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Transmission Strategy and Planning

TRANSMISSION SYSTEM PLANNING GUIDELINES

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Revision History

Date	Description
June 6, 1998	Initial LGEE document to establish guidelines applicable to both LG&E and KU
March 11, 2005	Expanded Table 1
March 1, 2007	Added NERC Categories to Table 1 and expanded
May 7, 2007	Better quantified thermal overload and voltage violations and added Section 4 – Impacted Facilities
September 11, 2007	Added section describing how Guidelines exceed NERC requirements
May 1, 2008	Added effective date, signatures, Revision History, Contingency Selection criteria, updated Tables 2 & 3 and updated certain references
July 1, 2008	Updated performance requirements and incorporated SOL Methodology

Purpose

This document describes the guidelines used for developing the E.ON U.S. (E.ON) Transmission Expansion Plan in accordance with the requirements of North American Electric Reliability Corporation's (NERC) Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0 and SERC Reliability Corporation (SERC) Supplements to those standards.

1. Overview

The primary purpose of E.ON's transmission system is to reliably transmit electrical energy from Designated Network Resources to Network Loads. Interconnections to other transmission systems have been established to increase the reliability of E.ON's transmission system and to provide access to emergency generation sources for Network Customers.

E.ON subscribes to and designs its transmission system to conform to the fundamental characteristics of a reliable interconnected Bulk Electric System (BES) recommended by NERC. Additionally, E.ON is a member of SERC Reliability Corporation (SERC) and subscribes to and designs its transmission system to comply with the reliability principles and responsibilities set forth in the SERC Supplements.

The Federal Energy Regulatory Commission (FERC) requires all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to have a non-discriminatory Open Access Transmission Tariff (OATT). E.ON's Operating Companies (KU/LG&E) have an OATT on file with FERC to provide Point-To-Point transmission service and Network Integration Transmission Service. E.ON is committed to provide the same reliability and priority of service to Long-Term Firm Point-To-Point Transmission Service with a contract period of five or more years as it does for its Network Customers.

The American National Standards Institute (ANSI) and The Institute of Electrical and Electronic Engineers, Inc. (IEEE) publish standards for power system equipment design and application. E.ON incorporates ANSI and IEEE standards in the design and application of equipment utilized in the transmission system.

2. NERC and SERC Reliability Standards Compliance

NERC Reliability Standards TPL-001 through TPL-004 outline the fundamental requirements for planning reliable interconnected Bulk Electric Systems and the required actions or system performance necessary for compliance. The Regions, sub-regions, power pools, and their members have the responsibility to develop their own appropriate or more detailed planning criteria and guides based on the NERC Reliability Standards.

E.ON has developed and adopted the following Transmission Reliability Planning Criteria that exceed the requirements of the NERC Reliability Standards and SERC Supplements. E.ON applies system performance criteria consistent with Category B contingencies (TPL-002) to the following contingencies, without manual system adjustments:

- The following Category C (TPL-003) contingencies:
  - A simultaneous outage of two generators
  - A simultaneous outage of one generator and one transmission circuit
  - A simultaneous outage of one generator and one transmission transformer
- The outage of one transmission circuit or transmission transformer with one generator outage and replacement generation maximized as specified in section 5.7.

SERC Supplement "Transmission System Performance" was prepared to outline SERC's interpretation and to clarify SERC's expectations of members with regard to the NERC Reliability Standards TPL-001 through TPL-004. The SERC Supplement contains the standards that transmission providers are expected to adhere to in their simulated testing and system performance evaluations. E.ON's Transmission Reliability Planning Criteria meet or exceed the requirements of the SERC Supplement.

3. Transmission Planning Process

E.ON assesses the performance of its transmission system annually. The assessments include steady state simulations and, as appropriate, dynamic simulations. Steady state simulations of contingencies with a Required Performance Level of 1 or 2 (see Table 1) will be performed annually. Other components of the assessment must be supported by studies or simulations that have been performed within three years.

The steady state simulations evaluate the adequacy of the transmission system to provide Network Integration Transmission Service using summer and winter peak models. Transmission constraints that may occur during shoulder and off-peak conditions will be managed in the Planning Horizon via the establishment of System Operating Limits. Studies for Generator Interconnections will also utilize other seasonal and light load models, as appropriate.

The dynamic simulations will be performed on summer peak and light load models. The summer peak models are used for angular and voltage stability and the light load models are used primarily for angular stability.

The goals of the Transmission Planning Process are to:

- Develop the Transmission Expansion Plan
- Support the Independent Transmission Organization's (ITO) evaluation of Generator Interconnection and Transmission Service requests
- Evaluate Transmission to Transmission Interconnection requests
- Indentify boundary conditions in the planning studies

4. Base Case Development

Power flow, stability and short circuit models are developed annually to support the planning process.

Power Flow

Transmission base cases (Base Case(s)) for steady state analysis are developed on an annual basis to reflect the most current information and assumptions available concerning the modeling of future years' system load level and load distribution, generation and transmission expansion, firm transmission service obligations and representations of similar assumption for other systems.

Base Case models are developed for each of the summer and winter peak periods included in the most recent NERC Multi-Regional Modeling Working Group (MMWG) Base Case Series. Additionally, a Long-Term (10+ year) winter peak Base Case is developed utilizing the last winter peak case in the series. Each Base Case contains a detailed representation of the E.ON and East Kentucky Power Cooperative (EKPC) control areas from 69 kV through 500 kV. The NERC representation of all fist-tier systems in the NERC models is incorporated into the Base Cases. Second-tier systems and beyond are grouped considering geographic location and electrical interconnections and then equivalences are developed.

The generation in the E.ON control area is economically dispatched. The transmission level voltage at the power plants will be regulated in the Base Case models as shown in Table 2.

Network Customers provide forecasts of the Network Load levels to include in the models. E.ON's load level is based on the Company 50/50 forecast with all interruptible or curtailable loads being served. The anticipated transmission configuration is based upon the most recent Transmission Expansion Plan submitted to the ITO. Planned maintenance outages are not modeled. Existing and planned outages of generators and transmission facilities of more than three months in duration that are likely to occur at the time of peak of the Base Case season will be simulated.

Stability

The models available in the most recent NERC MMWG Base Case Series are used for stability simulations. The E.ON Bulk Electric System is reviewed and modified, if necessary, to be consistent with the Transmission Expansion Plan.

5. Reliability Planning Criteria

The evaluation of power flows and steady state voltages are the normal means by which the transmission planner shall determine satisfactory performance of the transmission system. Power flows and system voltages are evaluated for normal conditions and post-contingency conditions.

E.ON's Transmission Reliability Planning Criteria consists of a list of credible contingencies and associated performance requirements utilized in assessing and testing its transmission system.

5.1 Performance Requirements

E.ON has established the following levels of performance consistent with the requirements of the NERC Reliability Standards and the perceived risk. Levels 1 and 2 maintain Interconnection Integrity and serve the entire customer demand. Levels 3 and 4 allow Non-Consequential Load Loss in order to maintain Interconnection Integrity. Construction and upgrades necessary to meet the requirements of Performance Levels 1-4 will be identified and incorporated into the Transmission Expansion Plan. Special Protection Schemes will not be used to delay necessary construction and upgrades. Mitigation Plans will be developed if construction and upgrades cannot be completed when required. E.ON does not have any established normal (pre-contingency) operating procedures and therefore none are in place when simulations are performed. See Table 1 for the required performance levels associated with each of the NERC contingency categories.

<u>Level 1</u>
Power flows will not exceed the normal thermal limit
System voltages shall be within the limits specified for normal conditions
Network Loads are served from normal delivery points

<u>Level 2</u>
Power flows shall not exceed the emergency thermal limit
Transmission voltages at Generator Connections shall be greater than specified in Table 3
System voltages shall be within the limits specified for contingency conditions
Network Loads that are removed from service due to the fault clearing action can be reconnected using <u>Load Restoration and Switching</u> procedures.

<u>Level 3</u>
Transmission voltages at Generator Connections shall be greater than specified in Table 3
Bulk Electric System voltages shall be greater than 0.80 p.u.
Subsequent tripping of Bulk Electric System facilities with power flows in excess of the emergency thermal limit shall not cause

1) Low voltage at generators connected to the Bulk Electric System
2) Power flows in excess of the emergency thermal limit on two or more Bulk Electric System facilities
3) Non-Consequential Load Loss in excess of 10 percent of the forecasted seasonal peak load

<u>Level 4</u>
Following generation redispatch or shedding of 5 percent of forecasted seasonal peak load

1) Bulk Electric System power flows shall not exceed the emergency thermal limit
2) System voltages shall be within the limits specified for contingency conditions
3) Transmission voltages at Generator Connections shall be greater than specified in Table 3

Level 5
If the analysis concludes that there are cascading outages caused by the occurrence of the event, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted.

5.2 Thermal Facility Limits

E.ON has established normal and emergency thermal limits (MVA) for each facility based upon its established ratings methodology. The emergency thermal limits used in the planning process are long-term limits the facility can withstand through the daily demand cycle without significant loss of equipment life.

A facility will be overloaded when the MVA flow, rounded to two decimal places, exceeds the applicable rating. The recorded circuit flow will be the maximum MVA flow of either end. The recorded transformer flow will be the "design output" flow, GSU flows will be measured at the HV side, step-down transformers will be measured at the LV side and system tie transformers will be measured on the side where the flow exits the transformer.

5.3 System Voltage Limits

A voltage violation will occur when the percent nominal voltage, rounded to two decimal places, is outside the applicable criteria.

A transmission voltage of 94 percent of the nominal value is the minimum acceptable for normal load service and should be maintained at all load serving buses with normal generation and normal transmission system conditions. The voltage at any 500 kV system bus should not exceed 110 percent of the nominal value and any other transmission bus should not exceed 105 percent of the nominal value.

A transmission voltage of 90 percent of the nominal value is the minimum acceptable for contingency load service and should be maintained at all load serving buses during any transmission system contingency or generation and transmission system contingency.

Generators and plant auxiliary systems are generally designed to operate within +/- 5 percent of the nameplate or nominal voltage. Table 3 shows the minimum acceptable transmission level voltage at each generating unit connection to maintain generator voltage and auxiliary bus voltage above 95 percent of nominal with the unit operating at maximum MW and MVAR output. Only on-line generators are applicable to the analysis.

5.4 Voltage Stability Limits

The methods used for assessing voltage stability are V-Q and P-V analysis. Bulk Electric System buses with the lowest voltage or the highest voltage deviation are candidates for voltage stability analysis.

Voltage stability analysis will be performed via V-Q analysis if the BES contingency simulated in the steady-state analysis causes a BES voltage deviation greater than 8 percent or a post-contingency, pre-capacitor switching BES voltage less than 85 percent.

V-Q analysis quantifies the Reactive Power Margin at the bus. The Reactive Power Margin is defined as the value of the condenser output at the voltage collapse point on the V-Q curve where dQ/dV = 0. The voltage collapse point shall not occur above 0.85 p.u. voltage.

P-V analysis quantifies the load level that will cause voltage collapse, the point on the P-V curve where dV/dP = -1. The study load level must be less than the maximum load operating point determined at

1) 5 percent below the load at the collapse point on the P-V curve for simulations of contingencies with a Required Performance Level of 1 or 2 (see Table 1), or
2) 2.5 percent below the load at the collapse point on the P-V curve for simulations of contingencies with a Required Performance Level of 3 or 4.

5.5 Transient Stability Limits

All generators must remain stable. The Bulk Electric System voltage at the generator interconnections must recover to 0.9 p.u. voltage within 1.0 seconds after the fault is cleared. All machine rotor angle oscillations will be positively damped.

5.6 Credible Contingency Selection

<u>Generator Contingency Selection</u>
The Single Generator Contingency analysis will simulate an outage of the largest generator at each transmission bus. The Double Generator Contingency analysis will simulate an outage of the two largest generators at each plant and at each transmission bus. Smaller generators or combinations thereof will produce less severe results.

<u>Transmission Contingency Selection</u>
Category B analyses will simulate each Branch Contingency and each Multiple Branch Contingency in E.ON, each Branch Contingency in EKPC that would cause an E.ON transmission flow increase greater than 10 percent of the element Emergency rating and each 100 kV or higher Branch Contingency in other first-tier utilities that would cause an E.ON flow increase greater than 10% of the element Emergency rating. Category C2 and C3 contingencies will be tested by simulating all combinations of the Single Generator Contingencies and all Category B Transmission Contingencies. All Category C bus and

double circuit (>1 mile) contingencies and all Category D contingencies in the E.ON system will be simulated.

Branch Contingency
A Branch is a connection between buses with 3 or more network connections. When a branch has multiple segments with multiple loads and/or radial connections, the outage of the segments on each end of the branch will be simulated individually to create the worst case Branch contingency.

Multiple Branch Contingency

A single fault may outage multiple transmission components and Branches in the common zone of relay protection. Reclosure of the non-faulted components will be evaluated but reclosing is not required if violations occur as a result of the post-fault restoration. Procedures should be developed and documented if the component is not to be reclosed.

High Voltage Direct Current (HVDC) Contingencies
E.ON does not operate any HVDC facilities and is not aware of any HVDC within first-tier utilities. Therefore, E.ON does not evaluate HVDC contingencies.

5.7 Other Modeling Considerations

Generation Re-dispatch
Replacement generation required to offset unit outages should be simulated from the most restrictive of internal sources, Midwest Independent System Operator (MISO), and/or Tennessee Valley Authority (TVA) and /or PJM.

In addition to unit outages, the Assessment also includes contingencies that consist of a unit outage coupled with maximum output from the plant that is replacing the lost generation.

When simulating a maximum plant output scenario, the lost generation will be replaced at another plant and, when necessary, additional reductions will be prorated across all on-line units to achieve maximum output. Maximum plant output scenarios are only simulated for outages of units of 200 MW or greater and only at plants that have sufficient excess capacity to absorb the outaged unit..

Load Restoration and Switching
Post-fault conditions and conditions after load restoration and/or switching should be evaluated. Post-contingency operator-initiated actions to restore load service must be simulated. Load that is off-line as a result of the contingency being evaluated may be switched to alternate sources during the restoration process, but load should not be taken off-line to perform switching. Post-contingency operator-initiated actions may be simulated to reduce the flow through transformers or increase voltages but not to reduce line flows.

Transmission Capacitor Switching
Transmission capacitor status (on/off) should be simulated consistent with automatic voltage control (on/off) settings and operating practice during normal transmission system conditions. Capacitor switching should not be simulated to eliminate voltage violations that result from a contingency unless the automatic voltage control would cause the capacitor to operate.

Off-Peak Voltage Control
Transmission system changes to manage Off-Peak voltages will be identified and evaluated using operation data. Seasonal adjustment of fixed taps on transmission transformers should not be required to control voltages within the acceptable ranges. Switching Extra High Voltage (EHV) (345 kV and up in E.ON) system facilities out of service to reduce off-peak voltages is undesirable.

Voltage Fluctuations
E.ON limits voltage fluctuation due to customer load variations and transmission capacitor switching to a maximum of 3 percent during normal transmission conditions and 6 percent during single transmission contingencies. These maximum values apply if the fluctuation occurs less frequently than once per hour. If more frequent, the maximum allowable voltage fluctuation is reduced per Figure A.1 – Flicker tolerance curve from IEEE standard 141-1933/IEEE Std 519-1992 published in IEEE Std 1453-2004. The maximum normal and contingency fluctuations are limited to the “Borderline of Visibility of Flicker” and the “Borderline of Irritation” curves, respectively.

6. Impacted Facilities

Generator Interconnections, Transmission to Transmission Interconnections, Network Integration Transmission Service, and Long-Term (1 year or longer) Firm Point-To-Point Requests require studies to identify facilities that are impacted. The following minimum requirements are used to identify Impacted Facilities:

- the flow increases by 1.00 percent or more
- the voltage decreases by 0.50 percent or more
- the short circuit current increases by 5.00 percent or more

Impacted Facilities that are identified with pre-existing criteria violations (simulations on base case models) will be evaluated to determine the upgrade required to mitigate the pre-existing violation. Such upgrades and associated ratings will be used to determine if additional costs are required due to the Request.

7. System Operating Limits Methodology

The annual Assessment of Bulk Electric System performance will include evaluation of boundary conditions in the near-term planning horizon and the establishment of System Operating Limits (SOL's), as necessary, to maintain transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading outages or uncontrolled separation shall not occur. The annual Assessment will include pre-contingency, single contingency and multiple contingencies, indicated as NERC Categories A, B and C in Table 1. The SOL shall not exceed the associated Facility Ratings. SOL's that result in uncontrolled tripping of Extra High Voltage (EHV) facilities in other areas or generators in other areas will be considered Interconnected Reliability Operating Limits (IROL's). The Tv for an IROL in the planning horizon is 30 minutes.

The SOL evaluation will use the Base Case models developed annually to support the planning process. Section 4 – Base Case Model Development describes the anticipated transmission system configuration, generation dispatch, load level, outages and other internal and external modeling details incorporated into the models.

The SOL evaluation will use the contingency selection criteria used in the planning process. Section 5.6 – Credible Contingency Selection describes the contingencies.

The steady-state analysis of system performance simulates single and multiple contingencies without implementation of manual or automatic system adjustments. Voltage Stability analysis will be performed if a BES contingency simulated in the steady-state analysis causes a BES voltage deviation greater than 8 percent or a post-contingency, pre-capacitor switching BES voltage less than 85 percent. Angular Stability analysis will be performed to assess the impact of the subsequent tripping of facilities with a post-contingency flow in excess of 110 percent of the emergency thermal limit.

Steady-state voltage stability analysis will be performed via V-Q analysis on summer and winter peak models. Transient voltage stability analysis will be performed on summer and winter peak models. Transient and dynamic angular stability will be performed on

1) summer peak models with all generators at maximum output and the necessary export split equally to the north and south, and
2) light load models with all coal fired generators at maximum output and an incremental 500 MW export split equally to the north and south.

The applicable reliability margins for stability are described in section 5.4 – Voltage Stability Limits and section 5.5 – Transient Stability Limits. E.ON does not use Special Protection Systems.

The determination of SOL's, starting with all Facilities in service, may include the following actions in response to a single contingency:

- Planned or controlled interruption of radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area
- System reconfiguration through manual or automatic control or protection actions
- To prepare for the next contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology

In addition to the preceding actions in response to a single contingency, the determination of SOL's, starting will all Facilities in service, may include the following action in response to multiple contingencies:

- Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable) electric power transfers

Table 1
Transmission Contingencies and Measurements

NERC Cat	Contingency	Steady State Analysis	Dynamic Analysis	Required Performance Level
A	No Contingencies	Yes		1
B 1-3	Outage of a generator, transmission circuit, transformer or shunt device.	Yes	a,b	2
C3	Outage of two generators.	Yes	b	2
C3	Outage of a generator and a transmission circuit.	Yes	b	2
C3	Outage of a generator and a transformer.	Yes	b	2
	Outage of a transmission circuit or transformer with plant at maximum output.	Yes		2
C1	Outage of a bus section.	Yes	c	3
C2	Outage of a breaker.	Yes	c	3
C5	Outage of two circuits on a multiple circuit tower line. [more than 1 mile in length]	Yes	d	3
C3	Outage of two transmission circuits.	Yes	b	4
C3	Outage of a transmission circuit and a transformer.	Yes	b	4
C3	Outage of two transformers.	Yes	b	4
C6-8 D1-3	Outage of a generator, transmission circuit or transformer.	No	e,f	2
C9,D4	Outage of a bus section.	No	e,f	3
D5	Outage of a breaker.	No	g	3
D6	Outage of tower line with three or more circuits	Yes	a	5
D7	All transmission on a common right-of way [more than 1 mile in length]	Yes	a	5
D8	Outage of a substation (one voltage level plus transformers	Yes	a	5
D9	Outage of a switching station (one voltage level plus transformers	Yes	a	5
D10	Outage of all generating units at a station	Yes	a	5
D11	Loss of a large load or major Load center	Yes	a	5

Fault Types:

a) None
b) Single Line Ground or 3-Phase, with Normal Clearing
c) Single Line Ground, with Normal Clearing
d) Non 3-Phase, with Normal Clearing
e) Single Line Ground, with Delayed Clearing
f) 3-Phase with Delayed Clearing
g) 3-Phase with Normal Clearing

Table 2
Regulated Plant Voltage

Power Plant	Transmission Bus (kV)	Voltage (kV)	Per Unit Voltage
Brown	Brown N 138	141	1.022
Bluegrass	Buckner 345	352	1.020
Cane Run	Cane Run Sw 138	139	1.007
Ghent	Ghent 345	352	1.020
Green River	Green River 138	141	1.022
Mill Creek	Mill Creek 345	352	1.020
Paddys Run	Paddys Run 138	139	1.007
Trimble County	Trimble Co 345	352	1.020
Tyrone	Tyrone 69	70	1.014
Elmer Smith	Smith 138	141	1.022

Table 3
Minimum Transmission Voltage at Generator Connections

Transmission Bus	Connected Generator	Minimum kV Voltage	Minimum p.u. Voltage	Limit
Brown Plant 138	Brown 1		0.935	Gen
	Brown 2	133.0	0.964	Aux
Brown North 138	Brown 3	128.5	0.931	Aux
Brown CT 138	Brown 5		0.928	Gen
	Brown 6	128.2	0.929	Gen
	Brown 7		0.929	Gen
	Brown 8		0.918	Gen
	Brown 9		0.918	Gen
	Brown 10		0.918	Gen
	Brown 11		0.918	Gen
Cane Run Sw 138	Cane Run 4		0.936	Gen
	Cane Run 5	129.9	0.941	Gen
Cane Run 6	Cane Run 6	129.7	0.940	Gen
Ghent 138	Ghent 1	130.7	0.947	Aux
Ghent 345	Ghent 2		0.959	Gen
	Ghent 3	332.6	0.964	Gen
	Ghent 4		0.963	Gen
Green River 138	Green River 3		0.926	Aux
	Green River 4	130.3	0.944	Aux
Mill Creek 345	Mill Creek 1		0.958	Gen
	Mill Creek 2	330.5	0.958	Gen
	Mill Creek 3		0.953	Gen
	Mill Creek 4		0.953	Gen
Paddys Run 138	Paddys Run 13	129.3	0.937	Gen
Trimble Co 345	Trimble Co 1	331.2	0.960	Gen
Trimble Co CT 345	Trimble Co 5	325.3	0.943	Gen
	Trimble Co 6		0.943	Gen
	Trimble Co 7		0.943	Gen
	Trimble Co 8		0.943	Gen
	Trimble Co 9		0.943	Gen
	Trimble Co 10		0.943	Gen
Smith 138	Smith 1		0.942	Gen
	Smith 2	130.4	0.945	Gen