DUKE ENERGY PROGRESS

TRANSMISSION SYSTEM PLANNING SUMMARY

Transmission Department

Transmission Planning – Duke Energy Progress

TABLE OF CONTENTS

I. SCOPE

This document contains an overview of the fundamental guidelines followed by Duke Energy Progress Transmission Planning Unit employees to plan Duke Energy Progress' (DEP's) 500 kV, 230 kV, 115 kV, and 69 kV transmission systems. FERC Order 890 requires that public utilities document and make available to stakeholders their basic methodology, criteria, and processes in order to ensure that transmission planning is performed on a consistent basis. The Transmission System Planning Summary contains general information on Duke Energy Progress transmission planning practices and provides links to other Duke Energy Progress documents that contain additional detail.

The Duke Energy Progress transmission system is planned to meet NERC Reliability Standards. Any reliable transmission network must be capable of moving power throughout the system without exceeding voltage, thermal and stability limits, during both normal and contingency conditions. These guidelines and referenced documents are designed to aid Transmission Planning Unit employees in planning and designing a safe and reliable transmission system. Duke Energy Progress retains the right to amend, modify, or terminate any or all of these guidelines and referenced documents 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 in the Duke Energy Progress service territory.
- Balance the risks and expenditures required to ensure a reliable transmission system while maintaining the flexibility to accommodate future uncertainties.
- 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 Reliability Standards that are in effect (http://www.nerc.com/pa/stand/Pages/default.aspx).
- Adhere to applicable regulatory requirements.
- Minimize losses where cost effective.
- Provide for the efficient and economic use of all generating resources in accordance with applicable tariffs and regulatory requirements.
- Provide for comparable service under the Duke Energy Progress Open Access Transmission Tariff.

- Satisfy contractual commitments and operating requirements of inter-system agreements.

III. TRANSMISSION PLANNING ASSUMPTIONS

A. Load Levels Modeled

Duke Energy Progress updates its power flow models on an annual basis. Loads plus losses at the transmission level will be scaled to match the system forecast for each load level. Models for the load levels listed below are developed annually. When conditions warrant, additional cases may be generated to examine the impact of other load levels.

- Summer Peak (for year 1 and next 9 years)
- Winter Peak (for year 1 and next 9 years)
- Spring Valley (near term and long term)

B. Generation Modeled

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. Non-Duke Energy Progress generators with confirmed, firm transmission reservations or designated as network resources are modeled as being in-service. Units serving network/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

Power Flow analysis is used to determine the voltage schedules for major system generating units. The voltage schedules are tailored to take into account equipment capabilities and load level to meet system reactive power requirements.

3. Reactive Capability

Reactive capability data is included in the base power flow models so that the impact of reactive power available from generators and other sources can be reproduced in the system model. Reactive power output is evaluated to ensure sufficient reactive capacity exists.

4. Power Transactions

Long-term firm power 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 such a manner that it will induce stress on the system.

Duke Energy Progress participates in several reliability groups that perform transfer studies on a annual basis: CTCA (Carolinas Transmission Collaborative Arrangement); SERC Intra-Regional Long-Term and Near-Term Power Flow Study Groups ; RFC (ReliabilityFirst Corporation) - SERC East; and the North Carolina Transmission Planning Collaborative (www.nctpc.org/nctpc) .

More detailed information can be found in the following documents:

Regional Transmission Assessment Study Processes within SERC

NC Load Serving Entities' Transmission Planning Participant Agreement

Eastern Interconnection Reliability Assessment Group (ERAG) Agreement

C. Facility Ratings

- The methodology used to rate transmission facilities encompasses 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. More detailed information can be found in the following document:

  Transmission Facilities Rating Methodology

- Transmission Planning maintains rating spreadsheets for transmission facilities in accordance with the current Transmission Facilities Rating Methodology. The roles and responsibilities of various Transmission organizations in maintaining these ratings are provided in TOP Carolinas Transmission Facilities Limiting Element Business Practices.

- Transmission Planning will provide requested facility ratings information as specified below (for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities) to its associated Reliability Coordinator(s), Transmission Owner(s) and Transmission Operator(s). Requests can be made through the OASIS Provider Contact. Transmission Planning will provide the ratings information specified below, within 30 calendar days (or a later date if specified by the requester), for any requested Facility with a thermal rating that limits the use of facilities under the requester's authority. This commitment includes facility ratings that cause any of the following: 1) An Interconnection Reliability Operating Limit, 2) A limitation of Total Transfer Capability, 3) An impediment to generator deliverability, or 4) An impediment to service to a major load center.

Transmission Planning will provide the following:

a) Identity of the existing next most limiting equipment of the Facility

b) The Thermal Rating for the next most limiting equipment identified in a) above.

D. Nominal Voltages

Nominal voltages on the Duke Energy Progress system are 500 kV, 230 kV, 115 kV, and 69 kV. Additional nominal voltages of 161 kV and 100 kV are utilized for some of Duke Energy Progress' interconnections with other utilities.

IV. STUDY PRACTICES

Duke Energy Progress conducts a variety of transmission planning studies on an annual basis including, but not limited to:

- Screening of Voltage
- Screening of Thermal Loading
- Grid Voltage Study For Nuclear Loss-Of-Cooling Accident (LOCA)
- Power Flow Studies For Generator Voltage Schedules And Capacitor Additions
- Angle Stability Analyses
- Power Transfer Studies
- System Impact and Facilities Studies

- Generation Interconnection and Affected System Studies
- Fault Duty Analyses
- Miscellaneous Losses Evaluation
- New Customer Connection Evaluations
- Severe Contingency Studies

During the course of transmission planning activities, the identification of a System Operating Limit (SOL) or an Interconnected 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.

DEP Transmission Planning serves as both Transmission Planner and Planning Authority for DEP. If a transmission planning activity identifies a SOL or IROL in the operating horizon, System Operations (as DEP's Transmission Service Provider and Transmission Operator), VACAR South Reliability Coordinator, adjacent Transmission Planners and adjacent Planning Authorities shall be notified in accordance with FAC-014-2. In accordance with FAC-003-2 Applicability – Transmission Facilities 4.2.2, if an overhead transmission line operated below 200 kV is identified as an element of an IROL, DEP's Manager, Vegetation Management shall be notified. SOL or IROL limit violations identified in the planning horizon should normally be corrected/mitigated in advance of the operating horizon.

More detailed information can be found in the following document:

System Operating Limits in the Planning Horizon

V. PLANNING GUIDELINES

Transmission Planning is charged with planning the transmission system (500 kV, 230 kV, 115 kV, and 69 kV) 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 bulk transmission system give consideration to the effect Duke Energy Progress may have on the planning and operation of neighboring utilities as well as the effect they may have on the Duke Energy Progress 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 requirement limits adverse system operations from crossing a control area boundary. To meet this obligation, Duke Energy Progress participates in several reliability groups: CTCA (Carolinas Transmission Collaborative Arrangement); SERC Intra-Regional Long-Term and Near-Term Power Flow Study Groups; RFC-SERC East; and the North Carolina Transmission Planning Collaborative. 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. Additional information on SERC region efforts to coordinate planning activities related to reliability and economic access can be found in the following documents:

Whitepaper on 'Reliability Planning in the Southeast and the Relationship between Reliability and Economic Planning'

Whitepaper on 'Southeast Inter-Regional Participation Process'

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 assessment for any one individual system. The main objective of these groups is to maintain adequate transmission reliability through coordinated assessment of the interconnected bulk transmission systems.

In addition to these regional and inter-regional reliability studies, Duke Energy Progress conducts its own assessments of the bulk transmission system. While these assessments are typically focused on the Duke Energy Progress system, they cannot be conducted without consideration of neighboring systems.

NERC Reliability Standards mandate that facility connection requirements for all facilities involved in the generation, transmission, and use of electricity be documented. All electric industry participants are required to document the facility connection requirements for their system.

Duke Energy Progress has a Facility Connection Requirements document that identifies the technical requirements for connecting load deliveries, generation facilities, and control area Interconnections to the Duke Energy Progress transmission system. The following is a link to the DEP document.

Facility Connection Requirements

The Facility Connection Requirements document is divided into two major sections: 1) Load Delivery Requirements and 2) Generation and Interconnection Requirements. Some projects may have both load and generation on site. These technical requirements are designed to ensure the safe operation, integrity, and reliability of the transmission system. Transmission planning studies are performed to ensure that these requirements will be met under the applicable operating conditions. The DEP FCR document states that its 500 kV transmission system is reserved for the bulk transport of large amounts of electricity. The DEP policy is to not allow generation connection of less than 500 MW to its 500 kV network. Connection to the 500 kV network of generation amounts larger than 500MW will be evaluated on a case by case basis.

Some of the other requirements are summarized below.

The voltage and thermal guidelines for the transmission system under normal and contingency conditions are described *infra* in Section V.A and Section V.B, respectively. A description of the contingencies studied as part of any voltage or thermal evaluation is provided in Sections V.C and V.D.9.

A. Voltage

Bus voltages are screened using the Transmission System Voltage Guidelines set forth below. The 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.

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.

230 kV & 500 kV Transmission System Voltage Guidelines

Nominal Voltage (kV)	Absolute Voltage Limits Minimum	Maximum	Maximum Allowable Contingency Voltage Drop
230	90%	105%	8%
500	100%	108%	5%

69 kV & 115 kV Transmission System Voltage Guidelines

Nominal Voltage (kV)	Absolute Voltage Limits Minimum	Maximum	Maximum Allowable Contingency Voltage Drop
69	90%	105%	10%
115	90%	105%	8%

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 Duke Energy Progress' 230/115 kV autotransformers is 115 kV.

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 guideline shall be used to ensure acceptable thermal loadings:

> Under normal and contingency conditions, no facility should exceed its continuous thermal loading capability.

C. Selected Contingencies

The planning studies for the transmission system are performed for normal and contingency conditions in accordance with NERC Reliability Standards. 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) Combinations of generating units, transmission circuits, capacitor banks, and transformers. Section V.D.9 describes DEP practices in more detail.

Part of the judgment used for any analysis is the definition of line outages for common tower lines. There are situations where two lines may leave a station in the same direction on common towers or come together on common towers for some short distance to pass through a congested corridor. In other cases, two lines may be constructed on common towers for long distances. While there are no clear cut rules, the length of exposure of common tower lines and the criticality of the circuits involved, must be considered when defining which common tower outages should be studied. Duke Energy Progress considers common tower line segments of greater than one mile as a single contingency.

D. Miscellaneous

1. Delivery Point Power Factor Standard

Duke Energy Progress has established a power factor standard for all delivery points. This target is:

- 99.0% lagging power factor or better during Duke Energy Progress peak load conditions (leading power factors are acceptable) and
- 100% (Unity) power factor or below (lagging) during valley load conditions (leading power factors are not acceptable).

Some delivery points have contractual power factor requirements that vary from the standard. The power factor standard is designed to allow full utilization of transmission system equipment, provide support of system voltage levels during peak loading conditions and contingencies, and to help prevent high system voltage levels during valley load conditions.

2. Reactive Studies

Power Flow studies are conducted to determine the generator voltage schedules and for reactive power planning. Reactive study results are utilized to reduce system losses by adjusting VAR resources and by planning additional resources.

3. Stability

Duke Energy Progress performs stability analyses on generating units as major generation or transmission changes occur on the system and as required by the Nuclear Regulatory Commission for the nuclear plants. In addition, stability analysis will be performed to comply with NERC Reliability Standards. 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 Duke Energy Progress system and neighboring systems must be maintained for the contingencies specified in the applicable sections of the NERC Reliability Standards and the SERC requirements.

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

4. 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 associated with a generation interconnection request or a transmission service request, as well as with the regional study groups to ensure system reliability.

Long-Term Assessments

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

Duke Energy Progress also maintains adequate export capability with the four VACAR systems that share operating reserves to deliver Duke Energy Progress' portion of the reserve sharing commitment.

Available Transmission Capability (ATC) is the measure of the transfer capability remaining in the physical transmission network for further transmission service over and above committed use. The guidance for calculating and coordinating ATC is set forth in Attachment C of its open access tariff. Pursuant to Order 1000, changes to this Attachment may occur. Duke Energy Progress participates in industry organizations developing the methodologies and intends to apply applicable NERC, SERC and other industry guidance for calculating ATC.

When performing long-term firm Transmission Service Request (TSR) analyses DEP begins with the most current power flow base case for the starting year of the study period requested. Generally, firm counter-flow reservations are removed except for certain load-serving dynamic schedule reservations. All long-term firm reservations, as well as the DEP Transmission Reliability Margin (TRM) requirements, in the same import/export direction are added to the case. For Affiliate import requests, a 129 MW[1] additional transfer on the DUK:CPLE interface will be modelled to ensure that the committed set-aside is retained for non-affiliates. This additional transfer will be implemented in the power flow model by

[1] Although the FERC order requires a set aside of only 25 MW, the company has elected to implement a set aside of 129 MW in the context of long term reservations until FERC rules on Duke Energy's Motion to Supplement. This is a conservative decision. It is likely an academic matter because the company does not expect any long term requests for firm reservations from affiliates prior to the time FERC rules on the Motion to Supplement.

decrementing the DEC system load by 129 MW and redispatching the DEP generation to accept the additional import. This step will not be performed for any period of time when a new post-merger non-affiliate long-term firm request of 129 MW or more on the DUK:CPLE interface has been received and confirmed. Contingency analysis, consistent with DEP transmission planning criteria and assessment practices will be performed on the modified power flow base case to determine if adequate transfer capability is available to accept the request.

5. Impact Studies

Impact studies are performed to identify any problems associated with a requested or 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 Analysis*
Other analyses as required for a particular request.

As required by FERC Order 890, Conditional Firm Service and Planning Redispatch Service will be evaluated as options to allow the customer to have annual firm transmission service with some restrictions.

6. Fault Duty

Fault duty studies are performed to determine the available fault duty for each transmission system (500, 230, 115, and 69 kV) breaker location. The fault duty study results are used to verify the fault current capacity of existing breakers. The results are also used to assist in sizing the ampacity of new breakers to be installed. As system changes or additions are made, a fault duty study is done as needed for both current and future system configurations.

<u>Network</u>
Faults are evaluated for each breaker location to find the highest available fault current for the following conditions:

- single phase to ground fault
- two 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
- all generation units included
- adjacent system fault contributions included
- 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 could exist.

<u>Radial</u>
Fault duty for radial locations not explicitly modeled are calculated using fault duty at the associated network bus and the impedance of the radial elements.

7. 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.

8. New Customer Connection Evaluations

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

9. Severe Contingency Studies

NERC Reliability Standards instruct transmission planners to evaluate extreme (highly improbable) contingency events resulting in multiple elements removed or cascading out of service.

Selected severe contingency simulations are analyzed to verify that cascading off system does not occur. The following sections describe the DEP rationale for selection of transmission planning assessments to address NERC Reliability Standards TPL-003 and TPL-004 for powerflow and dynamics studies.

For Powerflow Studies:

DEP annually performs powerflow screening studies to identify thermal overload and voltage problems for contingencies in excess of those required by the NERC Table 1 Category C and Category D contingencies. This includes examining the effect of contingency outages of transmission lines/transformers with any one major unit down and the remaining generation scaled back for a total reduction approximately equal to the DEP TRM requirement (approximately 1830 MW emergency import). The contingencies studied on this high import, generation down case include common tower outages. DEP plans its transmission system to this standard in addition to the NERC Reliability Standards.

Other annual powerflow screening studies identify thermal overloads and voltage problems during the simulated loss of any entire transmission-to-transmission substation or single voltage level transmission switching station. DEP evaluates these low probability events for risks and consequences.

Additionally, DEP participates in the CTCA Powerflow Working Group studies, which address selected Category C or D events as part of its annual studies.

With respect to Categories C.1, C.9, D.8 and D.9 (for outages of Bus Sections and Voltage Level plus transformation), DEP periodically perform assessments of those substations on our system where a bus outage would result in the loss of multiple other transmission elements (i.e., lines, transformers, etc.). Assessments are performed to determine situations where the resulting loss would be particularly problematic (i.e. would result in significant other overloads or possible cascading outages). As a result of this assessment, a number of substations/buses have been upgraded or identified for upgrades to minimize the consequences of a bus outage.

Although DEP does not assess every Category C and D contingency, using the above described studies and methodology, it is DEP's best judgment that its analyses adequately envelop all Category C and D type contingencies. This judgment is based on the fact that

DEP does analyze contingencies deemed to be more severe than those called for in Categories C and D. DEP also plans its system using selected Category B contingencies under more extreme high import, multiple generators out conditions.

For Dynamic Studies:

For dynamic studies, DEP generally uses a double line to ground (DLG) fault with delayed clearing as a minimum criteria for stability. DEP considers the DLG Delayed Clearing fault to be a Category D type fault which, in virtually all cases, is more severe than any of the Category C contingencies of Table 1 (which are 3-phase normal clearing or SLG delayed clearing type faults).

Additionally, actual system breaker configuration is appropriately simulated during dynamic studies. For example, in a breaker-and-a-half scheme substation, delayed clearing is simulated by assuming the tie breaker (middle breaker) of the scheme fails to operate. This results in tripping of the faulted element (line, transformer, etc.) plus tripping of the adjacent element in that breaker-and-a-half string. Automatic reclosing is also simulated, where judged to be material to the simulation results.

With respect to Category D events, as stated above DEP considers the DLG Delayed Clearing fault to be a Category D type fault. Three-phase faults are relatively rare and a three-phase fault with delayed clearing is extremely rare. This is supported by a review of recent fault history which indicates that less than 7% of faults on the DEP system are 3-phase faults and an extremely small number of any type of fault involves a breaker failure (i.e. delayed clearing). Therefore, the DLG Delayed Clearing fault is judged to be of sufficient severity to address reasonably expected system events.

VI. REVISION HISTORY

Version	Date	Description
V1	12/07/2007	Initial Release
V2	03/02/2008	Added detail to Section V.D.9 Severe Contingency Studies
V3.0	05/17/2013	Section V – FCR – Added restrictions to connection of generation to the 500 kV network, updated links, and changed PEC to DEP
V3.1	06/17/2013	Added detail in Section IV on notification of SOLs and IROLs and added Revision History
V4.0	05/15/2014	Added detail in Section V.D.4 Power Transfer Studies to accommodate the 129 MW DUK:CPLE set-aside