



***DUKE ENERGY CAROLINAS
TRANSMISSION SYSTEM
PLANNING GUIDELINES***

Transmission Planning

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I. SCOPE

This document was designed to provide a summary of the fundamental guidelines used by Transmission Planning employees to plan Duke Energy Carolinas' (DEC) 500 kV, 230 kV, 161 kV, 100 kV, 66 kV and 44 kV transmission systems.

Any reliable transmission network must be capable of moving power throughout its system without exceeding voltage, thermal and stability limits, during both normal and contingency conditions. These guidelines are designed to help Transmission Planning employees identify potential system conditions that require further study. **It does not provide criteria for which absolute decisions are made regarding transmission system improvements.** Duke Energy Carolinas retains the right to amend, modify, or terminate any or all of these guidelines at its option.

II. TRANSMISSION PLANNING OBJECTIVES

The guidelines in this document are formulated to meet the following objectives:

- Provide an adequate transmission system to serve the network load of the Duke Energy Carolinas service territory.
- Balance risks and expenditures to ensure a reliable system while maintaining flexibility to accommodate an uncertain future.
- Maintain adequate transmission thermal capacity and reactive power reserves (in the generation and transmission systems) to accommodate scheduled and unscheduled transmission and generation contingencies.
- Achieve compliance with the NERC and SERC Reliability Standards that are in effect.
- Adhere to applicable regulatory requirements.
- Minimize losses where cost effective.
- Provide for the efficient and economic use of all generating resources.
- Provide for comparable service under the Duke Energy Carolinas, LLC FERC Open Access Transmission Tariff.
- Satisfy contractual commitments and operating requirements of inter-system transactions.

III. PLANNING ASSUMPTIONS

A. Load Levels

- Summer Peak (for current year and next 10 years)
- Winter Peak (for current year and next 10 years)
- Spring Valley (for current year and next 2 years)
- Loads plus losses at the transmission level will be scaled to match the system forecast for each load level. When conditions warrant, additional cases may be generated to examine the impact of other load levels.

B. Generation

1. Dispatch

Generation patterns may have a large impact on thermal loading levels and voltage profiles. Therefore, varying generation patterns shall be examined as a part of any analysis. Generators with confirmed, firm transmission reservations or designated as network resources are modeled as being available for dispatch. Units serving native load are economically dispatched for normal and contingency conditions. Normal outages for maintenance, forced outages, and combinations of normal and forced outages are modeled. Generating units are modeled at their expected seasonal continuous capability.

2. Voltage Schedules

An optimal power flow program is used to determine the voltage schedules for major system generating units. The schedules are tailored for season and load level to meet system reactive power requirements.

3. Reactive Capability

Generator reactive capability data is included in the base power flow models so the impact of reactive power available from generators can be reproduced in the system model. The generator MW dispatch module within the power flow analysis program applies generator reactive power limits based on the real power output levels and reactive capability of each unit.

C. Power Transactions

Long-term firm transactions between control areas are included in the appropriate power flow base cases and shall be consistent with contractual obligations. For an emergency transfer analysis, generation is reduced in a manner that will cause stress on the system.

DEC participates in several reliability groups that perform transfer studies on a regular basis: VACAR (Virginia-Carolinas Subregion of SERC), SERC Intra-Regional Long-Term and Near-Term Power Flow Study Groups (VACAR-Southeastern-Central-Delta-Gateway regions), SERC East-RFC (ReliabilityFirst Corporation), NCTPC (North Carolina Transmission Planning Collaborative), CTCA (Carolinas Transmission Coordination Arrangement), SERTP (Southeastern Region Transmission Planning).

D. Equipment Ratings

The methodologies used to rate transmission facilities encompass all components (e.g., transformers, line conductors, breakers, switches, line traps, etc.) from bus to bus. Wind speed and angle, ambient temperature, acceptable operating temperatures, as well as other factors, are used in determining facility ratings. All facilities are composed of eight ratings reflecting the following capabilities for both summer and winter seasons:

- continuous
- long-term emergency (1 year)
- 12-hour emergency
- 1-hour emergency

E. Nominal Voltages

Nominal voltages on the DEC system are 500 kV, 230 kV, 161 kV, 100 kV, 66 kV and 44 kV. Additional nominal voltages of 138 kV and 115 kV are utilized for some of DEC's interconnections with other utilities.

F. Common Right-of-Way

Part of the judgment used for any analysis is the definition of line outages on a common right-of-way. Clearly, there are situations where multiple lines may leave a station in a similar direction and along a common corridor for some short distance. While there are no clear cut rules, the length of exposure of a common right-of-way and the criticality of the circuits involved must be considered when defining which rights-of-way should be studied.

IV. STUDY PRACTICES

DEC conducts transmission planning studies including, but not limited to:

- Screening of Voltage Guidelines
- Screening of Thermal Guidelines
- Grid Voltage Study For Nuclear Loss-Of-Cooling Accident (LOCA)
- Spare Transformer Study
- Transformer Tertiary Study
- Optimal Power Flow Studies For Generator Voltage Schedules And Capacitor Additions
- Angle and Voltage Stability Analyses
- Power Transfer Studies
- System Impact Studies
- Generation Interconnection and Affected System Studies
- Fault Duty Analyses
- Miscellaneous Losses Evaluation
- Facilities Adequate Evaluations
- Severe Contingency Studies

During the course of transmission planning activities, the identification of a System Operating Limit (SOL) or an Interconnection Reliability Operating Limit (IROL) in the planning or operating horizon is possible. SOL's and IROL's are defined as:

SYSTEM OPERATING LIMIT (SOL) - The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post-contingency equipment or facility ratings)
- Transient Stability Ratings (Applicable pre- and post-contingency stability limits)
- Voltage Stability Ratings (Applicable pre- and post-contingency voltage stability)
- System Voltage Limits (Applicable pre- and post-contingency voltage limits)

INTERCONNECTION RELIABILITY OPERATING LIMIT (IROL) - A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Bulk Electric System.

If a transmission planning activity identifies a SOL or IROL may be exceeded in the operating horizon, System Operations Engineering (as DEC's Transmission Service Provider, Transmission Operator and Reliability Coordinator) should be immediately notified in accordance with FAC-014-2. The SOL or IROL information shall also be provided to adjacent Planning Authorities and adjacent Transmission Planners. In accordance with FAC-003-4 Applicability – Transmission Facilities 4.2.2, if an overhead transmission line operated below 200 kV is identified as an element of an IROL, DEC's Manager, Vegetation Management must be notified. SOL or IROL limit violations identified in the planning horizon should be corrected and/or mitigated in advance of the operating horizon.

V. PLANNING GUIDELINES

Transmission Planning is charged with planning the transmission system (500 kV, 230 kV, 161 kV, 100 kV, 66 kV, 44kV) and the system interconnections, as well as consulting in planning the distribution system (34.5 kV and below). Voltages and thermal loadings that violate the following guidelines will result in further analyses. Studies of the transmission system give consideration to the effect we may have on the planning and operation of neighboring utilities as well as the effect they may have on our system.

As a part of the NERC Reliability Standards, utilities are charged with planning their system in a manner that avoids uncontrolled cascading beyond predetermined boundaries. This is to limit adverse system operations from crossing a control area boundary. To this extent, DEC participates in several regional reliability groups: VACAR (Virginia-Carolinas Subregion of SERC), SERC Intra-Regional Long-Term and Near-Term Power Flow Study Groups (VACAR-Southeastern-Central-Delta-Gateway regions), SERC East-RFC (ReliabilityFirst Corporation), NCTPC (North Carolina Transmission Planning Collaborative), CTCA (Carolinas Transmission Coordination Arrangement), SERTP (Southeastern Region Transmission Planning) . Each of these reliability groups evaluates the bulk transmission system to ensure: 1) the interconnected system is capable of handling large economy and emergency transactions, 2) planned future transmission improvements do not adversely affect neighboring systems, and 3) the interconnected system's compliance with selected NERC Reliability Standards.

Each of these study groups has developed its own set of procedures that must be followed. These study groups do not have as one of their objectives the analysis and planning for any one individual system. The main objective of these groups is to maintain adequate transmission reliability through coordinated planning of the interconnected bulk transmission systems.

In addition to these regional reliability studies, DEC conducts its own assessments of transmission system performance. While these assessments are typically focused on the DEC system, they cannot be conducted without consideration of neighboring systems.

The voltage and thermal guidelines for the transmission system under normal and contingency conditions are described in Section A and Section B, respectively. A description of the contingencies studied as part of any voltage or thermal evaluation is provided in Section C.

A. Voltage

Bus voltages are screened using the Transmission System Voltage Guidelines below. These guidelines specify minimum and maximum voltage levels, the percent voltage regulation during both normal and contingency conditions, and the percent voltage drop due to contingencies, as part of the Duke Energy Carolinas Transmission Operator plan to operate within System Operating Limits and Interconnection Reliability Operating Limits.

Absolute Voltage Limits are defined as the upper and lower operating limits of each bus on the system. The absolute voltage limits are expressed as a percent of the nominal voltage. All voltages should be maintained within the appropriate absolute voltage bounds for all conditions.

Voltage Regulation is defined as the difference between expected maximum voltage and minimum voltage at any particular delivery point. The voltage regulation limits are expressed as a percent of the nominal voltage and are defined for both normal and contingency conditions. Voltage regulation for delivery point voltages should not exceed the guidelines.

Contingency Voltage Drop is defined as the maximum decrease in voltage due to any single contingency.

161 kV, 230 kV, & 500 kV Transmission System Voltage Guidelines

Nominal Voltage (kV)	Absolute Voltage Limits		Maximum Allowable Contingency Voltage Drop
	Minimum	Maximum	
161	95%	105%	5%
230	95%	105%	5%
500	100%	110%	5%

44 kV, 66 kV, & 100 kV Transmission System Voltage Guidelines

Nominal Voltage (kV)	Absolute Voltage Limits		Voltage Regulation	
	Minimum	Maximum	Normal	Contingency
44	94%	109%	8.5%	10%
66	94%	109%	8.5%	10%
100	95%	107%	6%	7%

Autotransformer voltage limits are based on the secondary tap setting. The minimum voltage is 95% of the tap voltage and the maximum voltage is 105% of the tap voltage under full load and 110% of the tap voltage under no load. Thus, the voltage limits for transformers vary with both loading and tap setting. The secondary tap on most of DEC's 220/100 kV autotransformers is 100 kV. The one exception is AT-2 at Pisgah Tie; it is set at 95 kV. This implies a maximum voltage of 99.75 to 104.5 kV, depending on loading. The following table shows what stations have 220 kV transformers and how many there are at each station.

220/100 kV Autotransformers

Station	Number of 220 kV Autotransformers	Bank #
Anderson	1	1
Beckerdite	2	2, 3
Eno	1	4
Morning Star	2	3, 4
N. Greenville	2	1, 2
Pacolet	1	1
Pisgah*	1	2

*Pisgah AT-2 is on the 95 kV tap.

Nuclear voltage limits are based on the design of electrical auxiliary power systems within the plants and Nuclear Regulatory Commission (NRC) requirements. There are two sets of these limits: minimum and maximum generator bus voltage limits and minimum grid voltage limits.

B. Thermal

The following guidelines shall be used to ensure acceptable thermal loadings:

- a) Under normal conditions, no facility should exceed its continuous thermal loading capability.
- b) With a transmission contingency having an expected duration of less than 12 hours (line outage or single phase transformer outage where spare is available), no facility should exceed its 12-hour emergency loading capability.
- c) With a capacitor, transformer (three phase or single phase with no spare) or generator contingency having an expected duration of more than 12 hours, no facility should exceed its long-term emergency loading capability.

C. Selected Contingencies

The planning studies for the transmission system are performed for normal and contingency conditions. The thermal and voltage guidelines should not be violated for either normal operations or under the loss of:

- a) A single transmission circuit
- b) A single transformer
- c) A single generating unit
- d) A single reactive power source or sink
- e) A transmission circuit opening on one end
- f) Combination of a single generating unit and a single transmission circuit, capacitor bank, or transformer
- g) Combination of two generating units

Several 230 kV tie stations on the DEC system have incomplete Double bus or Breaker-and-a-half designs. Thus, abnormal single contingency configurations can result. To properly screen for violations of the guidelines, the following table indicates the transformers that should be evaluated for abnormal single contingencies. Breaker contingencies must be evaluated based on the individual configuration.

230 kV Tie Stations With Abnormal Single Contingency Configurations

Tie Station	Outaged facilities for 230 kV line fault	Outaged facilities for 230/100 kV autotransformer fault
Bush River	The line and transformer	The transformer and a line
Hodges	The line	The transformer and a line
Lakewood	The line and transformer	The transformer and a line
McDowell	The line	The transformer and a line*
Morningstar	The line	The transformer and possibly a line *
Peacock	The line	The transformer and a line
Shady Grove	The line	The transformer and tap line
Tuckasegee**	The line	The transformer and a line
Woodlawn	The line and transformer	The transformer and possibly a line *

* Depends on which 230/100 kV transformer experiences the fault.

** 230/161 kV transformer

When appropriate, additional analyses will be conducted to review the impact of a combination of single contingencies, considering the probability of occurrence, the appropriate customer outage costs, and the possible system improvements to determine what, if any, remedial actions need to be taken.

D. Miscellaneous

1. Spare Transformer Policy

This policy is reviewed periodically to account for changes in failure rates, transformer lead times, and outage costs. Currently, the following number of spares should be available:

Spare Transformer Requirements

Type of Transformer	# of Spares
230/100/xx kV Autotransformer	4
30/40/50 MVA 3 phase 100/44 kV	0
20/27/33 MVA 3 phase 100/44 kV	1
12/16/20 MVA 3 phase 100/44 kV	1

2. Transformer Tertiary Study

This study determines the minimum number of tertiaries required in service to operate the system reliably. Having only the required amount of tertiaries in service reduces failures from detrimental in-service events like faults.

3. Optimal Power Flow (OPF) Studies

OPF studies are conducted to determine the seasonal generator voltage schedules and support reactive power planning. OPF study results are utilized to minimize system losses by optimizing the use of existing VAR resources and planning additional future resources.

4. Stability

a) Angle

DEC performs stability analyses on large generating units as major generation or transmission changes occur on the system and as required by the NERC Reliability Standards. In addition, stability analysis will be performed for the nuclear plants in compliance with Nuclear Regulatory Commission requirements. These studies assess the ability of the interconnected network to maintain angular stability of the generating units under various contingency situations. Many different contingencies are considered and the selection is dependent on the type of study and location within the transmission system. The stability of the DEC system and neighboring systems must be maintained for the contingencies specified in the applicable sections of the NERC Reliability Standards.

b) Voltage

An important part of preventing cascading outages is ensuring that voltage collapse will not cascade for the applicable contingencies defined in the NERC Reliability Standards.

Voltage stability analyses are performed using both traditional ZIP models and complex load models for all load in and near DEC. The DEC system is studied on system peak applying various single and multiple contingencies to detect voltage collapse for single contingencies and voltage collapse for multiple element and delayed clearing contingencies.

The corrective measures such as faster relaying, transmission upgrades, or unit tripping are determined on an individual basis after considering economics, probability of occurrence, and severity of the disturbance.

5. Power Transfer Studies

Power transfer studies may be conducted as a part of a facility addition or upgrade analysis, as a part of a system impact study, as well as with the regional study groups to ensure system reliability.

Long-term Planning

An 1100 MW first contingency incremental transfer capability (FCITC) level should be maintained for imports into the DEC system from VACAR to ensure system reliability. DEC has an agreement with four systems within VACAR (Duke Energy Progress, Santee Cooper Public Service Authority, South Carolina Electric and Gas, and Dominion Virginia Power) to share contingency reserves. By maintaining the 1100 MW level of FCITC with VACAR, DEC has the capability to import the shared reserve requirements from the member systems.

The following first contingency incremental transfer capability levels should be maintained for exports from the DEC system to ensure system reliability:

Non-Simultaneous Export Capability

Importing System	Minimum FCITC (MW)
CP&LE	600
SCPSA	600
SCE&G	600
DVP	600

DEC maintains adequate export capability with the four VACAR systems that share operating reserves to deliver DEC’s portion of the reserve.

6. Impact Study

Impact studies are performed to identify any problems associated with a requested/proposed system change. The following analyses are performed if necessary:

- A. **Power Flow Analysis**
 A power flow analysis will be performed to determine any violations of the planning guidelines due to the addition of the request. Projects that will be accelerated by the request will be identified as well as projects that will be needed to correct violations prior to implementation of the request.
- B. **Transfer Analysis**
 A transfer analysis will be performed to determine the impact on the bulk power system and to assess the changes that will occur in other areas resulting from the request.
- C. **Stability Analysis**
 A stability analysis will be performed to determine any violations to planning guidelines.
- D. **Fault Analysis**
 A fault analysis will be performed to determine information necessary for sizing equipment.
- E. **Other analyses as required for a particular request.**

7. Fault Duty

Fault duty studies are performed to determine the available fault current for each transmission system (500, 230, 161, 100, 66, and 44 kV) breaker location. A Breaker

Rating Module (BRM) program that resides within the fault study is used to check if the fault current capacity of the existing breakers is being exceeded. Action is taken to upgrade a breaker when studies indicate the fault current is 98% or greater of the breaker's rating. Fault duty studies are also used to assist in sizing the interrupting capacity of new breakers being installed on the system. When major system changes or additions are to be implemented, a BRM study is performed for both the existing and future state system configurations to determine the impact on the Transmission System and if any breaker's capacity will be exceeded.

Network

Faults are evaluated for each breaker location to find the highest available fault current for the following conditions:

- single phase to ground fault
- three phase to ground fault
- fault resistance assumed to be zero
- location of fault assumed to be at terminals of the breaker in question
- all breakers at a bus in service
- breakers taken out, one at a time
- line mutual impedance included
- all generation units included
- adjacent system fault contributions included
- 5% above nominal operating voltage

The maximum calculated fault current at each breaker location and the associated breaker fault duty capability are compared to determine where violations of the breaker rating exist.

Radial

Fault duty for radial locations not explicitly modeled is calculated using fault duty at the associated network bus with the impedance of the radial line segment included.

8. Miscellaneous Losses Evaluations

Various equipment and system loss evaluations are performed to aid in the selection of equipment, to meet contractual obligations and to compare system configurations.

9. Facilities Adequate Evaluations

Facility evaluations are performed when a customer requests a change in contract MW. The existing equipment, metering and analysis are evaluated for the proposed increase in load and a determination is made concerning any necessary improvements.

10. Contingency Studies

NERC Reliability Standard TPL-001-4 instructs transmission providers to evaluate single and multiple contingency events. It also requires evaluation of extreme events resulting in the loss of multiple elements and extreme (severe, but highly improbable) contingency events. Contingency simulations are analyzed to verify that specific performance requirements are met for each category and to allow the development of corrective action and mitigation plans.