TRANSMISSION PLANNING GUIDELINE

FOR

NORTHEAST UTILITIES

May 2008

Northeast
Utilities System

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1.0 PURPOSE

The purpose of this Transmission Planning Guideline is to define the criteria used by Northeast Utilities ("NU") to assess the reliability of the existing and future NU transmission system. These guideline criteria are consistent with the criteria established for the interconnected bulk power system by the Federal Energy Regulatory Commission ("FERC"), the North American Reliability Corporation ("NERC"), the Northeast Power Coordinating Council, Inc. ("NPCC") and the Independent System Operator - New England ("ISO-NE").

2.0 GENERAL REQUIREMENTS

2.1 Defined Terms

Each of the defined terms used in the Transmission Planning Guideline has a specific definition which can be found in Section 6.0. Throughout this guideline, defined terms appear in bold. The Transmission Planning Guideline also uses terms that are common in the electric utility industry; therefore, these terms are not defined in Section 6.0.

2.2 Applicability

This Transmission Planning Guideline applies to the entire NU **transmission system,** including both the inter-connected New England **bulk power system** and **local area systems.** The criteria established by FERC, NERC, NPCC and ISO-NE pertain only to the **bulk power system.**

The NU facilities which are part of the interconnected New England **bulk power system** shall be designed in accordance with NERC Planning Standards, the NPCC's Basic Criteria for Design and Operation of Interconnected Power Systems ("A-2"), ISO-NE Reliability Standards for the New England Area Bulk Power Supply System (Planning Procedure No. 3, "PP3") and the NU Transmission Planning Guideline.

Transfers of power to and from another **Area**, as well as within ISO-NE, shall be considered in the design of inter-**Area** and intra-**Area** transmission facilities. **Transfer capabilities** will be based on the load and **generation** conditions expected to exist for the period under study.

The NU transmission customers which are interconnected to other New England transmission owners shall have transmission service designed in accordance with the interconnected transmission owner's planning guideline and applicable regional standards.

The NU facilities that are not part of the interconnected New England **bulk power system** shall be designed in accordance with the NU Transmission Planning Guideline. The **local area systems** shall be designed for a level of **reliability** such that the loss of a major portion of the system, or the unintentional separation of any portion of the system, will not result from reasonably foreseeable **contingencies**.

The **local area system** must be designed to withstand representative **contingencies** as defined in this Transmission Planning Guideline. Simulations of these **contingencies** must include assessment of the potential for widespread cascading outages due to voltage collapse, instability or thermal overloads. In applying the Transmission Planning Guideline, loss of customer load may occur following certain multiple **contingencies.** The temporary loss of small portions of the distribution and/or **transmission system** may be tolerated if the **reliability** of the overall **bulk power system** is not jeopardized. The Transmission Planning Guideline establishes minimum design criteria for the **local area systems**. Due to local considerations, more rigid designs may be applied in some **areas** including the application of **resources**. These considerations may include the physical environment in which transmission service is provided, the time peak **area** loads are experienced and the ability to implement restoration and repairs.

The **local area systems** shall be designed with sufficient transmission capability to integrate **area** loads with sufficient **generation** to provide a reliable supply. Design studies shall assume power flow conditions utilizing **transfers**, load, and **generation** conditions that reasonably stress the system.

In addition, subject to system planning study results, facilities not classified as part of the **transmission system** may also be subject to the Transmission Planning Guideline and shall be designed to have no **significant adverse impact** on the **reliability** of the **transmission system**.

2.3 Service Expectations

Compliance with the Transmission Planning Guideline ensures the **reliability** and efficiency of the **transmission system** through the coordination of system planning, design and operation in accordance with **good electric utility practice**. There may be circumstances that may expose customers to the increased possibility of more frequent and/or more extensive transmission outages. It may not always be possible to achieve the designed level of **reliability** due to delays in siting and permitting new facilities, construction delays, load growth that exceeds predicted levels or delays due to actions taken by others beyond the control of NU.

The Transmission Planning Guideline also intends to serve customer needs and to meet regulatory requirements by providing for a reliable and efficient **transmission system**.

3.0 TRANSMISSION PLANNING STUDY REQUIREMENTS

Electrical models for the NU **transmission system** shall include the interconnecting **generating plant** facilities and distribution systems in accordance with FERC, NPCC and ISO-NE requirements. These power flow models shall accurately represent system conditions and be regularly updated to reflect the most recent information concerning current and future configuration of transmission, **generation** and load levels.

3.1 Generation Dispatch

The **transmission system** includes major tie-lines to neighboring electric utilities within the ISO-NE **control area** and to other electric utilities in New York. Inter-**Area** and intra-**Area** transmission **transfers** are created as a result of variations to **generation** and load patterns. **Transfer capabilities** from one **area/Area** to another, as well as within **areas/Areas**, shall be considered in the design of transmission facilities and to assure that the conditions specified in Sections 4.1 and 4.2 can be sustained without a **significant adverse impact** on the **transmission system** including the **bulk power system**.

It may be necessary to vary the output of a **generating plant(s)** under contingency conditions. This may be necessary to maintain system **stability** or to maintain transmission line loadings within appropriate thermal **ratings**.

System planning studies for the NU **transmission system**, including **local area systems,** must consider reasonably stressed **transfers** using various load and **generation** conditions. Development of **generation** dispatches for system planning studies may:

a. reflect seasonal variations in river flow and/or pond capacity for hydro-electric **generating plants**;
b. reflect **generating plant** start-up, minimum run and down times;
c. reflect pumping operation of pump storage hydro-electric **generating plants**;
d. reflect operating characteristics of fossil fuel and nuclear **generating plants**;
e. recognize the higher forced-outage rates and start-up failure rates of fast-start **generating plants**;
f. consider the long-term operating economics (viability) of **generating plants**;
g. consider short-term **generating plant** market economics;
h. consider **generating plant** operating limitations (ie., environmental restrictions, fuel supply, etc.);
i. consider the guidelines under ISO-NE Minimum Interconnection Standard ("MIS") and ISO-NE Planning Procedure to Support the Forward Capacity Market (Planning Procedure No. 10, "PP10");
j. consider fuel availability and the mix of fossil fired **generation** in an area;
k. consider the impact of variable **generation** resources such as "wind power farms"; and
l. consider other pertinent factors which may affect **generation** availability.

3.2 Load Profile

System planning studies for the NU **transmission system**, including **local area systems,** shall be based on the ISO-NE extreme weather (90/10) forecast. System planning studies must consider seasonal peak **network loads** or **area** loads that, as a result of diversity from **network load**, lead to stressed **transfers** or low/high system voltage responses coupled with sensitivities to **generation** dispatch. System planning studies must also include the assessments of intermediate and light load forecasts based on ISO-NE normal forecast data.

Unless otherwise required, load power factors at the interface between the **transmission system** and the distribution system, for all load cycles and all **elements** available shall be designed to unity as seen at the low-side of the step-down transformers. In general, load power factors shall be consistent with the limits established by ISO-NE Operating Procedure 17 (“OP 17”).

3.3 Transmission System Configuration

System planning studies will include the complete representation of the electrical network similar to such data found in FERC Form 715. The power-flow models shall include facilities that are operated normally closed and normally open. To the extent necessary, models of lower voltage distribution systems may be included.

4.0 TRANSMISSION SYSTEM PERFORMANCE CRITERIA

Assessing the performance of the NU **transmission system** may include analyses, such as:

1. Stability assessment, the analysis of system dynamic performance as a result of sudden system changes including those caused by a **contingency**;
2. Steady state assessment, the analysis of power flows before and after **contingencies** when the system has returned to synchronism;
3. Voltage assessment, the analysis of reactive power sources/sinks to control voltage;
4. Fault current assessment, the analysis of the capability of electrical devices to physically withstand and interrupt short-circuit currents; and
5. Power-quality assessment, the analysis of current and voltage waveforms for distortion.

4.1 Stability Assessment

Stability of the **transmission system** shall be maintained during and following the most severe of the **contingencies** stated below, **with due regard to reclosing**, and before making any manual system adjustments. These requirements will also apply after any critical transmission **element**, or HVDC pole has already been removed from service and after assuming all appropriate and timely system adjustments have been made.

In accordance with NPCC A-2, for each of the **bulk power system contingencies** listed 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 by the “system B” protection group.

For each of the **local area systems contingencies** listed below that involves a **fault**, **stability** shall be maintained when the simulation is based on **fault clearing** initiated by either protection group on the faulted **element** without consideration to equipment failures.

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 transmission 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 and other similar situations can be excluded on the basis of acceptable risk, provided that ISO-NE and NPCC specifically approve each request for exclusion.

c. A permanent phase-to-ground **fault** on any transmission circuit, transformer or bus section with **delayed fault clearing**. This **delayed fault clearing** could be due to circuit breaker, relay system or signal channel malfunction.

d. Loss of any **element** without a **fault**.

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

f. The failure of any **special protection systems** (“SPS”) which is not functionally redundant to operate properly when required following the **contingencies** listed in "a" through "e" above.

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

4.2 Steady State Assessment

Transmission system equipment loadings shall be within normal **ratings** for pre-**contingency** conditions and within applicable emergency **ratings** for the system load and **generation** conditions that exist following the **contingencies** specified below and with due regard to electrical system reconfiguration:

a. **Contingencies** listed in Section 4.1.

b. The **transmission system** shall be designed such that the loss of any single **element** will not result in the loss of customer load, except in cases where customers are served by a single transmission **elemen**t. Where alternate transmission or distribution service exists, interruption of customer load for a radial line contingency will occur only for the short time required to transfer the load to the alternate service connection. Absent such transfer capability, the acceptable magnitude of customer load lost under a single **element contingency** will depend upon the local area system load profile, available **resources**, the expected duration of an outage caused by equipment failure, and the availability of spare equipment to support restoration efforts.

For **contingencies** involving multiple **elements** that interrupt transmission service to **local area systems**, measures should be taken to reduce the frequency and/or the impact of such **contingencies** when the amount of customer peak load interrupted exceeds 100 MW. For **contingencies** involving multiple **elements** that interrupt transmission service to **local area systems** with less than 100 MW of peak demand, measures should be evaluated to mitigate the frequency and/or the impact of such **contingencies** depending on the **local area system's** load profile, available **resources**, the expected duration of an outage caused by equipment failure, and the availability of spare equipment to support restoration efforts.

4.3 Voltage Assessment

Design **contingencies** listed in Section 4.1 and 4.2 shall not result in voltage collapse of the **bulk power system**, **local area system** or initiate a cascade outside of the **local area system**. Reactive power capacity with adequate reserves and appropriate controls shall be installed to maintain system voltages within normal limits for pre-**contingency** conditions, and within limits listed below for the steady-state system conditions that exist following the **contingencies** specified in Section 4.1 and 4.2.

a. Voltages for **transmission system** facilities equal to or greater than 230 kV, during **normal** conditions, shall not exceed plus 5% or minus 2% of nominal. Voltages for facilities equal to or greater than 230 kV, during **emergency** conditions, shall not exceed plus or minus 5% of nominal.

b. Voltages for **transmission system** facilities equal to 115 kV and below, during **normal** or **emergency** conditions, shall not exceed plus or minus 5% of nominal.

c. The permissible **transmission system** minimum voltage at nuclear **generating plants** may be restricted to a fixed minimum limit less than 5% of nominal.

d. The instantaneous voltage change resulting from equipment switching not associated with **fault clearing** shall not exceed plus or minus 2.5% of nominal voltage. During **emergency** conditions, such as having a line out of service, the instantaneous voltage change resulting from equipment switching not associated with **fault clearing** shall not exceed plus or minus 6% of nominal voltage. (Reference IEEE-141).

e. Overvoltages (transient and temporary) must be within the rating capabilities of the electrical equipment as defined by the manufactures (Reference IEEE-1313).

f. Scheduled bus voltages for **generators** shall be maintained in accordance with ISO-NE and NU requirements.

4.4 Fault Current Assessment

In each **area,** the system design must ensure that equipment (circuit breakers, switches, buswork, wave traps, etc.) capabilities are adequate to withstand fault current levels (example: a circuit breaker's interrupting capability must exceed the available fault current at its location). The system design must be coordinated with adjacent **areas** and neighboring electric utilities. Short-circuit studies shall be performed to ensure that all transmission system equipment is capable of withstanding the forces generated under **fault** conditions and that the **fault** can be safely interrupted. These studies shall be performed with all **generation** (excluding retirements) connected to the power system in operation. Equipment shall be considered over-dutied and either replaced or upgraded, depending on system conditions, when the corrected fault current level (accounting for voltage, X/R, etc.) is in excess of 90% of the manufacturer's nameplate rating and must be replaced or upgraded when the corrected fault current level exceeds 100% of the manufacturer's nameplate rating.

4.5 Power Quality Assessment

The **transmission system** including customer interconnections shall be designed in a manner that avoids:

a. harmonic frequencies exceeding the guidelines established by the latest revision of IEEE-519;
b. voltage flicker exceeding the guidelines established by the latest revision of IEEE-141;
c. frequency variations; or
d. voltage or power factor levels that could adversely affect electrical equipment.

4.6 Generator Output Assessment

Transmission system switching can change the electrical power output (commonly referred to as "delta P") of a **generator** and introduce mechanical forces on **generator** equipment. **Generator** output assessments shall be performed in accordance with ISO-NE methods and procedures.

5.0 PROTECTION SYSTEMS

NPCC document titled "Classification of Bulk Power System Elements" ("A-10") provides the methodology for the identification of those **elements** of the NU **transmission system** to which NPCC **bulk power system** criteria are applicable. Protection systems for the **bulk power system** shall be designed in accordance with the NPCC Bulk Power System Protection Criteria ("A-5"). Protection systems for **local area systems** may use less rigid design objectives and practices due to local considerations. However, they shall have no **significant adverse impact** on the **bulk power system**. In general, the function of a protection system is to limit the severity and extent of **faults** or **contingencies** and possible damage to electrical equipment.

An SPS may be used in the design of the **bulk power system** and **local area systems**. The requirements of an SPS are defined in the NPCC Regional Reliability Reference Directory #7 - Special Protection System. A set of guidelines for application of an SPS on the ISO-NE system is contained in the ISO-NE Special Protection Systems Application Guidelines (Planning Procedure No. 5-5, "PP5-5"). An SPS may be used to provide protection for infrequent contingencies, or for temporary conditions that may exist as the result of project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages. The decision to employ an SPS should take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits. All SPSs proposed for use on the **bulk power system** and the **local area systems** must be reviewed and/or approved by ISO-NE and NPCC.

6.0 GLOSSARY OF TERMS

The NERC Glossary of Terms Used in Reliability Standards, NPCC Glossary of Terms (as defined in NPCC A-7), IEEE Standard Dictionary of Electrical and Electronics Terms, and the FERC pro-forma tariff are sources for some definitions. Revised definitions in these sources will not supersede the definitions listed in this section.

1. **AREA** (As defined in NPCC A-7 and modified by NU.)

   An **Area** (when capitalized) refers to one of the following: New England, New York, Ontario, Quebec or the Maritimes (New Brunswick, Nova Scotia and Prince Edward Island); or, as the situation requires, area (lower case) may mean a part of a system or more than a single system. Within NPCC, Areas (capitalized) operate as **control areas** as defined by the North American Electric Reliability Corporation (NERC).

   Within NU, area/s (lower case) is a collection of electrical buses or nodes that make up a portion of the NU **transmission system** that under **contingency** conditions exhibit unique and identifiable behavior when compared to the entire **transmission system**.

2. **BULK POWER SYSTEM** (As defined in NPCC A-7 and modified by NU.)

   The interconnected electrical systems within northeastern North America comprised of system **elements** on which **faults** or **disturbances** can have a **significant adverse impact** outside of the **local area**.

   The NPCC Document A-10 titled "Classification of Bulk Power System Elements" provides the methodology for the identification of those **elements** of the NU **transmission system** to which NPCC **bulk power system** criteria are applicable.

3. **CONTINGENCY (or CONTINGENCIES)** (As defined in NPCC A-7.)

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

4. **CONTROL AREA** (As defined in NPCC A-7.)

   An electric system or systems, bounded by interconnection metering and telemetry, capable of controlling **generation** to maintain its net interchange schedule with other **control areas** and contributing to frequency regulation of the **interconnection**.

5. **DISTURBANCE** (As defined in NPCC A-7)

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

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

6. **ELEMENT** (As defined in NPCC A-7 and modified by NU.)

Any electric device with terminals that may be connected to other electric devices, such as a **generator**, autotransformer, phase angle regulating transformer, circuit, circuit breaker, capacitor, series reactor, shunt reactor or bus section.

7. **EMERGENCY** (As defined in NPCC A-7.)

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. An **emergency** is considered to exist in an **area** if firm load may have to be shed.

8. **FAULT** (As defined in NPCC A-7.)

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.

9. **FAULT CLEARING** (As defined in NPCC A-7.)

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.

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.

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.

10. **GENERATOR/GENERATING PLANT/GENERATION**

The single or multiple points of injection of electrical energy considering the processes of producing electrical energy. The single points of injection are considered units. Example: A combined cycle plant with a single gas supply system may have two gas turbine/**generators** and one steam turbine/**generator**, each considered a unit and in aggregate a plant. A combined cycle plant with a single gas supply system may have a gas turbine and steam turbine coupled with a single **generator**- this is considered a single unit. 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).

11. **GOOD ELECTRIC UTILITY PRACTICE**

Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Electric Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

12. **INTERCONNECTION** (As defined in NPCC A-7 and modified by NU.)

When capitalized, any one of the five major electric system networks in North America: Eastern, Western, ERCOT, Quebec, and Alaska. When not capitalized, the facilities that connect two systems or **control areas**. Additionally, an interconnection refers to the facilities that connect a **generator** to a **control area** or system.

13. **LOCAL AREA SYSTEM** (As defined in NPCC A-7 and modified by NU.)

A confined or radial portion of the NU **transmission system**. The geographic size and number of system elements contained will vary based on system characteristics. A local area may be relatively large geographically with relatively few buses in a sparse system, or be relatively small geographically with a relatively large number of buses in a densely networked system.

14. **NETWORK LOAD**

The load that a customer designates for transmission service under the ISO-NE Open Access Transmission Tariff Schedule 21-NU.

15. **NORMAL**

Any typical system condition that does not require 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.

16. **RATING** (As defined in NPCC A-7 and modified by NU.)

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

Normal Rating — The rating that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units, that a system, facility, or **element** can support or withstand continuously through the daily demand cycles without loss of equipment life.

Emergency Rating — The rating that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units, that a system, facility, or **element** can support or withstand for a finite period. The rating shall incorporate seasonal differences in ambient temperatures and other factors.

Long Time Emergency (LTE) Rating — The maximum rating of electrical equipment based on nominal ambient conditions, preloading conditions and recognizing the nominal load cycle for a long period such as 12 hours. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

Short Time Emergency (STE) Rating — The maximum rating of electrical equipment which can be sustained for 15 minutes based on nominal ambient conditions and recognizing preloading conditions. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved.

17. **RELIABILITY** (As defined in NPCC A-7 and modified by NU.)

The degree of performance of the 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**.

18. **RESOURCE** (As defined in NPCC A-7.)

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.

19. **SIGNIFICANT ADVERSE IMPACT** (As defined in NPCC A-7.)

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 clearly demonstrated to be positively damped within 30 seconds of the initiating event

c. unacceptable equipment tripping;
   • tripping of an un-faulted bulk power-system **element** (which has already been classified as bulk power system) under a 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; and

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

20. **SPECIAL PROTECTION SYSTEM** (As defined in NPCC A-7.)

A protection system designed to detect abnormal system conditions, and take corrective action other than the isolation of faulted **elements**. Such action may include changes in load, **generation**, or system configuration to maintain system **stability**, acceptable voltages or power flows. Automatic underfrequency load shedding as defined in the

Emergency Operation Criteria A-3, is not considered an SPS. Conventionally switched, locally controlled shunt devices are not SPSs.

21. **STABLE (STABILITY)** (As defined in NPCC A-7.)

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

22. **TRANSFER CAPABILITY** (As defined in NPCC A-7 and modified by NU.)

The measure of the ability of interconnected electric systems to move or transfer power in a reliable manner from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). In this context, "area" may be an individual electric system, power pool, **control area**, subregion, or NERC region, or a portion of any of these. Transfer capability is directional in nature. That is, the transfer capability from "Area A" to "Area B" is not generally equal to the transfer capability from "Area B" to "Area A."

Normal Transfer Capability — The amount of power transfer allowed between **areas/Areas** or within an **area/Area** when considering load profiles coupled with typical and/or distributed **generation**.

Stressed Transfer Capability — The amount of power transfer allowed between **areas/Areas** or within an **area/Area** when considering load profiles coupled with either excess or a deficiency in **generation**.

23. **TRANSMISSION SYSTEM**

All facilities rated 69 kV and above (excluding generator leads), owned, controlled or operated by NU, or its designee, that are used to provide transmission service. Those facilities not included in transmission are considered distribution.

24. **WITH DUE REGARD TO RECLOSING** (As defined in NPCC A-7.)

This phrase means that before any manual system adjustments, recognition will be given to the type of reclosing; i.e., manual or automatic, and the kind of protection.

Lead Group: Transmission Planning

Reviewed for concurrence by: Transmission Operations, System Protection, Substation Engineering, and Transmission Line Engineering

Review frequency: Periodically

References:

NERC Transmission Planning Standards (TPL)

NERC Glossary of Terms Used in Reliability Standards

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

NPCC Bulk Power System Protection Criteria (A-5)

NPCC Glossary of Terms (A-7)

NPCC Classification of Bulk Power System Elements (A-10)

NPCC Regional Reliability Reference Directory #7 – Special Protection Systems

ISO-NE Reliability Standards for the New England Area Bulk Power Supply System (PP3)

ISO-NE Special Protection Systems Application Guidelines (PP5-5)

IEEE Standard Dictionary of Electrical and Electronics Terms

Adopted by Northeast Utilities, as amended to date.

Approved by:

Dave Boguslawski
Vice President

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