NPCC
Regional Reliability Reference Directory # 1
Design and Operation of the Bulk Power System

Task Force on Coordination of Planning Revision Review Record:
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<tr>
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<td>4/20/2012</td>
<td>Errata changes in Appendix B and Appendix E.</td>
<td>Errata</td>
</tr>
</tbody>
</table>
Table of Contents

1.0 Introduction ............................................................................................................................................. 5
  1.1 Title - Design and Operation of the Bulk Power System ........................................................................ 5
  1.2 Directory Number 1 ................................................................................................................................ 5
  1.3 Objective ................................................................................................................................................ 5
  1.4 Effective Date – December 01,2009 ....................................................................................................... 5
  1.5 Background .......................................................................................................................................... 6
  1.6 Applicability ......................................................................................................................................... 6
  1.6.1 Functional Entities ........................................................................................................................... 6

2.0 Terms Defined in this Directory ............................................................................................................. 6

3.0 NERC ERO Reliability Standard Requirements .................................................................................... 6
  3.1 EOP-001-0 - Emergency Operations Planning .................................................................................... 6

4.0 NPCC regional Reliability Standards Requirements ........................................................................... 7

5.0 NPCC Full Member, More Stringent Criteria ....................................................................................... 7
  5.1 General Requirements .......................................................................................................................... 7
    5.1.1 Design Criteria ............................................................................................................................... 7
    5.1.2 Operating Criteria .......................................................................................................................... 8
    5.1.3 Data Exchange Requirements for Modeling and System Analysis .................................................. 9
  5.2 Resource Adequacy – Design Criteria ................................................................................................. 9
  5.3 Resource Adequacy – Operating Criteria ........................................................................................... 10
  5.4 Transmission Design Criteria ............................................................................................................. 10
    5.4.1 Stability Assessment ....................................................................................................................... 10
    5.4.2 Steady State Assessment ............................................................................................................... 11
    5.4.3 Fault Current Assessment ............................................................................................................. 12
  5.5 Transmission Operating Criteria .......................................................................................................... 12
    5.5.1 Normal Transfers ............................................................................................................................ 12
    5.5.2 Emergency Transfers .................................................................................................................... 14
    5.5.3 Post Contingency Operation ......................................................................................................... 15
    5.5.4 Operation under High Risk Conditions ....................................................................................... 15
  5.6 Extreme Contingency Assessment ........................................................................................................ 15
  5.7 Extreme System Conditions Assessment ............................................................................................. 17

Appendix A - Definition of Terms .................................................................................................................. 1

Appendix B - Guidelines and Procedures for NPCC Area Transmission Reviews ...................................... 1

Appendix C - Procedure for Testing and Analysis of Extreme Contingencies .......................................... 1

Appendix D - Guidelines for Area Review of Resource Adequacy .............................................................. 1

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

Appendix F – Procedure for Operational Planning Coordination .............................................................. 1

This document, when downloaded or printed, becomes UNCONTROLLED. Users should check the 
NPCC website for the current CONTROLLED version of this document.
Procedure for Operational Planning Coordination – Attachment B ............................................................. 1
Procedure for Operational Planning Coordination - Attachment C ............................................................. 1

Appendix G - Procedures for Inter Reliability Coordinator Area Voltage Control ........................................ 1
1.0 Introduction

1.1 Title - Design and Operation of the Bulk Power System

1.2 Directory Number 1

1.3 Objective

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

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

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

a. Consideration of a balanced relationship among the fuel type, capacity, physical characteristics (peaking/base load/etc.), and location of resources.

b. Consideration of a balanced relationship among transmission system elements to avoid excessive dependence on any one transmission circuit, structure, right-of-way, or substation.

c. Transmission systems should provide flexibility in switching arrangements, voltage control, and other control measures.

1.4 Effective Date - December 01, 2009
1.5 Background

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

1.6 Applicability

1.6.1 Functional Entities

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

2.0 Terms Defined in this Directory

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

3.0 NERC ERO Reliability Standard Requirements

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

3.1 EOP-001-0 - Emergency Operations Planning
3.2 FAC-011-2 - System Operating Limits Methodology for the Operations Horizon
3.3 IRO-002-1 - Reliability Coordination - Facilities
3.4 IRO-014-1 — Procedures, Processes, or Plans to Support Coordination Between Reliability Coordinators
3.5 MOD-010-0 - Steady-State Data for Transmission System Modeling and Simulation
3.6 MOD-011-0 — Regional Steady-State Data Requirements and Reporting Procedures
3.7 MOD-012-0 — Dynamics Data for Transmission System Modeling and Simulation
3.8 MOD-013-1 — RRO Dynamics Data Requirements and Reporting Procedures
3.9 MOD-014-0 — Development of Interconnection-Specific Steady State System Models
3.10 MOD-015-0 — Development of Interconnection-Specific Dynamics System Models
3.11 MOD-016-1 — Actual and Forecast Demands, Net Energy for Load,
Controllable DSM
3.12 TOP-001-1 — Reliability Responsibilities and Authorities
3.14 TOP-003-0 — Planned Outage Coordination
3.15 TOP-004-2 — Transmission Operations
3.16 TPL-001-0 — System Performance Under Normal Conditions
3.17 TPL-002-0 — System Performance Following Loss of a Single BES Element
3.18 TPL-003-0 — System Performance Following Loss of Two or More BES Elements
3.19 TPL-004-0 — System Performance Following Extreme BES Events
3.20 TPL-005-0 — Regional and Interregional Self-Assessment Reliability Reports
3.21 TPL-006-0 — Assessment Data from Regional Reliability Organizations
3.22 VAR-001-1 — Voltage and Reactive Control

4.0 NPCC regional Reliability Standards Requirements

None

5.0 NPCC Full Member, More Stringent Criteria

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

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

5.1 General Requirements

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

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

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

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

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

The requirements of special protection systems are defined in the NPCC Bulk Power System Protection Criteria, (Directory#4), and the Special Protection Systems, (Directory #7).

5.1.2 Operating Criteria

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

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

The operating criteria define the minimum level of reliability that shall apply to inter-Reliability Coordinator Area operation. Where inter-Reliability Coordinator Area reliability is affected, each Reliability
Coordinator shall establish limits and operate so that the **contingencies** stated in Section 5.5.1 and 5.5.2 can be withstood without causing a **significant adverse impact** on other Reliability Coordinator Areas.

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

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

5.1.3 Data Exchange Requirements for Modeling and System Analysis

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

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

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

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

5.2 Resource Adequacy – Design Criteria

The probability (or risk) of disconnecting **firm load** due to resource deficiencies shall be, on average, not more than one day in ten years as
determined by studies conducted for each Resource Planning and Planning Coordinator Area. Compliance with this criterion shall be evaluated probabilistically, such that the loss of load expectation (LOLE) of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Planning Coordinator Areas, transmission transfer capabilities, and capacity and/or load relief from available operating procedures.

5.3 Resource Adequacy – Operating Criteria

Each Balancing Authority shall have procedures in place to schedule outages and deratings of resources in such a manner that the available resources will be adequate to meet the Resource Planner’s and Planning Coordinator’s forecasted demand and reserve requirements, in accordance with the NPCC Operating Reserve Criteria (Directory#5).

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

5.4 Transmission Design Criteria

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

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

5.4.1 Stability Assessment

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

a. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section with normal fault clearing.

b. Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with normal fault clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded. Other similar situations can be excluded on the basis of acceptable risk, provided that the Reliability Coordinating Committee specifically accepts each request for exclusion.

c. A permanent phase to ground fault on any transmission circuit, transformer, or bus section with delayed fault clearing.

d. Loss of any element without a fault.

e. A permanent phase to ground fault on a circuit breaker with normal fault clearing. (Normal fault clearing time for this condition may not always be high speed.)

f. Simultaneous permanent loss of both poles of a direct current bipolar facility without an ac fault

g. The failure of a circuit breaker to operate when initiated by a SPS following: loss of any element without a fault; or a permanent phase to ground fault, with normal fault clearing, on any transmission circuit, transformer or bus section.

5.4.2 Steady State Assessment

a. Each Transmission Planner shall design its system in accordance with these criteria and its own voltage control procedures and criteria, and coordinate these with adjacent Transmission Planner Areas. Adequate reactive power resources and appropriate controls shall be installed in each Transmission Planner Area to maintain voltages within
normal limits for pre-disturbance conditions, and within applicable emergency limits for the system conditions that exist following the contingencies specified in 5.4.1.

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

5.4.3 Fault Current Assessment

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

5.5 Transmission Operating Criteria

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

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

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

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

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

a. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section, with normal fault clearing.

b. Simultaneous permanent phase to ground faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with normal fault clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded. Other similar situations can be excluded on the basis of acceptable risk, provided that the Reliability Coordinating Committee specifically accepts each request for exclusion.

c. A permanent phase to ground fault on any transmission circuit, transformer, or bus section with delayed fault clearing.

d. Loss of any element without a fault.

e. A permanent phase to ground fault on a circuit breaker, with normal fault clearing. (Normal fault clearing time for this condition may not always be high speed.)

f. Simultaneous permanent loss of both poles of a direct current bipolar facility without an ac fault.

g. The failure of a circuit breaker to operate when initiated by a SPS following: loss of any element.
without a fault; or a permanent phase to ground fault, with **normal fault clearing**, on any transmission circuit, transformer or bus section.

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

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

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

5.5.2 Emergency Transfers

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

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

a. A permanent three-phase fault on any generator, transmission circuit, transformer or bus section, with **normal fault clearing**.

b. The loss of any **element** without a fault.
Immediately following the most severe of these **contingencies**, voltages, line and equipment loadings will be within **applicable emergency limits**.

**5.5.3 Post Contingency Operation**

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

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

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

**5.5.4 Operation under High Risk Conditions**

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

**5.6 Extreme Contingency Assessment**

Extreme **contingency** assessment recognizes that the **bulk power system** can be subjected to events which exceed, in severity, the **contingencies** listed in Section 5.4.1. One of the objectives of extreme **contingency** assessment is to
determine, through planning studies, the effects of extreme contingencies on system performance. This is done in order to obtain an indication of system strength, or to determine the extent of a widespread system disturbance, even though extreme contingencies do have low probabilities of occurrence.

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

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

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

a. Loss of the entire capability of a generating station.

b. Loss of all transmission circuits emanating from a generating station, switching station, dc terminal or substation

c. Loss of all transmission circuits on a common right-of-way.

d. Permanent three-phase fault on any generator, transmission circuit, transformer, or bus section, with delayed fault clearing and with due regard to reclosing.

e. The sudden dropping of a large load or major load center.

f. The effect of severe power swings arising from disturbances outside the Council's interconnected systems.

g. Failure of a special protection system, to operate when required following the normal contingencies listed in Section 5.4.1.

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

i. Sudden loss of fuel delivery system to multiple plants, (i.e. gas pipeline contingencies, including both gas transmission lines and gas mains.)
Note: The requirement of this section is to perform extreme contingency assessments. In the case where extreme contingency assessment concludes there are serious consequences, an evaluation of implementing a change to design or operating practices to address such contingencies shall be conducted.

5.7 Extreme System Conditions Assessment

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

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

a. Peak load conditions resulting from extreme weather conditions with applicable rating of electrical elements.

b. Generating unit(s) fuel shortage, (i.e. gas supply adequacy)

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

Prepared by: Task Force on Coordination of Planning

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

Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast.
Revisions pertaining to the Appendices or any other portion of the document such as Links glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document.

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

References:

NPCC Glossary of Terms
Bulk Power System Protection Criteria (Directory#4)
Emergency Operations (NPCC Directory #2)
Special Protection Systems (Directory #7)
Appendix A - Definition of Terms

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

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

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

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

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

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

**NPCC Specific Definitions:**

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

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

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

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

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

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

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

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

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

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

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

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

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

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

High speed fault clearing - Fault clearing consistent with correct operation of high speed relays and the associated circuit breakers without intentional time delay. **Notes:** The specified time for high-speed relays in present practice is 50 milliseconds (three cycles on a 60Hz basis) or less. [IEEE C37.100-1981]. For planning purposes, a total clearing time of six cycles or less is considered high speed.

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

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

NPCC Specific Definitions:
Firm Load - Loads that are not **Interruptible Loads**.

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

**Power**

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

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

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

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

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

**Notes:**


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

**Terminal Basis**

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

Pilot Protection - A form of line protection that uses a communication channel as a means to compare electrical conditions at the terminals of a line.
Rating - The operational limits of an electric system, facility, or element under a set of specified conditions.

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

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

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

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

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

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

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

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

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

Reserve - In normal usage, reserve is the amount of capacity available in excess of the demand
Reserve Requirement - That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages, and local area supply adequacy

NPCC Specific Definitions:

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

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

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

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

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

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

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

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

a. instability:
   • any instability that cannot be demonstrably contained to a well defined local area,
   • any loss of synchronism of generators that cannot be demonstrably contained to a well-defined local area.

b. unacceptable system dynamic response:
• an oscillatory response to a contingency that is not demonstrated to be clearly positively damped within 30 seconds of the initiating event.

c. unacceptable equipment tripping:
  • tripping of an un-faulted bulk power system element (element that has already been classified as bulk power system) under planned system configuration due to operation of a protection system in response to a stable power swing,
  • the operation of a Type I or Type II Special Protection System in response to a condition for which its operation is not required

d. voltage levels in violation of applicable emergency limits;

e. loadings on transmission facilities in violation of applicable emergency limits.

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

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

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

Transient Stability - The ability of an electric system to maintain synchronism between its parts when subjected to a disturbance, and to regain a state of equilibrium following that disturbance.
Appendix B - Guidelines and Procedures for NPCC Area Transmission Reviews

1.0 Introduction

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

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

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

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

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

3.0 The Study Year to be considered

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

4.0 Types and Frequency of Reviews

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

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

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

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

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

5.0 Format of Presentation – Comprehensive and Intermediate Review

Introduction

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

- Describe the type and scope of this review.

- For a Comprehensive Review, describe the existing and planned bulk power system facilities included in this review.

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

- Include maps and one-line diagrams of the system showing proposed changes as necessary.

- Describe the selected demand levels over the range of forecast system demands.
• Discuss projected firm transfers and interchange schedules.

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

a) Discuss the scope of the analyses. The analyses conducted for a Comprehensive Review should be thorough, but an Intermediate Review may focus on specific areas of the system, specific system conditions, or a more limited set of “critical” contingencies.

b) Steady State Assessment

- Discuss the load model, power factor, demand side management, and other modeling assumptions used in the analysis. Discuss the methodology used in voltage assessments. (An Intermediate Review may refer to the discussion from the last Comprehensive Review.)

- Provide supporting information on the contingencies selected for evaluation and an explanation of why the remaining simulations would produce less severe results.

- Include plots of "base case" load flows with all lines in service for the various conditions studied, e.g., peak, off-peak, and heavy transfers.

- Discuss the load flows showing the effects of major planned changes on the system.

- Discuss applicable transfer limits between contiguous areas.

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

- Include in the study the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

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

- Provide supporting information on the contingencies selected for evaluation and an explanation of why the remaining simulations would produce less severe results.

- Nature of fault, elements switched, switching times.

- Plots of angles versus time for significant machines, HVdc and SVC response, voltages at significant buses and significant interface flows.

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

- Include the effects of existing and planned control devices.

- Include in the study the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

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

d) Fault Current Assessment

- Discuss the methodology and assumptions used in the fault current assessment. (An Intermediate Review may refer to the discussion from the last Comprehensive Review.)

- Discuss instances where fault levels exceed equipment capabilities and measures to mitigate such occurrences.

- Discuss changes to fault levels at stations adjacent to other Planning Coordinator Areas.
a) Discuss the scope of the analyses. The analyses conducted for a Comprehensive Review should be thorough, but an Intermediate Review may focus on specific areas of the system, specific system conditions, or a more limited set of “critical” contingencies.

b) Provide supporting information on the extreme contingencies selected for evaluation and an explanation of why the remaining simulations would produce less severe results.

c) Discuss and/or refer to significant load flow studies showing the base case and the post fault conditions for the contingencies as specified in Section 5.6 of Directory #1 entitled "Extreme Contingency Assessment". Report on the most severe contingencies tested.

d) Discuss and/or refer to significant stability studies showing the effect on the system of contingencies as specified in Section 5.6 of Directory #1. Report on the most severe contingencies tested.

e) In the case where contingency assessment concludes serious consequences, conduct an evaluation of implementing a change to address such contingencies.

Extreme System Condition Assessment

a) Discuss the scope of the analyses.

b) Discuss and/or refer to significant load flow studies showing the effect on the steady state performance of extreme system conditions as specified in Section 5.7 of Directory #1, entitled "Extreme System Condition Assessment". Report on the most severe system conditions and contingencies tested.

c) Provide supporting information on the contingencies selected for evaluation and an explanation of why the remaining simulations would produce less severe results.

d) Discuss and/or refer to significant stability studies showing the effect on the dynamic performance of extreme system conditions as specified in Section 5.7 of Directory #1. Report on the most severe system conditions and contingencies tested.

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

Review of Special Protection Systems (SPSs)
a) Discuss the scope of review. A Comprehensive Review should review all the existing, new, and modified SPSs included in its transmission plan. An Intermediate Review may focus on the new and modified SPSs, and just those existing SPSs that may have been impacted by system changes since they were last reviewed.

b) For those SPSs whose failure or misoperation has an inter-Planning Coordinator Area or interregional effect, discuss and/or refer to appropriate load flow and stability studies analyzing the consequences.

c) For those SPSs whose failure or misoperation has only local or intercompany consequences, discuss and/or refer to load flow and stability studies demonstrating that this is still the case for the time period being reviewed.

d) For instances where a SPS which was formerly considered to have only local consequences is identified as having the potential for inter-Planning Coordinator Area effects, for the time period being reviewed, the TFSS should notify the Task Forces on Coordination of Planning, System Protection and Coordination of Operation. In such instances a complete review of the SPS should be made, as per the Procedure for NPCC Review of New or Modified Bulk Power System Special Protection Systems (SPS) in Directory #7.

Review of Dynamic Control Systems (DCSs)

For those DCSs whose failure or misoperation may have an inter-Planning Coordinator Area or interregional effect, discuss and/or refer to appropriate stability studies analyzing the consequences of such failure or misoperation in accordance with the Joint Working Group (JWG)-1 report, "Technical Considerations and Suggested Methodology for the Performance Evaluation of Dynamic Control Systems". A Comprehensive Review should address all potentially 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.

Review of Exclusions to the Basic Criteria.

Review any exclusions granted under the NPCC Guidelines for Requesting Exclusions to Sections 5.4.1(b) and 5.5.1(b) Directory #1 Design and Operation of the Bulk Power System (Appendix E). A Comprehensive Review should address all exclusions, but an Intermediate Review may focus
on just those exclusions that may have been impacted by system changes since they were last reviewed.

Overview Summary of System Performance for Year Studied

6.0 Format of Presentation - Interim Review

Introduction of Interim Review

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

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

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

Brief Impact Assessment and Overview Summary

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

7.0 Documentation

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

The documentation required for an Interim Review should be in the form of a
summary report (normally not exceeding 5 pages), containing a description of system changes and a brief assessment on their impact on the reliability of the interconnected bulk power system.

8.0 Task Force Follow-Up Procedures

8.1 Once a Planning Coordinator has presented its Review report to the TFSS, TFSS will review the Planning Coordinator’s report and any supporting documentation and:

a. Consider whether to accept the report as complete and in full conformance with these Guidelines. If the report is found to be unacceptable, TFSS will indicate to the Planning Coordinator the specific areas of deficiency, and request the Planning Coordinator to address those deficiencies.

b. Consider their concurrence with the results and conclusion(s) of the Planning Coordinator’s Review. If there is not concurrence, TFSS will indicate to the Planning Coordinator the specific areas of disagreement, and work with the Planning Coordinator to try to achieve concurrence. If agreement has not been reached within a reasonable period of time, TFSS shall prepare a summary of the results of its review, including a discussion of the Planning Coordinators of disagreement.

8.2 If the results of the Area Review indicates that the Planning Coordinator’s planned bulk power transmission system is not in conformance with NPCC Directory #1, TFSS will request the Planning Coordinator to develop a plan to achieve conformance with the Criteria.

8.3 If the Area Review indicates an overall bulk power system reliability concern (not specific to the Planning Coordinator’s planned bulk power transmission system), TFSS will consider what additional studies may be necessary to address the concern, and prepare a summary discussion and recommendation to the Task Force on Coordination of Planning.

8.4 Upon completion of an Area Review, TFSS will report the results of the review to the Task Force on Coordination of Planning and to the Reliability Coordinating Committee.
Appendix C - Procedure for Testing and Analysis of Extreme Contingencies

1.0 Introduction

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

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

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

2.0 Choosing Contingencies for Testing

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

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

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

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

4.0 Evaluating Individual Test Results

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

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

9. **Relay** operations or the proximity of apparent impedance trajectories to **relay** trip characteristics,

10. The angle across opened breakers,

11. Adequacy of computer simulation models and data.

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

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

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

5.0 Evaluating the Results of a Program of EC Testing

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

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

NPCC follow-up, after publication of a final report, is appropriate only for instances
of possible general system weakness. In these instances, the results should be specifically referred to the affected Planning Coordinator or Planning Coordinators for further and more detailed investigation with subsequent reporting to NPCC.
Appendix D - Guidelines for Area Review of Resource Adequacy

1.0 Introduction

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

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

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

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

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

2.0 Purpose of Presentation

The purpose of the presentation associated with a resource adequacy review is to show that each Planning Coordinator's proposed resources are in accordance with the NPCC Directory #1 - Design and Operation of the Bulk Power System. By such a presentation, the Task Force will satisfy itself that the proposed resources of each NPCC Planning Coordinator will meet the NPCC Resource Adequacy -
Design Criteria, as defined NPCC Directory #1, over the time period under consideration. The review by the Task Force on Coordination of Planning does not replace Planning Coordinator and/or company responsibility to assess their systems in conformity with the NPCC Basic Criteria in Directory #1.

3.0 Time Period to be Considered

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

4.0 Format of Presentation and Report – Comprehensive Review

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

4.1 Executive Summary

4.1.1 Briefly illustrate the major findings of the review.

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

4.2 Table of Contents

4.2.1 Include listing of all tables and figures.

4.3 Introduction

4.3.1 Reference the previous NPCC Area Review.

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

4.4 Resource Adequacy Criterion
4.4.1 State the Planning Coordinator’s resource adequacy criterion.

4.4.2 State how the Planning Coordinator criterion is applied; e.g., load relief steps.

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

4.4.4 If the Planning Coordinator criterion is different from the NPCC criterion, provide either an estimate of the resources required to meet the NPCC criteria or a statement as to the comparison of the two criteria.

4.4.5 Discuss resource adequacy studies conducted since the previous Area Review, as appropriate.

4.5 Resource Adequacy Assessment

4.5.1 Evaluate proposed resources versus the requirement to reliably meet projected electricity demand assuming the Planning Coordinator's most likely load forecast.

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

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

4.5.4 Review the impacts that major proposed changes to market rules may have on Planning Coordinator Area reliability.

4.6 Proposed Resource Capacity Mix

4.6.1 Discuss any reliability impacts resulting from the proposed resources fuel supply and transportation or environmental considerations.

4.6.2 Describe available mechanisms to mitigate any potential reliability impacts of resource fuel supply, demand resource response, transportation issues and/or environmental considerations.
4.6.3 Discuss any reliability impacts related to an Area’s compliance with state, Federal or Provincial requirements (such as environmental, renewable energy, or greenhouse gas reductions).

5.0 Format of Presentation and Report – Annual Interim Review

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

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

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

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

A. Description of Resource Reliability Model

1.1 Load Model

1.1.1 Description of the load model and basis of period load shapes.

1.1.2 How load forecast uncertainty is handled in model.

1.1.3 How the electricity demand and energy projections of interconnected entities within the Planning Coordinator Area that are not members of the Planning Coordinator Area are addressed.
1.1.4 How the effects (demand and energy) of demand-side management programs (e.g., conversion, interruptible demand, direct control load management, demand (load) response programs) are addressed.

1.2 Supply Side Resource Representation

1.2.1 Resource Ratings

1.2.1.1 Definitions.


1.2.2 Unavailability Factors Represented

1.2.2.1 Type of unavailability factors represented; e.g., forced outages, planned outages, partial derating, etc.

1.2.2.2 Source of each type of factor represented and whether generic or individual unit history provides basis for existing and new units.

1.2.2.3 Maturity considerations, including any possible allowance for in-service date uncertainty.

1.2.2.4 Tabulation of typical unavailability factors.

1.2.3 Purchase and Sale Representation.

1.2.3.1 Describe characteristics and level of dependability of transactions.

1.2.4 Retirements.

1.2.4.1 Summarize proposed retirements.

1.3 Representation of Interconnected System in Multi-Area Reliability Analysis, including which Planning Coordinator Areas and regions are considered, interconnection capacities assumed, and how expansion plans of other Planning Coordinators and regions are considered.
1.4 Modeling of Variable and Limited Energy Sources.

1.5 Modeling of Demand Side Resources and Demand (Load) Response Programs.

1.5.1 Description should include how such factors as in-service date uncertainty, rating, availability, performance and duration are addressed.

1.6 Modeling of all Resources.

1.6.1 Description should include how such factors as in-service date uncertainty; capacity value, availability, emergency assistance, scheduling and deliverability are addressed.

1.7 Other assumptions i.e., internal transmission limitations, maintenance over-runs, fuel supply and transportation and environmental constraints.

1.8 Incorporate the reliability impacts of market rules.

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

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

C. Task Force Follow-Up Procedures

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

1. Prepare a brief summary of key issues discussed during the presentation.

2. Note where further information was requested and the results of such further interrogations.

3. Note the specific items that require additional study and indicate the responsibilities for undertaking these studies.
4. Recommend approval to the Reliability Coordinating Committee.
Appendix E - Guidelines for Requesting Exclusions to Sections 5.4.1 (B) and 5.5.1 (B) of NPCC Directory #1 – Design and Operation of the Bulk Power System

1.0 Introduction

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

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

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

2.0 Documentation

The documentation supporting a request for exclusion to Sections 5.4.1(b) and 5.5.1(b) of the Basic Criteria must include the following:

2.1 A description of the facilities involved, including geographic location, length and type of construction, and electrical connections to the rest of the interconnected power system;

2.2 Relevant design information pertinent to the assessment of acceptable risk, which might include: details of the construction of the facilities, geographic or
atmospheric conditions, or any other factors that influence the risk of sustaining a multi-circuit contingency;

2.3 An assessment of the consequences of the occurrence of a multi-circuit contingency, including, but not limited to, a discussion of levels of exposure and probability of occurrence of significant adverse impact outside the local area;

2.4 For existing facilities, the historical outage performance, including cause, for multi-circuit contingencies on the specific facility (facilities) involved as compared to that of other multi-circuit tower facilities;

2.5 For planned facilities, the estimated frequency of multi-circuit contingencies based on the historical performance of facilities of similar construction located in an area with similar geographic climate and topography.

3.0 Procedure for obtaining an Exclusion

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

3.1 The entity requesting the exclusion (the Requestor) shall submit the request and supporting documentation to the Task Force on System Studies (TFSS) after acceptance has been granted by the Requestor’s own Planning Coordinator, if such process is applicable.

3.2 TFSS shall review the request, verify that the documentation requirements have been met, and determine the acceptability of the request.

3.3 If TFSS deems the request acceptable, TFSS shall request the Task Force on Coordination of Planning (TFCP), the Task Force on Coordination of Operation (TFCO), and the Task Force on System Protection (TFSP) to review the request. The Requestor shall provide copies of the request and supporting documentation to the other Task Forces as directed by TFSS. If additional information is requested by the other Task Forces as part of their assessment, the Requestor will provide this information directly to the interested Task Force, with a copy to the TFSS. The other Task Forces shall review the request and indicate their acceptance or non-acceptance to TFSS.

3.4 If any of the four Task Forces determines the request is not acceptable, TFSS will respond to the Requestor with the determination and inform the RCC and the other Task Forces of the decision.

3.5 TFSS shall notify TFCP, TFCO, and TFSP of an exclusion that has been accepted by the Task Forces and the basis for the exclusion. The TFSS will then make a recommendation to the RCC regarding the exclusion.
3.6 The NPCC Policy for Alternative Dispute Resolution is available for use if the decision is unacceptable to the Requestor.

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

4.0 Periodic Review of Exclusions of Record

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

1.0 Introduction

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

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

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

2.0 Load/Capacity Forecasts

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

The results will be reviewed by the NPCC Task Force on Coordination of Operation (TFCO) and the NPCC Reliability Coordinating Committee (RCC) in advance of the spring and autumn meetings of both groups.
2.2 Each week, each RC Area will review its weekly net resource capacity margin, as defined in Attachment A, for the twelve weeks to follow and forward the information to the NPCC Staff for distribution to all NPCC RC Areas. If an NPCC RC Area identifies a deficiency or light load condition, the RC Area should identify the cause(s) and mitigation measures that have been implemented, or will be implemented, to manage the issue.

3.0 Generator Outage Coordination

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

4.0 Transmission Outage Coordination

4.1 Advance Planning of Transmission Facility Outages

NPCC Document Directory#1, *Basic Criteria for Design and Operation of Interconnected Power Systems*, requires that scheduled outages of transmission facilities that affect **reliability** between RC Areas be coordinated sufficiently in advance of the outage to permit the affected RC Area to maintain **reliability**. For the purposes of this procedure, each RC should exchange critical transmission outages as identified in coordination agreements with their interconnected neighbors and jointly develop and maintain a Facilities Notification List.

4.2 Facilities Notification List

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

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

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

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

The Task Force on System Protection develops yearly the list of NPCC Type 1 **special protection systems** with input from the Task Force on System Studies.
It should be noted that revisions to the Facilities Notification List only will not follow the NPCC Process for Open Review due to the secure nature of the information contained, and Attachment D is not openly published with this Procedure.

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

4.3 Notifications of Work

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

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

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

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

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

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

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

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

5.0 **Data Providers**

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

6.0 **Specific Communications**

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

6.1 **Weekly**

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

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

The NPCC Staff will prepare Conference Call Notes that will be forwarded to the conference call participants and members of the TFCO by the following Friday afternoon.
If a deficiency or light load condition, or if adverse system operating conditions are expected within the next week, any RC Area may recommend that an Emergency Preparedness Conference Call (NPCC Document C-01) take place at an appropriate time.

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

6.2 Emergency Preparedness Conference Call

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

6.3 Daily Conference Calls

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

Load and Capacity Table Instructions

and

Generating Capacity Worksheet Instructions

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

<table>
<thead>
<tr>
<th>Description</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Known Unavailable Capability (Line Item 8)</strong></td>
<td>Include all known outages, as well as those deratings or unit outages presently forced out, unavailable, on extended cold standby or which are anticipated to remain out of service. This would also include capacity unavailable due to transmission constraints.</td>
</tr>
<tr>
<td><strong>Net Reserve (Line Item 9)</strong></td>
<td>Available Reserve plus Demand Side Management minus Known Unavailable Capacity. (Line 6+Line 7-Line 8)</td>
</tr>
<tr>
<td><strong>Required Operating Reserve (Line Item 10)</strong></td>
<td>The methodology used by each RC Area in calculating operating reserve must, as a minimum, meet the requirements of NPCC Document A-06, “Operating Reserve Criteria.” Methodologies differing from the A-06 requirements should be clarified in Attachment B, “NPCC Weekly Conference Call Generating Capacity Worksheet,” under the tab for “Operating Reserve.”</td>
</tr>
<tr>
<td><strong>Gross Margin (Line Item 11)</strong></td>
<td>Subtract Required Operating Reserve from Net Reserve. (Line 9-Line 10)</td>
</tr>
<tr>
<td><strong>Unplanned Outages (Line Item 12)</strong></td>
<td>Estimate the amount of generating capacity which will be unavailable. This quantity should be based on historical averages for forced outages and deratings.</td>
</tr>
<tr>
<td><strong>Net Resource Capacity Margin (Line Item 13)</strong></td>
<td>Subtract Unplanned Outages from Gross Margin. A positive value reflects surplus reserve. A negative value reflects a deficiency. (Line 11-Line 12)</td>
</tr>
<tr>
<td><strong>Forecast High / Low Temperatures and Days (Line Item 14)</strong></td>
<td>Include the expected high and low temperatures for the RC Area for the week, and indicate the day on which they are expected to occur.</td>
</tr>
<tr>
<td>Attachment A (continued)</td>
<td></td>
</tr>
<tr>
<td>--------------------------</td>
<td></td>
</tr>
<tr>
<td><strong>Seasonal High / Low Temperatures (Line Item 15)</strong></td>
<td>Include the expected high and low forecast seasonal temperatures for the RC Area.</td>
</tr>
<tr>
<td><strong>Minimum Load Forecast (Line Item 16)</strong></td>
<td>The minimum load forecast should be the best estimate of the RC Area’s minimum load exposure anticipated for the week reported.</td>
</tr>
<tr>
<td><strong>Minimum Resources (Line Item 17)</strong></td>
<td>The Minimum Resources are the Reliability Coordinator Area’s total expected on-line generator minimum output capability and must-take purchases.</td>
</tr>
<tr>
<td><strong>Light Load Margin (Line Item 18)</strong></td>
<td>Subtract Minimum Resources from Minimum Load Forecast. A negative number indicates a light load condition. (Line 16-Line 17)</td>
</tr>
</tbody>
</table>
Procedure for Operational Planning Coordination – Attachment B

NPCC Weekly Conference Call Generating Capacity Worksheet

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

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

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

NPCC Facilities Notification List

Attachment D is not publicly available due to the confidential nature of the information presented.
Appendix G - Procedures for Inter Reliability Coordinator Area Voltage Control

1.0 Introduction

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

2.0 Principles

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

2.1 To effectively coordinate voltage control, location and placement of metering for reactive power resources and voltage controller status should be consistent between adjacent Transmission Operators.

2.2 the availability of voltage regulating transformers in the proximity of tie lines;

2.3 voltage levels, limits, and regulation requirements for stations on either side of an inter-Transmission Operator Area interface;

2.4 the circulation of reactive power (export at one tie point in exchange for import at another);

2.5 tie line reactive losses as a function of real power transfer;

2.6 reactive reserve of on-line generators;

2.7 shunt reactive device availability and switching strategy; and

2.8 static VAR compensator availability, reactive reserve, and control strategy.
3.0 Procedure

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

3.1 Normal Voltage Conditions

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

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

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

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

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

This voltage profile, adjusted for changes in operating conditions, should be considered as the basis for determining which Transmission Operator should implement necessary measures to alleviate abnormal voltage conditions affecting more than one Transmission Operator as discussed in 3.2.10 below.
3.1.2 Each Transmission Operator should anticipate voltage trends and initiate corrective action in advance of critical periods of heavy and light loads.

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

4.1 On, or shortly before, the first of July, the TFCO Secretary will write to each TFCO member, requesting a written response by the end of July in the form of:

a) A copy of any new procedures and principles between the reporting Reliability Coordinator and adjacent Reliability Coordinators providing detailed application, or,

b) a copy of any new understanding, such as the minutes of an operating committee meeting between Reliability Coordinators, indicating that such detailed application is not required, and why;

c) a copy of any revisions to the procedures and principles, or understandings currently on file at NPCC, that exists between the reporting Reliability Coordinator and adjacent Reliability Coordinators;

d) a response indicating no change to existing procedures and principles, or understandings currently on file at NPCC.

4.2 The TFCO Secretary will draft a report summarizing the extent to which responses indicated conformance with the NPCC Procedures, and will forward it to TFCO members at least two weeks prior to the October TFCO meeting.

4.3 Following TFCO review and adoption, the TFCO Chairman will forward the report to the Chairman of the Reliability Coordinating Committee (RCC) recommending acceptance or other action as deemed appropriate. This will normally be forwarded three weeks prior to the next regularly scheduled RCC meeting.