent
   - Flows on the transmission system are affected adversely by ADI.
   - Data received from a participating Area does not meet the data refresh criterion. (This is intended to be monitored by the EMS).

3.3 Participants may adjust their respective ADI limits and participation. All such changes must be communicated through the Central Controller. Limit changes to control inadvertent accumulations will be made simultaneously by the Central Controller and communicated to all participants.

3.4 Any participant may request that ADI be enabled or disabled globally

3.5 All actions to globally enable or disable ADI or otherwise modify ADI parameters will be communicated electronically, via Hotline, or
Conference Call as appropriate. A concise reason for the change is to be given.

3.6 Participants will disable ADI participation automatically if AGC execution is paused, suspended, placed in a monitor mode, or if data quality problems result in an unreliable calculation of the unadjusted ACE.

3.7 The NPCC Control Performance Working Group (CO-1) shall monitor the ADI process to determine the appropriate ADI operating parameters and to assure that reliability is not adversely affected by its use.

Prepared by: Task Force on Coordination of Operation

References: Criteria for Review and Approval of Documents (Document A-1)

Monitoring Procedures for Control Performance (Document C-8)

ADI Operating Concepts and Requirements (CO-1 Working Group Document, August 17, 2001)
Procedure for
Operating Reserve Assistance

Approved by the NPCC Task Force on Coordination of Operation on November 5, 2002 as Reference Document RD-05.
Re-designated as Procedure Document C-38 on August 18, 2005.

Reviewed: August 18, 2005
1.0 **Introduction**

The NPCC Areas except Hydro-Quebec have agreed to share resources to meet **operating reserve requirements**. This procedure enables Areas to assist each other in meeting their **ten minute reserve requirement**.

2.0 **Operating Procedure**

2.1 **Areas** must commit sufficient **resources** to meet the **reserve requirements** prescribed by Northeast Power Coordinating Council (NPCC) Document A-6, *Operating Reserve Criteria*.

2.2 Each **Area** may count a contribution of 50 MW as **ten minute non-synchronized reserve** towards its **ten-minute reserve requirement** from participating **Area(s)**, provided that the **Regional Reserve Sharing Energy** (RRSE) is available in the participating **Area(s)** and deliverable to the **Area**, and not activated.

2.3 A participating **Area** delivering RRSE to a contingent **Area** includes that energy as part of its **ten minute reserve** for meeting its **ten minute reserve requirement**.

2.4 **NYISO** serves as the coordinator of **Regional Reserve Sharing** (RRS). **NYISO** will continually monitor the availability and deliverability of RRSE among NPCC **Areas**. **NYISO** will communicate significant changes in the status of the availability and deliverability of RRSE to each NPCC **Area** and PJM.

2.5 **Areas** will inform the **NYISO** of the availability and deliverability of the RRSE described in this procedure during ordinary real time operational and operational planning communications. Exceptions and restrictions will be noted by all **Areas**.

2.6 Temporary restrictions in the availability of RRSE to be shared with other **Areas** by one **Area** do not preclude that **Area** from receiving RRSE from other **Areas**. Temporary restrictions in deliverability of RRSE by one **Area** to another **Area** do not preclude that **Area** from receiving RRSE from other **Areas**.

2.7 RRSE meets the sustainability requirements of NPCC Document A-6, *Operating Reserve Criteria*.

2.8 RRSE is physically delivered only if the contingent **Area** continues to need assistance, already being provided as **Shared Activation Reserve Energy**, beyond the thirty minute limitation for **Shared Activation Reserve Energy**. The **NYISO** will convert 100 MW of **Shared Activation Reserve Energy** to RRSE thirty minutes after the contingency. **NYISO** will inform the contingent and assisting **Areas** of the new adjusted shares related to the conversion from **Shared Activation Reserve Energy** to RRSE, with the greatest practical lead time. Refer to Attachment 1 for an illustration indicating the differences between Shared
Activation of Reserve and Shared Activation of Reserve with **Regional Reserve Sharing**.

2.9 RRSE is terminated when it is no longer needed by the contingent **Area**, but within sixty minutes of activation.

2.10 When a contingent **Area** terminates the delivery of RRSE from participating **Areas**, all **Areas** will employ a ten minute ramp in their interchange schedules.

2.11 If the RRSE from an assisting **Area** can no longer be delivered to the contingent **Area**, the assisting **Area** notifies the NYISO. Its RRSE being withdrawn will be reallocated to other assisting **Areas** to the greatest extent possible by the NYISO.

2.12 An **Area** may declare itself unavailable as a provider of RRSE if it becomes deficient in its **synchronized** portion of its **ten minute reserve**, or if it becomes deficient in **ten minute reserve** after including the effect of RRSE that it can receive from other **Areas**.

2.13 RRSE is available to an **Area** as a discrete 100 MW block; an Area may not request partial activation.

2.14 Although PJM is a participant in shared activation of reserve, it neither receives nor provides RRSE.

2.15 RRSE exchanged under this procedure will create inadvertent and will be treated in accordance with NPCC Document C-12, *Procedures for the Shared Activation Of Ten Minute Reserve*. 
Prepared by: NPCC Task Force on Coordination of Operation

Review frequency: 3 years

References

*Operating Reserve Criteria* (NPCC Document A-06)

*NPCC Glossary of Terms* (NPCC Document A-07)

*Procedures for Shared Activation of Ten Minute Reserve* (NPCC Document C-12)
The above two charts demonstrate how Shared Activation Reserve Energy (SAR) is converted to reserve sharing energy 30 minutes after a supply-side resource contingency.

The upper chart shows idealized response when a SAR event occurs for the loss of 500 MW of generation. The contingent Area needs to provide 250 MW of additional generation within 15 minutes or less to do its share to assure a timely recovery. The assisting Areas also need to provide 250 MW of additional generation within 15 minutes to do their share to assure a timely recovery. In most realistic scenarios, the increased generation of the contingent Area might not begin for a minute after the contingency. The step schedule changes to effect the SAR may actually take place about 3 minutes after the contingency occurs. The provision of additional generation from the assisting Areas may not begin until about 4 minutes after the contingency occurs due to delays in communications. However, SAR events most often result in full recovery within 15 minutes of the contingency.

With an SAR event, the contingent Area most often cancels SAR assistance shortly after recovery if adequate resources are available to replace the assistance at that time. When adequate resources are not immediately available, the contingent Area may retain the assistance up to 30 minutes after the contingency. All 250 MW of assistance are ramped out over ten minutes by the contingent and assisting Areas.

The lower chart shows idealized response when a contingent Area activates RRSE. The first 30 minutes exactly matches that of an SAR only event that reaches the 30 minute delivery limit. However, at 30 minutes, only 150 MW of assistance is ramped out over ten minutes, while 100 MW of the assistance already delivered in converted immediately
into delivered RRSE. While the RRSE would typically be ramped out over ten minutes when it is no longer needed, it must be ramped out at no later than 90 minutes after the contingency.