PURPOSE

This document, effective January 13th, 2017 provides the criteria to be used by the transmission planners when studying the performance of Northern States Power Company - Minnesota and Northern States Power Company - Wisconsin (jointly referred to as NSP) transmission facilities. This includes voltage, line loading, transient stability, flicker, and transmission line reclosing criteria. The document also provides guidance for acceptable forms of mitigation plans and NSP's policy for use of remedial action schemes.

APPLICABILITY AND RESPONSIBILITIES

Northern States Power Company – Minnesota and Northern States Power Company – Wisconsin

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VERSION HISTORY

Effective Date	Version Number	Supersedes	Change
2/4/2013	1.0	N/A	Initial ProjectWise Document. Original document version is 1.0—ProjectWise version
3/18/2015	2.0	1.0	-Updated the nuclear plant voltage requirements -Added the criterion for Ferranti voltage rise -Added transformer loading criteria for planning -Updated damping criteria for stability analysis -Update Criteria for TPL-001-4 Standard -Update interim mitigation plans in Transmission Plans section -Replaced Special Protection Systems (SPS) with Remedial Action Schemes (RAS)
1/13/2017	3.0	2.0	-Updated bus voltage criteria Table 2

			-Changed Section 3 from Voltage Deviation to Rapid Voltage Change to better align with IEEE 1453 terminology -Removed RAS exception for sub-synchronous resonance

TABLE OF CONTENTS

1. Voltage Criteria

When performing steady state analysis, the following voltage criteria applies to NSP's buses under system intact (pre contingent) and post contingent conditions:

Table 1

Facility	Maximum voltage (p.u.) Pre Contingent	Minimum voltage (p.u.) Pre Contingent	Maximum voltage (p.u.) Post Contingent	Minimum voltage (p.u.) Post Contingent
Default for all buses > 100 kV	1.05	0.95	1.05	0.92
Default for all buses < 100 kV*	1.05	0.95	1.05	0.92
Default for all generator buses**	1.05	0.95	1.05	0.95

*For 34.5 kV and below non-generation buses, pre and post contingent voltage of 0.9PU would be acceptable.
**For all Category P0, P1, P2, P4, P5, and P7 contingencies. [1] After a Category P3 or P6 contingency, generator bus voltage would be allowed to drop to 0.92 PU.

Table 1 above presents the general voltage criteria for most of the NSP owned facilities; however specific voltage criteria exist for some of the high voltage buses, these criteria are listed below in Table 2

Table 2

Facility	Maximum (p.u.) Pre Contingent	Minimum (p.u.) Pre Contingent	Maximum (p.u.) Post Contingent	Minimum (p.u.) Post Contingent
Roseau 500 kV bus	1.10	0.95	1.10	0.92
Prairie 115 kV main bus	1.09	0.95	1.09	0.90
Prairie 115 kV capacitor bus	1.15	0.95	1.15	0.92
Sheyenne 115 kV capacitor bus	1.15	0.95	1.15	0.92
Running 230 kV capacitor bus	1.10	0.95	1.10	0.92
Roseau 230 kV capacitor bus	1.05	0.95	1.10	0.92
Chisago 500 kV bus	1.10	0.95	1.10	0.92
Forbes 500 kV bus	1.10	0.95	1.10	0.92
Bison 345 kV bus	1.05	0.95	1.10	0.92
Briggs Road 345 kV bus	1.05	0.95	1.10	0.92

In order to comply with the NUC-001 standard, for nuclear plant off-site source requirements, specific voltage criteria has to be met for Prairie Island and Monticello substation buses. The Nuclear Plant Interface Requirements (NPIR) provides the voltage requirements for the nuclear plants. Contact NSP's transmission planning group to obtain the most up to date voltage criteria for the nuclear plants.

1.1 Ferranti Voltage Rise

Voltage rise on open end of a long line, due to charging current, has to be taken into account when performing line energization studies. The maximum permissible voltage on the open end of the line is 1.05 PU unless the equipment (CCVTs, PTs and Breakers) at the open end of the line are rated to withstand higher voltage. [2]

2. Facility Loading Criteria

The ratings for facilities (transmission lines, transformers and series compensators) owned by NSP are specified in the NSP Ratings Database. The winter and summer ratings of facilities account for the thermal limit of all equipment, and relay loadability limits, as specified in NERC FAC-008-3 standards.

When planning NSP's system, for system intact condition, the current flowing through a facility should not exceed the normal rating of that facility. When studying contingency conditions, the current flowing through a facility should not exceed the emergency rating of that facility. During transmission outages, it should be assumed that the system operators, if required, would take remedial action when the current on a facility is lower than the emergency rating and greater than the normal rating. When such remedial action is not available, the normal rating of the facility should be used.

Certain facilities on NSP's system are dynamically rated, the ratings of these facilities change based on the ambient conditions, such as wind speed. When monitoring these facilities for overloads, appropriate ratings have to be chosen. The up-to-date list of dynamically rated transmission lines can be obtained from NSP's Transmission Planning or Transmission Operations Departments.

2.1 Transformer Loading Criteria for Planning Studies

When performing transmission planning studies for NSP's system the applicable transformer ratings are as follows (the percentages are based on the continuous rating of the transformer):

Table 3

Contingency	Summer	Winter
System Intact (Category P0)	100%	100%
Post Contingent (Category P1-P7)	115%	130%

The overload capability of the transformer is applicable only if there are no other limiting elements (such as bus conductor, CTs, bushings, switches or breakers) on the transformer branch. In the presence of a limiting element, the transformer branch rating would be limited by the lowest rated equipment.

3. Rapid Voltage Change Criteria

When performing planning studies for the transmission system, the following criteria applies to the NSP's system:

- The maximum voltage deviation caused by switching of any shunt device (motor load, capacitor or inductor), under system intact condition, should not exceed more than 3% at any load serving bus. [3]
- The maximum voltage deviation caused by switching of any shunt device (motor load, capacitor, or inductor), during prior outage of the largest fault current contributing element, should not exceed more than 5% at any load serving bus.

4. Voltage stability criteria

Voltage stability analysis is performed as part of load serving studies, as well as generation outlet studies, to identify the maximum transfer capability of the transmission system before a voltage collapse occurs. While performing this analysis, sufficient voltage margin has to be maintained by operating at or below Pcrit. Pcrit is determined by developing PV (Power-voltage) curves for those buses that have the largest contribution to voltage instability for any given outage. P_{limit} is calculated as the lesser of

- (0.9) * P_{crit} [where P_{crit} is defined as the maximum power transfer or system demand (nose of PV curve)] or
- The maximum power transfer or system demand which does not result in a post-contingent voltage violation as defined in Tables 1 and 2.

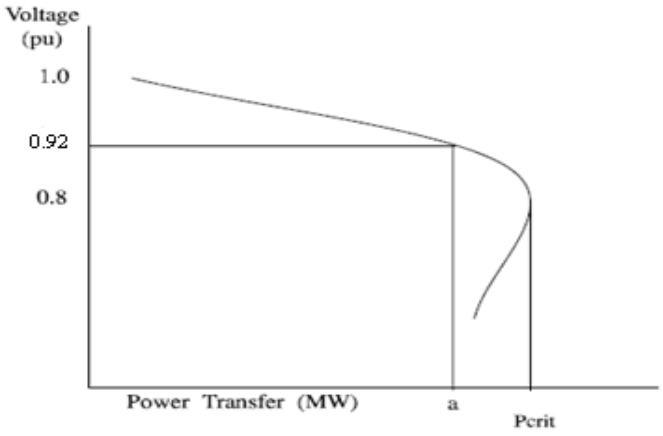

Figure 4.1

5. Steady state planning contingencies evaluated

The contingencies used for planning studies are based on the currently effective NERC TPL-001-4 standard. Refer to Table 1 of TPL-001-4 standard for the category P0 to P7 contingency events evaluated for NSP's Bulk Electric System.

For facilities not classified as Bulk Electric System, only category P0, P1, and P2.1 (opening of line section without fault) contingencies are evaluated.

6. Transient Voltage Criteria

When performing transient stability studies, after the fault is cleared, the following criteria apply to post fault voltages on NSP's buses.

Table 4

Facility	Vmax P.U	Vmin P.U
Default for all Buses	1.2	0.7
Fast Switched Capacitor buses	1.65 P.U for <5 cycles	0.7

NSP does not allow the transient voltage to dip below .7 p.u. for any amount of time.

7. Damping Criteria for Transient Stability Studies

When performing transient stability studies, the following criteria apply to generator angle oscillations:

- The generator angles should always be positively damped
- The successive peak ratio (SPPR), defined by
  SPPR=Successive swing amplitude / Previous swing amplitude
  should be less than 0.95
- The damping factor defined by
  %Damping factor = (1-SPPR)*100
  should be at least 5%

Prony analysis could be used to identify the modes. The damping factors of the modes could be calculated using the following expression:

$$\text{Damping ratio } \zeta = -\sigma / \sqrt{(\sigma^2+\omega^2)}$$

Where $\sigma \pm j\omega$ represents the mode and the frequency of the mode is given by $\omega/2\pi$.

The damping ratio, for disturbances with faults, should be at least 0.0081633. The damping ratio, for disturbances without faults, should be at least .016766.

8. Distance Relaying - Apparent Impedance Criteria

The transient apparent impedance swings on all lines can be monitored by the PSS/E model "MRELY1" against a three zone mho circle characteristics described below:

Circle A = 1.00 x line impedance
Circle B = 1.25 x line impedance
Circle C = 1.50 x line impedance

Apparent impedance transient swings into Circles A or B are considered unacceptable. Any violation of this criterion has to be investigated to ensure that additional transmission

elements do not trip after the fault is cleared. Any valid violation has to be appropriately mitigated.

In addition to the generic distance relay model, specific models are included for the out of step relays on the tie lines between US and Manitoba Hydro system. When performing planning studies, it should be ensured that relay margins for the out of step relays are respected as required by the respective transmission owner. Any unintended tripping of the out of step relays is not acceptable. Any valid violation of these criteria has to be communicated with the transmission owner and should be mitigated if required.

9. Types of Disturbances Studied

The disturbances simulated for the planning studies are based on the currently effective NERC TPL-001-4 standard.

10. Sync Check Relay - Angle Separation Criteria

When reclosing a transmission line, sync check relays are used to ensure that the angle separation between the two ends of the line is not too large. This is to ensure generators, close to either end of the transmission line, do not sustain damage due to large change in power. NSP allows a maximum angle separation of 30 degrees for reclosing of a transmission line.

Under certain conditions, lines could be allowed to reclose at angle separation greater than 30 degrees. In order to allow reclosing lines, with angle separation greater than 30 degrees, switching studies have to be performed to demonstrate that the change in power at any generator does not exceed 50% of its rated power. [1]

11. Short Circuit Criteria

When planning the transmission system, the fault current design capabilities of the facilities should be respected. This includes

- Fault interrupting device capabilities
- Ground grid burn off, and Step and Touch potentials
- Structural strength of bus spans, insulators, etc.
- Personal Protection Equipment for maintenance

Any violation of facilities' capability or personal safety has to be mitigated appropriately.

12. Transmission Plans

Any valid violation of criteria, listed in sections 1 through 11, identified through planning study or assessment has to be addressed by developing an appropriate transmission plan. The plans could involve building new transmission facilities or upgrading existing transmission facilities or re-configuring existing transmission system without causing any new violations.

In addition, use of under-voltage load shedding, reverse power relays, and over current relays could be an acceptable interim mitigation plan for violations of this criteria due to single initiating events. When determining settings on relays to trigger automatic action, operational considerations should be evaluated against the Planning criteria. Settings higher or lower than the established Planning criteria may be necessary to achieve optimal system operation. Deviations from this criterion in the operational timeframe should be evaluated on a case-by-case basis.

Operating guides are used by system operators to address specific challenges that are encountered during the day to day operation of the transmission system and to meet the NERC TOP standards. For long term planning purpose, use of operating guides to meet the NERC TPL standards should be limited to address violations associated with prior outage conditions or to address violations associated with category P6 contingencies.

13. Other Studies

Additional technical studies should be performed as required to maintain system reliability and to follow good utility practice. These include studies related to voltage imbalance, harmonics, sub-synchronous resonance, small signal stability, etc.

14. NSP's policy for use of Remedial Action Schemes

It is NSPM and NSPW (jointly NSP) policy not to install, own or administer new Remedial Action Schemes (RAS), or to expand any existing RAS, to mitigate pre- or post-contingent system reliability concerns on the NSP transmission system (NSP System) or the transmission system of an interconnected neighboring utility transmission system. Reliability concerns include, but are not limited to thermal overloads, voltage violations, and system stability violations.

14.1 Retirement of existing RASs owned by NSP

For each RAS already placed in service on the NSP System, periodic reviews will be performed to ensure that the RAS is deactivated by NSP when the conditions requiring its use no longer exist, or system improvements necessary to remove the RAS are in service.
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14.2 Modification of existing RASs Owned by NSP

Modification of existing RASs would be allowed if a new transmission project requires altering the facilities associated with an existing RAS. This type of modification should be backed by a supporting technical study that demonstrates that the system reliability would not be degraded due to the modification. In addition, the required approvals from the regional reliability organization should also be obtained in accordance with NERC PRC-15 standard.

The modification of existing RASs would not be allowed for generator or load interconnections, transmission service requests or to avoid generation curtailment of existing generation resources.

14.3 New Temporary RAS

New temporary RASs could be allowed on NSP's transmission system only if the following conditions are met:

1. If the RAS is needed as a temporary measure to maintain system reliability during construction of a transmission project, such that the RAS could be retired after the completion of the project.
2. If the RAS is proposed as a short term measure to provide transmission service or allow generator or load interconnection. This would be allowed only if there is a written agreement with NSP, with a committed in-service date for the transmission facilities that would eliminate the need for the RAS.

In order to install the temporary RAS, technical studies have to be performed to demonstrate that the system reliability is not degraded. In addition, approval has to be obtained from the regional reliability organization in accordance with the NERC PRC-015 standard.

Midwest reliability Organization (MRO) reviews the effectiveness of each RAS every 5 years. NSP would not participate in this review of temporary RAS at the end of the fourth year, and will retire the temporary RAS at the end of fourth year. This could result in the generator or load losing its ability to stay interconnected to the transmission system or lose its transmission service, if the transmission facilities required for retiring the RAS are not in-service.

Temporary RASs would not be installed to avoid generation curtailment of existing or future generators that are designated "Energy Resource".

14.4 RASs Owned by Entities Other Than NSP

NSP would not support or participate in the installation of RASs by any entity on NSP's system that would require tripping or switching of NSP's transmission facilities or any generating facility interconnected to NSP's transmission system.

For a RAS owned and administered by an entity other than NSP, that does not require tripping of NSP's transmission facilities or generating facilities interconnected to NSP's transmission system, that requires installation of monitoring and communication equipment on the NSP System, NSP will cooperate with installation of such monitoring and communications equipment on the NSP System, provided the following conditions are met:

1) The entity owning and administering the RAS agrees to perform the necessary technical studies required to support the need, and the impact of the RAS on the transmission system, as required by applicable NERC standards for Special Protection Systems, and obtain the necessary approval from the applicable regional entity (e.g., the Midwest Reliability Organization)

2) The entity owning the RAS agrees to be responsible for complying with misoperation reporting requirements as required by the applicable NERC standards for RASs, and will be responsible for coordinating any corrective actions with the NSP System.

3) The entity identified as the Transmission Operator of the RAS, for the RAS owner, would be solely responsible for monitoring the status of the RAS and notifying affected entities of changes in the status of the RAS, including any degradation or potential failure to operate as expected as required by PRC-001-1 R6 and IRO-005-3a R9.

Works Cited

[1] IEEE Std C50.13™-2014, IEEE Standard for Cylindrical-Rotor 50 Hz and 60 Hz Synchronous Generators Rated 10 MVA and Above.

[2] IEEE Std 37.012™-2014, IEEE Guide for the Application of Capacitance Current Switching for AC High-Voltage Circuit Breakers Above 1000 V

[3] IEEE Std 1453™-2015, IEEE Recommended Practice for the Analysis of Fluctuating Installations on Power Systems.