Planning Coordinator and/or Transmission Planner

TRANSMISSION SYSTEM PLANNING GUIDELINES

Effective Date: October 15, 2015

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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
August 14, 2009	Added statement reiterating comparable treatment of service requests per FERC Order.
November 30, 2010	Changed Company name from E.ON to LG&E/KU; edited to match other guidelines; added detail to stability section
September 1, 2012	General Update Added detail to stability analysis section
December 20, 2013	General Update Added detail to multiple sections to provide clarification
December 30, 2013	Correct error in footnote 13 on page 8
July 30, 2014	Changes required to address new TPL-001-4 standard
October 30, 2014	Make corrections; section 5.8, 5.10, 6.4, 7.2, 7.5.2, 8.2, Attachment A
September 15, 2015	Section 1: applicability to 2015 TEP removed; section 5.4 details of load scenarios described; section 5.6 DNR changed to NITS capacity; added section 5.8 to described ratings in off-peak models; removed unnecessary paragraph 5.10.1; section 5.12 added language in case ERAG models are late; section 6and 6.7 removed flowgate analysis requirement; added section 6.2.1.1 details of sensitivity study requirements; section 6.6 added language to match TPL-001-4 2.5; section 6.7 added NITS capacity sensitivity study; previous section 8.2 “Corrective Action Plan” moved to new section 10; section 8.2 added clarification for TPL-001-4 footnote 12; revised stability criteria to accommodate load inductor model section 8 and 9.2; RC requested changes to Instability Identification Section 9.1 and 9.2.

Table of Contents

1 Purpose

This document describes the guidelines used for developing the LG&E and KU Energy LLC (LG&E and KU) Transmission Expansion Plan (TEP). The TEP is intended to show compliance with NERC Reliability Standard TPL-001-4. LG&E and KU is registered as both a Planning Coordinator and Transmission Planner. The LG&E and KULG&E and KU Transmission Planning Group performs the functions for both the Planning Coordinator and Transmission Planner. This document establishes the minimum planning criteria for the LG&E and KU transmission System. The transmission System includes equipment and Facilities operated at 69 kV and above.

2 Overview

The primary purpose of LG&E and KU'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 LG&E and KU's transmission System and to provide access to emergency generation sources for Network Customers.

The Federal Energy Regulatory Commission (FERC) requires all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce have a non-discriminatory Open Access Transmission Tariff (OATT). LG&E and KU's Operating Companies have an OATT on file with FERC to provide Point to Point Transmission Service and Network Integration Transmission Service. LG&E and KU is committed to provide the same reliability and priority of service firm Point to Point Transmission Service for its network customers. LG&E and KU is committed to ensuring that customers with comparable service requests are treated comparably for transmission planning purposes.

3 NERC Reliability Standards Compliance

NERC Reliability Standard TPL-001-4 governs the requirements for planning the interconnected Bulk Electric System (BES) such that the network can be operated to supply real and reactive forecasted loads and projected Firm (non-recallable reserved) Transmission Services. LG&E and KU's Transmission System Planning Guidelines is intended to meet or exceed the requirements of TPL-001-4.

4 Definitions

The following is a list of NERC definitions used in these Planning Guidelines and can be found in the NERC Glossary.

Balancing Authority (BA): The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

Bulk Electric System (BES): Definition is too lengthy to include in this document. It should be reviewed on the NERC Glossary of terms.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual substation bus configurations.

Cascading: The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

Capacity Benefit Margin (CBM): The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

Consequential Load: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Contingency: The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.

Corrective Action Plan(s): A list of actions and an associated timetable for implementation to remedy a specific problem.

Demand Side Management (DSM): The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use.

Element: Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.

Facility: A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)

Facility Rating: The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Fault: An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.

Firm Transmission Service: The highest qualify (priority) service offered to customers under a fixed rate schedule that anticipates no planned interruption.

Load: An end-use device or customer that receives power from the electric system.

Load Serving Entity (LSE): Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Near-Term Transmission Planning Horizon: The transmission planning period that covers Year One through five.

Network Integration Transmission Service: Service that allows an electric transmission customer to integrate, plan, economically dispatch and regulate its network reserves in a manner comparable to that in which the Transmission Owner serves Native Load customers.

Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.

Off-Peak: Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of lower electrical demand.

On-Peak: Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand.

Operating Reserve: That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.

Planning Authority: The responsible entity that coordinates and integrates transmission facility and service plans, resource plans and protection systems.

Planning Coordinator: See Planning Authority

Point to Point Transmission Service: The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery.

Protection System:

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions
- Voltage and current sensing devices providing inputs to protective relays,
- Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

Resource Planner: The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority Area.

Special Protection System (SPS) or Remedial Action Scheme: An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.

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

System: A combination of generation, transmission, and distribution components.

Transmission: An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.

Transmission Reliability Margin (TRM): The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

Transmission Planner (TP): The entity that develops a long-term (generally one year beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion for the Planning Authority Area.

Year One: The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For an assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecast peak Load period for either 2012 or 2013.

The following are LG&E and KU Transmission Planning Defined Terms used in these Planning Guidelines:

Extreme Event Report: Report of the results for the extreme events studies for TPL-001-4 Table 1 extreme events.

HV: Facilities operated between 100 kV and 300 kV.

5 Models

This section describes the models that are built for compliance with TPL-001-4.

5.1 Normal System Condition Models

Per TPL-001-4 R1, LG&E and KU maintains normal System condition models within its respective area for performing the studies needed to satisfy the requirements of TPL-001-4 Standard. The models use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, and shall represent projected System conditions. The process for developing the steady state and stability models are described in this section. Normal System condition models shall include:

- Existing Elements[1]: model of 69 kV and above lines, transformers, substations etc.
- Known outage (s) of generation or Transmission facilities described in Section 5.2.
- New planned Elements and Facilities and changes to existing Elements and Facilities as described in 5.3.
- Real and reactive forecasted load as described in 5.4.
- Known commitments for Firm Transmission Service and Interchange as described in 5.5.
- Resources (supply or demand side) required for Load

[1] TPL-001-4 1.1.1

The above models represent normal System conditions and must meet the performance requirements of TPL-001-4 Table 1 Category P0.[2] The applicable Facility Rating for TPL-001-4 Table 1 Category P0 is the seasonal normal rating.

5.2 Known Outages

Known outages in the Near Term of generation or transmission Elements and Facilities with a duration of at least six months will be modeled for the seasons and years in which the outage is scheduled in both the System Peak and Off-Peak models[3]. Models will be developed, and an assessment of the System with these outages will be completed by analyzing Categories P0 and P1 planning events in Table 1 of TPL-001-4[4].

5.3 New planned Elements and Facilities

The steady state and stability models developed will include projects as documented in the previous year's TEP including new planned Elements and Facilities and changes to existing and planned Elements and Facilities.[5] For both steady state and stability models, projects from the previous year's TEP are included according to the expected in-service dates. In addition, all projects that were completed after the completion of the previous year's TEP will be included in the Base Case Series (BCS) models.

5.4 Real and Reactive Forecasted Load

Load Serving Entities (LSEs) provide delivery point forecast for real power and power factor. The reactive load can be calculated with the real power and power factor. The LSE load forecast for network load levels are included in the models.[6]

Load forecasts are typically provided for the following conditions:

- Summer and Winter Peak – 50/50 peak forecast
- Off-Peak[7] –
    - Light Load – typical early morning load level (i.e. Easter Morning) representing minimum load conditions
    - Summer Shoulder – expected loads during a 70 to 80 degree Fahrenheit summer day

[2] TPL-001-4 R1
[3] TPL-001-4 1.1.2
[4] TPL-001-4 2.1.3
[5] TPL-001-4 1.1.3
[6] TPL-001-4 1.1.4
[7] TPL-001-4 2.1.2

Additional forecasts may be requested on an as needed basis.

5.5 Transmission Service Reservation (TSR)

For both steady state and stability models, firm transmission service reservations that are annual, confirmed, and have a contract period of five or more years may be included[8] in the models. A list of the TSRs included in the base case models are documented in the TEP report. TSRs that are not included in the models will be evaluated in the sensitivity study discussed in section 6.7.

5.6 Real Power Resource Modeling

This section applies to real power resource modeling of units connected to the LG&E and KU transmission system.

The real power resource modeling, for generating units connected to the LG&E and KU transmission system, for steady state and stability models is provided by Generator Owners and/or Resource Planners, and includes capabilities for both On-Peak and Off-peak scenarios[9]. Off-peak scenarios are described in Section 5.4. The generation that is on-line initially comes from a merit order that is also provided to the Transmission Planner by the Resource Planner. Operating Reserves are modeled if sufficient generation is available. The process of modeling Operating Reserves dispatches large units (25 MW or greater) to some value less than their maximum output, so that the sum total of available output for online units meets or exceeds the reserve requirements.

There could be instances where there may not be enough generation resources to cover the load, particularly in the Long-Term Transmission Planning Horizon models. In those instances, the TP may choose to model a future expected generating unit, fictitious generating Facility, or energy imports. The TP will not utilize these options solely to meet Operating Reserves.

Maximum output will be either the value provided by the Generator Owner (GO) in their resource plan or the Network Integrated Transmission Service (NITS) Capacity value posted on the LG&E and KU OASIS plus firm point to point transmission, whichever is lower. Units are dispatched using the Merit Order (MO) provided by the GO.

5.7 Reactive Power Resource Modeling[10]

[8] TPL-001-4 1.1.5
[9] TPL-001-4 1.1.6
[10] TPL-001-4 1.1.6

This section applies to reactive power resource modeling of units connected to the LG&E and KU transmission system.

The reactive power resource capability for the steady state and stability models is supplied by the GO or RP to the LG&E and KU Planning Coordinator. The transmission level voltage at the power plants will be regulated in the Base case models to the target voltage in Table 1 of the LG&E and KU *Voltage and Reactive Power Schedule (VAR-001)* document.

Capacitor banks will be modeled with the actual voltages (or typical settings for future installations) at which the capacitor bank turns on and off for regulating voltage.

5.8 Modeled Facility Ratings

The TP models Facility Ratings as follows:

- Summer Peak - 104°F
- Winter Peak - 23°F
- Off-Peak - 104°F[11]

5.9 Base Case Series Models

Base case series (BCS) models are developed for Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon for steady state models, where the Near-Term Transmission Planning Horizon are years one through five, and Long-Term Transmission Planning Horizon are years six through ten. Specific models may vary from series to series, and may include one or more models for the years in the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon.

Each BCS model contains a detailed representation of the LG&E and KU Balancing Authority control area from 69 kV through 500 kV.

Portions of the models outside the LG&E and KU model area are taken from the most recent NERC Eastern Interconnection Reliability Assessment Group (ERAG) Base Case Series. The specific ERAG model used will be the same time-frame as, or a model nearest the time-frame of, the target model being built. LG&E and KU may coordinate models with neighboring TPs, and may alter their Systems in the ERAG models to reflect that coordination.

BCS models will be provided to the ITO for review as soon as available.

[11] Off-Peak models are created using 104°F ratings. However, when analyzing results of screens on Off-Peak model, the Transmission Planner evaluates potential constraints using 95°F ratings.

The BCS models are the starting point for the annual planning assessment, and are used for TEP development. Stability analysis is not required to be performed on the BCS models, but is performed on TEP models developed later in the Planning Assessment.

5.10 Transmission Expansion Plan (TEP) Models

At the completion of the annual Planning Assessment, TEP projects are identified and timed. A set of TEP models are created for use in future studies with the new TEP projects and retiming of projects. Both steady state and stability TEP models are created. At the completion of the TEP process, the TEP models are delivered to both the Reliability Coordinator (RC) and the ITO

5.11 Steady State Models

Steady State models are developed for winter On-Peak, summer On-Peak and Off-Peak Load conditions. Transmission base cases 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 (provided by the LSE), generation (provided by the GO) and the previous year's TEP.

Steady state models in the Near-Term Transmission Planning Horizon will include summer and winter On-Peak load models for Year One or year two and year five[12]; at least one Off-Peak model in the Near-Term Transmission Planning Horizon is developed. Long-term Transmission Planning Horizon On-Peak Load models will generally include year ten only. A year ten model is used since it is expected that the loads will be higher than year six through nine models[13]. At least one summer and winter On-Peak load model for years six through ten will be included. Other models may be developed to support timing of issues associated with significant construction and/or System changes.

5.12 Stability Models

Stability models are developed using the TEP steady state models which include the most recent projects timings. Dynamic models are developed for summer On-Peak and Off-Peak conditions. At least one On-Peak and one Off-Peak model in the Near-Term Transmission Planning Horizon will be developed. Long-term stability models will be developed to address the impact of proposed material generation additions or changes, if any, in that timeframe. If there are no material generation additions or changes, a stability model in the Long-Term Transmission Planning Horizon will not be built. The TEP will include documentation to support the technical rationale for determining

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[12] TPL-001-4 2.1.1

[13] TPL-001-4 2.2.1

generation material changes[14]. A minimum of at least one stability model with maximized generation, utilizing the generation interconnection capacity (GIC) values, within the LG&E and KU BA will be developed. Other stability models may be developed as necessary.

The LG&E and KU dynamics parameters are also updated to the latest available data. All new dynamics data will be tested to make sure that a dynamics stability for no fault analysis lasting twenty seconds shows flat line voltages and rotor angles.

The stability models for the TEP are dependent on industry dynamic models (e.g. ERAG) developed annually. The models have roots in the previous year's ERAG steady state models. Although uncommon, it is possible that the current year ERAG models may not be available in time for TEP model development. In this scenario the ERAG dynamic models from the previous year will be utilized for the outside world.

The ERAG stability models are updated within the LG&E and KU BA with the most recent load forecast. Generation levels use merit order and also incorporate Operating Reserves as described in Section 5.6.

The final stability models will match the topology of the steady state models for the LG&E and KU BA. Due to the ERAG Dynamic Model Building process, the outside world may not match between the stability and steady state models.

5.13 Short Circuit Models

LG&E and KU maintains a perpetually updated short circuit model that reflects the current topology of the LG&E and KU Transmission System with Elements and Facilities in their normal status. LG&E and KU participates in the SERC Short Circuit Database Working Group (SCDWG) process in which a SERC regional model is developed annually, in accordance with the SCDWG procedure manual. The procedure manual requires cases be developed for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon and the SCDWG coordinates its schedules with the SERC Multi-Regional Modeling Working Group (MMWG) process. In conjunction with SCDWG process, LG&E and KU incorporates a reduction of the most recent SCDWG near-term model each year to represent the Transmission Network outside LG&E and KU, and also incorporates a current detailed model of East Kentucky Power Cooperative (EKPC) short circuit model during the annual update.

The current short circuit model is used to perform the annual breaker duty study of the current Transmission System[15]. It will be modified as needed to perform other ad hoc studies, including, where appropriate, replacing the outside world model with a reduced SCDWG long-term model.

[14] TPL-001-4 2.5
[15] TPL-001-4 2.3

The short circuit model is limited to one model in the Near-Term Transmission Planning Horizon and one model in the Long-Term Transmission Planning Horizon.

6 Annual Planning Assessment Per TPL-001-4 R2

LG&E and KU conducts an annual Planning Assessment in order to plan the transmission System to meet TPL-001-4. The annual Planning Assessment includes analysis of both the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. The Planning Assessment simulates contingencies for steady state, stability analysis, and short circuit studies[16]. If there are no material generation additions or changes in the Long-Term Transmission Planning Horizon, a stability study for the Long-Term Transmission Planning Horizon will not be done[17].

6.1 Non-BES Annual Assessment

LG&E and KU defines BES to only include those Facilities operated at 100 kV and above. BES transformers are those transformers with a primary and at least one secondary voltage operated above 100 kV. For purposes of this document, LG&E and KU non-BES elements are elements operated at 69 kV and those transformers whose secondary voltage is operated at 69 kV. An annual planning assessment of the 69 kV Elements is performed for the Near-Term Transmission Planning Horizon as well as the Long-Term Transmission Planning Horizon. The non-BES planning assessment only includes contingencies and performance requirements for P0, P1 and P3 of TPL-001-4 Table 1. Stability analysis as well as P2, P4-P7 and extreme events for steady state is not analyzed on non-BES Elements. Non-BES elements are not monitored for steady state analysis of P2, P4-P7 and extreme events for either stability or steady state assessments.

The non-BES annual Planning Assessment may utilize a qualified past study or a current study to meet the requirements of TPL-001-4 Table 1 P0, P1 and P3. If a qualified past study is used, it must meet the requirements of TPL-001-4 2.6. Material changes in determination of a qualified past study would include substantial changes to the System represented in the study. If a qualified past study is used, the study reports will be included as attachments in the TEP.

[16] TPL-001-4 2.3
[17] TPL-001-4 2.5

6.2 Steady State BES Assessment for the Near-Term Transmission Planning Horizon

The Planning Assessment in the Near-Term Transmission Planning Horizon will include steady state analysis of the BES based on computer simulation of contingency events[18]. The study is performed using a computer simulation of planning and extreme events to determine whether the BES meets the performance requirements of TPL-001-4 Table 1[19]. The contingency selection for the planning events is discussed in section 7 of this document. The annual Planning Assessment for the Near-Term Transmission Planning Horizon may utilize a qualified past study or a current study to meet the requirements of TPL-001-4. If used, a qualified past study must meet the requirements of TPL-001-4 2.6. Material changes in determination of a qualified past study would include substantial changes to the System represented in the study. If a qualified past study is used, the study reports will be included as attachments in the TEP or Extreme Event Report. The Near-Term Transmission Planning Horizon assessment will simulate P1 through P7 planning events and extreme events for BES Facilities using the performance requirements of TPL-001-4 Table 1[20]. In the event that the Contingency analyzed does not meet the respective performance requirements of TPL-001-4 Table 1 P1 through P7, a Corrective Action Plan(s) will be developed to ensure that the System meets the required performance requirements. The Corrective Action Plan(s) are documented in the TEP.

The extreme event analysis for Near-Term Transmission Planning Horizon will use the identification of System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding criteria described in section 9. If the extreme event shows potential for System instability, then an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences is conducted and documented in the Extreme Event Report.

6.2.1 Steady State Sensitivity Studies for Near-Term Transmission Planning Horizon

The Near-Term Transmission Planning Horizon portion of the steady state analysis will include an assessment of at least one of the following varying conditions[21]:

- Real and reactive forecasted Load
- Expected transfers not included in the BCS models

[18] TPL-001-4 R3
[19] TPL-001-4 3.1
[20] TPL-001-4 3.2
[21] TPL-001-4 2.1.4

- Expected in service dates of new or modified Transmission Facilities that may or may not have all required approvals.

- Reactive resource capability.

- Generation additions that have not yet completed a large generation interconnection agreement and/or anticipated retirement of generation not yet announced.

- Controllable Loads and Demand Side Management (modeled in selected Off-Peak).

- Duration or timing of known Transmission outages (when outages are known to occur in the Near-Term or Long Term Transmission Planning Horizon).

For the sensitivity portion, the Planning Assessment may utilize a qualified past study or a current study to meet the requirements of TPL-001-4. A qualified past study must meet the requirements of TPL-001-4 2.6. Material changes in determination of a qualified past study would include substantial changes to the System represented in the study. If a qualified past study is used, the study reports will be included in the new TEP. The Near-Term Transmission Planning Horizon steady state analysis sensitivities described above will include P0, P1 and P3 for non-BES Elements. The Near-Term Transmission Planning Horizon steady state analysis sensitivities will include P0 trough P7 and extreme events for BES Facilities. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity study in accordance with Requirements TPL-001-4 2.1.4 and 2.4.3.[22]

6.2.1.1 Sensitivity Study Impacts

Impacts in sensitivity studies will be identified using the following flow and voltage criteria:

- The flow on a Facility increases by 1% or more when compared to the base case flow
- The voltage on a Facility increases a high voltage violation by 0.5% or decreases a low voltage violation by 0.5% or more when compared to the base case voltage

6.2.2 Unavailable Long Lead Item BES Assessment

A list of BES Equipment with a lead time of one year or more will be identified from the appropriate LG&E and KU department. One winter On-Peak and one summer On-Peak model in the Near-Term Transmission Planning Horizon is developed that model the BES transformers out of service that do not have a spare. Example, if there are three BES

[22] TPL-001-4 2.7

transformers that do not have spares, then six additional models are developed, one for each of the three transformers out of service for winter and summer. Other equipment with long lead times and no spares will be included if such exist. A steady state assessment is performed on these unavailable spare transformer models for TPL-001-4 Table 1 Categories P0, P1 and P2[23]. The impact of this possible unavailability on System performance shall be studied as a portion of the Near-Term Transmission Planning Horizon assessment. The result of the assessment of potential unavailable equipment is included in the TEP. Corrective action plans will be developed if necessary.

6.3 Steady State BES Assessment for Long-Term Transmission Planning Horizon

The Planning Assessment in the Long-Term Transmission Planning Horizon will include steady state analysis of the BES based on computer simulation of contingency events[24]. The study is performed using a computer simulation of planning and extreme events to determine whether the BES meets the performance requirements of TPL-001-4 Table 1[25]. The contingency selection for the planning events is discussed is section 7 of this document. [26]The annual Planning Assessment for the Long-Term Transmission Planning Horizon may be supported by a current study and supplemented with a qualified past study to meet the performance requirements of TPL-001-4. At least one winter On-Peak and one summer On-Peak steady state models will be developed for the Long-Term Transmission Planning Horizon. These models are used to simulate P1 through P7 planning events and extreme events for BES Facilities using the performance requirements of TPL-001-4 Table 1[27]. In the event that the Contingency analyzed does not meet the respective performance requirements of TPL-001-4 Table 1 P1 through P7, a Corrective Action Plan(s) will be developed to ensure that the System meets the required performance requirements. The Corrective Action Plan(s) are documented in the TEP.

The extreme event analysis for Long-Term Transmission Planning Horizon will use the identification of System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding criteria described in section 9. If the extreme event shows potential for System instability, , then an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences is conducted and documented in the Extreme Event Report.

6.4 Short Circuit Analysis

The short circuit analysis portion of the Planning Assessment shall be conducted annually utilizing one model in the Near-Term Transmission Planning Horizon and one model in

[23] TPL-001-4 2.1.5
[24] TPL-001-4 R3
[25] TPL-001-4 3.1
[26] TPL-001-4 2.2
[27] TPL-001-4 3.2

the Long-Term Transmission Planning Horizon[28]. The short circuit analysis may utilize a qualified past study or a current study to meet the requirements of TPL-001-4. A qualified past study must meet the requirements of TPL-001-4 2.6. Material changes in determination of a qualified past study would include substantial changes to the System represented in the study. If a qualified past study is used, the study reports will be copied in the TEP.

The interrupting requirements of LG&E and KU circuit breakers must remain within circuit breaker interrupting capabilities. LG&E and KU calculates circuit breaker interrupting duty utilizing a recognized industry standard software application for short circuit analysis. The software calculates the breaking currents using procedures recommended by ANSI/IEEE.

Breaker duty studies are performed with all Transmission Facilities, and all generators in service. Studies are performed on the Transmission System in its current topology at least annually, and internal ad hoc studies are performed as necessary to determine short circuit impacts of projects under consideration. For ad hoc studies, the model will be modified to simulate as accurately as possible the Transmission System configuration when the project is expected to go into service.

In service circuit breakers with fault duties in excess of interrupting capabilities will have a TEP project for breaker replacement. The project schedule will follow the rules of TEP project schedule considering lead times necessary to complete breaker replacements. When the scheduled date is beyond the need date for a breaker replacement, the first corrective action tested will be to disable automatic reclosing. If the breaker duty still exceeds the breaker interrupting capability additional corrective action measures will be tested. A corrective action plan which mitigates all criteria violations will be documented in the TEP report. The TEP report will list short circuit study deficiencies and the associated actions needed to achieve the required System performance[29]. The actions will include a list of breaker replacements required so as not to overload the breaker duty rating. The list of breaker replacements will be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures[30].

6.5 Near Term Transmission Planning Horizon Stability BES Assessment

Per TPL-001-4 R4, the Near-Term Transmission Planning Horizon Stability Assessment will only be analyzed for BES Facility disturbances. Only BES Facilities will be monitored for the performance requirements of TPL-001-4. The stability assessment will include TPL-001-4 P1 through P7 planning events and extreme events[31]. For the stability

[28] TPL-001-4 2.8
[29] TPL-001-4 2.8.1
[30] TpL-001-4 2.8.2
[31] TPL-001-4 4.1 and 4.2

portion of the Planning Assessment, the Near-Term Transmission Planning Horizon may utilize a qualified past study, five calendar years old or less, or a current study to meet the requirements of TPL-001-4[32]. A qualified past study must meet the requirements of TPL-001-4 2.6. Material changes in determination of a qualified past study would include substantial changes to the System represented in the study. If a qualified past study is used, the study reports will be copied in the TEP and/or Extreme Event Report. Documentation to support the technical rationale for determining material changes will also be included in the TEP.

TPL-001-4 Table 1 P1 through P7 faults on the near-term models shall be analyzed. The respective performance requirements of P1 through P7 will be used as well as the performance requirements of section 8 in these planning guidelines. Where a fault does not pass the respective performance requirements, a Corrective Action Plan will be developed to ensure the problem is mitigated and therefore meeting the performance requirements. The Corrective Action Plan(s) are documented in the TEP.

Stability analysis will be performed on the following models:

- At least one near-term Off-Peak Load model[33]
- At least one near-term On-Peak Load model

These models will represent the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads[34]. The model uses an aggregate System Load model which represents the overall dynamic behavior of the Load.

6.5.1 BES Stability Sensitivity Studiesfor Near-Term Transmission Planning Horizon

The annual assessment for the Near-Term Transmission Planning Horizon portion of the stability analysis shall be performed for at least one of the following varying conditions[35]:

- Load level, Load forecast, or dynamic Load model assumptions
- Expected transfers not previously included in the stability models
- Expected in service dates of new or modified Transmission Facilities that may or may not have all required approvals.
- Reduced reactive resource capability.

[32] TPL-001-4 2.4
[33] TPL-001-4 2.4.2
[34] TPL-001-4 2.4.1
[35] TPL-001-4 2.4.3

- Generation additions that have not yet completed a large generation interconnection agreement and/or anticipated retirement of generation not yet announced.

For the sensitivity portion, the Planning Assessment may utilize a qualified past study or a current study to meet the requirements of TPL-001-4. A qualified past study must meet the requirements of TPL-001-4 2.6. Material changes in determination of a qualified past study would include substantial changes to the System represented in the study. If a qualified past study is used, the study reports will be copied in the TEP and/or extreme event report. The near-term stability analysis sensitivity will include P1 trough P7 and extreme events for BES Facilities only. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity study analyzed in accordance with TPL-001-4 2.1.4 and 2.4.1.[36] A corrective action plan is required for performance deficiencies identified in multiple sensitivity studies or a rationale for why actions were not necessary will be provided.[37]

6.6 Stability BES Assessment for the Long-Term Transmission Planning Horizon

Per TPL-001-4 R4 the Long-Term Transmission Planning Horizon Stability Assessment will only be analyzed for BES Facility disturbances. Only BES Facilities will be monitored for the performance requirements of TPL-001-4. If there are proposed material generation additions or changes in the Long-Term Planning Horizon timeframe, the Stability analysis portion of the Long-Term Transmission Planning Horizon will be analyzed on at least one model. If there are no proposed material generation additions or changes in the Long-Term Transmission Planning Horizon, a stability assessment will not be performed in that time frame. The stability assessment may utilize a qualified past study or a current study to meet the requirements of TPL-001-4. A qualified past study must meet the requirements of TPL-001-4 2.6. Material changes in determination of a qualified past study would include substantial changes to the System represented in the study.[38] The material changes may or may not include proposed generation that does not have a signed large generation interconnection agreement. The long-term model will include proposed transmission Elements and Facilities. The stability analysis will include TPL-001-4 Table 1 P1-P7 and extreme events. Where analysis does not pass the performance requirements of TPL-001-4 Table 1 P1 through P7, a Corrective Action Plan will be developed to ensure the problem is mitigated meeting the performance requirements. Additionally, extreme event analysis will use the identification of System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding criteria described in section 9. If the extreme event shows a potential for System instability, then an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences is conducted and documented in the Extreme Event Report.

[36] TPL-001-4 2.7
[37] TPL-001-4 2.7.2
[38] TPL-001-4 2.6

6.7 Other Sensitivity Studies

Sensitivity studies described in sections 6.2.1 and 6.5.1 are performed on models for the Near-Term Transmission Planning Horizon only. There are other sensitivity studies, described below, performed on both the Near-Term Transmission Planning Horizon and the Long-Tem Transmission Planning Horizon models. Impacts will be identified in these sensitivities through the process described in section 6.2.1.1. The sensitivity studies could include, but are not limited to:

- TSR Sensitivity: Confirmed firm TSRs that were not included at maximum level in the BCS models, are modeled in the appropriate time frame. The TSRs have to be firm and have a contract period of at least one year. This study ensures that these TSRs can be served. Only steady state analysis for P0, P1, P2 EHV only, P3, P4 EHV only planning events is simulated. Corrective Action Plans will be developed for criteria violations identified. This will include operating guides for criteria violations associated with TSRs with a contract period of less than five years.

- NITS Capacity: The NITS capacity analysis evaluates the adequacy of the transmission system for P0-P7 contingencies while modifying generator PMax values to their NITS capacity values. The NITS capacity values are posted on the LG&E and KU OASIS site. When the PMax values are modified, generation is re-dispatched in merit order. Operating reserve requirements are also taken into consideration when possible. Corrective Action Plans will be developed for criteria violations identified. If there are violations of the performance requirements per TPL-001-4 Table 1 for P1 through P7 planning events, an operating guide allowing generation re-dispatch will be used.

7 Contingencies

The contingencies of TPL-001-4 Table 1 P1 through P7 and extreme events simulated for the assessment will only include those that are expected to produce more severe System impacts on the LG&E and KU portion of the BES[39]. The list of Contingencies being simulated is included in appropriate TEP and Extreme Event reports.

Category P1-5, P3-5, P6-4, and P7-2 refer to HVDC outages. There are no HVDC lines within or near the LG&E and KU BA that affect the LG&E and KU System. The Planning Assessment does not evaluate HVDC contingencies and no P1-5, P3-5, P6-4, or P7-2 contingencies are simulated in either the steady state or stability analyses.

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[39] TPL-001-4 3.4

7.1 Contingency List Coordination

Per TPL-001-4 3.4.1 and 4.4.1, LG&E and KU Transmission Planner (TP) will coordinate with adjacent Planning Coordinators (PCs) and TPs to ensure that Contingencies on adjacent Systems which may impact the LG&E and KU System are included in the Contingency list. The LG&E and KU BES Contingency list will be shared with the LG&E and KU neighbor TP with a request for the neighbor TP to recommend contingencies in its System that should also be evaluated in the LG&E and KU Planning Assessment. All contingencies recommended by neighboring TPs and/or PCs will be assessed for inclusion in the LG&E and KU Contingency list to be included for evaluation in the LG&E and KU annual Planning Assessment.

7.2 Generation Replacement Scenarios

To maintain the capability to serve native load after loss of a generator, for an LG&E and KU generator owner outage greater than 50 MW, replacement generation shall be simulated from the most restrictive combination of internal resources, Tennessee Valley Authority (TVA), Midcontinent Independent System Operator (MISO) or PJM. Generator contingencies are selected that produce the most severe System impacts on the BES and may be used to limit the number of generator outage and replacement generation scenarios, such as the largest unit per plant, or BES voltage connection point.

For non LG&E and KU owned generator unit outages greater than 50 MW connected to the LG&E and KU transmission system, replacement generation to cover non LG&E and KU load will be simulated from TVA, MISO or PJM whichever is the most restrictive. Generator contingencies are selected that produce the most severe System impacts on the BES and may be used to limit the number of generator outages, such as the largest unit per plant, or BES voltage connection.

For non-affiliate generator units, posted as DNRs on OASIS, and not connected to the LG&E and KU transmission system, replacement generation to cover non LG&E and KU load served from the LG&E and KU system will be simulated from other associated DNRs as available, and replacement generation to cover non LG&E and KU load will be simulated from TVA, MISO or PJM whichever is the most restrictive unless customer discussions indicate that some of these scenarios are not needed.. If replacement generation is not available in a specific model, the dispatches will not be simulated.

For generator outages greater than 50 MW and not connected to the LG&E and KU transmission system replacement generation will be simulated from an area on the opposite side of the generating unit area from the LG&E and KU system.. Generator contingencies are selected that produce the most severe System impacts on the BES and may be used to limit the number of generator outages, such as the largest unit per plant, per BES voltage connection.

In addition to LG&E and KU generator unit outages with replacement power as described above, analysis will consider certain dispatch scenarios with replacement from plants simulating maximum output level at the replacement site. Valid scenarios will be outages of single units greater than 200 MW, with replacement power sourced by maximizing the output at either Trimble County or Brown. If the site chosen for replacement power has inadequate available resources (i.e. less than the outaged unit), that particular scenario is not valid. Any excess created by maximizing plant output, after netting with the outaged unit, will be offset by proportionally reducing all other LG&E and KU units not directly involved. Generator contingencies are selected that produce the most severe System impacts on the BES and may be used to limit the number of generator outages, such as the largest unit per plant per BES voltage connection.

7.3 Automatic Control Inclusion

[40]The simulated contingencies must remove all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention.

The LG&E and KU System does not currently have any Special Protection Systems. Simulations of Protection System responses during a fault or Contingency are analyzed with that Contingency. The LG&E and KU BA does not have any generation tripping or run back scheme other than what would be tripped as a result of clearing a fault. If generation is tripped as a result of fault clearing, then that tripping scheme will be studied as part of the Contingency analyzed.

Per TPL-001-4 3.3.1.1, LG&E and KU will build a project to ensure that generators do not trip due to low voltage on the generator bus after a P1 or P3 planning event. The minimum generator steady state or ride through voltage limit is 0.95 pu at the generator bus. Tripping of generators will be included in the simulation by running the simulation manually if the screen result indicates the generator bus voltage falls below 0.95 pu for a P2, P4 through P7 and extreme events.

7.3.1 Steady State Automatic Control Inclusion

If the results of the steady state analysis show an overload of Facility (ies), prior to loss of load if allowed by TPL-001-4 Table 1, a verification of the relay loadability values is completed. Verification is done via the CASCADE database or through communication with the Protection department. If the MVA flow on a BES Facility exceeds the relay loadability setting, the steady state simulation will include the outage of that Facility that exceeds the relay loadability setting.

[40] TPL-001-4 3.3.1 & 4.3.1

The LG&E and KU transmission System does not contain any phase-shifting transformers. There are switched capacitors on the LG&E and KU transmission System and those facilities are modeled with the voltage levels at which they are switched on and off[41]. Transmission capacitor status (on/off) are simulated consistent with automatic voltage control (on/off) settings and operating practice during normal transmission System conditions. Therefore, when the solution of the power flow analysis has capacitor bank switching enabled, the automatic switching of capacitor banks are simulated. .

7.3.2 Stability Assessment Protection System Inclusion

Per TPL-001-4 4.3.1.1 the stability simulation will include successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

7.4 Load Restoration and Switching Procedure.

During breaker to breaker outages, some Consequential Load loss is possible. The simulation of the load restoration and switching procedure is performed as part of the Planning Assessment. Post-fault conditions and conditions after load restoration, switching, or transmission reconfiguration should be evaluated. Post-Contingency operator-initiated actions to restore load service are simulated. Post-contingency operator-initiated actions including switching may be simulated to reduce the flow through transformers or increase voltages but not to reduce line flows. Load that is off-line as a result of the Contingency (consequential load loss) being evaluated may be switched to alternate sources during the restoration assessment, but load is not taken off-line to perform switching.

7.5 Steady State Planning Events

The steady state Planning Assessment studies are performed based on a Contingency list created to meet requirements of TPL-001-4 R3. The Contingency list includes those planning events in TPL-001-4 Table 1 that are expected to produce more severe System impacts on its portion of the BES. Since the Contingency list that produces the most severe events may vary year to year of the planning assessment, the Contingency list will be documented in the TEP. This section of the Planning Guidelines will document the methodology used to develop the Contingency list which will produce the most severe System impacts.

The Extreme Event Report will also list those contingencies analyzed and expected to produce more severe System impacts. The extreme event analysis may utilize a qualified past study or a current study to meet the requirements of TPL-001-4. A qualified past

[41] TPL-001-4 3.3.2

study must meet the requirements of TPL-001-4 2.6. Material changes in determination of a qualified past study would include substantial changes to the System represented in the study.

7.5.1 TPL-001-4 Table 1 Category P1 Contingency Selection

TPL-001-4 Table 1 Category P1 is single contingencies including loss of generator, transmission circuit, transformer, or shunt device. The LG&E and KU Planning Assessment includes all single transmission circuits and transformers that are operated at 69 kV (secondary voltage) and above. In order to achieve the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention all breaker to breaker contingencies for transmission circuits and transformers are simulated for Category P1 events[42].
The single generator Contingency (ies), includes single generator units connected to the LG&E and KU System and simulates an outage of the largest generator at each transmission bus. The largest generator at a bus is considered to produce more severe System impacts than smaller units connected to the same bus. Similarly, single generator contingencies not connected to the LG&E and KU System, but that are in close proximity are also simulated by taking the outage of only the largest unit at a plant site. Multiple units that share a known single point of failure will be treated as a single generator Contingency.[43]

7.5.2 TPL-001-4 Table 1 Category P2 Contingency Selection

- Opening a line section without a fault: All line section outages of BES Facilities will be simulated to ensure the performance requirements of TPL-001-4 Table 1.

- Bus Section Fault: Many LGE&E/KU BES substations are designed with a breaker and a half or ring bus design. A bus section fault for a ring bus results in the same Contingency as P1, while a bus section fault of a breaker and a half design results in no transmission circuit outage or a P1 outage depending on the location of the bus. Therefore, the only Bus Section Faults analyzed for Category P2 are the BES buses that have a straight bus design. All BES Facilities in a straight bus configuration are simulated for Category P2-2.

- Internal Breaker Fault (non-Bus-tie Breaker): An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker. An internal breaker fault on a ring bus design is a double Contingency of the two Facilities that share a breaker in the ring. An internal breaker fault on a breaker in a breaker and a half design, results in a double Contingency of the two Facilities that share a breaker in the same bay. Therefore the internal fault contingencies simulated are those double

[42] TPL-001-4 3.3.1
[43] An example of this scenario would be Cane Run 7 (7A, 7B, 7C).

contingencies for BES Facilities that share a breaker for either a ring bus or breaker and a half design. An internal breaker fault for a breaker on a straight bus will be simulated when the fault causes more than just a disconnected bus, like an internal breaker fault where the breaker protects a three terminal line.

- Internal Breaker Fault (Bus-Tie Breaker): An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker. This contingency results in opening all breakers connected to both buses connected by the bus-tie breaker. All of the internal breaker faults for bus-tie breakers are simulated.

7.5.3 TPL-001-4 Table 1 Category P3 Contingency Selection

Category P3 includes the loss of a single generator unit, as described in section 7.5.1, followed by system adjustments. After system adjustments, all P1 contingencies are simulated. This includes generator, transmission circuit, transformer, and shunt device contingencies. For P3 events, LG&E and KU runs all single contingencies of 69 kV and above combined with a generator outage described in section 7.2. LG&E and KU also runs combinations of two generator outages.

7.5.4 TPL-001-4 Table 1 Category P4 and P5 Contingency Selection

Category P4 contingencies in steady state are multiple contingencies caused by a stuck breaker or relay failure where backup clearing is required to clear a fault. Category P4 is similar to P5 in steady state operation. With potentially different clearing times, P4 and P5 only differ in stability studies. Contingency selection for P4 and P5 are the same for steady state analysis.

7.5.5 TPL-001-4 Table 1 Category P6 Contingency Selection

The following are criteria for contingencies selected of Category P6 that produce more severe System results or impacts. All tested BES contingencies are analyzed to determine impacts on BES Facilities remaining in-service. When a BES Contingency shows an impact on any BES Facility remaining in-service, that Contingency will be paired with any other BES Contingency that impacts the same in-service BES Facility. Category P6 contingencies include transmission circuit, transformer, and shunt devices. LG&E and KU does not currently have any shunt devices on the BES, but if/when any are installed, they will be added to the contingency list.

The contingencies selected that produce the most severe results in steady state are not always the same as those selected for stability analysis. LG&E and KU's Contingency Selection Criteria describes the rationale for Contingency selection that is consistent with TPL-001-4 R3 and is considered to produce more severe System results or impacts.

7.5.6 TPL-001-4 Table 1 Category P7 Contingency Selection

LG&E and KU maintains a list of adjacent circuits greater than one mile in length that reside on a common structure. Loss of all BES double circuit Facilities that reside on a common structure are simulated for Category P7.

7.6 Steady State Extreme Events

LG&E and KU simulates the System performance for extreme events in TPL-001-4 Table 1 extreme events. The extreme events are selected that are expected to produce more severe System impacts. When LG&E and KU evaluates in steady state the performance of Category P6, there are no System adjustments after the first Contingency. Therefore, the P6 planning event is the same as the extreme event steady state part 1. The extreme events that are simulating in the TPL performance assessment include:

- Loss of a tower line that has three or more BES circuits when the common structure lines are more than one mile in length.

- Loss of all BES transmission lines on a common Right-of-Way when the common right of way is longer than one mile in length.

- Loss of a substation (one BES voltage level plus transformers) which are analyzed in the TEP process. A list of substations selected for this extreme event using will be included in the TEP report.

- Loss of all generating units at a station which is analyzed in the TEP process includes only the largest generation sites greater than 500 MW total generation capability in the LG&E and KU System.

- Loss of a large load or major load center which is analyzed in the TEP process includes tripping the load from the LG&E and KU largest single customers. This also includes large municipal loads.

- Loss of all gas-fired generation (two plants) served by a common large gas pipeline.

- Loss of two large generating stations in close proximity due to severe weather (e.g. tornado)

7.7 Stability Planning Events

The Stability portion of the Planning Assessment shall be performed for planning events to meet performance requirements in TPL-001-4 Table 1. The stability portion of the

Planning Assessment will only do analysis of disturbances on BES Facilities. The stability analysis shall use a current or qualified past study per TPL-001-4 2.6.

7.7.1 Category P1 Stability Disturbances Analyzed

Category P1 disturbances are selected to comply with NERC reliability standards including faults on generators, Transmission Circuits, and Transformers. Three phase faults with normal clearing (assumed six cycles) are initially analyzed for breaker to breaker BES Facilities in the stability model. A clearing time of six cycles is a worst case assumed clearing time. In the event that a Category P1 disturbance does not meet the performance requirements of TPL-001-4 Table 1, the Protection group is contacted to acquire the actual clearing time. The disturbance is re-simulated with the actual clearing time and the less severe single line to ground disturbances.

7.7.2 Categories P2 through P7 Stability Disturbances Analyzed

TPL-001-4 Table 1 Categories P2 through P7 disturbances are selected such that only the disturbances that produce the more severe System results or impacts are analyzed.[44] Categories P4-P7 stability disturbances may not be analyzed annually. A past study can be used per TPL-001-4 2.6 if there has not been a material change. Material changes in determination of a qualified past study would include substantial changes to the System represented in the study. When a past study is used, a new study would be required a minimum once every five years.

Bus Fault Contingency Selection: Bus faults are selected on buses which are generation points of interconnection except those that are interconnected in a breaker and a half design or ring bus design. The breaker and a half and ring bus schemes are designed for more reliable operation of a bus section disturbance. So faults on a breaker and a half scheme and ring bus are considered less severe. Disturbances are analyzed for straight bus designs.

Internal breaker faults: Internal breaker three phase faults are analyzed instead of the less severe single line to ground fault. These are analyzed on breakers considered to be more critical as documented in the TEP. The breaker and a half and ring bus schemes are designed for more reliable operation of a bus section disturbance. So faults on a breaker and a half scheme and ring bus are considered less severe. Therefore, internal breaker faults are analyzed for straight bus designs. Three phase faults are initially analyzed and if performance requirements are not met, then the less severe single line to ground fault is studied. Breakers are selected for internal fault or breaker failure, relay failure disturbances for Categories P2, P4 and P5 which are considered to produce the most severe results or impacts to the reliable operation of the BES.

[44] TPL-001-4 4.4

Category P3 starts with loss of a generator followed by “manual System adjustments” or replacement of the generation by another available source. Then a selected list of worst case BES Category P1 disturbances including breaker to breaker contingencies are analyzed on the generator outage model. The list includes faults one bus away from high side of the BES generators.

Category P4 and P5 Contingency Selection: For Category P4 and P5 three phase faults with a delayed clearing of 20 cycles, or worst case assumption, are analyzed on specific breakers. A more severe three phase fault is initially analyzed. If the three phase fault does not meet the performance requirements for P4 and P5, then the less severe single line to ground fault is analyzed. The stuck breakers selected are those that are expected to produce the most severe System results or impacts. In the event that a three phase fault with delayed clearing fails the performance requirements of TPL-001-4 Table 1, the Protection group is contacted to acquire the actual clearing times. The event is then re-simulated with the actual clearing times and using a single line to ground fault instead of a three phase fault. This analysis satisfies the requirements of P4, P5 and when required, extreme events. For P5 on a fault plus relay failure to operate, contingencies are selected at buses operated at 345 kV with four or more circuits.

Category P6 Contingency Selection: The n-2 BES contingencies are selected which produce the more severe System impacts of the BES. The rationale used to determine the more severe n-2 contingencies will be documented in the TEP report. The simulation uses a prior outage model followed by manual adjustments. Those manual adjustments can include generation re-dispatch, loss of firm transmission service and non-consequential load loss. Then after these adjustments, three phase faults are analyzed using the same faults as selected for P1 contingencies. The list of prior outages used as the initial condition is documented in the TEP Report.

Category P7 Contingency Selection: LG&E and KU maintains a list of BES transmission lines that are on common towers of greater than one mile in distance. Category P7 disturbances are analyzed by introducing a three phase fault on both lines of the common tower line at the same time with the appropriate clearing time for each line. The normal clearing and reclosing time (if high speed reclosed in less than one second) is simulated. For the common tower P7 disturbance, there are no manual System adjustments after one Contingency. The analysis is performed using two faults occurring at the same time in the stability analysis.

7.8 Stability Extreme Event Assessment

The stability portion of the Planning Assessment will perform studies to assess the impact of the extreme events of TPL-001-4 Table 1[45]. The events selected for evaluation are those that are expected to produce more severe System impacts. This section describes the rationale for the Contingencies selected for stability extreme events. If the Stability

[45] TPL-001-4 4.5

portion of the Planning Assessment for extreme events concludes there is instability (see section 9) caused by the occurrence of extreme events, an evaluation of possible action designed to reduce the likelihood or mitigate the consequences of the event will be conducted. This evaluation will be documented in the Extreme Event Report.

Protection Systems, including planned backup or redundant Systems, are accounted for in the analysis of breaker failure, internal fault of a breaker with delayed clearing contingencies. Redundant protection Systems may be a mitigating project when delayed clearing contingencies do not meet the performance requirements of the reliability standards.

Extreme Event Contingency Selection: Extreme events that are expected to produce more severe System impacts shall be identified. A three phase fault on a generator, transmission circuit, transformer, bus section with a stuck breaker, or relay failure resulting in delayed clearing: These disturbances are analyzed during the analysis for Categories P5 and P6 planning events. If the results of the P5 and P6 analysis do not meet the performance requirements P5 and P6 of TPL-001-4 Table 1, then the less severe single line to ground fault is analyzed. The performance of the three phase fault is then checked for potential instability (see section 9). The stuck breaker list for P5 and P6 contingencies are breakers that are located at BES buses that are also generator points of interconnection at sites with more than 500 MW of total generation capacity. Additionally, other non-generation point interconnection BES buses are included in the stuck breaker selection for Category P5 and P6 disturbances using the stuck breaker contingencies that will produce the more severe System impacts on the BES.

The selection of buses for analysis of the extreme event for a three phase fault on a bus with a stuck breaker analyzes those buses which are a generation point of interconnection except those that are interconnected in a breaker and a half scheme. The breaker and a half scheme is designed for more reliable operation of a bus section disturbance. So faults on a breaker and a half scheme are considered less severe.

The extreme event or three phase internal fault on a breaker is analyzed for the Category P2 less severe planning event using performance requirement for P2 of TPL-001-4 Table 1. If the performance requirements for the planning event are met, no additional work is required, since both the planning and extreme event pass the performance requirements of the planning event. If the extreme event does not pass the performance requirements of the planning event, the less severe single line to ground fault is simulated. The extreme event is then checked for potential instability (see section 9). Breakers are selected for internal fault and breaker failure disturbances, Category P2 which are considered to produce the most severe results or impacts to the reliable operation of the BES. The breakers selected for P2 contingencies are located at BES buses that are also generator points of interconnection at sites with more than 500 MW of total generation capacity. Additionally, other non-generation point of interconnection BES buses are included in the breaker selection for P2 disturbances using bus contingencies that will produce the more severe System impacts on the BES.

8 Performance Requirements

This section documents acceptable System steady state voltage limits, thermal limits, and the transient stability performance requirements for the LG&E and KU System[46]. Additionally performance requirements for P0 through P7 and extreme events described in TPL-001-4 Table 1 are included in the Planning Assessment TEP report.

Specific criteria for P1 planning events will be tested for TPL-001-4 4.1.1; P2 through P7 performance requirements in 4.1.2 and P1 through P7 performance requirements in 4.1.3.

8.1 Special Protection System

The LG&E and KU does not currently own or operate any Special Protection System (SPS) or Remedial Action Scheme in order to comply with the TPL Standards or these Planning Guidelines. Neither SPSs nor remedial action schemes should be considered when developing the Corrective Action Plan(s).

8.2 Steady State Voltage Performance Criteria

Per TPL-001-4 R5, the following is the steady state voltage criteria: A steady state System voltage violation will occur when the percent nominal voltage, rounded to one decimal place, is outside the applicable performance requirements.

The following are detailed voltage criteria for each of the TPL-001-4 Table 1 Categories.

1. Category P0 with all Elements and Facilities in service, the LG&E and KU Elements and Facilities of 69 kV and above shall perform within the following:

    - The minimum acceptable voltage criteria for Facilities of 69 kV and above are 94 percent of their nominal value. The maximum voltage criteria of any 500 kV System bus should not exceed 110 percent of the nominal value. All other transmission Elements and Facilities 69 kV to 345 kV should not exceed 105 percent of the nominal value.

2. Category P1and P3 voltage criteria:

    - The minimum acceptable voltage criteria for Elements 69 kV and above are 90 percent of their nominal value. The maximum voltage criteria of any 500 kV System bus should not exceed 110 percent of the nominal value. All other transmission Elements and Facilities 69 kV to 345 kV should not exceed 105 percent of the nominal value.

[46] TPL-001-4 R5

- The minimum generator steady state or ride through voltage limit is 0.95 pu at the generator bus after a P1 or P3 planning event[47].
- Load shed using TPL-001-4 footnote 12 is not used as a mitigation for P1 and P3 planning events.

3. Category P2, P4 through P7: Additional criteria for P2, P4 through P7 events which limit how much Non-Consequential Load Loss can be shed in order to meet the performance requirements of TPL-001-4 Table 1.

   - Where Non-Consequential Load Loss is allowed in TPL-001-4 Table 1, minimal load shed up to ten percent of the LG&E and KU Balancing Area load as modeled for P2, and P7 planning events; minimal load shed up to five percent for P4, P5 and P6
   - Interruption of Firm Transmission Service when permitted by TPL-001-4 HV.
   - After allowed Non-Consequential Load Loss and interruption of Firm Transmission Service, the minimum acceptable voltage criteria for BES Facilities is 90 percent of their nominal value. The maximum voltage criteria of any 500 kV System bus should not exceed 110 percent of the nominal value. All other transmission Elements and BES Facilities should not exceed 105 percent of the nominal value.
   - Load shed using TPL-001-4 footnote 12 is not used as a mitigation for P2, P4 through P7 planning events.

4. Steady state extreme events: Extreme events are only checked against the criteria in section 9.1 of these planning guidelines.

8.2.1 Steady State Thermal Facilities Limits

The applicable Facility Rating for TPL-001-4 Table 1 Category P0 is the seasonal normal Facility Rating. The applicable Facility Rating for TPL-001-4 Table 1 Categories P1 through P7 is the seasonal emergency rating. The recorded circuit flow will be the maximum MVA flow of either end. The recorded transformer flow on two-winding transformers will be the “design output” flow where step-down transformers will be measured at the low-voltage side and System tie transformers will be measured on the side where the MW flow exits the transformer. The loading of GSU transformers and all other equipment attached to and associated with generators are the responsibility of the generator owner; therefore they will not be monitored as part of the transmission planning assessment.

8.3 Transient Stability Performance Requirements

Transient stability studies shall be performed to meet TPL-001-4 Table 1 performance requirements. The System must remain stable per identification of System instability per Section 9 for TPL-001-4 Table 1 Categories P1 through P7 events. It is important to note that this criterion is applied when using an Inductive Motor Load model.

8.3.1 Angular Stability

The angular stability criteria for a generator are defined as: a generator rotor angle must remain less than 180 degrees with respect to the relative angle. LG&E and KU chooses the TVA's Brown Ferry, a nuclear unit, as the relative machine.

Instability must not occur for TPL-001-4 Table 1 Categories P1 through P7 disturbances per the dynamics identification of System instability in these planning guidelines Section 9.

8.3.2 Damping Criteria

For TPL-001-4 Table 1 Categories P1-P7 Power Oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner[48]. This damping criteria is: The angular variation of a machine must be tested showing visual damping for a five second run. If the angular variation is not visually damped after the five second run, a 20 second run will be completed. If after the 20 second simulation, the angular variation is still not visually damped, then the System will be determined to be unstable. LG&E and KU examines the stability plots as part of the Stability analysis.

8.3.3 TPL-001-4 Table 1 Categories P1-P7 Generator Synchronism

For TPL-001-4 Table 1 Category P1 through P7: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System (SPS) is not considered to be pulling out of synchronism[49]. LG&E and KU does not currently have an SPS.

The TPL-001-4 4.1.2 criteria for P2 through P7 is less conservative than TPL-001-4 4.1.1 for P1 planning events. LG&E and KU applies the TPL-001-4 4.1.1 P1 criteria to P2 through P7 planning events which is more conservative than the TPL-001-4 4.1.2 requirement.

[48] TPL-001-4 4.1.3
[49] TPL-001-4 4.1.1

8.3.4 TPL-001-4 Table 1 Categories P1 and P3 Transient Voltage Stability Performance Requirements:

Per TPL-001-4 R5, the following is the transient voltage stability criteria for P1 and P3 events: LG&E and KU's transmission System voltage must recover to 0.8 p.u. within 4 seconds after the fault is cleared. There cannot be any generation tripping except what is required to clear the faulted element. TPL-001-4 Table 1 Categories P1 and P3 stability faults must also pass the angular and damping stability performance requirements described in this section.

8.3.5 TPL-001-4 Table 1 Categories P2, and P4-P7 Transient Voltage Stability Performance Requirements:

Per TPL-001-4 R5, the following is the stability voltage criteria for P2 and P4-P7 events: These disturbances are less probable and may involve loss of some non-consequential load (when allowed by TPL-001-4) and/or generation tripping within the LG&E and KU control area. These disturbances must pass the angular and damping stability performance requirements described in this section. Within 4 seconds after a fault is cleared, there cannot be more than 6 BES buses with voltages less than 0.80 pu.

8.4 Extreme Events Stability Performance Requirements:

Stability disturbances for TPL-001-4 Table 1 extreme events are analyzed for those contingencies that would produce more severe System results or impacts[50]. If the analysis concludes there is potential instability per Section 9, caused by the occurrence of the extreme events, an evaluation of the possible actions designed to reduce the likelihood of or mitigate the consequences and adverse impacts of the event(s) will be conducted.

9 System Instability Criteria Methodology

As required by TPL-001-4 R6 this section defines and documents the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. It is the intent of the Planning Assessment to identify potential System instability before that instability actually occurs giving some margin in the assessment. The identification of potential instability in the power System simulation is different between the steady state study and the stability study.

[50] TPL-001-4 3.5, 4.5

9.1 Cascading, Voltage Instability, or Uncontrolled Islanding Identification in Steady State Simulations

For steady state power flow analysis, instability could result after one or more of the following occurs:

- Six or more BES buses steady state voltage is less than 0.80 pu after all capacitors have switched on.

- Three or more BES Facilities exceed 150% of the applicable seasonal rating.

9.2 Instability Identification for Stability or Dynamics Simulations

For purposes of these planning guidelines, instability includes dynamic instability, Cascading, voltage instability, or uncontrolled islanding. For dynamics analysis, instability could result after one or more of the following occurs:

- Generators from two or more plant sites in LG&E and KU's control area trip or slip a pole.
- 4 seconds after a fault is cleared, there exists more than six BES Facilities whose voltages are below 0.8 p.u.
- Violation of damping criteria per section 8.3.1

10 Corrective Action Plan(s)

For planning events shown in TPL-001-4 Table 1, when the analysis indicates an inability of the System to meet the performance requirements in TPL-001-4 Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met[51]. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements of TPL-001-4 Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity study analyzed in accordance with TPL-001-4 2.1.4 and 2.4.3[52]. The Corrective Action Plan(s) is documented in the TEP report. [53]The TEP report lists the System deficiencies and the associated actions needed to achieve the required System performance.

Operating Guides may be an acceptable Corrective Action Plan in order to meet the performance requirements if the violation only occurs in the Near-Term Planning Horizon and not in the Long-Term Planning Horizon. Operating guides may include; but

[51] TPL-001-4 2.7

[53] TPL-001-4 2.7.1

not limited to, generation re-dispatch, transmission reconfiguration, Non-Consequential Load Loss, and loss of firm transmission service in accordance with TPL-001-4.

The LG&E and KU Planning Assessment will NOT use Non-Consequential Load Loss when allowed per TPL-001-4 footnote 12 to satisfy the performance requirements of TPL-001-4.

The LG&E and KU BA does not have any automatic generation tripping or run back scheme other than what would be tripped as a result of clearing a fault. If generation is tripped as a result of the fault clearing, then that tripping will be studied as part of the Contingency analyzed. Automatic generator tripping or automatic generator run-back other than fault clearing should not be considered in the Corrective Action Plan(s).

The LG&E and KU System does have DSM programs, the load forecast supplied by the LSE's contain reductions in load as a result of the DSM programs. Therefore, DSM programs are not utilized in the Corrective Action Plan(s).

The previous TEP's Corrective Action Plan(s) are reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified of Systems Facilities or improvements to existing Systems Facilities[54].

10.1.1 Corrective Action Plan(s) for P0

The Corrective Action Plans for TPL-001-4 Table 1 Category P0 can include:

- Building new transmission Elements and Facilities
- Upgrading existing transmission Elements and Facilities

10.1.2 Corrective Action Plan(s) for P1 and P3

For events of TPL-001-4 Table 1 Categories P1 and P3 which require a Corrective Action Plan in order to meet the performance requirements of Table 1, the Corrective Action Plans may include:

- Building new transmission Elements and Facilities
- Upgrading existing transmission Elements and Facilities
- Switching procedures
- Transmission re-configuration

[54] TPL-001-4 2.7.4

10.1.3 Corrective Action Plan(s) P2, P4 through P7

For events of TPL-001-4 Table 1 Categories P2, P4 through P7 which require a Corrective Action Plan in order to meet the performance requirements of Table 1, the Corrective Action Plans may include:

- Building new transmission Elements and Facilities
- Upgrading existing transmission Elements and Facilities
- Switching procedures (see Section 7.4)
- Generation re-dispatch
- Transmission re-configuration
- Non-Consequential Load Loss where specifically allowed in TPL-001-4 Table 1. However non-consequential load loss allowed per footnote 12 will not be used in the Corrective Action Plan.

10.2 Project Timing

If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in TPL-001-4 Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation.[55] The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated and the use of Non-Consequential Load Loss and curtailment of Firm Transmission Service.

Operating guides are used to document the mitigation steps when a construction project with a need date in the first year of the Planning Horizon (first year of models) is not expected to be completed on time per TPL-001-4 2.7.3. When necessary, an operating guide could include the use of Non-Consequential Load Loss and curtailment of Firm Transmission Service in accordance with TPL-001-4.

The goal of timing projects is to ensure that the project is completed before the loading reaches 100% of the emergency seasonal rating. Due to varying conditions, this may not be possible. Therefore, utilization of TPL-001-4 2.7.3 may be used in the form of an operating guide when studies indicate there is an overload of 100% or more of the seasonal rating.

All existing projects that are not determined to be under construction are reviewed annually to determine if the current timing should be changed.

For P0, P1 and P3 thermal overload of a Facility, the following criteria will be used to determine the needed timing for the Corrective Active Plan to address the issue:

[55] TPL-001-4 2.7.3

1. The flow on the Facility must be equal to or exceed 100% of the applicable thermal rating of the Facility at the end of the Long-Term Transmission Planning Horizon without the Corrective Action Plan. An issue that does not equal or exceed 100% of the thermal rating of the Facility in the Long-Term Transmission Planning Horizon is not required to have a Corrective Action Plan.
2. Corrective Action Plans for new issues will be timed to the year and season when the flow is equal to or exceeds 98% of the applicable thermal rating of the Facility. The timing of new projects (construction) will not be any earlier than the first model year of the TEP. However, the Corrective Action Plan will contain potential actions, if needed, that can be taken to mitigate the identified constraint in the Planning Horizon prior to the expected completion of construction.
3. Existing Corrective Action Plans that had a timing in the previous TEP will be retimed by the following:
    a. If the flow on the Facility is less than to 96% of the applicable thermal rating for the timing year and season in the previous TEP, the Corrective Action Plan will be retimed to the year and season when the flow is equal to or exceeds 98% of the applicable thermal rating of the Facility.
    b. If the flow on the Facility is equal to or greater than 100% of the applicable thermal rating prior to the timing year and season in the previous TEP, the Corrective Action Plan will be retimed to the year and season when the flow is equal to or exceeds 98% of the applicable thermal rating of the Facility. The timing of new projects (construction) will not be any earlier than the first model year of the TEP. However, the Corrective Action Plan will contain potential actions, if needed, that can be taken to mitigate the identified constraint in the Planning Horizon prior to the expected completion of construction.
    c. If the flow on the Facility is equal to or greater than 96% and less than 100% of the applicable thermal rating for the timing year and season in the previous TEP, the timing of the Corrective Action Plan will remain the same as the previous TEP. Facilities that do not exceed the applicable thermal rating in the Long-Term Planning Horizon will have their Corrective Action Plan delayed beyond the Long-Term Planning Horizon.

Voltage performance driven projects will be timed with a need date base on the performance criteria of section 8. There will not be a timing date associated with these projects.

Until January 1, 2021, Corrective Action Plans applying to the following Categories of Contingencies and events identified in the TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3) that would not otherwise be permitted by the requirement of TPL-001-4:.

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)

- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

11 Responsibility Coordination TPL-001-4 R7

Each PC, in conjunction with the TP, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. LG&E and KU is registered as a PC and TP. LG&E and KU is not a member of a Reliability Transmission Organization (RTO). The LG&E and KU Planning Coordinator area consists only of the LG&E and KU Transmission Owned Facilities. All responsibilities for the studies required by TPL-001-4 and the Planning Assessment are the sole responsibility of the LG&E and KU Transmission Planning group.

The required studies are performed in two parts. Part 1, the TEP uses the study results for planning events (TPL-001-4 Table 1 P0 through P7) and corresponding Corrective Action Plan(s) to demonstrate compliance with TPL-001-4 planning events. The annual planning assessment TEP may utilize a qualified past study when allowed by TPL-001-4 and requirements of TPL-001-4 2.6, are met.

Part 2 is the extreme event report which documents the results of the study for extreme events of TPL-001-4 Table 1. The extreme event report may not be performed annually, and may use a qualified past study as long as the past study for the extreme event analysis is less than five years old and there have been no material changes since the previous past study as discussed in Section 7.5.

11.1 ITO Approval

The ITO reviews and prepares an Assessment of the TEP. When that Assessment is completed, the ITO will send it to the Stakeholders for a 30-day comment period. After comments are received and addressed, the ITO approves the TEP. Per TPL-001-4 R8 when approval of the TEP is complete, the LG&E and KU Transmission Planner will distribute the TEP to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days.