Annexe E

Documents de référence fournis

[4] NPCC, Directory 4 « Bulk Power System Protection Criteria »

[5] NPCC, Directory 3 « Maintenance Criteria for Bulk Power System Protection »

[6] NPCC, Directory 1 « Design and Operation of the Bulk Power System »

[7] NPCC, Directory 2 « Emergency Operations »

[8] NPCC, B-1 « Guide for Application of Autoreclosing to the Bulk Power System »

[9] NPCC, Directory 7 « Special Protection System »

[10] NPCC, C-29 « Procedures for System Modeling: Data Requirements & Facility Rating »

[11] Hydro-Québec, Système d'excitation statique pour les alternateurs (EX-STA-01-06)]

[12] Hydro-Québec, Stabilisateur multi-bandes de type delta-oméga (MB-PSS-01-02)

[14] Hydro-Québec, Spécifications d'exigences – Acquisition des données éoliennes

[19] NPCC, Directory 9 (Generator Gross/ Net Real Power Capability)

[20] NPCC, Directory 10 (Generator Gross/ Net Reactive Power Capability)

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

Task Force on System Protection Revision Review Record:
December 1, 2009

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

Revision History

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

Table of Content

1.0 Introduction

1.1 Title — Protection Criteria

1.2 Directory Number — 4

1.3 Objective

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

1.4 Effective Date — December 01, 2009

1.5 Background

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

1.6 Applicability

1.6.1 Functional Entities

Transmission Owners
Generator Owners

1.6.2 Facilities

1.6.2.1 New Facilities

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

1.6.2.2 Existing Facilities

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

1.6.2.2.1 Planned Renewal or Upgrade to Existing BPS Facilities

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

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

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

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

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

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

1.6.2.2.3 Additions to **Bulk Power System** Facilities

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

1.6.2.2.4 "In-Kind" Replacement of **Bulk Power System** Equipment

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

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

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

1.6.3 Responsibility

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

2.0 Terms Defined in this Directory

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

3.0 NERC ERO Reliability Standard Requirements

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

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

4.0 NPCC Regional Reliability Standard Requirements

None.

5.0 NPCC Full Member, More Stringent Criteria

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

5.1 General Criteria

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

5.2 Criteria for Dependability

5.2.1 Except as identified otherwise in these criteria, all elements of the **bulk power system** shall be protected by two protection **groups**, each of which is independently capable of performing the specified protective function for that **element.** This requirement also applies during energization of the **element.**

5.2.2 Except as identified otherwise in these criteria, the two **protection groups** shall not share the same component**.**

5.2.3 Means shall be provided to trip all necessary local and remote breakers in the event that a breaker fails to clear a fault. This **protection** need not be duplicated.

5.3 Criteria for Security

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

5.4 Criteria for Dependability and Security

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

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

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

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

5.5 Operating Time Criteria

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

5.6 Current Transformer Criteria

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

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

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

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

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

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

5.7 Voltage Transformer and Potential Devices Criteria

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

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

5.7.2 The two **protection groups** protecting an element shall be supplied from separate voltage sources. The two protection groups may be supplied from separate secondary windings on one transformer or potential device, provided all of the following requirements are met:

5.7.2.1 Complete loss of one or more phase voltages does not prevent all tripping of the protected **element**;

5.7.2.2 Each secondary winding has sufficient capacity to permit fuse **protection** of the circuit;

5.7.2.3 Each secondary winding circuit is adequately fuse protected.

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

5.8 Batteries and Direct Current (DC) Supply Criteria

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

5.8.1 No single battery or dc power supply failure shall prevent both independent **protection groups** from performing the intended function. Each battery shall be provided with its own charger. Physical separation shall be maintained between the two station batteries or dc power supplies used to supply the independent **protection groups**.

5.8.2 Each station battery shall have sufficient capacity to permit operation of the station, in the event of a loss of its battery charger or the ac supply source, for the period of time necessary to transfer the **load** to the other station battery or re-establish the supply source. Each station battery and its associated charger shall have sufficient capacity to supply the total dc **load** of the station.

5.8.3 A transfer arrangement shall be provided to permit connecting the total **load** to either station battery without creating areas where, prior to failure of either a station battery or a charger, a single event can disable both dc supplies.

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

5.8.5 Dc systems shall be continuously monitored or annunciated to detect abnormal voltage levels (both high and low), dc grounds, and loss of ac to the battery chargers, in order to allow prompt attention by the appropriate operating authorities.

5.8.6 **Protection group** dc sources shall be continuously monitored to detect loss of voltage in order to allow prompt attention by the appropriate operating authorities.

5.9 Station Service ac Supply Criteria

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

5.10 Circuit Breaker

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

5.11 Teleprotection Criteria

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

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

5.11.1.2 **Teleprotection** equipment shall be monitored to detect loss of equipment and/or channels to allow prompt attention by the appropriate operating authorities.

5.11.1.3 **Teleprotection** equipment shall be provided with means to test for proper signal adequacy.

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

5.11.1.5 Except as identified otherwise in these criteria, the two **teleprotection** groups shall not share the same component.

5.11.1.5.1 The use of a single communication tower for the radio communication systems used by two **protection groups** protecting a single **element** is permitted as long as directional diversity of the communication signals is achieved.

5.12 Environment

5.12.1 Each separate **protection group** and **teleprotection** protecting the same system **element** shall be on different non-adjacent vertical mounting assemblies or enclosures.

5.12.2 Wiring for separate **protection groups** and **teleprotections** protecting the same system **element** shall not be in the same cable.

5.12.3 Cabling for separate **protection groups** and **teleprotections** protecting the same system **element** shall be physically separated. This can be accomplished by being in different raceways, trays, trenches, etc.

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

5.13 Grounding Criteria

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

5.13.1 Can be traced to a recognized calculation methodology

5.13.2 Considers cable shielding

5.13.3 Considers equipment grounding

5.14 Transmission Line Protection Criteria

5.14.1 **Protection system** settings shall not constitute a loading limitation as per NERC requirement/standard. In cases where NERC approved exceptions are used the limits thus imposed shall be adhered to as system operating constraints.

5.14.2 A **pilot protection** shall be so designed that its failure or misoperation will not affect the operation of any other **pilot protection** on that same **element**.

5.15 Breaker Failure Protection Criteria

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

5.15.1 Breaker failure **protection** shall be initiated by each of the **protection groups** which trip the breaker, with the optional exception of a breaker failure **protection** in an adjacent zone.

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

5.16 Generating Station Protection Criteria

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

5.17 Automatic Under frequency Load Shedding Protection System Criteria

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

5.18 HVdc System Protection Criteria

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

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

5.19 Protection System Testing and Maintenance Criteria

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

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

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

5.20 Analysis of Protection Performance Requirements

5.20.1 **Bulk power system** automatic operations shall be analyzed to determine proper **protection system** performance. Corrective measures shall be taken promptly if a **protection group** fails to operate or operates incorrectly.

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

5.20.3 Internal clocks in event and **fault** recording equipment shall be time synchronized to within 2 milliseconds or less of Universal Coordinated Time scale. The time zone shall be clearly identified as either universal time zone or local time zone.

5.20.4 Each **protective relay** which trips **Bulk Power System** equipment shall provide separate target indication.

6.0 Measures and Assessments

None developed at this time.

7.0 Compliance Monitoring

7.1 Each member shall provide the Task Force on System Protection (TFSP) with advance notification of any of the member's new **bulk power system protection systems**, or significant changes in the member's existing **bulk power system protection systems**.

7.2 Each member shall also provide the TFSP with advance notification of non-member **protection** facilities as required per *NPCC Bylaws*.

7.3 Each new or revised **protection system** shall be reported to the TFSP. It is recommended this reporting be in accordance with the procedure detailed in Section 4.0 of Appendix A of this Directory, or in a form consistent with the intent of the procedure.

7.4 Adherence to these Criteria shall be reported by the responsible entity in a manner and form designated by the Compliance Committee.

Prepared by: Task Force on System Protection

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

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

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

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

Appendix A
Guideline and Procedure for Bulk Power System Protection

1.0 Introduction

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

2.0 Design Considerations

2.1 General Considerations

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

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

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

2.2 Issues Affecting Dependability

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

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

2.2.3 In addition to the separation requirements in the criteria, areas of common exposure should be kept to a minimum to reduce the

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possibility of both **protection groups** being disabled by a single event such as fire, excavation, water leakage, and other such incidents.

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

2.3 Issues Affecting Security

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

2.3.2 For planned system conditions, **protection systems** should not operate to trip for stable power swings.

2.4 Issues Affecting Dependability and Security

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

2.4.2 The components and software used in **protection systems** should be of proven quality, as demonstrated either by actual experience or by stringent tests under simulated operating conditions.

2.4.3 **Protection systems** should be designed to minimize the possibility of component failure or malfunction due to electrical transients and interference or external effects such as vibration, shock and temperature.

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

2.4.5 **Protection system** automatic self-checking facilities should be

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designed so as to not degrade the performance of the **protection system**.

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

2.4.7 **Protection systems**, including intelligent electronic devices (IEDs) and communication systems used for **protection**, should comply with applicable industry standards for utility grade **protection** service. Utility Grade **Protection System** Equipment are equipment that are suitable for protecting transmission power system elements, that are required to operate reliably, under harsh environments normally found at substations. Utility grade equipment should meet the applicable sections of all or some of the following types of industry standards, to ensure their suitability for such applications:

- IEEE C37.90.1-2002 (oscillatory surge and fast transient)
- IEEE C37.90.1-2002 (service conditions)
- IEC 60255-22-1, 2005 (1 MHz burst, i.e. oscillatory)
- IEC 61000-4-12, 2001 (oscillatory surge)
- IEC 61000-4-4, 2004 (EFT)
- IEC 60255-22-4, 2002 (EFT)
- IEEE C37.90.2-2004 (narrow-band radiation)
- IEC 60255-22-3, 2000 (narrow-band radiation)
- IEC 61000-4-3, 2002 (narrow-band radiation)
- IEEE 1613 (communications networking devices in Electric power Substations)

2.5 Operating Time

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

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

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2.6 Current Transformer

None.

2.7 Voltage Transformers and Potential Devices

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

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

2.8 Batteries and Direct Current (dc) Supply

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

2.8.2 The design for the regulation of the dc voltage should be such that, under all anticipated charging and loading conditions, voltage within acceptable limits will be supplied to all devices, while minimizing ac ripple and voltage transients.

2.9 Station Service ac Supply

None.

2.10 Circuit Breakers

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

2.11 Teleprotection

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

2.11.2 Two identical **teleprotection** equipments should not be used in independent **protection groups**, due to the risk of simultaneous failure of both groups because of design deficiencies or equipment problems.

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2.11.3 Areas of common exposure should be kept to a minimum to reduce the possibility of both groups being disabled by a single event such as fire, excavation, water leakage, and other such incidents.

2.11.4 **Teleprotection** systems should be designed to mitigate the effects of signal interference from other communication sources and to assure adequate signal transmission during **bulk power system disturbances**.

2.12 Environment

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

2.13 Grounding

None.

2.14 Transmission Lines Protection

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

2.15 Breaker Failure Protection

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

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

2.16 Generating Station Protection

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

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

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

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

2.16.2.2 When a directional over current or distance **relay** is applied to remove the generator for slowly cleared **faults** on the external system, such **protection** is a backup and need not be duplicated.

2.16.2.3 The apparatus should be protected when the generator is starting up or shutting down as well as running at normal speed; this may require additional **relays** as the normal **relays** may not function satisfactorily at low frequencies.

2.16.2.4 Generator **protection systems** should not operate for stable **power swings** except when that particular generator is out of step with the remainder of the system. This does not apply to **Special Protection Systems** designed to trip the generator as part of an overall plan to maintain **stability** of the power system.

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

2.16.2.6 It is recognized that the overall **protection** of a generator involves non-electrical considerations that have not been included as a part of the criteria in this Directory.

2.16.2.7 All over frequency, overvoltage and under voltage **protection systems** designed to disconnect generators from the power system should be coordinated with automatic under frequency **load shedding** programs.

2.17 Automatic Under frequency Load Shedding Protection Systems

2.17.1 Automatic under frequency **load shedding protection systems** are not generally located at **bulk power system** stations; however, they have a direct effect on the operation of the **bulk power system** during major **emergencies**.

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2.17.2 Automatic under frequency **load shedding protection** need not be duplicated.

2.17.3 Under frequency **relays** which operate at a discrete frequency value are called "under frequency threshold **relays**." Selection of under frequency sensing devices should be on a threshold basis. Alternatively, rate of change of frequency **load shedding** may be used when the requirements of the Balancing Authority indicate that this method will achieve the intent of the **load shedding** program. Appropriate studies are necessary to determine the application and settings of the rate of change of frequency **relays** for a particular Balancing Authority area.

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

2.17.5 Additional Application Considerations

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

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

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

2.17.5.4 Due regard should be given to the expected power system voltage during events for which the underfrequency **relays**

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are expected to operate. The **relay's** minimum AC voltage operating characteristic should not inhibit proper **relay** operation, nor should the Voltage Inhibit feature, where it exists, be set to prevent proper operation.

2.17.6 Settings and Maintenance Recommendations

2.17.6.1 Pickup Time Delay Settings

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

2.17.6.2 Relay Performance Considerations

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

2.17.6.3 Maintenance

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

2.18 HVdc Systems Protection

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

- ac and dc undervoltage,
- ac and dc overvoltage,

Appendix A

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

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

2.19 Protection System Testing and Maintenance

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

2.20 Analysis of Protection System

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

2.21 Transmission Station Protection

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

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

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

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

2.22 Capacitor Banks

Appendix A

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

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

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

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

2.23 Static Var Compensation (SVC) Protection

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

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

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

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

2.24 Logic System

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

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

Appendix A

accounted for in the overall design.

2.25 Microprocessor-Based Equipment and Software

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

2.26 Control Cable, Wiring and Ancillary Control Devices

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

2.27 Environment

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

3.0 Guideline for Application of Remote Access to Protection System

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

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

3.1 Definitions for Use in this Guideline Only

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

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

Appendix A

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

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

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

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

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

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

3.2 Governing Principles

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

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

Appendix A

3.3 Guideline

3.3.1 Authentication

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

3.3.1.1 Something the user knows, such as passwords, or IP addresses.

3.3.1.2 Something the user has, such as a key, or cryptographic token.

3.3.1.3 Something the user is, such as fingerprints and voiceprints

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

3.3.2 Substation IED Access Point

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

3.3.3 Approved Remote Access Authorization List

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

Appendix A

3.3.4 Remote Access Configuration

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

3.3.5 Password

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

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

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

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

3.3.6 Logging/Alarming

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

3.3.7 Controlling Authority Approval

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

Appendix A

3.3.8 Disable User Function

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

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

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

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

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

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

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

Appendix A

3.4.5 Isolation from the Business/Corporate Network

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

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

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

4.1 Additional Requirements for Presentation and Review

4.1.1 A presentation will be made to the TFSP on new facilities or a modification to an existing facility when requested by either a member entity or the TFSP.

4.1.2 A presentation will be made to the TFSP when the design of the **protection** facility deviates from the criteria set forth in this Directory.

4.1.3 A presentation will be made to the TFSP when a member entity is in doubt as to whether a design meets the **protection** criteria set forth in this Directory.

4.2 Data Required for Presentation and Review of Proposed Protection Facilities

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

Appendix A

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

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

4.3 Procedure for Presentation

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

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

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

4.4 TFSP Procedures

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

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

Appendix A

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

4.4.1.3 Acceptance of the submitted proposal

4.4.1.4 Conditional acceptance of the submitted proposal*.

4.4.1.5 Rejection of the submitted proposal*.

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

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

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

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

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

Protection System Review Form (Formerly C-22 Forms)
(Directory 4, Appendix A)
December 2, 2009

Terminal Station	Station Name	Member System
Station #1		
Station #2		
Station #3		

1 Instructions

1.1 The intent of these forms is to provide the user with a simplified means of providing adequate information to the Task Force on System Protection to facilitate reviews. This does not imply that these forms will necessarily give a complete or comprehensive picture of the protection system and the user should feel free to modify or change the data to provide what is believed to be necessary information to describe the particular situation.

1.2 The following diagrams shall be provided for review by the Task Force on System Protection.

1.2.1 Geographical map showing the electrical systems involved.

1.2.2 Associated relay Protection system one-line diagrams.

1.2.3 Associated protection and control function diagrams.

1.2.4 A physical layout of protection panels and batteries for the purpose of illustrating physical separation will also be included, unless prohibited by NERC CIP Standards. If prohibited by NERC CIP Standards, a statement shall be made in the cover letter confirming that physical separation as per D4 requirement is maintained.

1.3 For any systems not meeting the criteria portion of Directory 4[1], an exception request is to be outlined in section 15.

[1] Formerly Criteria Document A-05

2 System Element being reported on.

All elements with identical protections can be reported using the same form, please enter element designations below.

Element Type	Element Designations

Communication Equipment utilized by Protection (Yes or No)?	

3 Transmission Line Protection

3.1 Voltage Level

	kV

3.2 Line Protection – Phase

Protection Group 1 Designation:				
Station		Protection Scheme	Model	MFR
1				
2				
3				

Protection Group 2 Designation:				
Station		Protection Description	Model	MFR
1				
2				
3				

3.3 Line Protection – Ground

Protection Group 1 Designation:				
Station		Protection Description	Model	MFR
1				
2				
3				

Protection Group 2 Designation:				
Station		Protection Description	Model	MFR
1				
2				
3				

3.4 Line Protection – Reclosing

Station	Reclosing

4 Transformer Protection

4.1 Station Designation

4.2 Voltage Level

kV

4.3 Unit Designation

4.4 Transformer Protection

	PROTECTION GROUP:			PROTECTION GROUP:	
PROTECTION	TYPE	MFR.		TYPE	MFR.
Differential					
Gas (Pressure)					
Sudden Pressure					

5 Generator Protection

5.1 *Station Designation*

5.2 *Voltage Level*

kV

5.3 *Unit Designation*

5.4 *Generator Protection*

PROTECTION	PROTECTION GROUP:			PROTECTION GROUP:	
	TYPE	MFR.		TYPE	MFR.
Differential					
Loss of field					
Neg. phase sequence					
Anti-motoring					
Overexcitation					
Out-of-step					
Underfrequency					
Overfrequency					
Over/Under Voltage					
Field ground					
Other					

6 Bus Protection

6.1 Station Designation

6.2 Voltage Level

kV

6.3 Bus Designation

6.4 Bus Protection

	PROTECTION GROUP:			PROTECTION GROUP:	
PROTECTION	TYPE	MFR.		TYPE	MFR.
Differential					
Other					

7 Shunt Capacitors and Filter Protection

7.1 Station Designation

7.2 Voltage Level

kV

7.3 Designation

7.4 Protection

	PROTECTION GROUP:			PROTECTION GROUP:	
PROTECTION	TYPE	MFR.		TYPE	MFR.

8 HVDC Protection

8.1 Voltage Level (AC)

kV

8.2 Station Designation

8.3 Number of Poles

8.4 HVDC Protection

PROTECTION	PROTECTION GROUP:			PROTECTION GROUP:	
	TYPE	MFR.		TYPE	MFR.
Commutation Failure					
DC Power Reversal					
DC Fault					
Other					

9 Special Protection System (SPS)

9.1 Functional Description

Function	
Generator Rejection (GR)	
Transmission Cross Tripping (TCT)	
Load Rejection (LR)	
Other (O)	

9.2 Designation

9.3 Classification (Type I or II)

9.4 Initiating Conditions

9.5 Action(s) Resulting

9.6 Reason for Installation

9.7 How is Redundancy Achieved

9.8 Arming Method

Description:

9.9 If provisions for breaker failure are required, please describe how this is accomplished.

10 Other Protections

10.1 Description

11 Communication Link

PROTECTION FUNCTION	PROTECTION GROUP		PROTECTION GROUP		ROUTE DIVERSITY (YES/NO)
	ROUTE DESIGNATION (i.e. Path 1)	COMM. MEDIUM (Type)	ROUTE DESIGNATION (i.e. Path 2)	COMM. MEDIUM (Type)	

ADDITIONAL INFORMATION:

12 Equipment Detail

12.1 Current Transformer Type

	Station	Current Transformer Type
1		
2		
3		

12.2 Voltage Transformer Type

	Station	Voltage Transformer Type
1		
2		
3		

12.3 Station Battery

	Station	Transfer Capability (Yes or No)	# of Battery Banks
1			
2			
3			

12.4 Physical Separation (Yes/No)

	Station	Relay Systems	Wiring	Battery Banks	Telecom Equipment
1					
2					

3					

12.5 Breakers

12.5.1 Breaker Type

	Station	Breaker Type
1		
2		
3		

12.5.2 Operation (Single Phase or Three Phase)

	Station and Breaker Designation	Breaker Operation
1		
2		
3		

12.5.3 Trip coils

	Station and Breaker Designation	Number of Trip Coils
1		
2		
3		

12.5.4 Protection

	Station and Breaker Designation	Ground Fault CTs	Breaker Failure
1			
2			
3			

13 Disturbance Monitoring Equipment (DME)

Station		Sequence of Events Recording Capability (SER)		Dynamic Disturbance Recording Capability (DDR)		Digital Fault Recording Capability (DFR)	
1		Designated Recorder		Designated Recorder		Designated Recorder	
		Functional Capability in lieu of Designated Recorder		Functional Capability in lieu of Designated Recorder		Functional Capability in lieu of Designated Recorder	
		Time Synchronized		Time Synchronized		Time Synchronized	
2		Designated Recorder		Designated Recorder		Designated Recorder	
		Functional Capability in lieu of Designated Recorder		Functional Capability in lieu of Designated Recorder		Functional Capability in lieu of Designated Recorder	
		Time Synchronized		Time Synchronized		Time Synchronized	
3		Designated Recorder		Designated Recorder		Designated Recorder	
		Functional Capability in lieu of Designated Recorder		Functional Capability in lieu of Designated Recorder		Functional Capability in lieu of Designated Recorder	
		Time Synchronized		Time Synchronized		Time Synchronized	

NOTES:

14 Protection System Settings

Does the following statement accurately describe the settings applied to the protection system being submitted?

"Protection system settings shall not constitute a loading limitation as per NERC requirements/standard. In cases where NERC approved exceptions are used the limits thus imposed shall be adhered to as system operating constraints"

Response (Yes or No)	

15 Exception Request

Station	Element	Relevant Section in D4
Assessment Summary		
Station	Element	Relevant Section in D4
Assessment Summary		
Station	Element	Relevant Section in D4
Assessment Summary		

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

Task Force on System Protection Revision Review Record:
July 11, 2008
June 30, 2009

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

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	7/11/08		New
1	6/30/09	Revised Section 5.5, Sect 5.6, and Sect 5.7.	Revisions

Table of Content

1.0 Introduction

1.1 Title — Maintenance Criteria for BPS Protection

1.2 Directory Number — 3

1.3 Objective

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

1.4 Effective Date — July 11, 2008

1.5 Background

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

1.6 Applicability

1.6.1 Functional Entities[1]

Transmission Owners
Generator Owners
Distribution Providers

1.6.2 Facilities

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

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

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

2.0 Terms Defined in this Directory

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

3.0 NERC Reliability Standard Requirements

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

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

4.0 NPCC Regional Reliability Standard Requirements

None developed at this time.

5.0 NPCC Full Member, More Stringent Requirements

5.1 General Criteria

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

5.2 **Protection** Assembly Testing Requirements

Refer to Figure 1, equipment marked as [1]

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

5.2.1 Make visual inspections,

5.2.2 Verify inputs and outputs,

5.2.3 Confirm that the intended version of software is installed (microprocessor-based **relays**),

5.2.4 Verify correct **protection** operation,

5.2.5 Verify the integrity of current and voltage transformers and associated circuitry. This verifies that the correct secondary quantities are input to the **relay**. For microprocessor **relays**, verify the internal analog inputs with an independent source.

TABLE 1
INTERVALS FOR PROTECTION ASSEMBLY TESTING

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

Notes:

(1) Non-Self Monitored **protection** assemblies include electromechanical **relays** and solid state **relays**.

(2) Microprocessor-based **protection** assemblies where the principal fault-sensing and logic components include self monitoring or self checking, and the failure alarm is annunciated to a 24/7 staffed Operations Center that can initiate an investigation of the problem.

(3) Microprocessor-based **protection** assemblies as per Note (2), plus additional self monitoring or self checking of ac voltage and current input integrity, and the failure alarm is annunciated to a 24/7 staffed Operations Center that can initiate an investigation of the problem.

5.3 **Protection Group** DC Circuits Testing Requirements

Refer to Figure 1, equipment marked as [2]

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

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

TABLE 2
INTERVALS FOR DC CIRCUIT TEST TRIPPING

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

Note (1): Trip coil and DC circuit continuity is annunciated upon loss of continuity to a 24/7 staffed Operations Center that can initiate an investigation of the problem**.**

5.4 Battery Banks and Chargers Testing Requirements

Refer to Figure 1, equipment marked as [5]

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

TABLE 3
INTERVALS FOR BATTERY BANKS AND CHARGER TESTING

	Non-Monitored	Monitored Note (1)
Battery Bank Voltage	One month	None

Note (1): Battery Bank Voltage alarms are annunciated to a 24/7 staffed Operations Center that can initiate an investigation of the problem**.**

5.5 Breaker Trip Testing Requirements

Refer to Figure 1, equipment marked as [4]

The ability of the breaker(s) to trip via each trip coil shall be verified every two years with the following exception. Nuclear plant **bulk power system** unit breaker trip tests shall be completed at an interval not to exceed three years.

5.6 Telecommunication Testing Requirements

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

5.6.1 Terminal Equipment

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

5.6.2 Channel Health

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

For trip equipment which uses frequency shift keying (FSK) mode of communication and the channel (for example, Guard Signal) is continuously monitored, the ability to perform its intended trip function shall be verified every twelve months. Failure of the channel shall be annunciated to a 24/7 staffed Operations Center that can initiate an investigation of the problem.

For telecommunication system channels that are continuously monitored and continuously provide verification of trip capability to an Operator, no additional testing is necessary. Failure of the channel or of the trip capability shall be annunciated to a 24/7 staffed Operations Center that can initiate an investigation of the problem.

5.7 Underfrequency Load Shedding and Generator Underfrequency Relay Testing Requirements

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

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

6.0 Measures and Assessments

None developed at this time.

7.0 Compliance Monitoring

Adherence to requirements in this Directory must be reported in a manner and form designated by the Compliance Committee. Exceptions to the requirements stipulated herein are acceptable if the exceptions are completely removed within five (5) months of the end of the calendar year in which the testing is due. The intervals specified in this document refer to calendar year in which testing is due regardless of the date.

Prepared by: Task Force on System Protection

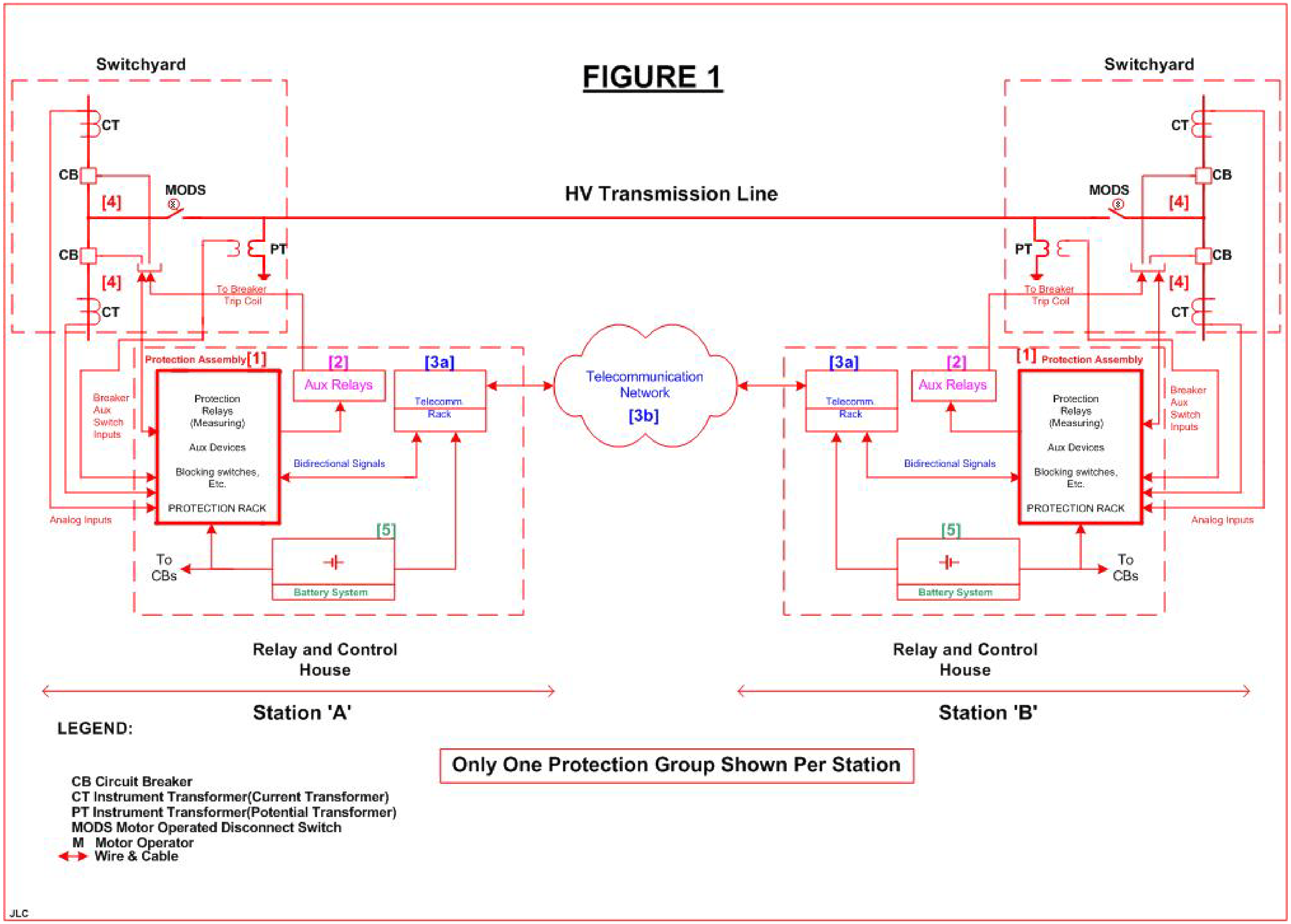
Review and Approval: Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their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

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

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

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

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



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

Appendix A
Definition of Terms

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

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

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

NPCC Specific Definitions:

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

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

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

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

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

Notes:

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

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

Protection system

Element Basis

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

Terminal Basis

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

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

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

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

Appendix B
Guideline and Procedure for Maintenance of Bulk Power System Protection

1.0 Introduction

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

2.0 General

2.1 Generator Under-frequency Tripping

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

2.2 Circuit Breaker Trip Testing

Credit can be obtained for normal breaker operations if the equipment design permits verification and documentation of breaker tripping by each individual trip coil.

3.0 Microprocessor-based Protective Relays

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

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

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

3.1 Testing of Microprocessor-Based Relays

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

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

3.2 Analog Input Section

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

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

3.3 Digital Input and Output Sections

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

3.3.1 Inputs

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

3.3.2 Outputs

Outputs of the IED should be verified either by:

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

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

3.4 Processor Section

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

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

3.5 Power Supply Section

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

3.6 Integrity Testing

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

3.7 Multi-Processor Based IEDs

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

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

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

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

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0			New
1	4/20/2012	Errata changes in Appendix B and Appendix E.	Errata

Table of Contents

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,

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.

S**pecial 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**.

<u>NPCC Specific Definitions:</u>

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

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

Power

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

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

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

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

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

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

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

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

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

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

Reclosing

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

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

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

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

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

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

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

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

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

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

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

NPCC Specific Definitions:

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

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

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

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

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

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

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

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

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

b. unacceptable system dynamic response:

- an oscillatory response to a contingency that is not demonstrated to be clearly positively damped within 30 seconds of the initiating event.

c. unacceptable equipment tripping:

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

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

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

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

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

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

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

Appendix B - Guidelines and Procedures for NPCC Area Transmission Reviews

1.0 Introduction

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

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

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

2.0 Purpose of Area Review Presentation

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

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

3.0 The Study Year to be considered

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

4.0 Types and Frequency of Reviews

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

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

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

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

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

5.0 Format of Presentation – Comprehensive and Intermediate Review

Introduction

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

- Discuss projected firm transfers and interchange schedules.

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

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

b) Steady State Assessment

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

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

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

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

- Discuss applicable transfer limits between contiguous areas.

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

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

c) Stability Assessment

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

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

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

d) Fault Current Assessment

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

Extreme Contingency Assessment

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

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

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

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

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

Extreme System Condition Assessment

a) Discuss the scope of the analyses.

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

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

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

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

Review of Special Protection Systems (SPSs)

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

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

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

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

Review of Dynamic Control Systems (DCSs)

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

1.1 Load Model

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

1.1.2 How **load** forecast uncertainty is handled in model.

1.1.3 How the electricity demand and energy projections of interconnected entities within the Planning Coordinator Area that are not members of the Planning Coordinator Area are addressed.

1.1.4 How the effects (demand and energy) of demand-side management programs (e.g., conversion, interruptible demand, direct control **load** management, demand (**load**) response programs) are addressed.

1.2 Supply Side **Resource** Representation

1.2.1 Resource Ratings

1.2.1.1 Definitions.

1.2.1.2 Procedure for verifying **ratings**. Reference NPCC Document B-9, *Guide for Rating Generating Capability*.

1.2.2 Unavailability Factors Represented

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

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

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

1.2.2.4 Tabulation of typical unavailability factors.

1.2.3 Purchase and Sale Representation.

1.2.3.1. Describe characteristics and level of dependability of transactions.

1.2.4 Retirements.

1.2.4.1 Summarize proposed retirements.

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

1.4 Modeling of Variable and Limited Energy Sources.

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

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

1.6 Modeling of all **Resources**.

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

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

1.8 Incorporate the **reliability** impacts of market rules.

B. <u>Other Factors, If Any, Considered in Establishing Reserve Requirement Documentation</u>

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. <u>Task Force Follow-Up Procedures</u>

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 <u>Generator Outage Coordination</u>

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

4.0 <u>Transmission Outage Coordination</u>

4.1 <u>Advance Planning of Transmission Facility Outages</u>

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 <u>Facilities Notification List</u>

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 <u>Notifications of Work</u>

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

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

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

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

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

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

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

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

5.0 Data Providers

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

6.0 Specific Communications

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

6.1 Weekly

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

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

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

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

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

6.2 Emergency Preparedness Conference Call

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

6.3 Daily Conference Calls

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

Procedure for Operational Planning Coordination – Attachment A

Load and Capacity Table Instructions

and

Generating Capacity Worksheet Instructions

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

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

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

Procedure for Operational Planning Coordination – Attachment B

NPCC Weekly Conference Call Generating Capacity Worksheet

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

Procedure for Operational Planning Coordination - Attachment C

<u>CONDITIONS FOR DISCUSSION</u>

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.

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
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NPCC
Regional Reliability Reference Directory # 2
Emergency Operations

Task Force on Coordination of Operations Revision Review Record:
October 21, 2008
June 26, 2009

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

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	10/21/08	Effective Date	New
1	6/26/09	Transfer Auto UFLS language to D#12	Revision
2	8/19/09	Removed references to Automatic UFLS in Section 7 to reflect transfer of Automatic UFLS language to D#12.	Errata
3	1/06/2011	Inserted proper reference to Directory #12 Figure #1 App. B Sect. 6	Errata

Table of Content

1.0 Introduction

1.1 Title Emergency Operations

1.2 Directory Number 2

1.3 Objective

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

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

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

1.4 Effective Date **October 21, 2008**

1.5 Background

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

1.6 Applicability

1.6.1 Functional Entities

Reliability Coordinators
Balancing Authorities
Transmission Operators
Generator Operators

2.0 Terms Defined in this Directory

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

3.0 NERC ERO Reliability Standard Requirements

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

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

4.0 NPCC Regional Reliability Standard Requirements

None.

5.0 NPCC Full Member, More Stringent Criteria

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

5.1 General Criteria

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

The circumstances under which each of these system operating limits are applied shall be clearly indicated by written instructions.

5.2 Manual **Load Shedding** Requirement

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

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

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

6.0 Measures and Assessments

None developed at this time.

7.0 Compliance Monitoring

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

Prepared by: Task Force on Coordination of Operation

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

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

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

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

References: None

Appendix A
Definition of Terms[1]

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

The following AGC modes are typically available:

a. **Tie Line Bias** Control — Automatic generation control with both frequency and net **interchange** terms of **Area Control Error** considered.

b. Constant Frequency (Flat Frequency) Control — Automatic generation control with the net **interchange** term of **Area Control Error** ignored. This Automatic Generation Control mode attempts to maintain the desired frequency without regard to **interchange**.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

<u>NPCC Specific Definitions:</u>

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Appendix B
Guideline and Procedure for Emergency Operation

1.0 Introduction

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

2.0 Minimizing the Impact of Events

2.1 It is recognized that provisions are made in the design of a power system for the satisfactory performance of the system during certain **faults** or incidents of **equipment** failure. It is also recognized that the power system should be operated in a prescribed manner to withstand these contingencies.

2.2 When planning for near term forecast conditions, each Balancing Authority and Transmission Operator should develop operating strategies that provide for sufficient generation and transmission to meet the following objectives:

2.2.1 **Operating reserve** requirements.

2.2.2 **Automatic generation control** and frequency control requirements.

2.2.3 Line/tie line loadings within applicable normal operating limits.

2.2.4 **Bulk power system** voltage within normal limits**.**

2.3 When operating conditions deviate from the boundaries that are planned for, a Balancing Authority area or a Transmission Operator area may experience abnormal operating conditions. If such conditions persist, the Balancing Authority or the Transmission Operator may need to declare and enter into an **emergency.** When operating under abnormal and emergency conditions, the guideline and procedure as presented in Sections 3.0 to 6.0 should be followed.

3.0 Operating Under Abnormal Voltage Conditions

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

3.1.1 actual voltages are outside applicable normal (pre-contingency) voltage ranges.

3.1.2 expected post-contingency voltages violate applicable post-contingency minimum and maximum levels following applicable NPCC Normal or Emergency Criteria Contingencies.

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

3.2 Correction of Abnormal Voltage Conditions

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

3.2.1 If a Transmission Operator area is experiencing abnormal voltage conditions, the Transmission Operator should implement the steps in Section 3.2.2 and 3.2.3 to return voltages to normal condition.

3.2.2 If the **bulk power system** voltage is rapidly decaying, the Balancing Authority or Transmission Operator area, if identifiable, causing the decay should immediately implement all possible action, including the shedding of **firm load**, to correct the problem. All other Transmission Operator areas experiencing the rapid voltage decay should immediately implement all possible action, including the shedding of **firm load**, to correct the problem, until such time that the Balancing Authority or Transmission Operator area causing the decay has implemented actions to correct the problem.

3.2.3 When a Transmission Operator anticipates or is experiencing an abnormal, but stable, or gradually changing **bulk power system** voltage condition, it should implement steps to correct the situation. Recognizing that voltage problems are most effectively corrected by control actions as close to the source as possible, the Transmission Operator should use its own resources, but may request assistance from adjacent Transmission Operator areas. Provided below is a guide for the implementation of potential control actions with the provision that individual steps may be eliminated if considered ineffective for the particular situation.

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

3.2.3.1.1 adjust transformer taps.

3.2.3.1.2 switch capacitors/reactors.

3.2.3.1.3 adjust static VAR compensators.

3.2.3.1.4 utilize full reactive capability of on-line generators.

3.2.3.1.5 deploy synchronous condensers.

3.2.3.1.6 other actions as local voltage control procedures allow.

3.2.3.1.7 dispatch additional generation.

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

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

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

Authority areas, and/or deviate from economic dispatch.

3.2.3.3.2 operate hydraulic units as synchronous condensers, where possible.

3.2.3.3.3 reschedule pumped hydro units to generate or motor over the critical period.

3.2.3.3.4 purchase energy.

3.2.3.3.5 reduce generator **real power** output to increase reactive capability.

3.2.3.3.6 start additional generation.

3.2.3.3.7 switch out internal transmission lines provided system operating limits are not violated.

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

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

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

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

3.2.5 If two or more Transmission Operators are experiencing voltage problems simultaneously, they will assist each other as above to the extent feasible. If the problem is so severe as to require the shedding of **firm load**, the shedding should be done to the extent required to control the situation. Transmission Operators that have mutually agreed upon a normal schedule of **reactive power** flow should adhere to this schedule to the extent possible.

3.2.6 If the abnormal voltage is caused by conditions external to NPCC, the following steps should be implemented by the NPCC Transmission Operator experiencing abnormal voltage conditions as required and appropriate.

3.2.6.1 Using available voltage and **reactive power** flow information, determine which system is causing the abnormal voltage or the trend toward abnormal voltage.

3.2.6.2 Establish communication with the system causing the abnormal voltage

3.2.6.3 All NPCC Transmission Operators in a position to assist should take any available action to relieve the abnormal voltage condition, excluding the shedding of **firm load** or opening transmission circuits. Assistance should normally only be requested after similar action has been implemented by the requesting Transmission Operator(s).

3.2.6.4 If the action in 3.2.6.3 above is insufficient, the Transmission Operator experiencing the difficulty should promptly take all steps necessary to relieve the abnormal voltage condition, including shedding **firm load** and/or opening transmission circuits.

4.0 Actions to Contain an Emergency

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

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

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

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

4.1.1 Attempt to identify the specific cause(s) and communicate with relevant Transmission Operator. Request assistance if required.

4.1.2 Manually shed **firm load** or reject **generation** as appropriate.

4.1.3 Communicate (if time permits and only if beneficial) to the adjacent Transmission Operator that the tie lines will be opened if immediate action is not taken to alleviate the **emergency**.

4.1.4 Open tie lines to prevent damage to equipment, if necessary.

4.1.5 If a Balancing Authority area is experiencing a capacity or **emergency**, it should issue the appropriate NERC Energy Emergency Alert level and follow procedures in NERC Standard *Emergency Preparedness and Operations* EOP-002-0 *Attachment 1*.

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

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

4.2.1 Attempt to identify the specific cause(s) and communicate with relevant Balancing Authority or Transmission Operator. Request assistance if required.

4.2.2 Manually shed **firm load** until transmission loading and voltage return to acceptable values at all known problem locations.

4.2.3 Open or close tie lines as required.

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

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

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

4.3.1 Large Frequency Deviation

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

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

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

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

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

4.3.3 Suspension of Tie Line Bias Area Control Mode

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

4.3.3.1 The Balancing Authority area loses synchronism with the Eastern Interconnection.

4.3.3.2 The Balancing Authority area is uncertain whether it is still connected to the Eastern Interconnection.

4.3.3.3 Values included in the ACE equation are suspect and may result in significant errors in control signals issued.

4.3.3.4 Continued operation in the tie line bias area control mode is, or has a reasonable probability of, adversely affecting reliability.

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

4.3.4 Use of Alternative Balancing Authority Control Mode

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

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

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

4.3.5.1 Inform the senior shift authority in each of the other affected Balancing Authorities of the NPCC.

4.3.5.2 Initiate, or request NPCC Staff to initiate, an NPCC Emergency Preparedness Conference Call, as defined in NPCC Reference Document RD-01, *NPCC Emergency Preparedness Conference Call Procedures – NPCC Security Conference Call Procedures*.

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

5.0 Correction of Transmission Loading if Exceeding Limits

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

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

5.1.1.1 adjust internal **generation,**

5.1.1.2 transfer **load**,

5.1.1.3 adjust phase angle regulators (phase shifters), and

5.1.1.4 redeploy reactive resources:

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

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

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

5.1.5 Activate/implement voltage reduction.

5.1.6 Utilize the NERC TLR process.

5.1.7 Operate to **emergency condition limits**.

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

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

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

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

6.0 Generation Tripping at Low Frequency

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

6.1 Generator Tripping at Frequency below the Curve in Directory #12 Figure 1

If the frequency decays below the curve shown in Directory#12 Figure 1, steps may be taken to protect generating equipment, including separation from the system with or without **load**. In such cases isolation onto a generator's own auxiliaries is preferred to facilitate rapid resynchronization as soon as system conditions permit. For time periods exceeding 300 seconds, manual load shedding may need to be implemented to correct the low frequency problem.

Document B-1

NPCC, Inc.

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Guide for the Application of Autoreclosing to the Bulk Power System

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

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Notes:

Terms in bold face type are defined in the *NPCC Glossary of Terms* (Document A-7). Italicized terms are defined in Section 3.0 of this Guideline.

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

1.0 Objectives

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

2.0 Introduction

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

3.0 Definitions

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

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

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

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* See note on Table of Contents Page

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

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

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

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

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

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

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

4.0 Common Considerations to High-Speed and Delayed Autoreclosing

4.1 *Blocking* of **Autoreclosing**

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

4.2 Turbine-Generator Considerations

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

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* See note on Table of Contents Page

4.3 Circuit Breaker Capability

The design and implementation of **autoreclosing** system should consider the circuit breaker capability. **Autoreclosing** times and sequences should be selected with due regard to circuit breaker interrupting capability, duty cycle, derating, voltage withstand capability, resistor thermal capability, and overall breaker design.

4.4 Number of Operations

*Multiple-shot **autoreclosing*** systems should be designed considering the breaker operating time, available air or gas pressure for breaker operation, and **system stability** margins.

4.5 Breaker Failure Operations

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

4.6 Other System **Elements**

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

Caution also should be taken when applying **autoreclosing** following **faults** on lines that terminate with or include transformers, enclosed busses, **cables**, etc. In these situations the same precautions should be applied unless means are provided to differentiate between **faults** on the line from **faults** on the transformer, enclosed bus, or **cable**, and to supervise **autoreclosing**.

4.7 Multiple Circuit Breaker Line Termination

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

4.8 Line Connected Shunt Capacitor

It is preferable that reclosing of line circuit breakers be completed before closing (normally by operator action) the shunt capacitor breaker.

5.0 High-Speed Autoreclosing Considerations

5.1 Tripping Requirements

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

5.2 **Stability** Considerations

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

5.3 Out-of-Step Conditions

Since **high-speed autoreclosing** is generally unsupervised, it should be *blocked* following an out-of-step **relay** operation.

5.4 Switching **Surge** Considerations

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

6.0 Delayed Autoreclosing Considerations

6.1 General Use

Delayed autoreclosing may be used following design analysis and may be preferable to **high speed autoreclosing**.

6.2 Frequency, Phase Angle and Voltage Considerations

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

6.3 **Autoreclosing** Time Considerations

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

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

Prepared by: Task Force on System Protection.

Review frequency: 3 years

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

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NPCC
Regional Reliability Reference Directory # 7
Special Protection Systems

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

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

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

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	12/27/07		New

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Introduction

1.1 Title Special Protection Systems

1.2 Directory Number 7

1.3 Objective

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

1.4 Effective Date Immediately upon Approval by the NPCC Full Members

1.5 Background

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

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

1.6 Applicability

1.6.1 Functional Entities

Transmission Owner, Generator Owner, Distribution Provider

1.6.2 Facilities

1.6.2.1 New Facilities

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

1.6.2.2 Existing Facilities

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

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

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

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

c. In-kind Replacement of SPS Equipment

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

1.6.3 Classification of **Special Protection Systems**

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

Type I — A **Special Protection System** which recognizes or anticipates abnormal system conditions resulting from design and operating criteria **contingencies**, and whose misoperation or failure to operate would have a **significant adverse impact** outside of the local area. The corrective action taken by the **Special Protection System** along with the actions taken by other **protection systems** are intended to return power system parameters to a stable and recoverable state.

Type II — A **Special Protection System** which recognizes or anticipates abnormal system conditions resulting from extreme **contingencies** or other extreme causes, and whose misoperation or failure to operate would have a **significant adverse impact** outside of the local area.

Type III — **Special Protection System** whose misoperation or failure to operate results in no **significant adverse impact** outside the local area. The practices contained in this document for a Type I SPS should be considered but are not required for a Type III SPS. It should be recognized that a Type III SPS may, due to system changes, become Type I or Type II.

2.0 Terms Defined in this Directory

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

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

3.0 Requirements

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

3.1.1 PRC-012-0 — Special Protection System Review Procedure

3.1.2 PRC-013-0 Special Protection System Database

3.1.3 PRC-014-0 — Special Protection System Assessment

3.1.4 PRC-015-0 — Special Protection System Data and Documentation

3.1.5 PRC-016-0 — Special Protection System Misoperations

3.1.6 PRC-017-0 - Special Protection System Maintenance and Testing

3.2 NPCC Regional Reliability Standard Requirements

None at this time. To be developed.

3.3 NPCC "Full Member", More Stringent Criteria

3.3.1 General Criteria

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

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

3.3.1.1 To enhance dependability, a **Special Protection System** shall be designed with sufficient redundancy such that the **Special Protection System** is capable of performing its intended function while itself experiencing a single failure.

3.3.1.2 Multiple protection groups that are used to obtain redundancy within a **Special Protection System** shall not share the same component.

3.3.1.3 A **Special Protection System** shall be designed to avoid false operation while itself experiencing a credible failure.

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

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

3.3.1.6 When remote access to **Special Protection Systems** is possible, the design shall include security measures to minimize the probability of unauthorized access to the **Special Protection System**.

3.3.1.7 An SPS shall be designed to take corrective action within times determined by studies with due regard to security, dependability and selectivity.

3.3.1.8 Status of SPS arming shall be monitored to allow prompt attention by appropriate operating authorities.

3.3.1.9 An SPS shall be equipped with means to enable its arming and to independently verify the arming.

3.3.2 Current Transformer Criteria

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

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

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

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

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

3.3.3 Voltage Transformer and Potential Device Criteria

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

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

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

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

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

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

3.3.4 Battery and Direct Current (dc) Supply Criteria

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

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

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

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

3.3.4.4 dc battery systems shall be continuously monitored to detect abnormal voltage levels (both high and low), dc grounds, and loss of ac to the battery chargers in order to allow prompt attention by the appropriate operating authorities.

3.3.4.5 **Special Protection System** dc supply circuits shall be continuously monitored to detect loss of voltage in order to allow prompt attention by the appropriate operating authorities.

3.3.5 Station Service ac Supply Criteria

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

3.3.6 Circuit Breakers Criteria

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

3.3.7 Teleprotection Criteria

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

3.3.7.1 Where the design of a **Special Protection System** is composed of multiple **protection groups** for redundancy and each group requires a communication channel, the equipment and channel for each group shall be separated physically and designed to minimize the risk of more than one **protection group** being disabled simultaneously by a single event or condition.

3.3.7.2 **Teleprotection** equipment shall be monitored to detect loss of equipment and/or channel to allow prompt attention by the appropriate operating authorities.

3.3.7.3 **Teleprotection** systems shall be designed to assure adequate signal transmission during **bulk power system** disturbances, and shall be provided with means to test for proper signal adequacy.

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

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

3.3.8 Physical Separation/Environment Criteria

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

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

3.3.9 Grounding Criteria

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

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

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

3.3.10 Provision for Breaker Failure Criteria

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

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

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

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

3.3.11 Testing and Maintenance Criteria

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

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

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

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

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

3.3.11.6 All positive combinations of input logic shall be tested regardless of the maintenance strategy used.

3.3.11.7 Sufficient testing shall be employed to ensure that timing races do not exist within hardwired or electronic logic, and that the SPS operating time is within design limits.

3.3.11.8 Each time the SPS is maintained, its hardware shall be tested in conjunction with the control facilities, related computer equipment, software and **operating procedures** to ensure compatibility and correct operation.

3.3.12 Analysis of SPS Performance

3.3.12.1 **Bulk power system** automatic operations shall be analyzed to determine proper **Special Protection System** performance. Corrective measures must be taken promptly if the **Special Protection System** or a **protection group** within the SPS fails to operate or operates incorrectly.

3.3.12.2 Event recording capability shall be provided to permit analysis of system operations and **Special Protection System** performance.

4.0 Measures and Assessments

None developed at this time.

Prepared by:	Lead Task Force- Task Force on System Protection
Review and Approval:	Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval. Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC Inc. Bylaws" in effect at the time the ballots are cast. Revisions pertaining to the Appendices or any other portion of the document such as Links, Glossary Terms, etc., will only require RCC Member approval of the document. Errata may be corrected by the Lead Task Force at any time and provide the appropriate notifications to the NPCC Inc. membership. This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC Regional Reliability Standards and other NPCC documents.
References:	NPCC RRS PRC-XXX-X (Future NPCC Regional Standard) Basic Criteria for Design and Operation of Interconnected Power Systems (Document A-2) Emergency Operation Criteria (Document A-3) Maintenance Criteria for Bulk Power System Protection (Document A-4) NPCC Glossary of Terms (Document A-7)

Attachment 1
Definition of Terms

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

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

Fault – An electrical short circuit.

Permanent Fault — A fault which prevents the affected **element** from being returned to service until physical actions are taken to effect repairs or to remove the cause of the fault.

Transient Fault — A fault which occurs for a short or limited time, or which disappears when the faulted **element** is separated from all electrical sources and which does not require repairs to be made before the **element** can be returned to service either manually or automatically.

Operating Procedures -A set of policies, practices, or system adjustments that may be automatically or manually implemented by the system operator within a specified time frame to maintain the operational integrity of the interconnected electric systems.

Automatic Operating Systems — **Special protection systems**, remedial action schemes, or other operating systems installed on the electric systems that require *no intervention* on the part of **system operators**.

Normal (Precontingency) Operating Procedures — Operating procedures that are normally invoked by the **system operator** to alleviate potential facility overloads or other potential system problems in anticipation of a **contingency**.

Postcontingency Operating Procedures — Operating procedures that may be invoked by the **system operator** to mitigate or alleviate system problems after a **contingency** has occurred.

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

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

Notes:

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

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

Protection system

Element Basis

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

Terminal Basis

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

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

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

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

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

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

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

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

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

Teleprotection - A form of **protection** that uses a communication channel

Appendix A
Guidance for Consideration in SPS Design

Introduction

This Appendix provides the guidance for consideration in the implementation of the **Special Protection System** design criteria stipulated in Section 3.3 of this Directory.

The general objective for any SPS is to perform its intended function (generator rejection, load rejection, etc.) in a dependable and secure manner. In this context, dependability relates to the degree of certainty that the SPS will operate correctly when required to operate. Security relates to the degree of certainty that the SPS will not operate when not required to operate.

The relative effects on the **bulk power system** of a failure to operate when desired versus an unintended operation should be weighed carefully in selecting design parameters. For example, the choice of duplication as a means of providing redundancy improves the dependability of the SPS but can also jeopardize security in that it may increase the probability of an unintended operation. This general objective can be met only if the SPS can dependably respond to the specific conditions for which it is intended to operate and differentiate these from other conditions for which action must not take place.

Close coordination should be maintained among system planning, design, operating, maintenance and **protection** functions, since both initially and throughout their life cycle, SPSs are a multi-discipline concern.

2.0 Considerations Affecting Dependability

2.1 Redundancy is normally provided by duplication. Some aspects of duplication may be achieved by overarming, which is defined as providing for more corrective action than would be necessary if no failures are considered. The redundancy requirements for an SPS apply only with respect to its response to the conditions it is required to detect.

2.2 For a **Special Protection System** that is composed of multiple **protection groups**, the risk of simultaneous failure of more than one **protection group** because of design deficiencies or equipment failure should be considered, particularly if identical equipment is used in each **protection group**. The extent and nature of these failures should be recognized in the design and operation of the **Special Protection System.**

2.3 Area of common exposure should be kept to a minimum to reduce the possibility of all groups being disabled by a single event such as fire, evacuation, water leakage, and other such incidents.

3.0 Considerations Affecting Security

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

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

3.3 The components and software used in **Special Protection Systems** should be of proven quality, as demonstrated either by actual experience or by stringent tests under simulated operating conditions.

3.4 **Special Protection Systems** should be designed to minimize the possibility of component failure or malfunction due to electrical transients and interference or external effects such as vibration, shock and temperature

3.5 **Special Protection Systems**, including intelligent electronic devices (IEDs) and communication systems used for **protection**, should comply with applicable industry standards for utility grade **protection** service. Utility Grade **Protection** System Equipment are equipment that are suitable for protecting transmission power system elements, that are required to operate reliably, under harsh environments normally found at substations. Utility grade equipment should meet the applicable sections of all or some of the following types of industry standards, to ensure their suitability for such applications:

- IEEE C37.90.1-2002 (oscillatory surge and fast transient)
- IEEE C37.90.1-2002 (service conditions)
- IEC 60255-22-1, 2005 (1 MHz burst, i.e. oscillatory)
- IEC 61000-4-12, 2001 (oscillatory surge)
- IEC 61000-4-4, 2004 (EFT)
- IEC 60255-22-4, 2002 (EFT)
- IEEE C37.90.2-2004 (narrow-band radiation)
- IEC 60255-22-3, 2000 (narrow-band radiation)
- IEC 61000-4-3, 2002 (narrow-band radiation)
- IEEE 1613 (communications networking devices in Electric power Substations)

3.6 **Special Protection System** circuitry and physical arrangements should be carefully designed so as to minimize the possibility of incorrect operations due to personnel error.

3.7 **Special Protection System** automatic self-checking facilities should be designed so as to not degrade the performance of the **Special Protection System**.

3.8 Consideration should be given to the consequences of loss of instrument transformer voltage inputs to **Special Protection Systems**.

3.9 Consideration should be given to the effect of the means of arming on overall security and dependability of the **Special Protection System**. Arming should have a level of security and dependability commensurate with the requirements of the SPS.

4.0 Considerations Affecting Performance

4.1 Control Cable, Wiring and Ancillary Control Device

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

4.2 Environment

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

5.0 Operating Time of an SPS

Adequate time margin should be provided taking into account study inaccuracies, differences in equipment, and **protection** operating times.

6.0 Arming of an SPS

Arming is the selection, which may be external to the **Special Protection System**, of desired output action based on power system conditions and recognized contingencies. Arming requirements of a Special Protection System are normally based upon the results of system studies which take into account recognized contingencies, operating policies/procedures and current power system load/generation conditions. For a simple **Special Protection System**, arming may be an on/off function. A **Special Protection System** can be armed either automatically or manually.

6.1 Automatic arming is implemented without human intervention.

6.2 Arming manually if the recognition, decision or implementation requires human intervention. Sufficient time with adequate margin for recognition, analysis and the taking of corrective action should be allowed.

7.0 Maintenance Considerations

7.1 Additional periodic maintenance is recommended on the following **protection** equipment:

- On continuously monitored analog **teleprotection** channels, verify signal adequacy every twelve months.
- On non-monitored analog **teleprotection** channels, verify signal adequacy every month.
- On digital **teleprotection** systems, which are inherently monitored, verify local function

  every two years.
- On batteries and chargers, verify proper operation and general condition every month.
- On circuit breakers, verify ability to trip via each trip coil every two years, with due regard to critical trip paths between sensing relays and the breaker trip coils.

7.2 It is the responsibility of each TO, GO and DP to evaluate its own particular circumstances and determine if any additional maintenance should be performed on its system. More extensive maintenance may be required but not limited to:

- during the initial break-in period,
- where **protection** systems are exposed to abnormal conditions such as temperature extremes, vibration, corrosive atmosphere, etc.,
- when the operating condition of **protection** system control wiring is suspect..

7.3 The design of a **Special Protection System** both in terms of circuitry and physical arrangement should facilitate periodic testing and maintenance in a manner that mitigates the risk of inadvertent operation. As a **Special Protection System** may be complex and may interface with other protection systems or control systems, special attention should be placed on ensuring that test devices and test interfaces properly support a clearly defined maintenance strategy.

7.4 Proper overlap is ensured if each portion of circuitry is seen to perform its intended function, such as operating a relay, from either a real or test stimulus, while observing some common reliable downstream indicator.

7.5 Whenever practicable, some of the maintenance testing requirements may be met by analyzing and documenting the detailed performance of the **Special Protection System** during actual events to demonstrate that the specific testing requirements have been fulfilled. Such an approach can reduce the probability of false operation during maintenance while effectively reducing the extent of planned maintenance.

Appendix B
Procedure for Review of Special Protection Systems

Introduction

This Appendix provide the procedure to follow to obtain concurrence from NPCC if an entity concludes that a new **Special Protection System** or a modification of an existing **Special Protection System** will be required which affects the **bulk power system**. The procedure is also shown on the attached flow chart.

2.0 NPCC Review and Concurrence

2.1 Allowing for sufficient lead time to ensure an orderly review, the entity will notify the chairman of the Task Force on Coordination of Planning (TFCP) of its proposal to install a new **Special Protection System** or modify an existing **Special Protection System**. The entity will send copies of the complete notification to TFCO and TFSP. This notification will include statements that describe possible failure modes and whether misoperation, unintended operation or failure of the **Special Protection System** would have local, inter-company, inter-**Area** or inter-Regional consequences, when the **Special Protection System** is planned for service, how long it is expected to remain in service, the specific **contingency**(s) for which it is designed to operate and whether the **Special Protection System** will be designed according to the NPCC *Bulk Power System Protection Criteria* (Document A-5) and the *Special Protection System Criteria* and Standards requirements listed in this docment.

2.2 If the **Special Protection System** is expected to have only local consequences, TFCP will request that the Task Force on System Studies (TFSS) and the Task Force on System Protection (TFSP) review the proposal.

2.2.1 TFSP will be notified of the proposed **Special Protection System**. TFSP will advise TFCP of any concerns.

2.2.2 TFSS will review the analyses that the proposing entity has performed. A presentation may be required from the proposing entity. The purpose of the review will be to confirm that there are no adverse inter-**Area** or inter-Regional consequences of either a failure of the **Special Protection System** to operate when and how it is required or an inadvertent or unintended operation of the **Special Protection System**. If necessary, TFSS will request that the proposing entity conduct additional analyses.

2.2.3 If the TFSS review confirms the **Special Protection System** has only local consequences, TFSS will send the information to TFCP. If TFCP concurs, they will then notify the proposing entity of NPCC's conclusions that the **Special Protection System** has only local consequences. TFCP will also notify the Reliability Coordinating Committee (RCC), all the Task Forces, the Compliance Committee (CC), the proposing entity and other Members that concurrence has been given to the proposing entity to modify an existing **Special Protection System** or install a new **Special Protection System**, at which time, the **Special Protection System** may be deployed.

2.2.4 If the TFSS review concludes that the **Special Protection System** could have inter-**Area** or inter-Regional consequences, they will inform the TFCP. Upon receipt of the TFSS conclusion or if TFCP separately determines the **Special Protection System** could have inter-**Area** or inter-Regional consequences, TFCP will arrange for an overall NPCC review as detailed in Step 3.

2.2.5 TFSS will update the NPCC **Special Protection System** list/database.

2.3 If the proposing entity expects the **Special Protection System** to have inter-**Area** or inter-Regional consequences, or if the TFSS or TFCP review concludes this to be the case, TFCP will request the Task Force on Coordination of Operation (TFCO), the Task Force on System Protection (TFSP) and TFSS to review it. Each of the Task Forces may require a presentation from the proposing entity.

2.3.1 TFSP will confirm the failure modes of the **Special Protection System**, including actions of back-up **protection**, and whether or not the **Special Protection System** complies with NPCC system **protection** standards. TFSP will review whether the new or modified **Special Protection System** is in conformance with the NPCC *Bulk Power System Protection Criteria* (Document A-5) and the *Special*

Protection System Criteria and Standards requirments listed in this document and forward a summary of their findings to TFCO, TFCP and TFSS. This summary will include a statement as to whether the **Special Protection System** is in conformance with the *Bulk Power System Protection Criteria* (Document A-5) and the *Special Protection System Criteria* and Standards requirments listed in this document and whether the Task Force has any objections to its modification or installation.

2.3.2 TFSS will review the analysis that the proposing entity has performed. The purpose of the review will be to assess the **Special Protection System** is in conformance with the *Basic Criteria for Design and Operation of Interconnected Power Systems* (Document A-2) and to determine the inter-**Area** or inter-Regional consequences of either a failure of the **Special Protection System** to operate when and how it is required or an inadvertent or unintended operation of the **Special Protection System**. If necessary, TFSS will request that the proposing entity conduct additional studies. When their review is completed, TFSS will forward a summary of their findings to TFCO, TFCP and TFSP. This summary will include a statement as to whether the **Special Protection System** is in conformance with the *Basic Criteria* (A-2) and whether the Task Force has any objections to its modification or installation.

2.3.3 TFCO will review the operability of the **Special Protection System** and forward a summary of their findings to TFCP, TFSS and TFSP. This summary will include a statement as to whether the Task Force has any objections to its modification or installation.

2.3.4 TFCP will prepare an overall summary for the RCC. This summary will include the findings of the other Task Forces and whether there are any objections to the modification of the existing **Special Protection System** or the installation of the new **Special Protection System** and as a minimum, include the following information:

- Function, i.e. GR-generation rejection etc.
- Identification
- Initiating condition
- Action(s) resulting
- Name of the **Special Protection System**, and owner, identification number
- Arming, i.e. percentage of time, system conditions for which it's needed, manual vs. automatic, etc.
- Reason for the installation
- Comments, explanations, such as "temporary until such time…"
- Company, owner
- SPS Number, drawn by NPCC staff
- Current Status, i.e. New, Changed or Removed
- Type Determination

- Determinations of the Task Forces' analyses
- Consequences of operation, misoperation and failure to operate
- Approximate of load or generation rejected by **Special Protection System** operation
- Proposed date of deployment
- Proposed date of retirement/deactivation

2.3.5 The RCC will review the summary report and act on the proposal to modify an existing **Special Protection System** or install a new **Special Protection System**. The RCC may also remand the review of the **Special Protection System** back to the TFCP if further analyses are determined to be needed.

2.3.6 The TFCP will notify the RCC, all the Task Forces, the CC, the proposing entity and other Members of the outcome of the review. Upon NPCC approval of the type and compliance with Criteria, the **Special Protection System** may be deployed.

2.3.7 The TFSS will then update the NPCC **Special Protection System** list/database.

3.0 Presentation and Review of Special Protection Systems

Each new or modified Type I or Type II **Special Protection System** shall be reported to the Task Force on System Protection in accordance with the following presentation and review procedure.

3.1 A presentation will be made to the TFSP on new facilities or a modification to an existing facility when requested by an NPCC Member or the TFSP.

3.2 A presentation will be made to the TFSP when the design of the **protection** facility deviates from the *Bulk Power System Protection Criteria* (Document A-5).

3.3 A presentation will be made to the TFSP when an NPCC Member is in doubt as to whether a design meets the *Protection Criteria*.

3.4 Data Required for Presentation and Review of Proposed **Special Protection System:**

3.4.1 The TO, GO or DP will advise the TFSP of the basic design of the proposed system. The data will be supplied on the attached forms, accompanied by a geographical map, a one-line diagram of all affected areas, and the associated **protection** and control function diagrams. A physical layout of **protection** panels and batteries for the purpose of illustrating physical separation will also be included.

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

3.5 Procedure for Presentation:

3.5.1 The TO, GO or DP will arrange to have a technical presentation made to the TFSP.

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

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

3.6 Review by TFSP

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

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

3.6.2 Acceptance of the TO, GO or DP statement of conformance to the *Protection Criteria*.

3.6.3 Acceptance of the submitted proposal.

3.6.4 *Conditional acceptance of the submitted proposal.

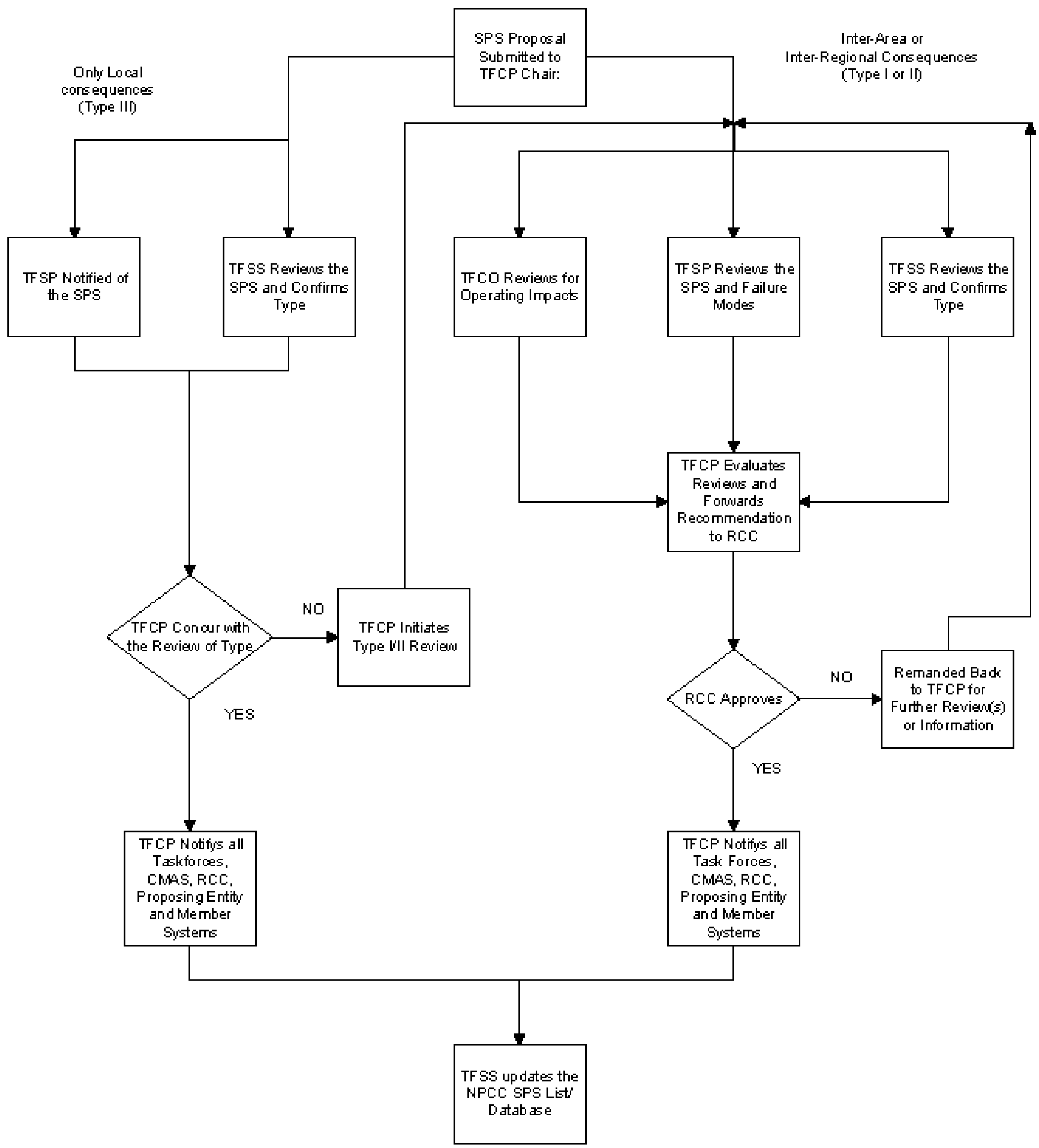
3.6.5 *Rejection of the submitted proposal

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

3.6.6 The results of the TFSP review will be documented in the following manner.

. A position statement will be included in the minutes of the meeting at which the proposed **protection** system was reviewed.
. If necessary, a letter outlining areas of nonconformance with the NPCC *Protection Criteria* and recommendations for correction will be submitted to the TO, GO or DP.
. The Task Force will maintain a record of all the reviews it has conducted.

PROCEDURE FOR NPCC REVIEW OF NEW OR MODIFIED BULK POWER SYSTEM SPECIAL PROTECTION SYSTEMS (SPS)



Document C-29

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Procedures for System Modeling: Data Requirements & Facility Ratings

Prepared by the SS-37 Working Group on Base Case Development for the Task Force on System Studies.

May 21, 2001
March, 2007

1.0 Introduction

Actual and forecast data of all the components including load are required to analyze study and plan the interconnected electric system. The detailed data of system components will be maintained and updated by the purchasers, sellers, marketers, and load-serving entities and provided to NPCC accurately and timely as needed for system analysis and distribution. This data may be required on an aggregated independent system operator, power pool, individual system, or on a dispersed substation basis for system modeling and reliability analysis.

Complete, accurate, and timely data is needed for system analyses to ensure the adequacy and security of the interconnected transmission systems, to meet projected customer demands, and to determine the need for system enhancements or reinforcements. The SS-37 Working Group, as directed by Task Force on System Studies, will collect data and develop a library of base case models for each year. The typical schedule along with roles and responsibilities of each SS-37 member is as per Table 1 in Appendix A.

System analyses include steady-state, transient, and dynamic simulations of the electrical networks. Data requirements for such simulations include information on system components, system configuration, customer demands, and electric power transactions.

Knowledge of facility ratings is essential for the reliable planning and operation of the inter-connected transmission systems. Such ratings determine the acceptable electrical duties on equipment, before, during, and after system contingencies.

1.1 Applicable NERC Reliability Standards

The NERC Compliance Program includes the following standards, which apply to the Regional Reliability Organizations for which NERC has compliance assessment responsibility.

MOD-014 Development of Steady-State System Models
MOD-015 Development of Dynamics System Models

This plan applies to those Regions in the Eastern Interconnection that have chosen to utilize the MMWG (Multiregional Modeling Working Group) to meet these requirements.

2.0 System Modeling

The NERC Reliability Standards, MOD-014 and MOD-015, state the following purposes.

MOD-014
To establish consistent data requirements, reporting procedures, and steady state system models to be used in the analysis of the reliability of the interconnected transmission systems.

MOD-015
To establish consistent data requirements, reporting procedures, and dynamics system models to be used in the analysis of the reliability of the interconnected transmission systems.

The NPCC Base Case Development (BCD) Working Group (SS-37) will develop a library of base case load flow and dynamic models each year for internal use by NPCC, its members, and NERCMMWG. The NPCC Task Force on System Studies (TFSS), to meet the needs of the members and other groups will establish the individual cases, which collectively comprise the library, each year. This annual development of base cases will serve as the main vehicle by which system data is collected and disseminated for internal use by NPCC and its members. It is expected that the system(s) conducting a study may find it necessary to expand and/or update the representation of system conditions and facilities in the area of particular concern.[1]

The NERC MMWG maintains a system dynamics database. NPCC will ensure that the MMWG database is updated annually such that the load flow cases and the dynamics data submitted to MMWG are compatible.

The system modeling in the BCD load flow cases is intended to be such that realistic events and conditions can be simulated using analytical software which NPCC has adopted as its current standard. While the data from these cases may be used by other software programs, no attempt is made by NPCC to ensure that the system modeling provided in these cases is such that commercially available software, other than its current standard, will realistically simulate system events.

Short circuit analysis is generally not required for interregional reliability studies. Therefore NPCC will not collect, maintain, or distribute, short-circuit data cases to its members or to NERC. Short circuit analysis studies are normally carried out on an Area or individual company basis. This procedure stipulates that facility owners must maintain short-circuit data and Areas and Companies shall maintain short-circuit models. The data and models should be provided to members on request. The interchange of short circuit data is currently required by NPCC procedures to permit modeling of neighboring systems[2]. NPCC will maintain a list of contacts from who short-circuit equivalents may be obtained for Area and/or Company systems. SS-37 will be responsible for maintaining this list.

2.1 Base Case Development Data Requirements

Load flow and dynamics data shall be submitted to NPCC annually by Areas and Companies to facilitate base case development. Generation and Transmission Facility Owners will be responsible to provide data for the Base Case Development (BCD). Submissions for this purpose shall be consistent with the modeling guidelines provided in the MMWG Procedural Manual notwithstanding the following:

2.1.1 The ratings of all static equipment must be consistent with the documentation available from facility owners as required by the NERC Planning Standard FAC-008 and in accordance with the procedures herein. The ratings included in each specific case shall be appropriate to the case (summer, winter, etc.).

2.1.2 The load flow cases provided by the Areas must have system loads and dispatches appropriate to the specific case (summer, winter etc) as defined in the MMWG Procedural Manual. The load and dispatch conditions will be the Areas best available forecast of expected conditions. Areas on each side of a tieline will agree transfers between those Areas, on a case-by-case basis.

2.1.3 Each Area, for the purpose of preparing load flow cases for stability analysis, will provide appropriate files with the cases submitted to facilitate conversion of loads and generators and the netting of generators with load as required for transient stability studies. The files are to be based on the areas best available data concerning load characteristics and will be reviewed and updated every three years as part of the triennial review process

2.1.4 The ratings of generation equipment must be consistent in all submissions from case to case. Only the real and reactive power set points, voltage set points, and station service loads should change unless physical re-rating of the equipment is anticipated.

2.1.5 The modeling of generators, plants and generator step-up transformers (GSU) must be consistent from case to case. This applies to the unit ratings, the representation of GSU, Pmax, Pmin, and the dynamics modeling.

2.1.6 Representation Of Units and Plants – Units at a particular bus may be lumped together and represented as one unit when they have the same electrical and control characteristics. Units that are lumped together should be rated less than 50 MVA each and the units lumped together at any location should have a combined rating of not more than 300 MVA. Units or plants rated less than 20 MVA may be netted with loads. The netting or lumping of units and plants in excess of the guidelines above is acceptable only when such representations are deemed acceptable for systems studies in the judgment of the Areas affected.

2.1.7 Generator step-up transformers should be represented explicitly as transformers. Correct impedance data, derived from test data, should be used for GSU impedance. Data for generator step-up transformers should include effective tap ratios and per unit impedance.

2.1.8 The representation of AC transmission lines and circuits (overhead and underground) should include nominal voltage, line charging, line shunt equipment, and ratings consistent with procedures and appropriate to the case.

2.1.9 Transformers shall be modeled in accordance with the application guide of the software program, adopted as NPCC's current standard, and the best available equipment data. Regulated bus and voltage set points shall be included where the devices are operated in automatic mode. Tap changer tables should be included only where they are judged necessary for the studies for which the base cases may be used.

2.1.10 Units not dispatched must be modeled with a status of “0”, or off-line, in the power flow model.

2.1.11 The modeling and ratings of tie lines provided should be agreed to by all of the owners of the facilities.

2.1.12 Each year, for the purpose of base case development, each Area will submit loadflow cases to NPCC in a standard format as agreed upon by the working group. One file shall be provided for each BCD case under development. The provider of such data will ensure that the representation of generators and the generator bus names are consistent with the previous years BCD cases. Any changes from the previous year should be noted in a “readme" file provided by the provider.

2.1.13 Each year, for the purpose of base case development, each Area will submit dynamics data to NPCC in the form as agreed upon by the working group. This data will include all appropriate files for dynamic simulation. Instructions should be also provided in the form of a “read-me” file to guide the user in creating dynamics cases from these files and merging the data with that from other areas. Each Area will also provide dynamics data updates, in the form of updates that facilitate updating the dynamics case such that it is made compatible with the remaining BCD cases in the set.

2.1.14 Each Area, after NPCC has merged the loadflow and dynamics data into preliminary BCD cases, will review the BCD loadflow cases for correctness and test the dynamics data by simulating limiting events within their system.

2.2 Data Requirements of Facility Owners

Generation and Transmission Facility Owners must develop, and maintain data for their facilities suitable for load flow and dynamics modeling and analysis as required by the NPCC Working Groups. Facilities owners must also develop and maintain short-circuit data. Facility owners must provide this data, in a suitable format, on request. Data provided by facility owners must comply with the NERC MMWG Procedural Manual and the procedures herein.

Some typical data required for load flow and dynamics modeling to conduct studies and analysis are as follows:

<u>Generation Facility Owners:</u>

2.2.1 Bus (substation and switching station): names, nominal voltage, and location.

2.2.2 Generating Units (including synchronous condensers, pumped storage, etc.): location, minimum and maximum ratings (gross real and reactive power), regulated bus and voltage set point, maintenance requirements as appropriate to the analysis, station service and auxiliary loads, and dynamics data.

2.2.3 Transformer (voltage and phase-shifting): nominal voltages of windings, impedance, tap ratios (voltage and/or phase angle or tap step size), regulated bus and voltage set point, normal and emergency ratings, and maintenance requirements as appropriate to the analysis.

2.2.4 Detailed unit-specific dynamics data for generators, excitation systems, voltage regulators, turbine-governor systems, power system stabilizers, relays and protection equipment (out of step, over-speed, etc), and other associated generation equipment. This includes complete and accurate models of controls suitable for integration with the analytical software. In no case shall other than unit-specific data be used for generator units installed after 1990.

2.2.5 Typical manufacturer’s dynamics data, based on units of similar design and characteristics, may be used when unit-specific dynamics data cannot be obtained.

2.2.6 Positive, negative, zero sequence and mutual impedance.

<u>Transmission Facility Owners:</u>

2.2.7 Bus (substation and switching station): names, nominal voltage, and location.

2.2.8 AC Transmission Line or Circuit (overhead and underground): nominal voltage, impedance, line charging, nominal and emergency ratings based on the most limiting element in the circuit, maintenance requirements as appropriate to the analysis, and metering locations.

2.2.9 Transformer (voltage and phase-shifting): nominal voltages of windings, impedance, tap ratios (voltage and/or phase angle or tap step size), regulated bus and voltage set point, normal and emergency ratings, and maintenance requirements as appropriate to the analysis.

2.2.10 Reactive Compensation (shunt and series capacitors and reactors): nominal ratings, impedance, percent compensation, connection point, and controller device.

2.2.11 Detailed dynamics data for all other facilities of significance and pertinent to dynamic simulations such as static-var compensators, Facts devices, Phase Angle Regulators, synchronous motors, HVdc facilities, relays, loads etc. Data must include complete and accurate control models suitable for integration.

2.2.12 Models of protective relay characteristics on all major interfaces and available on request for all transmission facilities.

2.2.13 Positive, negative, zero sequence and mutual impedance.

2.3 Data Requirements of Load-Serving Entities, Purchasers/Sellers/Marketers

Load-serving entities shall provide actual and forecast demands for their respective customers for steady state and dynamics system modeling in a timely manner.

Purchasers, sellers, marketers, and load-serving entities shall provide their existing and future contracted firm (non-recallable reserved) capacity transactions (including sources, sinks, amounts, duration, associated transmission, etc.) for steady-state and dynamics system modeling in a timely manner.

3.0 Facilities Ratings

The NERC Reliability Standard, FAC-008, Facility Ratings Methodology, states the following purpose.
To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an

established methodology or methodologies.

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Compliance with the above standard is provided for by the following procedure:

3.1 Facility owners shall document the methodology for determining facility ratings, including delineation and justification of assumptions, standards, and practices used in establishing the ratings. The documentation must state the ratings and their basis applicable to each of the six base case model types (summer peak, winter peak etc) as defined in the MMWG Procedural Manual.[3] This document must be maintained and provided to NPCC on request.

3.2 Facility owners shall provide facility ratings (applicable normal and emergency) for all facilities required for system modeling (as defined in this Procedure) to NPCC appropriate for base case development as requested in a timely fashion. The requirement to submit data to NERC is being fulfilled through the NPCC base case development effort.

3.3 The rating of a system facility (e.g., transmission line, transformer, etc.) shall not exceed the rating of the most limiting series element in the circuit or path of the facility, including terminal connections and associated equipment.

3.4 In cases where protection systems and control settings constitute a loading limit on a facility, this limit shall become the rating for that facility.

3.5 Ratings of jointly owned facilities shall be coordinated and provided on a consistent basis. The ratings submitted shall be agreed to through the consensus of the facility owners.

3.6 Facility ratings should be based on or adhere to applicable national electrical codes and electric industry rating practices consistent with good engineering practice.

Prepared by: The SS-37 Working Group on Base Case Development for the Task Force on System Studies

References:

[2] NPCC Reference Manual, Document A-5, "Bulk Power System Protection Criteria", Section 2.4.8, Draft of Document A-5 dated January 27, 1998.

[3] NERC MMWG Procedural Manual, Revision No. 21, April 27, 2005, Appendix V: "Power Flow Modeling Guideline".

[4] NERC MMWG Procedural Manual, Revision No. 21,April 27, 2006, Appendix II: "Dynamics DataSubmittal Requirements and Guidelines".

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[6] **Applicable NERC Reliability Standards**

FAC-008, Facility Ratings Methodology
MOD-014, Development of Steady-State System Models
MOD-015, Development of Dynamics System Models

APPENDIX A

TABLE – 1

SCHEDULE & RESPONSIBILITIES

Each year the SS-37 Working Group, as directed by the TFSS, will develop a library of base cases for the following year. MMWG Base Cases will be derived from this set as judged appropriate. A written description of the cases and procedures used to derive the MMWG Bases Cases from the BCD cases will be provided with the Base Case library by SS-37. The schedule and responsibilities necessary to achieve this are as follows:

TASK	DEADLINE	RESPONSIBILITY
Establish and release BCD/MMWG List of Cases	March	TFSS
Assign tasks to each SS-37 member to participate in the development and testing of base cases	SS-37 Meeting April	All
Establish and release Interchange Schedule & Tie Line Summary	May	SS-37, Each area Rep.
Areas submit near term base case data files to NPCC.	June	Each Area Rep.
Areas submit long term base case data files to NPCC	July	Each Area Rep
NPCC provide "BCD-Trial 1" cases to Areas	One week after submittals from Areas	NPCC, SS-37
Specify necessary revisions to be made to "BCD-Trial 1"cases.	One week after "BCD-Trial 1"	NPCC, Each Area Rep.
Update Dynamics Data and test BCD cases with and without faults	August	NPCC, Each Area Rep as assigned
Release BCD Library for subsequent year	December 31st	NPCC, SS-37
Submit data to MMWG as per their schedule	Presently starting June-December	NPCC

1.0 DESCRIPTION

Ce document fournit les exigences de performance se rapportant au système d'excitation de type statique pour les alternateurs. Il est à noter que le système d'excitation doit être équipé d'un stabilisateur multi-bandes de type delta-oméga. Les exigences de performance du circuit stabilisateur sont précisées dans les CEGR MB-PSS.

2.0 CARACTÉRISTIQUES GÉNÉRALES DU SYSTÈME D'EXCITATION

Le système d'excitation doit être de type statique. Les ponts convertisseurs triphasés à thyristors doivent être alimentés par un transformateur d'excitation raccordé aux bornes de l'alternateur. Le système d'excitation doit comprendre tous les dispositifs nécessaires à l'alimentation du champ d'un alternateur et doit pouvoir contrôler adéquatement la tension aux bornes de l'alternateur dans toutes ses conditions d'exploitation.

Tension de plafond

Le système d'excitation doit avoir des tensions de plafond de plus et moins 10 p.u.
La valeur unitaire de base pour la tension d'excitation est définie par résultat du produit du courant de champ, mesuré sur la droite d'entrefer à vide pour une tension nominale aux bornes de l'alternateur, par la valeur de la résistance de l'enroulement du champ à 100^{o}C.

Courant de plafond

Le courant de plafond du système d'excitation doit être au moins égal à 1.6 fois le courant nominal. Le système d'excitation doit être capable de fournir ce courant durant au moins 30 secondes. Le courant d'excitation négatif n'est pas requis, mais le système d'excitation doit pouvoir fournir le plafond de désexcitation jusqu'à la limite du courant d'excitation nul.

Contraintes en tension et fréquence imposées par le réseau

En plus des conditions normales d'exploitation du groupe et des conditions temporaires qui peuvent se présenter lors de l'arrêt ou du démarrage, le système d'excitation doit demeurer en fonction pour les conditions en tension et fréquence pouvant survenir lors de perturbations sur le réseau de transport (mesurée au point de raccordement de la centrale). Ces conditions sont décrites dans les tableaux 1, 2 et 3 de la section 4.2 Exigences générales relatives à la conception, à la réalisation et à l'exploitation des installations du producteur dans le document ''Exigences techniques du transporteur relatives au raccordement des centrales au réseau d'Hydro-Québec''.

Il est à noter que dans ces conditions, toute la capacité du système d’excitation doit être utilisée sans causer le déclenchement du système d’excitation et/ou de l’alternateur. À cet effet, des circuits limiteurs de sur et de sous excitation doivent être prévus pour prendre le contrôle du système d’excitation au besoin et forcer le courant de champ à demeurer à l’intérieur des limites imposées soit par la surcharge du système d’excitation (limiteur de surexcitation) ou encore par celles imposées par la perte de synchronisme et/ou les protections de l’alternateur (limiteur de sous-excitation).

3.0 RÉGULATEUR DE TENSION

Le comportement dynamique du système d'excitation en boucle ouverte doit être équivalent à celui d'une constante de temps de 0.02 seconde. Le gain doit être ajustable d'une façon continue de 10 à 400 p.u. Le régulateur de tension doit essentiellement être un contrôleur de type proportionnel afin d'éviter de modifier la fonction de transfert totale du stabilisateur et ce pour toute la plage de fréquence d'intérêt des différents circuits stabilisateurs. Le transducteur de mesure de la tension aux bornes doit être muni d'un filtre qui donne un facteur d'atténuation d'au moins 20dB à 60 Hz.

Le régulateur doit être muni d'un signal de stabilisation qui est introduit au niveau du sommateur de la tension de consigne et de la mesure de tension filtrée (sortie du traducteur de la mesure de tension et de son filtre).

Une entrée spécifique (analogique ou numérique) doit être prévue pour permettre l'addition aisée d'un signal de stabilisation (analogique ou numérique) en provenance d’une plate-forme matérielle différente de celle comprise avec le système d’excitation de la présente fourniture. L’échantillonnage de ce signal doit être effectué en première priorité par le régulateur de tension et ce avec un taux inférieur à 10 ms.

Le gain du régulateur de tension doit être modifié automatiquement lorsqu'il y a panne d'alimentation ou défectuosité du stabilisateur, défaut mécanique à l’alternateur ou encore lorsque le stabilisateur est mis hors service et que le disjoncteur principal est fermé. Le nouveau gain doit être ajustable de 10 à 100 p.u.

4.0 CIRCUITS LIMITEURS

Le système d'excitation doit comprendre un circuit limiteur de surexcitation ainsi qu'un circuit limiteur de sous-excitation.

4.1 Limiteur de surexcitation

Lors des sous-tensions temporaires, le système d'excitation doit demeurer en fonction pour ramener progressivement la tension aux bornes de l'alternateur près de sa valeur nominale. Un circuit limiteur de surexcitation doit prendre le contrôle du système d'excitation et réduire le courant de champ près de sa capacité nominale lorsque la capacité d'échauffement maximale du système d'excitation, mesurée par l'intermédiaire du courant de champ, est dépassée.

Le circuit limiteur de surexcitation doit avoir un comportement dynamique qui permet d'atténuer adéquatement les variations transitoires et ce, indépendamment des valeurs de réglage du régulateur de tension.

4.2 Limiteur de sous-excitation

Lors des surtensions temporaires, le système d'excitation doit demeurer en fonction pour ramener progressivement la tension aux bornes de l'alternateur près de sa valeur nominale. Lorsque le courant de champ devient trop faible, un circuit limiteur de sous-excitation doit prendre le contrôle du système d'excitation et maintenir le courant de champ de l'alternateur à une valeur suffisante pour éviter de perdre le synchronisme ou de déclencher celui-ci par la protection de perte de champ.

Le circuit limiteur de sous-excitation doit avoir un comportement dynamique qui permet d'atténuer adéquatement les variations transitoires et ce, indépendamment des valeurs de réglage du régulateur de tension.

5.0 ESSAIS SUR LE SYSTÈME D'EXCITATION

Les systèmes d'excitation doivent être soumis à des essais permettant une vérification complète des caractéristiques et des performances du système d'excitation. De plus, les essais doivent permettre d'identifier, bloc par bloc, les fonctions de transfert de tous les éléments qui constituent le système d'excitation (amplificateurs, constantes de temps, réponse des capteurs, limiteurs, éléments non linéaires, boucles auxiliaires de contrôle).

Les systèmes d'excitation doivent également être soumis à des essais de réception sur le site afin de s'assurer du bon fonctionnement de l'ensemble avec les réglages spécifiés par le transporteur et qu'ils respectent les exigences spécifiées dans ce document.

1.0 DESCRIPTION

Le but du signal de stabilisation est d'améliorer l'amortissement des oscillations de puissance d'une machine en modulant sa tension par l'intermédiaire de son système d'excitation. La phase et l'amplitude du signal de stabilisation sont minutieusement réglées pour obtenir l'amortissement désiré des oscillations de puissance. Le stabilisateur multi-bandes de type delta-oméga doit être réalisé sur une plate-forme numérique. Les principales fonctions comprises dans le stabilisateur sont d'une part, la synthèse de vitesse du rotor à partir des signaux de tension et de courant de l'alternateur et, d'autre part, la réalisation de la fonction de transfert du stabilisateur à l'aide d'une structure à trois bandes de fréquence.

2.0 SYNTHÈSE DE LA VITESSE DU ROTOR

La synthèse de la vitesse du rotor doit être calculée à partir des tensions et des courants qui sont mesurés aux bornes de l'alternateur. Cette synthèse doit être réalisée par deux capteurs numériques. Le premier capteur fournit le signal d'entrée de la bande basse-fréquence et de la bande de fréquence intermédiaire. Le second capteur fournit le signal d'entrée de la bande haute-fréquence. Le comportement dynamique des capteurs doit être équivalent à celui des modèles linéaires de la figure ci-dessous. Deux filtres numériques de type coupe-bande montés en cascade doivent être disponibles en option pour les applications avec des turbo-alternateurs afin d'atténuer suffisamment les effets des modes torsionnels sur la mesure de vitesse.

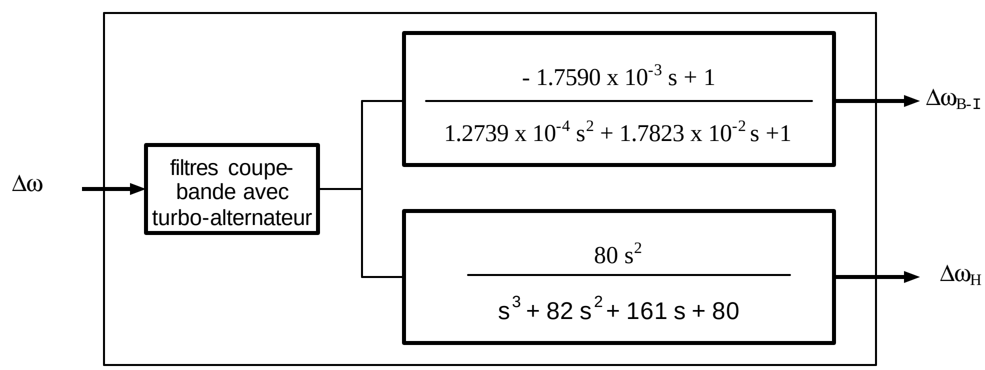

Figure 1 - Capteurs de vitesse du rotor

Lorsque des filtres coupe-bande $N_i\,(s)$ sont requis, ils doivent être réglables en fonction de la fréquence de résonance w_i et de la caractéristique de largeur de bande B_i à -3 dB tel que définis dans l'équation suivante :

$$N_i(s) = \frac{s^2 + w_i^2}{s^2 + B_i s + w_i^2}$$

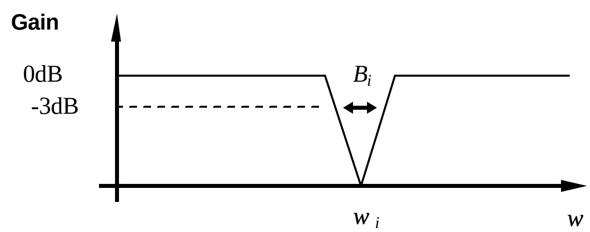

Figure 2 - Caractéristiques des filtres coupe-bandes

3.0 FONCTION DE TRANSFERT DU STABILISATEUR

3.1 Description

La fonction de transfert du stabilisateur multi-bandes doit être de la forme montrée à la figure 3. Cette fonction doit être conçue pour agir séparément sur trois bandes de fréquences. Chacune des bandes doit disposée d'un gain global et d'un limiteur. La fonction de transfert doit comprendre également un limiteur à la sortie du stabilisateur. Chacune des bandes doit être constituée de deux segments montés en filtre différentiel qui doivent comprendre chacun un gain, un bloc avance-retard ou passe-haut ainsi que deux blocs avance/retard.

La fonction de transfert doit disposer de deux entrées qui correspondent aux sorties des capteurs de vitesse qui sont définis à la section précédente. L'entrée de la bande basse-fréquence et de la bande de fréquence intermédiaire est la vitesse $\Delta\omega_{B-I}$ et l'entrée de la bande haute-fréquence est la vitesse $\Delta\omega_{H}$. La sortie de la fonction de transfert est le signal de stabilisation V_{ST}. Cette sortie doit être raccordée comme entrée au point de sommation de l'erreur de tension sur le régulateur de tension du système d'excitation de l'alternateur.

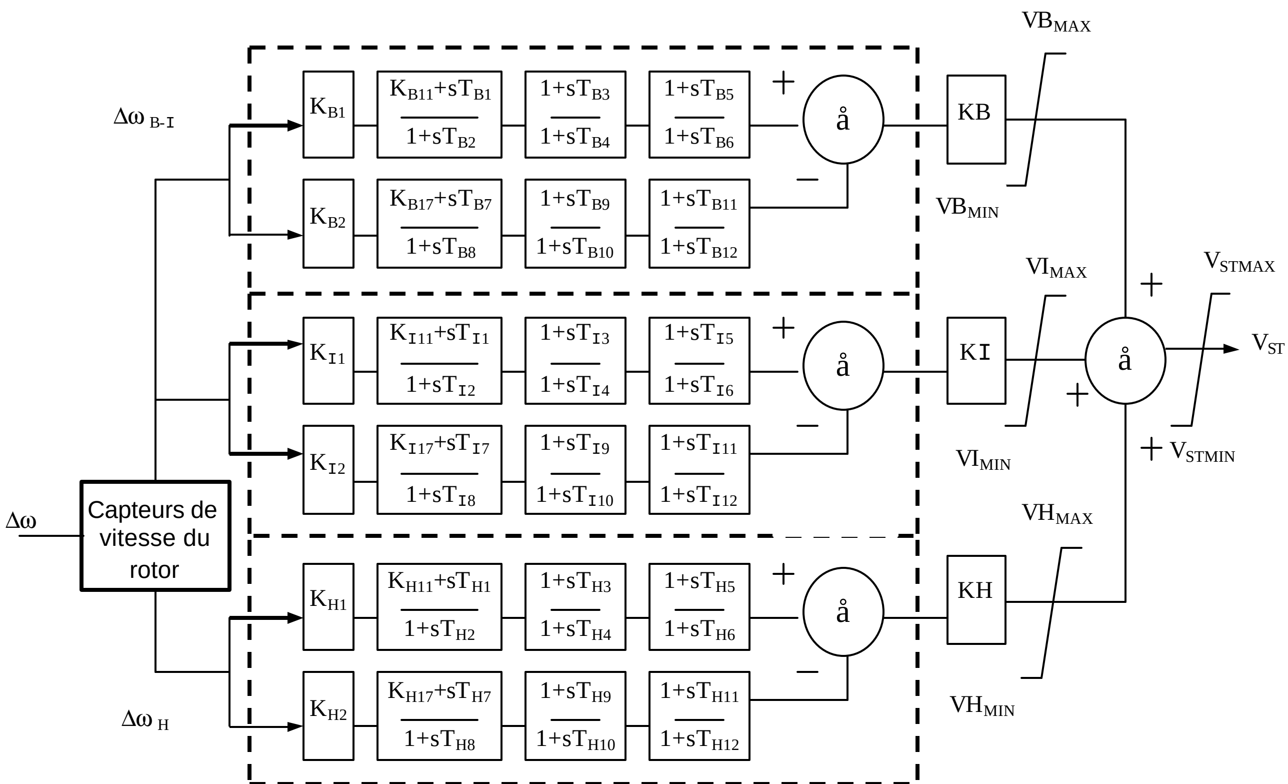

Figure 3 - Fonction de transfert du stabilisateur multi-bandes

3.2 Plage de réglages

Les paramètres KB1, KB2, KB, KI1, KI2, KI, KH1, KH2 et KH sont des gains et doivent être réglables sur une gamme de 0.00 à 300.00 p.u. par incrément d'au plus 0.01 p.u. Les paramètres KB11, KB17, KI11, KI17, KH11 et KH17 doivent être utilisés sur le premier bloc de chacun des segments de la fonction de transfert pour permettre de modéliser un bloc passe-haut ou un bloc avance-retard. Si le paramètre est nul alors le bloc est défini comme un bloc passe-haut. Si le paramètre est égal à un alors le bloc est défini comme un bloc avance-retard. Ces paramètres ne peuvent prendre que les valeurs zéro ou un.

Les constantes de temps TB1, TB2, TB3, TB4, TB5, TB6, TB7, TB8, TB9, TB10, TB11, TB12, doivent être réglables sur une gamme de 0.000 à 30.000 secondes par incrément d'au plus 0.001 seconde. Les constantes de temps TI1, TI2, TI3, TI4, TI5, TI6, TI7, TI8, TI9, TI10, TI11, TI12, doivent être réglables sur une gamme de 0.0000 à 3.0000 secondes par incrément d'au plus 0.0001 seconde. Les constantes de temps TH1, TH2, TH3, TH4, TH5, TH6, TH7, TH8, TH9, TH10, TH11 et TH12 doivent être réglables sur une gamme de 0.00000 à 0.30000 secondes par incrément d'au plus 0.00001 seconde.

La sortie de chacune des bandes de fréquence doit être limitée et la sortie de la somme des trois bandes de fréquence doit être également limitée. Les plafonds positif et négatif de ces limiteurs doivent être réglables indépendamment. Les plafonds positifs V_{BMAX}, V_{IMAX}, V_{HMAX}, et V_{SMAX} doivent être réglables sur une gamme de 0.00 à 1.00 p.u. par incrément d'au plus 0.01 p.u. et les plafonds négatifs V_{BMIN}, V_{IMIN}, V_{HMIN} et V_{SMIN} doivent être réglables sur une gamme de -1.00 à 0.00 p.u. par incrément d'au plus 0.01 p.u.

Un gain doit être prévu pour adapter la sortie du signal de stabilisation avec l'entrée sur le sommateur de l'erreur de tension du régulateur de tension. La plage de réglage doit être suffisante pour s'adapter aux divers systèmes d'excitation existants sur lesquels le stabilisateur multi-bandes peut être implanté.

4.0 Commande logique

La fonction de la commande logique doit à partir de certaines entrées logiques commander le fonctionnement du stabilisateur avec le système d'excitation.

Entrées logiques

- Commande externe En/hors local (contact sec ou interface personne-machine).
- Commande externe En/hors à distance (par commande impulsionnelle).
- Défaut mécanique (contact *sec).*

***Sorties* logiques**

- Commande de réduction du gain du régulateur de tension (contact sec).
- État de la commande en/hors du stabilisateur envoyé vers l'annonciateur et l'ECE (un contact sec à chacun). Il est à noter qu'un seul contact sec est suffisant si la centrale dispose d'un système informatisé de conduite d'une centrale (SICC).
- Signalisation du défaut du stabilisateur vers l'annonciateur et l'ECE (un contact sec à chacun). Il est à noter qu'un seul contact sec est suffisant si la centrale dispose d'un système informatisé de conduite d'une centrale (SICC).

Signaux internes

- Vitesse synthétisée exprimée en p.u. et calculée par l'algorithme de synthèse de vitesse.
- Puissance active (Pe) exprimée en p.u. et calculée par l'algorithme de synthèse de vitesse.
- Courant de séquence directe (I) exprimé en p.u. et calculé par l'algorithme de synthèse de vitesse.
- Défaut stabilisateur provenant des algorithmes de supervision du stabilisateur.
- Essai de réponse à un créneau en boucle ouverte.

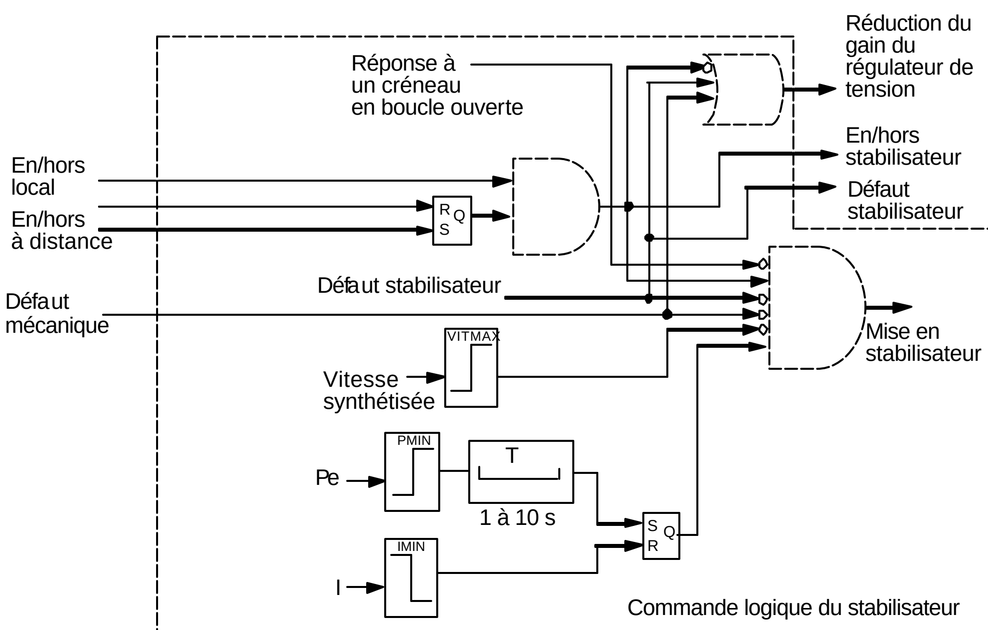

Figure 4 - Commande logique du stabilisateur multi-bandes

STABILISATEUR MULTI-BANDES DE TYPE DELTA-OMÉGA	MB-PSS-01-02

4.1 Commande locale et à distance du stabilisateur

Le signal de stabilisation doit pouvoir être mis en ou hors service localement ou à distance. La mise hors service du signal de stabilisation doit également commander, par l'intermédiaire d'un contact sec, une réduction du gain du régulateur de tension du système d'excitation de l'alternateur à une valeur présélectionnée.
Lorsque le stabilisateur est mis hors service localement, la commande de mise en/hors service à distance n'est plus permise. Toutefois la mise hors service locale ne doit pas bloquer le fonctionnement de la bascule de la commande à distance. Ainsi lorsque le stabilisateur est mis en service localement, on doit retrouver le dernier état de fonctionnement mémorisé de la bascule de la commande à distance.

4.2 Survitesse

Pour les groupes hydrauliques, le signal de stabilisation doit être mis hors service dès que la vitesse du groupe dépasse un seuil, Vitmax, réglable entre 105% et 120% de sa vitesse nominale. Le but de cette fonction est de limiter la surtension dynamique provoquée par le délestage de la charge d'une centrale. La vitesse doit être évaluée en temps réel par le stabilisateur (algorithme de synthèse de vitesse).

4.3 Défaut mécanique (86)

Le signal de stabilisation doit être mis hors service lors de la détection d'un défaut mécanique à l'alternateur par l'intermédiaire d'un contact sec en provenance de ces protections. La mise hors service du signal de stabilisation doit également commander, par l'intermédiaire d'un contact sec, une réduction du gain du régulateur de tension du système d'excitation de l'alternateur à une valeur présélectionnée

4.4 Synchronisation du groupe

Le signal de stabilisation ne doit entrer en service qu'après un délai suffisant pour permettre l'atteinte d'un régime équilibré lors de la synchronisation du groupe. Un régime équilibré est atteint si le disjoncteur principal du groupe a été préalablement fermé et qu'un minimum de puissance active a été générée pendant un délai réglable. La puissance active est évaluée en temps réel par le stabilisateur (algorithme de synthèse de vitesse). Une fois le stabilisateur en service, il doit demeurer en service quelque soit la valeur de la puissance active et ce jusqu'à la mise hors service du stabilisateur.

La variable logique de détection de puissance Pmin dépend des réglages suivants:
- la variable logique de détection de puissance active peut prendre les valeurs 1 ou 0 selon que le seuil minimum de puissance est ou non dépassé. Ce seuil est réglable de 0.1 à 0.2 p.u. sur la base de la puissance nominale de la machine.
- le délai est réglable de 1 à 10 sec

La condition de remise à zéro de la fonction de synchronisation du groupe est initiée lors du déclenchement du disjoncteur principal du groupe. L'état du disjoncteur est obtenu par la détection d'un bas courant de séquence directe Imin. Le courant est évalué en temps réel par le stabilisateur (algorithme de synthèse de vitesse). La détection de l'état du disjoncteur dépend des réglages suivants:

- la variable logique de la détection du bas courant peut prendre les valeurs 0 ou 1 selon que le seuil de bas courant est ou non dépassé après une temporisation fixe réglée à 1.0 seconde. Ce seuil est réglable de 0.05 à 0.10 p.u. du courant de séquence directe sur la base de la puissance nominale de la machine.

4.5 Défaut du stabilisateur

Le signal de stabilisation doit être mis hors service lors de la détection d'un défaut du stabilisateur à partir des algorithmes de supervision du stabilisateur. La mise hors service du signal de stabilisation doit également commander, par l'intermédiaire d'un contact sec, une réduction du gain du régulateur de tension du système d'excitation de l'alternateur à une valeur présélectionnée. Les algorithmes de supervision doivent inclure la détection d'un défaut du stabilisateur au moins dans les conditions suivantes:

- erreur détectée par le chien de garde dédié au stabilisateur (watch dog timer).
- erreur détectée lors de la perte d'une, de deux ou de trois phases de courant
- erreur détectée lors de la perte d'une, de deux ou de trois phases de tension.

4.6 Réponse à un créneau en boucle ouverte

Lors de l'essai de réponse à un créneau en boucle ouverte, le stabilisateur doit être mis hors sans réduction du gain du régulateur de tension.

4.7 Réduction du gain du régulateur de tension

Un seul contact sec est nécessaire pour la réduction du gain du régulateur de tension du système d'excitation de l'alternateur. Les trois conditions qui nécessitent la réduction du gain du régulateur de tension soit, la mise hors service du stabilisateur (voir 4.1), la détection d'un défaut dans le stabilisateur (voir 4.5) ou la détection d'un défaut mécanique de l'alternateur (voir 4.3) doivent être regroupés dans une fonction OU logique comme montré à la figure 4.

5.0 ESSAIS FONCTIONNELS DU STABILISATEUR

Des essais fonctionnels doivent être réalisés sur le stabilisateur afin de vérifier les caractéristiques et les performances de celui-ci et de valider les réglages implantés. À cet effet, le stabilisateur doit comprendre une fonction interne qui permet de réaliser un essai de réponse à un créneau du stabilisateur.

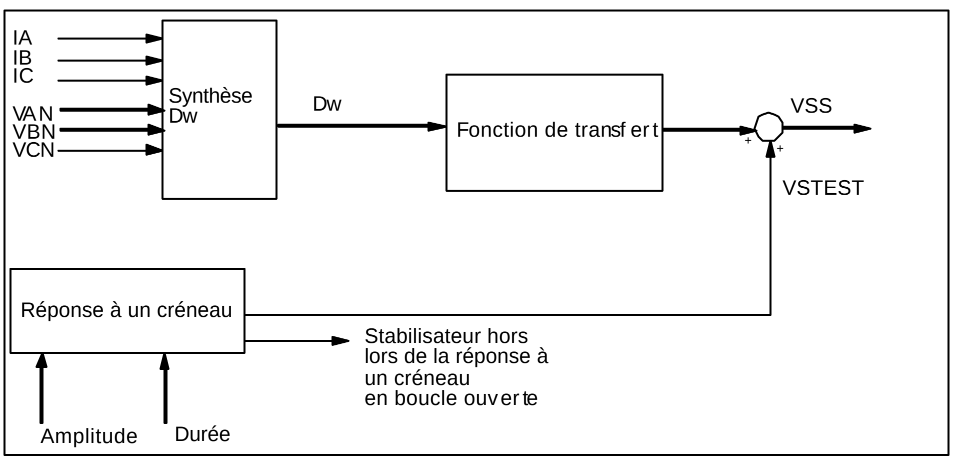

Figure 5 - Réponse à un créneau du stabilisateur multi-bandes

Cette fonction interne du stabilisateur a pour but de vérifier le bon fonctionnement de l'installation qui comprend le stabilisateur, le système d'excitation ainsi que l'alternateur synchronisé au réseau et ce selon les réglages désirés et de valider le comportement prévu par les études de simulation. L'essai de la réponse à un créneau peut être réalisé avec le stabilisateur en boucle ouverte ou en boucle fermée. Il est à noter que l'essai en boucle ouverte doit commander la mise hors du stabilisateur sans réduction du gain du régulateur de tension. Le signal interne du créneau est injecté au sommateur du signal de sortie du stabilisateur.

Signaux internes:

- La sortie de la fonction de réponse à un créneau est le signal VSTEST exprimé en p.u.
- L'essai de la réponse à un créneau en boucle ouverte doit commander la mise hors du stabilisateur sans réduction du gain du régulateur de tension.

Paramètres internes:

- La durée du créneau doit être fournie comme paramètre pour l'essai de réponse au créneau. La durée doit être réglable de 0 à 1.00 secondes.
- L'amplitude du créneau doit être fournie comme paramètre pour l'essai de réponse au créneau. L'amplitude doit être réglable de 0 à plus et moins 0.10 p.u.

Projets technologiques - Exploitation

Spécification d'exigences
Acquisition des données éoliennes

HQ-0230-01
15 octobre 2010

Ce document a été rédigé par Mario Vandal.

Fiche de contenu

Version	Date	Auteur	Commentaire
1.2	03/09/2010	Mario Vandal	Section A.1, A.1.8, A.1.9, A.1.10, A.1.11 Nouvelles données du système de gestion centralisé du parc éolien : consigne de tension, de statisme, de facteur de puissance et de limitation supérieure de la puissance produite. Section B.2 et B.2.2 Nouvelle donnée éolienne : Température au niveau de la nacelle Section B.1.1 Correction de la formule de calcul de la direction moyenne du vent
1.1	27/11/2007	Mario Vandal	Section 1.2.: Précisions sur le mécanisme de libération des connexions TCP. Section 2.1: Précision concernant le temps alloué à la transmissions des données pour une liaison par satellite. Section A.1 : Ajout de nouvelles données d'exploitation du poste: État des sélecteurs EN/HORS des téléprotec tions et état d'opération de la nouvelle protection de défaillance des disjoncteurs (protection «C»). Section B.3.1: Ajout des états d'opérations « Run up / Idling» et« Weather conditions» dans les conditions associées à l'état de disponibilité d'une éolienne.
1.0	03/02/2007	Mario Vandal	Émission officielle du document

À propos de ce document

Portée

Ce document décrit les exigences applicables aux dispositifs de communication utilisés dans les parcs éoliens pour la transmission des données éoliennes au système de conduite des centres informatiques de téléconduite (CIT) de la division TransÉnergie d'Hydro-Québec.

Sont exclus les données demandées par les divisions Distribution et Production pour fin d'études particulières en temps différé.

Auditoire

Ce document est destiné aux responsables de l'ingénierie des dispositifs de communication des Producteurs éoliens ainsi qu'au personnel de la direction Téléconduite impliqué dans la normalisation des stratégies d'acquisition des données éoliennes.

Abréviations

Tableau 1 Abréviations	
Abréviations HQ	**Description**
CCR	Centre de conduite du réseau
CIT	Centre Informatique Téléconduite
CT	Centre de Téléconduite : regroupement d'un CIT et de une ou plusieurs PAT
GEN-4	Système de contrôle et d'acquisition de données automatisé de la compagnie SNC-Lavalin utilisé dans les centres de téléconduite d'Hydro-Québec
HQD	Hydro-Québec Distribution
HQP	Hydro-Québec Production
N-510	Encadrement de la direction Téléconduite qui définit les règles de gestion des points d'alarme
PAT	Place d'Affaires Téléconduite
SOA	Service d'Ordinateur d'Acquisition
SOP	Service d'Ordinateur Principal
ST	Station Terminale

Références

Tableau 2 Références	
Groupe d'utilisateurs DNP	
[DNP-1]	« DNP 3.0 Subset definitions » , version 2.0 novembre 1995
[DNP-2]	« Transporting DNP V3.00 over Local and Wide Area Network “, version 1.0 décembre 1998
[DNP-3]	“DNP3-2001” – IED Certification Procedure subset Level 2, version 2.1, juillet 2001
SNC-Lavalin	
[SNC-1]	DNP3 Profile Document, ECS-DD-2000064
GE Energy	
[GE-1]	Technical Documentation – Wind Turbine Generator System, General Description, GEWE SCADA - RTCore OPC Server

Abrégé

Table des matières

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Chapitre 1 Exigences de communication

Ce chapitre présente les exigences de communication applicables aux dispositifs de communication des parcs éoliens. Elles sont divisées en deux catégories:

- Exigences de l'interface de communication
- Exigences du protocole de communication

1.1 Exigences de l'interface de communication

La Figure 1 illustre l'architecture de communication mise en œuvre. Le système de conduite GEN-4 d'un centre informatique Téléconduite (CIT) est responsable de l'acquisition des données éolienne. Il effectue la retransmission d'une partie de ces données selon les besoins et accès autorisés aux systèmes d'acquisition des utilisateurs externes soit les divisions Distribution (HQD), Production (HQP) ainsi que le CCR. La retransmission s'effectue par des liens de communication ICCP.

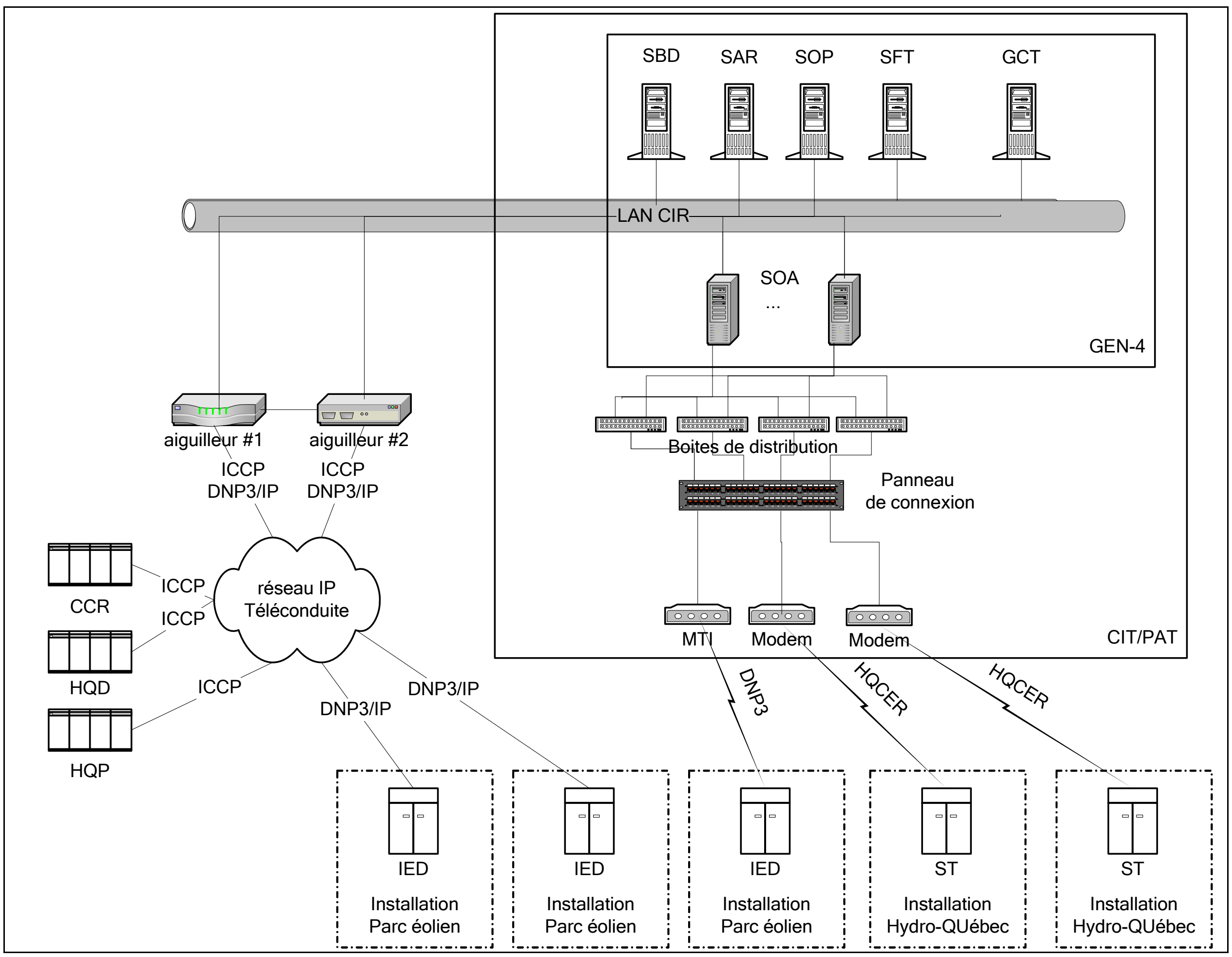
L'échange de données entre le système de conduite GEN-4 et le dispositif de communication d'un parc éolien peut s'effectuer de deux façons, soit à l'aide du réseau IP haute sécurité de Téléconduite ou par un lien de télécommunication dédié. Les exigences applicables aux interfaces de communication du dispositif sont les suivantes:

- Le dispositif doit être équipé d'une interface Ethernet 10 ou 100 Mbit/s permettant le raccordement au micro garde-barrière installé dans l'armoire de télécommunication d'Hydro-Québec.
- Le raccordement s'effectue à l'aide d'une interface en cuivre de type 100base-T (RJ45).
- Pour répondre aux exigences de sécurité informatique de Téléconduite, l'interface Ethernet ne doit être raccordée d'aucune façon au réseau de contrôle du Producteur éolien. Le dispositif devra être équipé d'une deuxième interface Ethernet pour les besoins d'échange de données avec les équipements de ce réseau. Cette exigence découle des besoins suivants :
  - Assurer une isolation entre le réseau de contrôle du Producteur éolien et le réseau IP d'Hydro-Québec.
  - Se prémunir contre le risque d'usurpation d'adresse IP (« spoofing ») par les utilisateurs externes qui ont accès au réseau de contrôle du Producteur éolien.
- L'adresse IP de l'interface Ethernet sera assignée par Hydro-Québec

- La bande passante requise pour les communications IP est estimée à 56 Kbit pour chaque parc éolien.
- Le dispositif doit être équipé d'une interface de communication de type RS-232 permettant le raccordement à un modem asynchrone pour la transmission des données à l'aide d'un lien de télécommunication dédié.

  Cette exigence est applicable uniquement si les infrastructures de télécommunication Hydro-Québec ne permettent pas un accès sécurisé au réseau IP haute sécurité de Téléconduite. Un lien asynchrone 19.2Kb est requis pour ce mode de communication.

Figure 1 - Architecture de communication du système



1.2 Exigences du protocole de communication

- Le protocole de communication DNP3 est exigé pour l'échange de données entre le dispositif de communication du parc éolien et le système GEN-4. Le rôle de maître est attribué au système GEN-4 et le rôle d'esclave au dispositif de communication.
- Le niveau d'implantation 2 est requis pour le protocole DNP3. Se référer au document DNP V3.00 ,SUBSET DEFINITIONS normalisé par le groupe d'usager DNP à ce sujet [DNP-1]
- L'encapsulation du protocole DNP3 dans une trame TCP/IP doit être supporté tel que défini dans le document « Transporting DNP V3.00 over Local and Wide area network » [DNP-2].
- Le dispositif de communication du parc éolien doit traiter les demandes de connexion TCP adressées au port 20,000. Ces demandes proviennent de 4 dispositifs maîtres associés au système GEN-4. Chaque dispositif maître utilise une adresse IP unique. Le dispositif de communication doit maintenir une seule connexion TCP active avec un des quatre dispositifs maîtres. Une connexion TCP active doit être libérée sur demande du dispositif maître ou sur expiration d'une minuterie de 45 secondes indiquant l'absence de message en provenance du maître.
- Afin de respecter l'exigence d'âge maximum d'une seconde pour certaines données, le dispositif de communication du parc éolien a l'obligation de transmettre les changements détectés à l'aide du mode de réponse non sollicité (« unsolicited response»). Le dispositif doit supporter les requêtes d'activation/inhibition de ce mode en provenance du système de conduite CIT.
- Le dispositif doit être en mesure de répondre aux requêtes de lecture d'intégrité transmises par le système de conduite du CIT selon une fréquence configurable. Cette requête est associée à la lecture des quatre classes de données (objet 60, classes 1,2,3,0) définies dans le protocole DNP3.
- Les règles d'utilisation des 3 classes de données de type événement sont les suivantes :
  - Classe 1 (haute priorité) : signalisations et alarmes reportées sur détection d'un changement (données temps réel)
  - Classe 2 (moyenne priorité) : mesures reportées sur détection d'un changement (données temps réel)
  - Classe 3 (basse priorité) : données rapportées en fonction d'un cycle de plusieurs minutes (données des éoliennes, des mâts météorologiques et de production du parc)
- Le mappage des points dans les 3 classes d'événement doit être configurable à partir des outils de maintenance du dispositif. Le support du mode de configuration à partir du système maître sera considéré comme un avantage supplémentaire.

- Le dispositif de communication doit permettre la configuration du mode de confirmation des trames de la couche lien et des messages de la couche application. Le mode de confirmation des trames niveau lien ne devrait pas être utilisé.
- Le dispositif doit supporter la transmission de message application (ASDU) d’une longueur de 2kbits.
- Le dispositif doit supporter la séquence d’initialisation transmise par le système de conduite GEN-4 du CIT. Se référer au document DNP3 Profile Document de SNC-Lavalin [SNC-1] et à l’annexe C.

Chapitre 2 Exigences d’acquisition des données

Ce chapitre présente les exigences applicables aux données qui doivent être transmises au système de conduite d’un CIT. Les exigences sont divisées en quatre catégories selon la nature des données :

- Les données du poste électrique
- Les données des mâts météorologiques
- Les données des éoliennes
- Les données de production du parc éolien

2.1 Données d’exploitation du poste électrique (poste de départ)

Les exigences applicables pour les données du poste électrique sont les suivantes :

- Les données doivent être transmises de deux façons :
  - Par le mode de réponse non sollicité suite à la détection par le dispositif d’un changement de la valeur ou des indicateurs de qualité d’une donnée. Ce mode de réponse est associé aux classes de données de type événements.
  - Sur demande d’une requête de lecture d’une des classes de données (0,1,2 ,3) par le système de conduite du CIT.

  Se référer aux exigences du protocole de communication.
- L’utilisation des classes de données de type événement est précisée au Tableau 3. Les données du poste électrique sont de type temps réel.

Tableau 3 Utilisation des classes événement 1,2,3

Classe	Type de données
1	Signalisations d’appareils et alarmes temps réel
2	Mesures d’appareil (MW,MX, KV,A..) temps réel
3	Données statistiques calculées sur un intervalle de temps

- lorsque le dispositif de communication initie la transmission d’une donnée temps réel par le mode de réponse non sollicité, l’âge maximum de cette donnée doit être de :
  - 1 seconde pour les signalisations et alarmes temps réel
  - 3 secondes pour les mesures temps réel

Il est recommandé de disposer d'une réserve de 100 msec allouée au temps de transmission et au temps traitement de la donnée par les frontaux de communication du système de conduite CIT. Cette réserve est applicable à une liaison par fibre optique. Elle doit être de 650 msec pour une liaison par satellite.

- Pour chaque donnée, le dispositif de communication doit transmettre une valeur accompagnée d'indicateurs de qualité permettant d'en déterminer la validité. Les objets DNP3 requis pour le reportage de ces données sont précisés au Tableau 4. Les compteurs d'énergie y sont présentés à titre de référence car il n'y a pas de besoins actuellement pour ce type de donnée.
- Tous les points de mesure sont en unité d'ingénierie. La valeur d'une mesure est transmise à l'aide d'un entier 32 bits signé (objets 30 et 32). Cette valeur doit être multipliée par un facteur d'échelle de 100 avant sa transmission afin d'inclure une résolution de 2 chiffres pour la partie décimale.
- Pour les signalisations, la valeur 1 indique l'état fermé pour un appareil, la présence d'une condition d'alarme pour un point d'alarme, l'état normal (non bloqué) des sélecteurs d'inhibition des téléprotections, l'état en fonction du système de gestion centralisé du parc ou son mode de régulation en tension.
- Une bande morte correspondant à un pourcentage de la valeur pleine échelle doit être configurable sur chaque point de mesure à partir des outils de configuration du dispositif. Cette bande morte vise à réduire le nombre de reportage en relation avec la détection de changements sur les points de mesure. La valeur par défaut est de 1 %. Des changements pourront être apportés selon les besoins lors des essais chantier ou à la suite de la mise en exploitation.
- La liste des données requises pour un poste électrique est présentée à l'annexe A. On y retrouve également des précisions sur le traitement de ces données.

Tableau 4 Objet/variation DNP3 pour les données éoliennes

Type de données	Objet	Variation	Description
Mesures analogiques/numériques	30 32	1 1	32 bit analog input 32 bit analog change event without time
Signalisations/alarmes	1 2	2 1	Binary input with status Binary input change without time
Compteurs d'énergie (KWH)	20 22	1 1	32 Binary Counter 32 Binary Counter without time

2.2 Données d'un mât météorologique

Les exigences applicables pour les données d'un mât météorologique sont les suivantes :

- Toutes les exigences décrites pour les données du poste électrique sont applicables à l'exception du critère de changement qui déclenche le reportage de ces données. Le critère requis est un reportage initié par le dispositif de communication à un intervalle de dix minutes à la suite de la compilation de données statistiques pour tous les points. Ce critère répond aux besoins suivants :

  - Éviter de monopoliser la bande passante du lien de télécommunication en raison de la fréquence élevée de changement des valeurs et du grand nombre de points.

  - Répondre aux exigences des utilisateurs soit une de compilation de données statistiques sur un intervalle de 10 minutes. Cette exigence fait en sorte que le dispositif doit maintenir deux tables de valeurs, soit les valeurs acquises des appareils de mesure et les valeurs compilées par ses fonctions internes de calcul. Le dispositif doit initier l'envoi des valeurs compilées à l'aide de la classe événement 3 une fois la période de compilation expirée.

    Il y a 6 intervalles de calcul par heure. Ils sont synchronisés sur l'heure juste. Pour l'heure *h*, ces intervalles sont :]*h:00,h:10],]h:10,h:20],]h:20,h:30],]h:30,h:40],]h:40,h:50] et]h:50,h:60]*. Les délimiteurs «] » et «] » indiquent respectivement les bornes ouvertes et fermées d'un intervalle.

    L'horloge du dispositif doit être synchronisée à partir d'un système de synchronisation externe basé sur le temps universel (ex IRIG-B, GPS, NTP). La précision demandée est de 0,5 seconde.

    Le dispositif doit avoir complété la transmission des données dans un délai maximum de 30 secondes suivant la fin d'un intervalle de calcul.

- Chaque donnée statistique doit être accompagnée d'un indicateur de qualité dont le traitement est le suivant :

  - La donnée est reportée valide s'il y a au minimum une mesure valide pour la compilation durant un intervalle de 10 minutes. La compilation s'effectue avec les mesures valides uniquement.

  - La donnée est reportée invalide lorsqu'il n'y a aucune mesure valide pour un intervalle de 10 minutes. La valeur transmise devra être celle de l'intervalle précédent ou 0 si non disponible.

- En cas d'une panne du lien de communication DNP3, le dispositif doit disposer d'une capacité de stockage permettant de conserver l'ensemble des données statistiques d'un intervalle de 10 minutes dans la classe événement 3. Lorsque la connexion DNP3 est rétablie, le dispositif doit être en mesure de retransmettre les données du dernier intervalle de 10 minutes qui ont été stockées durant la panne.
- Sur demande du responsable HQD ou HQP, le Producteur doit fournir les données des appareils de mesures qui sont conservées par l'enregistreur de données du mât (« data logger ») pour les 30 derniers jours. Ces données devront être transmises sous forme de fichiers. Le format des fichiers et le mode de transmission restent à préciser avec le demandeur en fonction des options disponibles.

La liste des données requises par mât météorologique est présentée à l'annexe B. On y retrouve également des précisions sur le traitement de ces données.

2.3 Données d'une éolienne

Les exigences applicables pour les données d'une éolienne sont les suivantes :

- Toutes les exigences décrites pour les données statistiques d'un mât météorologique sont applicables pour les données d'une éolienne à l'exception de la donnée *statut de la machine*. Ces données doivent être compilées et transmises par intervalle de 10 minutes.
- Toutes les exigences décrites pour les données du poste électrique sont applicables pour l'acquisition de la donnée *statut de la machine*. Ce statut est considéré comme une donnée temps réel qui doit être transmise à l'aide de la classe événement 2 du protocole DNP3 (Tableau 3). Le format est un entier 32 bits (objets 30 et 32).

La liste des données requises par éolienne est présentée à l'annexe B. On y retrouve également des précisions sur le traitement de ces données.

2.4 Données de production du parc éolien

Les exigences applicables pour les données de production du parc éolien sont les suivantes :

- Toutes les exigences décrites pour les données statistiques d'un mât météorologique sont applicables. Ces données doivent être compilées et transmises par intervalle de 10 minutes.

La liste des données de production requises par parc éolien est présentée à l'annexe B. On y retrouve également des précisions sur le traitement de ces données.

Chapitre 3 Exigences de configuration

Ce chapitre présente les exigences applicables à la configuration du dispositif de communication du parc éolien. Elles sont divisées en deux catégories:

- Paramètres de communication DNP3
- Liste des points

3.1 Paramètres de communication DNP3

- Le Producteur doit fournir la configuration des paramètres de communication DNP3 sous forme d'un document électronique. Le gabarit utilisé est celui identifié « Device profile document format » à l'appendice A du document DNP V3.00, SUBSET DEFINITIONS [DNP-1]
- Le document devra être livré aux responsables Téléconduite préalablement aux essais laboratoire si applicables ou pour les essais chantier
- Le Producteur devra préciser dans un document l'utilisation et l'interprétation des statuts de qualité définis dans la norme DNP3 pour les différents objets utilisés
- Le Producteur devra préciser dans un document l'utilisation et l'interprétation des statuts du mot d'état (IIN) qui sont définis dans la norme DNP3 pour un dispositif esclave

3.2 Liste de points

- Le Producteur doit fournir la liste des points dont les valeurs seront transmises au système de conduite CIT
- La liste doit être livrée sous forme d'un fichier MS-EXCEL dans lequel seront inclus trois feuilles de calculs: « entête », « liste des points de signalisation » et « liste des points de mesure ».
- La feuille de calcul « entête » précisera les informations suivantes :
  - le nom de l'installation
  - la date de mise en production de la liste de points
  - Le numéro de version du logiciel
  - Le numéro de version de la BDD
  - Le nom des responsables à contacter chez le Producteur et Hydro-Québec pour les besoins de maintenance

- L’adresse DNP3 des dispositifs maître et esclave. L’adresse 0 est utilisée pour le système GEN-4 (maître). Une adresse esclave unique doit être attribuée à chaque parc éolien
- Un historique de chaque changement, par ordre chronologique décroissant, dans lequel on retrouve la date, le responsable et un descriptif sommaire du changement

- Les feuilles « liste des points » fourniront l’information détaillée pour chacun des points transmis par le dispositif de communication. Les paramètres suivants seront requis pour chaque point :
  - Le type de point : mesure, mesure statistique, état, alarme, compteur d’énergie,.
  - L’adresse DNP3 en fonction du type de point
  - Le nom de point tel que défini dans l’installation du Producteur
  - Le nom du point tel que défini dans le système de conduite du CIT (paramètre HQ)
  - La description du point tel que définie dans l’installation du Producteur
  - L’interprétation de l’état 1 pour les points de signalisation
  - L’unité pour les points de mesure
  - Le facteur d’échelle appliqué dans le dispositif du Producteur
  - La bande morte appliquée (%)
  - La plage des valeurs (valeur maximale négative et positive)
  - L’objet DNP3 et la variation utilisés dans la réponse à une requête de lecture des classes de données 1, 2 et 3
  - L’objet DNP3 et la variation utilisés dans la réponse à une requête de lecture de la classe de données 0 si le format de la valeur diffère de celui utilisé pour les classes 1,2,3
  - Les statuts de qualité DNP3 applicables en fonction du(es) dispositif(s) source(s) (appareil de mesure)
  - Le nom du(es) dispositif(s) source(s) à partir duquel (desquels) la valeur du point est acquise
  - Le code de point d’alarme tel que défini dans la norme N-510 (paramètre HQ)
  - La description du point d’alarme tel que normalisé dans la BDD-510 de la direction Téléconduite (paramètre HQ)
  - Un champ « commentaire »

  La valeur des paramètres Hydro-Québec (paramètre HQ) sera transmise au Producteur par les responsables Téléconduite.

  Les champs « type de point » et « adresse DNP3 » constituent les clés primaire et secondaire pour le tri des données.

  Un exemple du gabarit Excel est disponible pour fin de consultation.

Chapitre 4 Exigences de certification

Ce chapitre présente les exigences applicables à la certification du dispositif de communication du parc éolien. Ces exigences sont divisées en deux catégories:

- Certification laboratoire
- Essais chantier

4.1 Certification laboratoire

- Le Producteur a l'obligation de fournir un dispositif pour des essais laboratoire qui seront réalisés sur le site Place Dupuis à Montréal. Le système GEN-4 de pré-production dédié au essais sera utilisé à cette fin.
- Le dispositif devra être équipé d'une console permettant la modification des valeurs des points de mesure et signalisation et si possible, des statuts de qualité des points et des statuts IIN.
- Le Producteur doit fournir les documents attestant la compatibilité du dispositif au niveau 2 de la norme DNP3. Se référer au document « Certification Procedure Subset Level 2 » [DNP-3] à ce sujet
- Le dispositif devra être livré avec la configuration chantier. Se référer aux exigences de configurations

L'exigence de vérification laboratoire est applicable à un nouveau modèle d'appareil utilisé par le Producteur ou à une nouvelle version du logiciel qui contient des changements majeurs. Lorsqu'un appareil d'un même modèle est déjà dans un parc éolien raccordé à un CIT, la certification laboratoire n'est pas requise.

4.2 Essais chantier

Des essais chantier sont requis avant la mise en exploitation du parc éolien. La liste des essais requis est la suivante:

- Confirmation verbale de la valeur locale pour chaque point transmis par le dispositif et de la valeur reçue par le système de conduite du CIT
- Essais de remise sous tension du dispositif de communication et des dispositifs d'acquisition des données (initialisation du système)
- Essais de panne du lien de télécommunication

La réussite de ces essais est une des étapes conditionnelles à l'acceptation du raccordement du parc éolien au réseau d'Hydro-Québec.

Chapitre 5 Exigences d’exploitation

Ce chapitre présente les exigences applicables au dispositif de communication du parc éolien en mode exploitation. Ces exigences sont divisées en trois catégories:

- Travaux planifiés
- Défaillance des dispositifs de communication et d’acquisition
- Rapport d’événement

5.1 Travaux planifiés

Le Producteur est tenu d'informer Hydro-Québec de tout travail ayant un impact sur la transmission des données en provenance de son parc éolien. L'objectif de cet avis est de réduire au minimum les conséquences de la réalisation des travaux dans un parc éolien et d'assurer, autant que possible, la continuité de la transmission des données requises par Hydro-Québec.

Ainsi, tout travail de maintenance affectant la transmission des données, toute mise à niveau de la configuration touchant la liste des points transmis ou toute mise à niveau du logiciel doit être planifié et précédé d'un avis au personnel d'Hydro-Québec (agents Planification des retraits) dix (10) jours avant le début des travaux. Afin d'uniformiser les façons de faire, le processus de communication requis est semblable à celui décrit au chapitre «Demande de retrait» dans l’instruction commune d’exploitation en vigueur pour chaque parc éolien.

5.2 Défaillance des dispositifs de communication et d’acquisition

La défaillance des dispositifs de communication et d'acquisition étant un événement fortuit, le Producteur est tenu d'informer le répartiteur du centre de téléconduite (CT) dans les meilleurs délais.

5.3 Rapport d’événement

Pour tout événement non planifié ou pour tout travail planifié affectant la transmission des données vers Hydro-Québec, le Producteur doit rédiger un «Rapport d'événement - Producteurs privés» et le transmettre selon les modalités mentionnées dans l'instruction commune d'exploitation.

Annexe A Données requises pour l'exploitation du poste électrique

Cet annexe présente la liste des données du poste électrique acquises par le système de conduite CIT pour les besoins d'exploitation du parc éolien par la direction Exploitation de TransÉnergie. On y retrouve également des précisions sur la définition et le traitement requis pour ces données.

A.1 Données d'exploitation du poste

Données	Fréquence d'échantillonnage	Unité	Accès en temps réel
Signaux d'alarme - protection	Voir section 2.1		
Opération de la protection « A » de ligne haute tension		-	Oui
Opération de la protection « B » de ligne haute tension		-	Oui
Condition anormale de la protection « A » de ligne haute tension		-	Oui
Condition anormale de la protection « B » de ligne haute tension		-	Oui
Opération de la protection « A » de sous-tension		-	Oui
Opération de la protection « B » de sous-tension		-	Oui
Opération de la protection « A » de surtension		-	Oui
Opération de la protection « B » de surtension		-	Oui
Opération de la protection « A » de sous-fréquence		-	Oui
Opération de la protection « B » de sous-fréquence		-	Oui
Opération de la protection « A » de surfréquence		-	Oui
Opération de la protection « B » de surfréquence		-	Oui
Opération de la protection « C » de défaillance du disjoncteur haute tension		-	Oui
Condition anormale de la protection « C » de défaillance du disjoncteur haute tension		-	Oui
Opération de la protection du transformateur haute tension (point regroupé)		-	Oui
Condition anormale de la protection différentiel du transformateur haute tension		-	Oui
Signaux d'alarme – téléprotection			
Réception d'un télédéclenchement en provenance de la protection «A» de l'installation HQ située à l'extrémité 1		-	Oui
Réception d'un télédéclenchement en provenance de la protection «A» de l'installation HQ située à l'extrémité 2		-	Oui
Réception d'un télédéclenchement en provenance de la protection «B» de l'installation HQ située à l'extrémité 1		-	Oui
Réception d'un télédéclenchement en provenance de la protection «B» de l'installation HQ située à l'extrémité 2		-	Oui
Réception d'un télédéclenchement en provenance de la protection «C» de l'installation HQ située à l'extrémité 1		-	Oui
Réception d'un télédéclenchement en provenance de la protection «C» de l'installation HQ située à l'extrémité 2		-	Oui
Émission par la protection «A» d'un téléblocage vers l'installation HQ située à l'extrémité 1		-	Oui
Émission par la protection «A» d'un téléblocage vers l'installation HQ située à l'extrémité 2		-	Oui
Émission par la protection «B» d'un téléblocage vers l'installation HQ située à l'extrémité 1		-	Oui
Émission par la protection «B» d'un téléblocage vers l'installation HQ située à l'extrémité 2		-	Oui
Émission par la protection «C» d'un télédéclenchement vers l'installation HQ situé à l'extrémité 1		-	Oui
Émission par la protection «C» d'un télédéclenchement vers l'installation HQ situé à l'extrémité 2		-	Oui
Condition anormale de la téléprotection «A» dédiée à l'installation HQ située à l'extrémité 1		-	Oui
Condition anormale de la téléprotection «A» dédiée à l'installation HQ située à l'extrémité 2		-	Oui

Données	Fréquence d'échantillonnage	Unité	Accès en temps réel
Condition anormale de la téléprotection «B» dédiée à l'installation HQ située à l'extrémité 1		-	Oui
Condition anormale de la téléprotection «B» dédiée à l'installation HQ située à l'extrémité 2		-	Oui
Condition anormale de la téléprotection «C» dédiée à l'installation HQ située à l'extrémité 1		-	Oui
Condition anormale de la téléprotection «C» dédiée à l'installation HQ située à l'extrémité 2		-	Oui
Signaux d'alarme – diverse	Voir section 2.1		
Basse pression SF6 du disjoncteur. haute tension (1er niveau)		-	Oui
Condition anormale du disjoncteur haute tension		-	Oui
Basse tension 129 Vcc - batterie 1		-	Oui
Basse tension 129 Vcc - batterie 2		-	Oui
Panne d'instruments d'acquisition		-	Oui
Signaux d'état			
État des disjoncteurs haute et moyenne tension		-	Oui
État des sectionneurs haute et moyenne tension incluant les sectionneurs de terre		-	Oui
État « en » ou « hors » du système de gestion centralisé du parc éolien		-	Oui
Mode de gestion centralisé sélectionné (tension ou facteur de puissance)		-	Oui
État « en » ou « hors » du sélecteur d'inhibition de la téléprotection « A » extrémité 1		-	Oui
État « en » ou « hors » du sélecteur d'inhibition de la téléprotection « A » extrémité 2		-	Oui
État « en » ou « hors » du sélecteur d'inhibition de la téléprotection « B » extrémité 1		-	Oui
État « en » ou « hors » du sélecteur d'inhibition de la téléprotection « B » extrémité 2		-	Oui
État « en » ou « hors » du sélecteur d'inhibition de la téléprotection « C » extrémité 1		-	Oui
État « en » ou « hors » du sélecteur d'inhibition de la téléprotection « C » extrémité 2		-	Oui
Mesures électriques			
Puissance active à la haute tension du poste		MW	Oui
Puissance réactive à la haute tension du poste		Mvar	Oui
Tension à la haute tension du poste (phase-phase A-B)		kV	Oui
Courant à la haute tension du poste (phase A)		A	Oui
Puissance active à chacune des lignes moyennes tension du poste		MW	Oui
Nombre d'éoliennes en production		-	Oui
Système de gestion centralisé du parc éolien			
État « en » ou « hors » du système de gestion centralisé du parc éolien		-	Oui
Mode de gestion centralisé sélectionné (tension ou facteur de puissance)		-	Oui
Consigne de tension (mode de gestion en tension)		kV	Oui
Consigne de statisme (mode de gestion en tension)		%	Oui
Consigne de facteur de puissance (mode de gestion avec facteur de puissance)		%	Oui
Consigne de limitation supérieure de la puissance produite (MW)		MW	Oui

A.1.1 Regroupement d'alarmes des dispositifs de protection

Un appareil de protection peut identifier la ou les phases en défaut en transmettant au Producteur un point d'alarme distinct pour chaque phase. Ce degré de précision, utile au Producteur, n'est pas requis pour Hydro-Québec. En conséquence, ces trois points d'alarme doivent être regroupés en un nouveau point qui doit être transmis à Hydro-Québec.

Si la qualité du point d'alarme d'un des appareils de protection est considérée douteuse par le dispositif de communication du parc éolien, le statut de qualité douteux doit être transmis à Hydro-Québec pour le point d'alarmes regroupées.

A.1.2 Calcul du nombre d’unités éoliennes en production

La donnée *nombre d’éoliennes en production* se définit comme étant la somme des éoliennes dont le statut d’opération indique une génération de puissance. Ce référer au statut « Turbine with grid connection » décrit dans la section B.2.3

Se référer à la section A.1.1 concernant le traitement du statut de qualité associé à la valeur transmise à Hydro-Québec.

A.1.3 Alarme de panne d’instruments d'acquisition

La donnée *Panne d'instruments d'acquisition* se définit comme suit :

> Tout mauvais fonctionnement d’un des dispositifs d’acquisition du Producteur qui compromet l'intégrité des données acquises par Hydro-Québec.

Cette condition doit être transmise à Hydro-Québec à l’aide d’un point d'alarme.

A.1.4 Sens des mesures de MW et Mvar à la haute tension du poste

Le sens des mesures de MW et Mvar à la haute tension du poste s’établit comme suit :

- Positif lorsque les MW et Mvar sont injectés dans le réseau d’Hydro-Québec
- Négatif lorsque les MW et Mvar sont reçus du réseau d’Hydro-Québec

A.1.5 Sens des mesures de MW à la basse tension du poste

Le sens des mesures de MW à la basse tension s’établit comme suit :

- Positif lorsque les MW sont injectés dans le réseau collecteur du Producteur
- Négatif lorsque les MW sont reçus du réseau collecteur du Producteur

A.1.6 Condition anormale de la téléprotection

La donnée *Condition anormale de la téléprotection indique le présence d'une des conditions* suivantes:

- Défaillance ou perte d'alimentation de la téléprotection

- Défaillance du lien de télécommunication
- État « hors » du sélecteur d'inhibition de la téléprotection

A.1.7 Mode de gestion centralisé sélectionné du parc éolien

Cette donnée indique le mode de gestion centralisé sélectionné. La valeur 0 correspond au mode de facteur de puissance et la valeur 1 au mode de tension. Pour la compagnie GE, le système de gestion centralisé est identifié *Wind Farm Management system* (WFMS).

A.1.8 Consigne de tension

Cette donnée indique la consigne de tension utilisée par le système de gestion centralisé lorsque ce dernier opère en mode de régulation par consigne de tension.

A.1.9 Consigne de statisme

Cette donnée indique le pourcentage de statisme utilisé par le système de gestion centralisé lorsque ce dernier opère en mode de régulation par consigne de tension.

A.1.10 Consigne de facteur de puissance

Cette donnée indique le facteur de puissance utilisé par le système de gestion centralisé lorsque ce dernier opère en mode de régulation par consigne de facteur de puissance. Les unités sont : % inductif ou % capacitif.

A.1.11 Consigne de limitation supérieure de la puissance produite

Cette donnée indique la limite supérieure de puissance pouvant être produite par le parc éolien si ce mode d'exploitation est requis pour une condition particulière de réseau.

Annexe B Données requises par les divisions HQD et/ou HQP

Cet annexe présente la liste des données d'un parc éolien qui sont acquises par le système de conduite CIT pour les besoins des divisions Distribution (HQD) et/ou Production (HQP) d'Hydro-Québec. On y retrouve également des précisions sur la définition et le traitement requis pour ces données.

Les données sont divisées en trois catégories soit :

- Données des mâts météorologiques
- Données des éoliennes
- Données de production du parc éolien

B.1 Données d'un mât météorologique

La précision des appareils de mesure de données météorologiques des mâts doit être conforme à la norme CSA-F417-M91

Données	Fréquence d'échantillonnage minimale	Période de compilation des statistiques	Statistiques compilées à transmettre	Unité	Cycle de transmission
Vitesse horizontale du vent (à chaque anémomètre du mât)	1/5 Hz	10 minutes	moyenne, minimum, maximum et écart-type	m/s	10 minutes
Vitesse verticale (à chaque anémomètre du mât si disponible)	1/5 Hz	10 minutes	moyenne, minimum, maximum et écart-type	m/s	10 minutes
Direction du vent (à chaque girouette)	1/5 Hz	10 minutes	moyenne, minimum, maximum et écart-type	Degrés (1)	10 minutes
Température (à chaque thermomètre du mât)	1/5 Hz	10 minutes	moyenne, minimum, maximum et écart-type	degrés Celsius	10 minutes
Humidité relative	1/5 Hz	10 minutes	moyenne, minimum, maximum et écart-type	%	10 minutes
Pression barométrique	1/5 Hz	10 minutes	moyenne, minimum, maximum et écart-type	kPa	10 minutes

(1) Degrés par rapport au nord géographique

B.1.1 Calcul de la direction moyenne du vent

La direction moyenne du vent doit représenter la moyenne des vecteurs de direction du vent.

- Si Θi est une mesure individuelle de la direction
- Si N est le nombre de données échantillonnées sur un certain intervalle de temps

Alors la direction moyenne, Θ, durant une intervalle de 10 minutes est :

$$\Theta = \mathrm{Arctan}(Ux\ /\ Uy) + \mathrm{K}$$

où

$$Ux = \left(\sum \sin \Theta_i\right) / N$$

$$Uy = \left(\sum \cos \Theta_i\right) / N$$

Valeur de K selon les cas possibles

Si	Ux = 0	Ux > 0	Ux < 0
Uy = 0	-	Note 1	Note 2
Uy > 0	360	0	360
Uy< 0	180	180	180

Note 1: dans ce cas $\Theta = 90^{\circ}$
Note 2: dans ce cas $\Theta = 270^{\circ}$

L'écart type de l'angle doit être calculé de la façon suivante:

$$\sigma = \arcsin(\varepsilon) * (1 + 0.1547*\varepsilon^3)$$

où

$$\varepsilon = [\ 1 - Ux^2 - Uy^2\ ]^{1/2}$$

B.2 Données d'une éolienne

Données	Fréquence d'échantillon-nage minimale	Période de compilation des statistiques	Statistiques compilées à transmettre	Unité	Cycle de transmission
Puissance active	1/5 Hz	10 minutes	moyenne, minimum, maximum et écart-type	kW	10 minutes
Direction de la nacelle	1/5 Hz	10 minutes	moyenne, minimum, maximum et écart-type	Degrés (1)	10 minutes
Position des pales	1/5 Hz	10 minutes	moyenne, minimum, maximum et écart-type	Degrés	10 minutes
Température au niveau de la nacelle	1/5 Hz	10 minutes	moyenne, minimum, maximum et écart-type	degrés Celsius	10 minutes
Vitesse du vent mesurée par l'anémomètre de la nacelle	1/5 Hz	10 minutes	moyenne, minimum, maximum et écart-type	m/s	10 minutes
Direction du vent mesurée par la girouette de la nacelle	1/5 Hz	10 minutes	moyenne, minimum, maximum et écart-type	Degrés (1)	10 minutes
Statut de la machine	1/5 Hz	N/A	N/A	N/A	Temps réel

(1) Degrés par rapport au nord géographique

B.2.1 Calcul de la direction moyenne du vent et de la nacelle

Se référer à la section B.1.1 qui décrit le calcul de la direction moyenne du vent pour les données d'un mât météorologique.

B.2.2 Température au niveau de la nacelle

La température au niveau de la nacelle correspond à la valeur de température externe mesurée pour les fins du contrôle de l'arrêt de l'éolienne pour cause de basse température.

B.2.3 Statut de la machine

La donnée *statut de la machine* est une valeur numérique de 32 bits dont la valeur indique l'état d'opération de l'éolienne.

Le Tableau 5 indique la description des valeurs transmises pour les éoliennes de la compagnie GE. Les valeurs 1 à 15 sont associées à l'état d'opération alors que les valeurs 1001 à 1365 indiquent la présence d'une condition d'erreur. Ces valeurs sont précisées dans les sections « State & fault » (6.1.5.6) et « Turbines additional information » (6.1.5) du document [GE-1].

Un statut supplémentaire permettant de détecter l'arrêt d'une éolienne pour cause de basse température est de plus nécessaire

Tableau 5 État d'opération d'une éolienne GE

valeur	Description
1	Turbine ok
2	Turbine with grid connection
3	Run up / Idling
4	Maintenance
5	Repair
6	Grid loss
7	Weather conditions
8	Stop extern
9	Stopped (manual Stop, if turbine ok)
10	Stopped (remote Stop, if turbine ok)
11	Emergency STOP
12	External Stop regarding Energy Curtailment
13	Customer Stop
14	Manual idle Stop
15	Remote idle Stop
1000+X	Event Message X is active

B.3 Données de production du parc éolien

Données	Fréquence d'échantillonnage minimale	Période de compilation des statistiques	Statistiques compilées à transmettre	Unités	Cycle de transmission
Puissance active	1/5 Hz	10 minutes	moyenne, minimum, maximum et écart-type	MW	10 minutes
Puissance disponible des éoliennes	1/5 Hz	10 minutes	moyenne, minimum, maximum	MW	10 minutes
Puissance disponible du poste	1/5 Hz	10 minutes	moyenne, minimum, maximum	MW	10 minutes
Puissance disponible du parc	1/5 Hz	10 minutes	moyenne, minimum, maximum	MW	10 minutes
Nombre d'éoliennes disponibles	1/5 Hz	10 minutes	moyenne, minimum, maximum	-	10 minutes
Nombre d'éoliennes à l'arrêt pour cause de faible vent	1/5 Hz	10 minutes	moyenne, minimum, maximum	-	10 minutes
Nombre d'éoliennes à l'arrêt pour cause de fort vent	1/5 Hz	10 minutes	moyenne, minimum, maximum	-	10 minutes
Nombre d'éoliennes à l'arrêt pour cause de basse température	1/5 Hz	10 minutes	moyenne, minimum, maximum	-	10 minutes

B.3.1 Calcul de la puissance disponible des éoliennes

La puissance disponible des éoliennes est la somme de la puissance disponible de chaque éolienne du parc.

La puissance disponible d'une éolienne est sa puissance maximale réduite pour prendre en compte les arrêts (pour maintenance, bris, basse température, etc.) ainsi que toute restrictions d'appareillage (électrique ou mécanique) ayant pour conséquence de limiter sa capacité de production.

Pour les éoliennes de la compagnie GE, un éolienne est considérée disponible lorsque un des états d'opérations suivant est présent : « Turbine ok », « Turbine with grid connection », « Run up / Idling» ou « Weather conditions». Se référer au Tableau 5 pour la description des états d'opération.

B.3.2 Calcul de la puissance disponible du poste

La puissance disponible du poste est la puissance maximale pouvant être transitée à travers les équipements du poste vers le réseau d'Hydro-Québec, en tenant compte des indisponibilités et restrictions d'appareillage ayant pour conséquence de réduire la capacité de transit du poste.

Cette puissance sera nulle lorsque le disjoncteur ou un des sectionneurs d'isolation du départ de ligne est ouvert.

B.3.3 Calcul de la puissance disponible du parc

La puissance disponible du parc se définit comme la valeur moindre entre d'une part la puissance disponible du poste (B.3.2) et d'autre part la puissance disponible des éoliennes (B.3.1) soit :

puissance disponible du parc =

$$\text{Min}\left(\text{puissance disponible du poste}, \sum_{i=1}^{\text{nbreArtères}} \text{étatArtère}_i * (\Sigma \text{ puissance disponible de chaque éolienne de l'artère } i)\right)$$

nbreArtères = le nombre d'artères du parc

étatArtère $_i$ = l'état de l'artère i, un booléen valant 1 si les sectionneurs et le disjoncteur de l'artère sont tous fermés, 0 sinon (i=1,2,…nbreArtères)

Annexe C Données requises pour la conduite du réseau électrique

Cet annexe présente la liste des données éoliennes qui sont requises par la direction Contrôle des Mouvements d’énergie de TransÉnergie pour les besoins de conduite du réseau électrique d’Hydro-Québec. Ces données sont transmises au centre de conduite du réseau (CCR) par le système GEN-4 du CIT.

Les données demandées correspondent à un sous-ensemble des données requises pour les besoins d’exploitation du poste électrique (Annexe A) ainsi que les besoins des divisions HQD et HQP (Annexe B). Il n’y a donc aucun point supplémentaire requis au niveau du parc éolien.

Données	Statistiques compilées à transmettre
Données d’exploitation du poste électrique (Annexe A.1)	
État "en" ou "hors" du système de gestion centralisée du parc	
MW, à la haute tension du poste et à chacune des lignes basse tension raccordées à la barre principale	
MW, à la haute tension du poste	
Mvar, à la haute tension du poste	
kV, à la haute tension du poste	
Amp. à la haute tension du poste	
Signalisation du disjoncteur à la haute tension du poste	
Données d’un mât météorologique (Annexe B.1)	
Vitesse horizontal du vent à chaque anémomètre du mât	Moyenne
Température à chaque thermomètre du mât	Moyenne
Direction du vent à chaque girouette du mât	Moyenne
Données de production du parc éolien (Annexe B.3)	
Puissance disponible du parc	Moyenne
Nombre d’éoliennes disponibles	Moyenne
Nombre d’éoliennes à l’arrêt pour cause de faible vent	moyenne, maximum
Nombre d’éoliennes à l’arrêt pour cause de fort vent	moyenne, maximum
Nombre d’éoliennes à l’arrêt pour cause de basse température	moyenne, maximum

Annexe D Séquence d'initialisation GEN-4

Cette annexe décrit sous forme d'un tableau la séquence des échanges entre le système GEN-4 et un poste esclave pour le rétablissement d'une connexion DNP3 en mode de réponse non sollicité.

Une trace des trames DNP3 associées à cette séquence est disponible sur demande.

Seq. #	Master	Slave (RTU)	Comments
1		Sends Null Unsolicited Response indicating pending events and asks for confirmation at the Application Level	The FRTU is in unsolicited events report mode
2	Sends the Reset Link		Optional step (for back compatibility with serial devices)
3		Acknowledges the Reset Link	Optional step (for back compatibility with serial devices)
4		Retries Null Unsolicited Message	This can happen at this point in time or later, depending on the RTU settings
5	Confirms Null Response		
6	Object 60, variations 2,3,4, function 21		Sends the Disable Unsolicited message for classes 1, 2, 3 events (DNP Level 3)
7		Response	
8	Object 60, variations 2, 3, 4, 1, function 1		Read request for class 1, 2, 3, 0 -all event and static data (BI, AI and Counters)
9		Object 2, variation 1 Object 2, variation 2 Object 32, variation 2 Object 32, variation 1 Object 23, variation 1 Object 1, variation 1 Object 30, variation 4 Object 30, variation 3 Object 20, variation 5	If there are events in any class, report the event first, then report all the static data. BI Event – Without Time BI Event – With Time 16 Bit AI Event- Without Time 32 Bit AI Event- Without Time 32 Bit Frozen Counter Event- Without Time Binary Input – No Status 16 Bit Analog Input – No Flag 32 Bit Analog Input – No Flag 32 Bit Binary Counter– No Flag If response contains events, then asks for and expects confirmation.
10	Confirmation		Sent by Application Layer
11	Object 60, variations 2,3,4, function 20		Sends the Enable Unsolicited message for classs 1,2,3 events. (DNP Level 3)
12		Response.	If more events were stored from last response, the response will be with those events and expects confirmation on the events.

NPCC, Inc.

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NPCC
Regional Reliability Reference Directory # 9
Verification of Generator
Gross and Net Real Power Capability

Task Force on Coordination of Operations Revision Review Record:
December 22, 2008
December 28, 2011

Adopted by the Members of the Northeast Power Coordinating Council, Inc., this December 22, 2008 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

Version History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	12/22/2008		New
1	07/07/2009	Included FAC-008 in Section 3.0	Errata
2	12/28/2011	Phase 2 format	Revisions

Table of Contents

Terms Defined in the Directory

There are no new terms defined in this Revision. The definitions of terms found in this Directory appearing in bold typeface, can be found in the NPCC *Glossary of Terms.*

A. Introduction

1. **Title:** Verification of Generator Gross and Net Real Power Capability

2. **Directory #:** 9

3. **Objective:**

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

   Compliance to the criteria requirements set forth in this Directory by each applicable entity assures accuracy of information used in the steady-state models to assess the reliability of the NPCC bulk power system.

   This Directory has been developed to ensure that the requirements specified in NERC Standard MOD-024-1, "Verification of Generator Gross and Net Real Power Capability" are met by NPCC and its applicable members responsible for meeting the NERC Reliability Standards.

4. **Effective Date: 12/22/2008**

5. **Background:**
   This Directory was developed from the draft NPCC A-13 Verification of Generator Gross and Net Real Power Capability Criteria document whose technical content was approved by the Reliability Coordinating Committee on March 5, 2008 for conversion into a Directory. Version 0 of the Directory became effective on December 22, 2008.

6. **Applicability:**

   6.1 Functional Entities (Responsible Entities)
   - Generator Owners
   - Transmission Operators (in whose area the generator or generation facility resides)

B. 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:

- MOD-024-1 -Verification of Generator Gross and Net Real Power Capability
- TOP-002-2 - Normal Operations Planning
- FAC-008-1 - Facility Ratings Methodology
- FAC-009-1 - Establish and Communicate Facility Ratings

C. NPCC Regional Reliability Standard Requirements

None.

D. NPCC "Full Member" More Stringent Criteria Requirements

1. Requirements

1.1 Developing the List of Generators or Generation Facilities to be verified

R1. The Transmission Operator shall develop and maintain documentation of those generators or generation facilities that must verify the **Gross Real Power Capability** and **Net Real Power Capability** for the summer and winter capability seasons. The documentation maintained by the Transmission Operator shall include the following:

R1.1 All generators or generation facilities **Declared Gross Real Power Capability** and **Declared Net Real Power Capability**.

R1.2 All generators or generation facilities **Verified Gross Real Power Capability** and **Verified Net Real Power Capability**, verification date and method of verification.

R1.3 Discrepancies between a Generator Owner's declared and verified **Gross Real Power Capability** and **Net Real Power Capability**, the reason for such discrepancies and the Generator Owner's plan to address the discrepancies.

R1.4 Generator Owner supplied **Gross Real Power Capability** and **Net Real Power Capability** testing, manufacturer data, performance tracking or operating historical data, certification documentation, as specified by the Transmission Operator.

R1.5. All generators or generation facilities exempted from the verification requirements and the basis for their exemption (see Section 1.5).

1.2 Establishing the Generator Real Power Capability Verification Program

R2. The Transmission Operator shall establish and document a program to periodically verify the **Gross Real Power Capability** and **Net Real Power Capability** of all generators and generation facilities that are subject to periodic seasonal **Gross Real Power Capability** and **Net Real Power Capability** verification.

R3. The Transmission Operator shall provide any changes to its verification process to the Generator Owners within 30 calendar days of issue.

R4. The Transmission Operator shall establish and document requirements for a Generator Owner to notify the Transmission Operator within a specified time period when its generator or generation facility cannot achieve the **Declared Gross Real Power Capability** or **Declared Net Real Power Capability** because of equipment issues.

R5. The Transmission Operator shall establish and document a time frame for the Generator Owner to address equipment issues that result in a generator or generation facility not achieving the **Declared Gross Real Power Capability** or **Declared Net Real Power Capability**.

R6. The Transmission Operator shall establish and document the ambient conditions that correspond to the summer and winter capability seasons for which the **Gross Real Power Capability** and **Net Real Power Capability** are verified.

R7. The Transmission Operator shall establish and document those intermittent or small generating units whose capability may be represented by verification results of a single generating unit.

1.3 Implementing the Generator Real Power Capability Verification Program

R8. The Transmission Operator shall request Generator Owners to verify the seasonal **Gross Real Power Capability** and **Net Real Power Capability** of their generators or generation facilities that are subject to periodic seasonal **Gross Real Power Capability** and **Net Real Power Capability** verification every three (3) years or more frequently as required by the Transmission Operator. The two (2) capability seasons are defined as summer and winter as specified by the Transmission Operator.

R9. If a Transmission Operator determines that only one seasonal generating capability value is required for NPCC Bulk Power System reliability analysis, then periodic verification will be required only for that particular season.

R10. If a Transmission Operator determines that the difference between the **Declared Gross Real Power** and **Declared Net Real Power Capability** of a generator or generation facility is insignificant for NPCC Bulk Power System reliability analysis, then periodic verification will be required for only one numerical value.

R11. The Generator Owner shall provide generator or generation facility **Declared Gross Real Power Capability** and **Declared Net Real Power Capability** to the Transmission Operator.

R12. The Generator Owner shall provide evidence, upon request, to the Transmission Operator that the generator or generation facility **Gross Real Power Capability** and **Net Real Power Capability** have been verified.

R13. The Generator Owner shall report to the Transmission Operator any discrepancies between declared and verified **Gross Real Power Capability** or **Net Real Power Capability** within a time frame specified by the Transmission Operator and develop and implement a plan to resolve the discrepancies.

R14. The Generator Owner shall determine and report to the Transmission Operator the generator or generation facility real power seasonal auxiliary loads (including common station loads).

1.4 Verification Criteria for Generator and Generation Facility Real Power Capability

R15. The Generator Owner shall comply with Transmission Operator requests for periodic verification of **Gross Real Power Capability** and **Net Real Power Capability** of their generators or generation facilities.

R16. The Generator Owner shall verify the **Gross Real Power Capability** and **Net Real Power Capability** of thermal generators on the basis of operation for no less than one hour.

R16.1. The verification of thermal generator’s capability shall include any of the following:

- Testing,

- Use of operating historical data,
- Commissioning data (for new generators only)**,**
- Performance tracking data acquired during the same seasonal capability period.

R17. The Generator Owner shall verify the **Gross Real Power Capability** and **Net Real Power Capability** of internal combustion generators and gas turbine generators. The verification shall correspond to operation for no less than one hour under the ambient conditions established in R6 for which the **Gross Real Power Capability** and **Net Real Power Capability** are being claimed.

R17.1. The verification of internal combustion and gas turbine generators capability shall include any of the following:

- Testing,
- Use of operating historical data,
- Commissioning data (for new generators only),
- Performance tracking data acquired during the same seasonal capability period.

R18. The Generator Owner shall verify the **Gross Real Power Capability** and **Net Real Power Capability** of hydro generators either on a generation facility or on an individual generator basis. The **Gross Real Power Capability** and **Net Real Power Capability** shall be determined on the basis of the availability of sufficient water at an adequate head to provide the output for no less than one hour.

R18.1. The verification of hydro generator's capability shall include any of the following:

- Testing,
- Use of operating historical data,
- Commissioning data (for new generators only),
- Performance tracking data acquired during the same seasonal capability period.

R19. The Generator Owner shall verify the **Gross Real Power Capability** and **Net Real Power Capability** of combined cycle generators on a generation facility, individual generator or on a generator stage basis for no less than one hour under the ambient conditions established by the Transmission Operator in R6 for which the **Gross Real Power Capability** and **Net Real Power Capability** are being claimed.

R19.1 The verification of a combined cycle generator's capability shall include any of the following:

- Testing,

- Use of operating historical data,
- Commissioning data (for new generators only),
- Performance tracking data acquired during the same seasonal capability period.

R20**.** The Generator Owner shall verify the **Gross Real Power Capability** and **Net Real Power Capability** of intermittent power resources (wind, solar, tidal geo-thermal, etc.) using any of the following:

- Manufacturer's data,
- Performance tracking,
- Operating historical data

R21. The Generator Owner shall verify the **Gross Real Power Capability** and **Net Real Power Capability** of multiple generator facilities when limited by common elements based on the real power capability of the facility and not the sum of the capabilities of the individual generators.

R22. The Generator Owner shall identify any equipment or other factor that will limit the capability of the generator or generation facility to meet its **Declared Gross Real Power Capability** or **Declared Net Real Power Capability**.

1.5 Exemption of Generators or Generation Facilities from Verification Testing

R23. The Generator Owner shall notify the Transmission Operator and request an exemption if it cannot conduct seasonal capability testing of a generator or generation facility for any of the reasons listed below.

- Adverse impact on transmission system reliability
- Potential damage to transmission system or generator equipment
- Environment conditions
- Governmental regulatory or operating license limitations
- An extended outage to the generator or generation facility

R24. The Transmission Operator shall, within 30 calendar days of receiving notification from a Generator Owner that it is requesting an exemption because it cannot perform verification for the required seasonal period, notify the Generator Owner whether its generator will be exempted from the seasonal capability testing. Where the exemption is approved, the Transmission Operator shall coordinate with the Generator Owner to reschedule the verification for the next seasonal verification period.

R25. The Generator Owner for a generator or generation facility exempted from seasonal capability testing shall submit the following to the Transmission Operator:

- For existing generators, generator operation records, manufacturer data, or performance tracking for the previous applicable seasonal verification period for this generator or generation facility.
- Engineering analysis in conjunction with performance tracking data to justify any difference between a generators or generation facilities declared capability and previous applicable seasonal performance tracking data.
- For new generators only, commissioning data.

E. Compliance

1. Compliance Monitoring Process

Compliance with the requirements set forth in this Directory will be in accordance with the NPCC Criteria Compliance and Enforcement Program (CCEP).

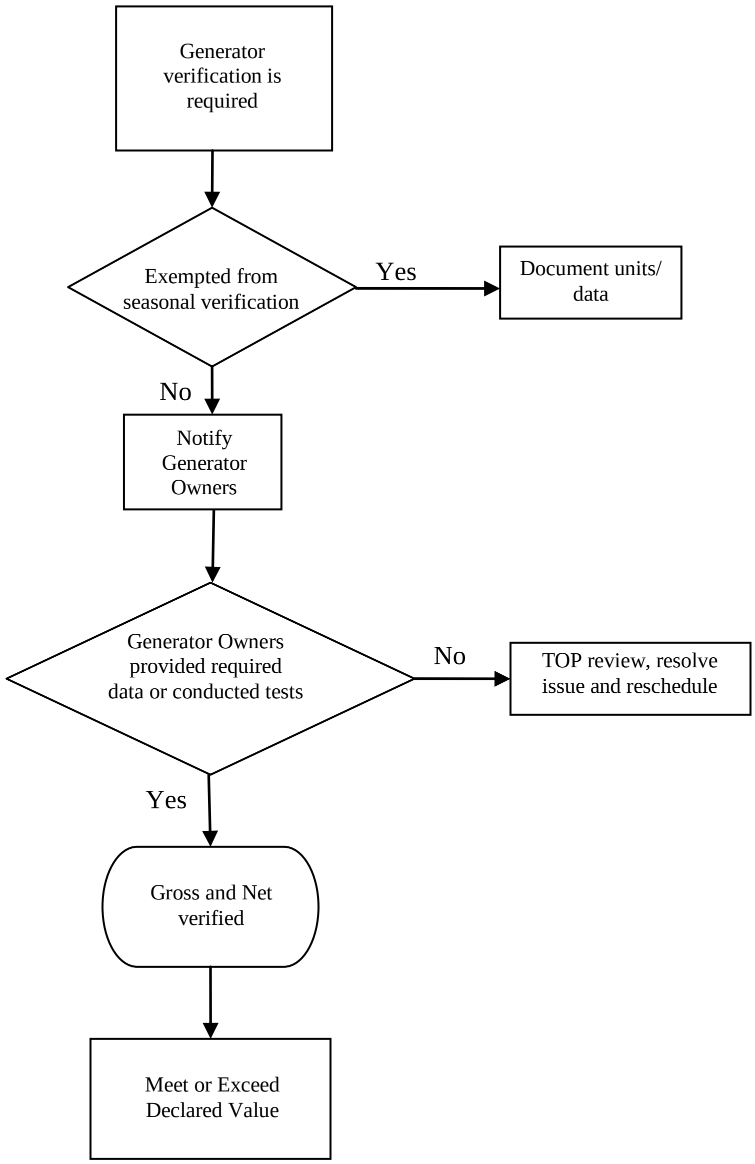
Measures and corresponding Levels of Non Compliance for these requirements are contained within the compliance template associated with this Directory.

2. Data Retention

Responsible Entities shall keep evidence of compliance for a minimum of three years. A Responsible Entity found non-compliant shall keep information related to the non-compliance until found compliant.

Prepared by:	Task Force on Coordination of Operation
Review and Approval:	Revision to any portion of this Directory will be posted by the lead Task Force in the NPCC Open Process for a 45 day review and comment period. Upon satisfactorily addressing all the comments in this forum, the Directory document will be sent to the remaining Task Forces for their recommendation to seek RCC approval. Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast. Revisions pertaining to the Appendices or any other portion of the document such as links, glossary 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

Appendix A- Basic Flow Chart for Verification of Generator Gross and Net Real Power Capability



NPCC, Inc.
NORTHEAST POWER COORDINATING COUNCIL, INC.
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NPCC
Regional Reliability Reference Directory # 10
Verification of Generator
Gross and Net Reactive Power Capability

Task Force on Coordination of Operations Revision Review Record:
December 22, 2008
December 28, 2011

Adopted by the Members of the Northeast Power Coordinating Council, Inc. this December 22, 2008 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

Version History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	12/22/2008		New
1	07/07/2009	Included FAC-008 in Section 3.0	Errata
2	12/28/2011	Phase 2 format	Revisions

Table of Contents

Terms Defined in the Directory

There are no new terms defined in this Revision. The definitions of terms found in this Directory appearing in bold typeface, can be found in the NPCC *Glossary of Terms.*

A. Introduction

1. **Title:** Verification of Generator Gross and Net Reactive Power Capability

2. **Directory #:** 10

3. **Objective:**

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

   Compliance to the criteria requirements set forth in this Directory by each applicable entity assures accuracy of information used in the steady-state models to assess the reliability of the NPCC bulk power system.

   This Directory has been developed to ensure that the requirements specified in NERC Standard MOD-025-1, "Verification of Generator Gross and Net Reactive Power Capability" are met by NPCC and its applicable members responsible for meeting the NERC Reliability Standards.

4. **Effective Date:** **December 22, 2008**

5. **Background:**

   This Directory was developed from the draft NPCC A-14 Verification of Generator Gross and Net Reactive Power Capability Criteria document whose technical content was approved by the Reliability Coordinating Committee on March 5, 2008 for conversion into a Directory. Version 0 of the Directory became effective on December 22, 2008.

6. **Applicability:**

   6.1 Functional Entities (Responsible Entities)

   - Generator Owners
   - Transmission Operators (in whose area the generator or generation facility resides)

B. 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:

- MOD-025-1 -Verification of Generator Gross and Net Reactive Power Capability
- TOP-002-2 - Normal Operations Planning
- FAC-008-1 - Facility Ratings Methodology
- FAC-009-1 - Establish and Communicate Facility Ratings

C. NPCC Regional Reliability Standard Requirements

None.

D. NPCC "Full Member" More Stringent Criteria Requirements

1. <u>Requirements</u>

1.1 Developing the List of Generators or Generation Facilities to be Verified

R1. Transmission Operators shall develop and maintain documentation of those generators or generation facilities that must verify the **Gross Reactive Power Capability** and **Net Reactive Power Capability** for the summer and winter capability seasons. The documentation maintained by the Transmission Operator shall include the following:

R1.1 All generators or generation facilities **Declared Gross Reactive Power Capability** and **Declared Net Reactive Power Capability** and seasonal auxiliary load reactive power requirements. (Reference Appendix B).

R1.2 All generators or generation facilities **Verified Gross Reactive Power Capability** and **Verified Net Reactive Power Capability**, verification date and method of verification.

R1.3 Discrepancies between a Generator Owner's declared and verified **Gross Reactive Power Capability** and **Net Reactive Power Capability**, the reason for such discrepancies and the Generator Owner's plan to address the discrepancies.

R1.4 Generator Owner supplied **Gross Reactive Power Capability** and **Net Reactive Power Capability** testing, manufacturer data, performance tracking or operating historical data, certification documentation, as specified by the Transmission Operator.

R1.5. Generators or generation facilities exempted from the verification requirements and the basis for their exemption (see Section 1.5).

1.2 Establishing the Generator Reactive Power Capability Verification Program

R2. The Transmission Operator shall establish and document a program to periodically verify the **Gross Reactive Power Capability** and **Net Reactive Power Capability** of all generators and generation facilities that are subject to periodic seasonal **Gross Reactive Power Capability** and **Net Reactive Power Capability** verification.

R3. The Transmission Operator shall provide any changes to its verification process to the Generator Owners within 30 calendar days of issue.

R4. The Transmission Operator shall establish and document requirements for a Generator Owner to notify the Transmission Operator within a specified time period when its generator or generation facility cannot achieve the **Declared Gross Reactive Power Capability** or **Declared Net Reactive Power Capability** because of equipment issues.

R5. The Transmission Operator shall establish and document a time frame for the Generator Owner to address equipment issues that result in a generator or generation facility not achieving the **Declared** Gross Reactive Power Capability and **Declared** Net Reactive Power Capability.

R6. The Transmission Operator shall establish and document the real power level at which the verification shall be performed, recognizing that the verification of lagging and leading reactive power capabilities should normally be performed during on-peak and off-peak hours, respectively.

R7. The Transmission Operator shall establish and document those intermittent or small generating units whose capability may be represented by verification results of a single generating unit.

1.3 Implementing the Generator Reactive Power Capability Verification Program

R8. The Transmission Operator shall request Generator Owners to verify the seasonal **Gross Reactive Power Capability** and **Net Reactive Power Capability** of their generators or generation facilities that are subject to periodic seasonal **Gross Reactive Power Capability** and **Net Reactive**

Power Capability verification every five (5) years or more frequently as required by the Transmission Operator. The two (2) capability seasons are defined as summer and winter as specified by the Transmission Operator.

R9. If a Transmission Operator determines that only one seasonal generating capability value is required for NPCC Bulk Power System reliability analysis, then periodic verification will be required only for that particular season.

R10. If a Transmission Operator determines that the difference between the **Declared Gross Reactive Power Capability** and the **Declared Net Reactive Power Capability** of a generator or generation facility is insignificant for NPCC Bulk Power System reliability analysis, then periodic verification will be required for only one numerical value.

R11. If a Transmission Operator determines that only the lagging or leading **Gross Reactive Power** Capability and **Net Reactive Power Capability** of a generator or generation facility is required for NPCC Bulk Power System reliability analysis, then periodic verification will be required only for that specific reactive power capability value.

R12. The Generator Owner shall provide generator or generation facility **Declared Gross Reactive Power Capability** and **Declared Net Reactive Power Capability** to the Transmission Operator.

R13. The Generator Owner shall provide evidence, upon request, to the Transmission Operator that the generator or generation facility **Gross Reactive Power Capability** and **Net Reactive Power Capability** have been verified.

R14. The Generator Owner shall report to the Transmission Operator any discrepancies between Declared and Verified **Gross Reactive Power Capability** and **Net Reactive Power Capability** within a time frame specified by the Transmission Operator and develop and implement a plan to resolve the discrepancies.

R15. The Generator Owner shall determine and report to the Transmission Operator the generator or generation facility reactive power seasonal auxiliary loads (including common station loads).

1.4 Verification Criteria for Generator and Generation Facility Reactive Power Capability

R16. The Generator Owner shall comply with Transmission Operator requests for periodic verification of **Gross Reactive Power Capability** and **Net Reactive Power Capability** of their generators or generation facilities.

R17. The Generator Owner shall verify the **Gross Reactive Power Capability** and **Net Reactive Power Capability** of their generators or generation facilities according to their types. As specified by the Transmission Operator, the verification shall include any of the following:

- Testing,
- Use of operating historical data,
- Commissioning data (for new generators only),
- Performance tracking data acquired during the same seasonal capability period.

R18. The Generator Owner shall verify the Gross Reactive Power Capability and Net Reactive Power Capability of Thermal Generators, Internal Combustion Generators, Gas Turbine Generators, Combined Cycle and Hydro Generators or generators operated as a synchronous condenser on the average leading reactive power output for at least a 15 consecutive minute period and average lagging reactive power output for at least a 60 consecutive minute period.

R19. The Generator Owner shall verify the Gross Reactive Power Capability and Net Reactive Power Capability of Intermittent power resources (wind, tidal or geo-thermal generators) on performance tracking data. Manufacturers' data or commissioning data can be used until sufficient performance tracking data is available to verify generator or generation facilities lagging and leading reactive capabilities.

R20. The Generator Owner shall verify the Gross Reactive Power Capability and Net Reactive Power Capability for multiple generator facilities when limited by common elements on the reactive power capability of the facility and not the sum of the capabilities of the individual generators.

R21. The Generator Owner shall identify any equipment or other factor that will limit the capability of the generator or generation facility to meet its **Declared Gross Reactive Power Capability** or **Declared Net Reactive Power Capability**.

1.5 Exemption of Generators or Generation Facilities from Seasonal Verification Testing

R22. The Generator Owner shall notify the Transmission Operator and request an exemption if it cannot conduct seasonal capability testing of a generator or generation facility for any of the reasons listed below.

- Adverse impact on transmission system reliability
- Potential damage to transmission system or generator equipment
- Environment conditions
- Governmental regulatory or operating license limitations
- An extended outage to the generator or generation facility

R23. The Transmission Operator shall, within 30 calendar days of receiving notification from a Generator Owner that it is requesting an exemption because it cannot perform verification for the required seasonal period, notify the Generator Owner whether its generator will be exempted from the seasonal capability testing. Where the exemption is approved, the Transmission Operator shall coordinate with the Generator Owner to reschedule the verification for the next seasonal verification period.

R24. The Generator Owner for a generator or generation facility exempted from seasonal capability testing shall submit the following to the Transmission Operator:

- For existing generators, generator operation records, manufacturer data, or performance tracking for the previous applicable seasonal verification period for this generator or generation facility.
- Engineering analysis in conjunction with performance tracking data to justify any difference between a generator's or generation facility’s **declared capability** and previous applicable seasonal performance tracking data.
- For new generators only, commissioning data.

E. Compliance

1. Compliance Monitoring Process

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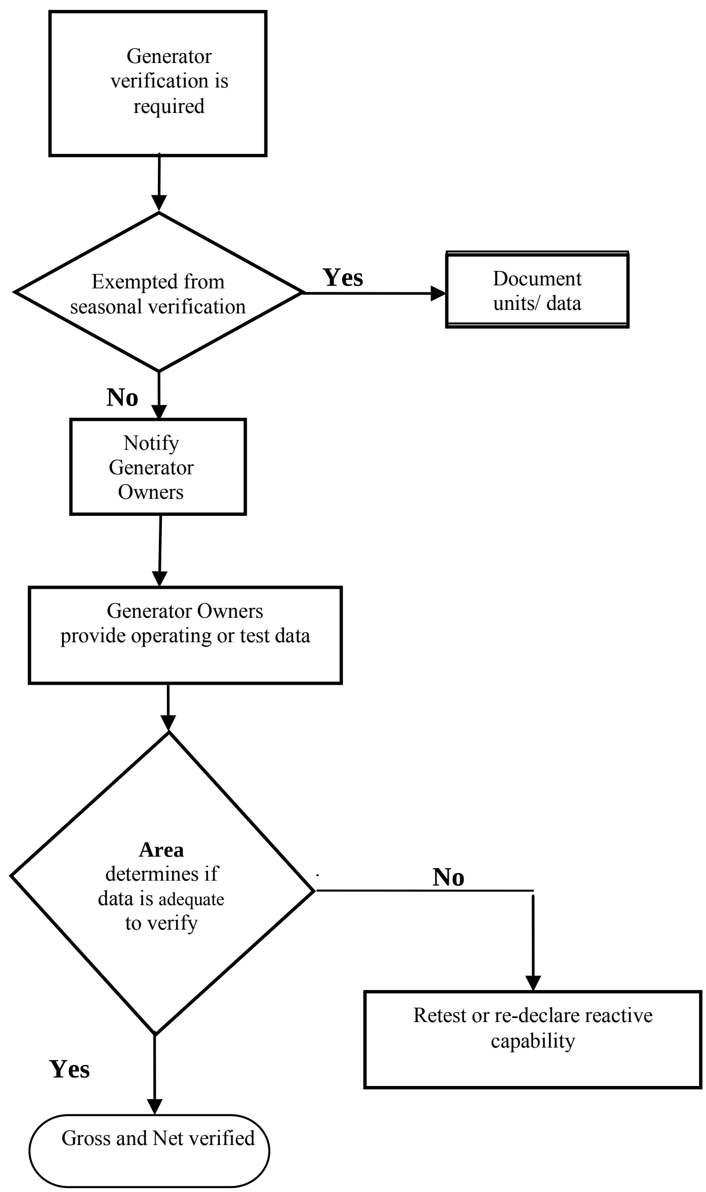
Appendix A- Basic Flow Chart for Verification of Generator Gross and Net Reactive Power Capability



Appendix B - Generator Reactive Capability Form

GENERATOR REACTIVE CAPABILITY DATA FORM

1. Data Preparation Documentation*

Generator Facility Name	Unit No.	Facility ID	Generator Owner	Primary Contact
Big Generator Station	1	12234	Big Power	Jim Smith
Prepared By	**Date prepared:**	**Effective Date**	**Contact Tel**	**Contact e-mail**
John Doe	01/05/2007	01/10/2007	XXX-XXX-XXXX	john@bigpower.com

Auxiliary Reactive Power Requirements	Summer MVAR	Winter MVAR
	20	15

Reactive Data*

Seasonal Data	Declared Real and Reactive Capability						Verified Reactive Capability and Season			Verification Method (T, P,C** as applicable)	Date Verified
	Summer			Winter			Winter				
	Gross MW	Gross MVAR	Net MVAR	Gross MW	Gross MVAR	Net MVAR	Gross MW	Gross MVAR	Net MVAR		Date
Lagging Capability	500	120	120	525	100	100	520	110	110	P	03/15/2007
Leading Capability	500	250	230	525	240	225	525	200 (1)	185(1)	T	01/25/2007

Data inputted for illustration purposes,* * T- Testing; P- Performance Tracking; C-Commissioning data*

Notes and Limitations:	(1) Full MVAR capability could not be achieved because of system voltage restriction. Engineering analysis was provided to demonstrate unit was capable of declared values.

Generating unit capability curve. *Please attach a .jpg image from the generating unit capability D curve*