PPL EU Planning Process, Methodology and Criteria

Executive Summary

The purpose of the "Transmission Planning, All PPL EU BES and Non-BES PJM Tariff Facilities" Practice is to document PPL EU's criteria and philosophy related to planning the transmission system. This practice document serves as PPL EU's Planning Criteria (used to fulfill the PPL EU portion of PJM's FERC 715 filing, Parts 4 and 5). The scope of this Practice includes all of PPL EU's BES transmission facilities and Non-BES PJM Tariff facilities. The criteria and philosophy contained in this Practice help ensure that PPL EU conducts a forward-looking planning process that results in a reliable, operable, and cost-effective transmission network as load, generation, transfers, and system topology continually change throughout time.

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1. PJM RTEP Planning Process and Underlying PPL EU Planning Process

In order to ensure reliable transmission service, PJM prepares an annual Regional Transmission Expansion Plan (RTEP) to identify system reinforcements that are required to meet the North American Electric Reliability Corporation (NERC) Reliability Standards, PJM reliability planning criteria, and Transmission Owner reliability criteria. The RTEP is a FERC-approved transmission planning process that results from a comprehensive analysis to identify existing and forecasted violations of the NERC Reliability Standards on the transmission system within PJM's service territory.

PJM's RTEP is an annual process that encompasses a series of analyses to ensure power continues to flow reliably to customers under a variety of system conditions from light load to peak conditions. The NERC reliability standards, PJM reliability planning criteria, and Transmission Owner criteria are used by PJM and PPL EU to analyze the system and determine the specific transmission upgrade projects that are needed to ensure short-term and long-term reliable electric service to customers.

For facilities that are defined as Bulk Electric System (BES) facilities according to the NERC BES definition[1], PJM conducts RTEP studies in conjunction with PPL EU and applies NERC TPL and / or PJM reliability criteria to specific conditions on the transmission system. These studies which are outlined in PJM Manual 14B, include Load Deliverability, Generator Deliverability, Baseline System N-1, N-1-1, Light Load, Short Circuit, and Stability analyses that check for both thermal and voltage violations. When any of these analyses show an inability of the transmission system to meet a specific reliability standard under these conditions (e.g. PJM or PPL EU thermal, voltage, or load loss criteria), PJM will document the reliability concern and seek solutions to address the problem per the process documented under Schedule 6 of the PJM Operating Agreement (PJM OA).

For reliability concerns that PJM posts in a FERC Order 1000 proposal window, any qualified entity can then propose an upgrade solution. PPL EU is a member of PJM, actively participates in the PJM transmission planning process, and is also a qualified entity that can propose system upgrade solutions.

Proposed solutions may include installation of new facilities or upgrades to existing facilities. The recommended solution will be presented by PJM to stakeholders at a Transmission Expansion Advisory Committee meeting or a Sub-Regional RTEP meeting. If an upgrade cannot be completed by the violation year, a Remedial Action Scheme (RAS) as defined by NERC may need to be applied as a temporary measure

[1] Bulk Electric System as defined by NERC: HTTP://WWW.NERC.COM/PA/RAPA/BES%20DL/BES%20DEFINITION%20APPROVED%20BY%20FERC%203-20-14.PDF

to restore facilities to within applicable emergency thermal and voltage ratings until a permanent transmission facility upgrade can be implemented.

Projects that are not specifically required to maintain PJM system regional reliability and do not alleviate any specific PJM regional planning criteria violations may also be initiated by PPL EU and reported to PJM for inclusion in the Regional Transmission Expansion Plan (RTEP) as a Supplemental Project. These Supplemental Projects are typically required to maintain or improve system reliability, resiliency, respond to customer requests, satisfy safety regulations, address local load growth, optimize asset performance and operational flexibility, replace deteriorated equipment, or address other needs.

For Non-Bulk Electric (non-BES)[2] facilities classified as tariff facilities by PJM, PJM does a preliminary assessment of the reliability concerns. PJM then provides the RTEP cases to the respective local Transmission Owners (such as PPL EU). The TOs are then responsible for verifying any reliability violations identified by PJM, and also any other reliability violations based on their own local Transmission Owner planning criteria as it is posted with PJM and provided to FERC in the PJM FERC 715 filing. PPL EU conducts studies as described in Table 1-1 to identify reliability concerns associated with the PPL EU local transmission system. As with BES facilities, for violations identified on Non-BES PJM Tariff facilities PJM will document the reliability concern and seek solutions to address the problem per the process documented under Schedule 6 of the PJM Operating Agreement (PJM OA).

[2] Non-BES facilities are facilities not included in the NERC BES definition from Footnote 1.

Table 1-1
PPL EU Transmission Planning Studies Conducted on a Regular Basis

Study Number	Study Name	Description / Purpose	Load Level	Study Frequency
1	**5 and 10 Year Steady State Network Analysis: Load Flow Summer Peak 50/50[1]**	N-1 Contingency Analysis checking for thermal, voltage and load loss level performance	50/50 Summer Peak PJM Forecast	Annual[7]
2	**5 and 10 Year Steady State Network Analysis: Load Flow Summer Peak 90/10[2]**	N-1 Contingency Analysis checking for thermal, voltage and load loss level performance	90/10 Summer Peak PJM Forecast	Annual[3,7]
3	**5 and 10 Year Steady State Network Analysis: Load Flow Winter Peak 50/50[1]**	N-1 Contingency Analysis checking for thermal, voltage and load loss level performance	50/50 Winter Peak PJM Forecast	Annual[7]
4	**5 and 10 Year Steady State Network Analysis: Load Flow Winter Peak 90/10[2]**	N-1 Contingency Analysis checking for thermal, voltage and load loss level performance	90/10 Winter Peak PJM Forecast	Annual[3,7]
5	**5 and 10 Year Steady State Network Analysis: Load Flow Summer Peak 50/50[1]**	N-1-1 Contingency Analysis checking for thermal, voltage and load loss level performance	50/50 Summer Peak PJM Forecast	Annual[4,7]
6	**5 and 10 Year Steady State Network Analysis: Load Flow Winter Peak 50/50[1]**	N-1-1 Contingency Analysis checking for thermal, voltage and load loss level performance	50/50 Winter Peak PJM Forecast	Annual[4,7]
7	**0 to 5 Year Steady State Network Analysis: Load Flow Spring / Fall Peak**	N-1-1 Contingency Analysis evaluating maintenance conditions	Spring/Fall Peak PJM Forecast	Annual[4,5,7]
8	**5 and 10 Year Steady State Network Analysis: Load Flow Light Load Level**	N-1 Contingency Analysis checking for thermal and voltage concerns	50% of 50/50 Summer Peak PJM Forecast	Annual[7]
9	**CIP-014**	Loss of all voltages at a substation to identify higher valued assets to protect against sabotage attack.	50/50 Summer Peak PJM Forecast	As required per NERC CIP-014 Standard
10	**NERC Extreme Events**	Various Steady State Extreme Event types: E1: N-2 Outage, E2B: Loss of ROW, E2C: Loss of one voltage at a station, and E2D: Loss of all generation at a plant	50/50 PJM Forecast	Upon Request[6]

Note 1: 50/50 Load Forecast is provided by PJM for both Summer and Winter. 50/50 load indicates that 50% of the time the actual load is higher than the 50/50 value and 50% of the time it is lower.

Note 2: 90/10 Load Forecast is provided by PJM for both Summer and Winter. 90/10 load indicates that 10% of the time the actual load is higher than the 90/10 value and 90% of the time it is lower.

Note 3: Transmission Planning will perform 90/10 analysis and evaluate on a case by case basis if a reinforcement is required for Operational Performance needs.

Note 4: Planning Studies 5, 6, and 7 are applied to the BES system only.

Note 5: This study type is used for outage scheduling purposes either for future maintenance or construction sequencing.

Note 6: After assessment of event probability and impact, PPL EU, at its own discretion, determines if there is a need to mitigate reliability exposure associated with extreme events, and if so, what upgrades are necessary to address concerns.

Note 7: PPL EU performs 5-year out summer, winter, and light load analyses on an annual basis. PPL EU will decide on a case by case basis whether additional sensitivity analyses such as 10-year out studies with varying load forecasts are required to identify any long term reliability issues, or help assess the longevity of transmission solutions to 5-year out reliability concerns.

PJM will evaluate the system reinforcement proposals based on solution effectiveness (i.e. determine if the proposed solution resolves the identified reliability, economic, or public policy concern), cost compared to competing solutions, and the feasibility to construct. PJM will then recommend a selected system reinforcement solution at a Transmission Expansion Advisory Committee (TEAC) or Sub-Regional RTEP stakeholder meeting.

In addition to RTEP Reliability, Market Efficiency, and Public Policy analyses, PJM also conducts Generator Interconnection Studies. PPL EU follows and adheres to the study schedule as specified in PJM Manual 14A.

2. PPL Study Methodology

2.1 Load Forecast

PPL Transmission Planning benchmarks the base case against actual summer and winter peak MW and MVAR data from SCADA and metered values on an annual basis. Distribution substation coincident peak loads are matched to each load in the model. Transmission line and regional transformer flows are used to reconcile all loads. The transmission planner identifies any errors in the SCADA and meter data and supplements the peak loads with any expected new or additional loads from Industrial Accounts, Distribution Planning, or other data sources. The PJM Load Forecast (50/50 and 90/10) is used to scale the peak load for the study year with industrial customer loads remaining fixed.

Regarding reactive load, MVAR values are initially set to match the actual summer and winter peak values. PPL EU has a goal to maintain unity on the low side of all Distribution substation transformers at peak load levels.

2.2 System Topology

Transmission Planning works with PJM to update the annual RTEP series of cases and verifies that the existing system topology in the various RTEP cases agrees with existing system one-line diagrams issued and used by T&D Operations and all new upgrades / modifications / deletions driven by future projects are accurate and included in cases as appropriate given the respective case year. For load flow analyses, all facilities are modelled in their normal operating status with the exception of studies focused on specific line-out conditions.

2.3 Generation Assumptions

In the Planning model, generation facilities are scaled to a percentage of their Pmax capacity values as identified in the Interconnection Service Agreements in alignment with PJM's method. As specified in Attachment O Appendix 2, Section 4 "Operations": Sub-Section 4.7 "Reactive Power" of the PJM OATT, a synchronous generator shall design its "Facility" to maintain a composite power factor delivery at continuous rated power output at the generator terminals at a power factor of at least 0.95 leading (absorbing MVArs) to 0.90 lagging (supplying MVArs). Non-synchronous generators shall hold a power factor of at least 0.95 leading (absorbing MVArs) to 0.95 lagging (supplying MVArs). Qmax and Qmin values in the load flow are set to these limits depending on the type of generator.

Generators connected to the 500 kV or 230 kV system are required to hold the voltage schedule specified by PPL EU. Generators connected to the 69 kV or 138 kV system are given a MW/MVAR schedule to limit their effect on the voltage at the point of interconnection.

PPL EU Transmission Planning studies the transmission system under various generation dispatch and load scenarios which produce typical conditions on the transmission system (e.g., light load, and both summer and winter peak load cases) to identify areas that require system reinforcement.

2.4 Study Parameters

For PPL EU Transmission Planning analyses, the solution parameters used are in alignment with PJM study methods as defined in PJM Manual 14B.

3. Contingency List

Contingencies are selected to ensure all contingency categories required for analysis by NERC are included for all BES facilities, and all contingency categories that are deemed applicable to Non-BES system reliability are applied when studying Non-BES facilities. Table 3-1 below identifies the NERC TPL Contingencies that are required to be studied by PJM and/or PPL EU during steady state power system analyses. Events are applicable to both the BES and Non-BES unless noted otherwise.

Certain contingency tests will be conducted to measure the ability of the system to withstand “reasonably expected” extreme events, and the results will be documented according to NERC TPL-001-4. While it is impossible to anticipate or test the BES for all possible contingencies and load levels that could occur, the Extreme Events listed in Table 3-1 will be evaluated. Decisions regarding the exposure mitigation actions to be taken for extreme events, if any, will be based on the following fundamental considerations, and will be at PPL EU’s discretion:

- Consequences of the disturbance
- Probability of the disturbance
- Cost of significantly changing the consequences or the probability

Table 3-1

NERC TPL Contingencies Studied During Typical PPL EU Transmission Planning Steady State Analyses[3]

Category	Initial Condition	Outage Event
P0: Normal System	Normal System	None
P1 Single Contingency	Normal System	P1-1: Generator
		P1-2: Transmission Line
		P1-3: Transformer
		P1-4: Shunt Device
P2 Single Contingency	Normal System	P2-1: Opening of Line Section without a Fault [2]
		P2-2: Bus Section Fault
P3 Multiple Contingencies	One (P1-1) outage event followed by System Adjustments	P3-1: Generator
		P3-2: Transmission Line
		P3-3: Transformer
		P3-4: Shunt Device
P4 Multiple Contingencies Due to Stuck Breaker during Initial Event	Normal System	P4-1: Generator & Stuck Breaker (Non-Bus Tie Breaker) [1]
		P4-2: Transmission Line & Stuck Breaker (Non-Bus Tie Breaker) [1]
		P4-3: Transformer & Stuck Breaker (Non-Bus Tie Breaker) [1]
		P4-4: Shunt Device & Stuck Breaker (Non-Bus Tie Breaker) [1]
		P4-5: Bus Section & Stuck Breaker (Non-Bus Tie Breaker) [1]
		P4-6: Bus Section & Stuck Breaker (Bus Tie Breaker) [1]
P6 Multiple Contingencies	One (P1-2, P1-3, or P1-4) outage event followed by System Adjustments	P6-1: Transmission Line
		P6-2: Transformer
		P6-3: Shunt Device
P7 Multiple Contingencies Due to a DCT Event	Normal System	P7-1: Double-Circuit Transmission Line
NERC Extreme Events	Normal System	Various Steady State Extreme Event types studied including: E1: N-2 Outage, E2B: Loss of ROW, E2C: Loss of one voltage at a station, and E2D: Loss of all generation at a plant

Note 1 - Bus-Sectionalizing breakers when operated normally closed are "Bus Tie Breakers".

Note 2 - P2-1 events are not applicable on the PPL EU Non-BES

Note 3 - PPL EU determines and implements upgrade solutions as necessary to resolve reliability concerns identified for the P1 through P7 contingency types described in this table. After assessment of event probability and impact, PPL EU, at its own discretion, determines if there is a need to mitigate reliability exposure associated with extreme events, and if so, what upgrades are necessary to address concerns.

4. PPL EU Planning Criteria

4.1 Thermal Criteria

Under normal conditions all facilities must operate within their respective normal ratings. After a contingency has occurred, lines and transformers must remain within their applicable emergency rating. For category P1 events, available system adjustments may be used to return all lines and transformers to within their normal rating in preparation for a second event.

Table 4.1-1 summarizes the maximum allowable thermal loading percentage and applicable rating for PPL EU facilities for each contingency category PPL EU analyzes.

Table 4.1-1
PPL EU Thermal Criteria [1]

Category	Initial Condition	Outage Event	BES and Non-BES Tariff Line Facilities May Not Exceed X% of Rating Y		BES and Non-BES Tariff Transformer Facilities May Not Exceed X% of Rating Y	
			Load Pct (X)	Rating (Y)	Load Pct (X)	Rating (Y)
P0: Normal System	Normal System	None	100%	Normal	100%	Normal
P1 Single Contingency [2]	Normal System	P1-1: Generator P1-2: Transmission Line P1-3: Transformer P1-4: Shunt Device	100%	Emergency	100%	Emergency
P2 Single Contingency	Normal System	P2-1: Opening of Line Section without a Fault [3] P2-2: Bus Section Fault	100%	Emergency	100%	Emergency
P3 Multiple Contingencies	One (P1-1) outage event followed by System Adjustments [4]	P3-1: Generator P3-2: Transmission Line P3-3: Transformer P3-4: Shunt Device	100%	Emergency	100%	Emergency
P4 Multiple Contingencies Due to Stuck Breaker during Initial Event	Normal System	P4-1: Generator & Stuck Breaker (Non-Bus Tie Breaker) P4-2: Transmission Line & Stuck Breaker (Non-Bus Tie Breaker) P4-3: Transformer & Stuck Breaker (Non-Bus Tie Breaker) P4-4: Shunt Device & Stuck Breaker (Non-Bus Tie Breaker) P4-5: Bus Section & Stuck Breaker (Non-Bus Tie Breaker) P4-6: Bus Section & Stuck Breaker (Bus Tie Breaker)	100%	Emergency	100%	Emergency
P6 Multiple Contingencies	One (P1-2, P1-3, or P1-4) outage event followed by System Adjustments [4]	P6-1: Transmission Line P6-2: Transformer P6-3: Shunt Device	100%	Emergency	100%	Emergency
P7 Multiple Contingencies Due to a DCT Event	Normal System	P7-1: Double-Circuit Transmission Line	100%	Emergency	100%	Emergency

Note 1 - Seasonal Ratings applicable dependent upon study type being done
Note 2 - For P1 events, following system adjustments, facilities must meet Normal System (P0) thermal criteria
Note 3 - P2-1 events are not applicable on the PPL EU Non-BES
Note 4 - For NERC contingency categories P3 and P6, following the initial N-1 outage event and system adjustments, facilities must not exceed 100% of the seasonal Normal rating

4.2 Voltage Criteria

BES Voltage Control

The guidelines used to establish BES voltage levels are:

- Voltage gradients throughout the PJM system should be minimized to a practical extent. Unusually large voltage gradients generally reflect an improperly balanced system condition, with some generators carrying more reactive burden than others. This frequently results in heavy reactive transfers between systems. This is contrary to the PJM obligation that each system should carry its own reactive load and losses under normal operating conditions.
- While voltage gradients should be minimized, during heavy transmission line load periods a voltage gradient from generator buses to load buses is necessary to utilize the reactive capability available from the generators. During light load conditions, lower voltage gradients will be required to maintain balanced reactive conditions.
- During heavy load periods, transmission system voltages shall be maintained as high as is reasonable taking into account equipment limitations. During such periods of heavy load, higher transmission system voltages can improve system dynamic stability margins. For steady-state conditions, a higher transmission system voltage increases the power transfer capability between areas.

Non-BES Voltage Control

PPL EU plans to the voltage criteria noted in Table 4.2-2. In all instances, voltage criteria are at least as stringent as the voltage criteria noted in PJM Manual 3 “Transmission Operations”, which is used by PJM for its internal RTEP Transmission Planning process studies.

Continual control of voltage and reactive supply on the Non-BES system will be accomplished by use of:

- Tap changing under load on bulk and non-bulk electric system transformers
- Dynamic reactive devices on the non-bulk electric system
- Capacitors on the non-bulk electric system

During system light load periods, PPL EU non-bulk electric system voltages should be reduced to provide required regulation to the distribution system. Lower system voltages reduce the effect of line charging current and increase reactive losses for the same MW flow.

The voltage at non-bulk transmission facilities shall be varied to assist in voltage control on distribution lines but such variation or regulation from heavy load to light load is generally kept to within 8% throughout the course of a typical day.

Nuclear Plant Voltage Criteria

Minimum voltage and allowable voltage drop are established in the NPIRs (Nuclear Plant Interface Requirements between PPL EU, PJM and Susquehanna Nuclear, LLC). PJM Manual 14B, Attachment G speaks to how PJM incorporates the NPIRs into its RTEP process.

Reactive Supply

Capacitors are required to supply reactive loads and losses and to maintain adequate transmission voltage levels during both normal and emergency conditions. Essentially, the reactive power required by each region of the PPL EU territory should be supplied from sources within the Non-BES network. This requirement is accomplished when reactive flows are balanced within Non-BES substations at peak load levels. Capacitors shall be installed on the non-bulk transmission and distribution systems in a coordinated manner so as to obtain the maximum voltage and capacity benefits at the lowest overall cost. Capacitors installed for voltage control shall have control for automatic operation. SCADA control of capacitors on the transmission system will be provided.

BES facility voltage schedules are coordinated among PJM member companies to prevent large inadvertent reactive power interchange. Sufficient reactive capacity shall be installed to minimize reactive power flow between the bulk electric system and the non-bulk electric system. The installed reactive supply shall be switched as necessary to ensure that the Voltage Criteria in Table 4.2-2 are not violated while assuming the study parameters in PJM Manual 14B as referenced in Section 2.4 of this document. Shunt reactors may be considered as a possible BES reinforcement option on a case by case basis if required to absorb reactive power during light load conditions. PPL EU capacitor and reactor switching voltage change criteria, under normal system operating conditions, may be found in Table 4.2-1.

Table 4.2-1 PPL EU Shunt Capacitor and Shunt Reactor Switching Delta Voltage Criteria				
Facility Type	**Shunt Capacitors Delta Voltage Upon Switching**		**Shunt Reactors Delta Voltage Upon Switching**	
	Manually Switched	Automatically Switched	Manually Switched	Automatically Switched
BES Facility	5.0%	2.5%	5.0%	2.5%
Non-BES Facility	5.0%	2.5%	5.0%	2.5%

<u>System Disturbance Voltage Performance</u>

Voltage deviations are generally indicators of the relative stiffness and adequacy of the transmission system in a particular area. For Non-BES facilities, which generally focus on serving a local load area, post-contingency voltage deviations are well defined and do not have the potential to develop into cascading events.

For the transient period after a fault, higher system voltages increase transient stability margins during peak load conditions. In addition, for the same MW flow, real (I^2R) and reactive (I^2X) power losses on the bulk system are reduced.

Voltage deviations at major 500 kV and 230 kV substations and switchyards with bulk electric system transfer responsibilities can impact large areas with undefined bounds. PJM has post-contingency voltage deviation ("Delta Voltage") criteria documented in PJM Manual 3.

Because voltage collapse could occur instantly, automatic sectionalizing, switched capacitors, or special protection schemes shall not be an acceptable means of restoring voltage levels prior to determining the change in voltage for a particular outage (i.e. the "Delta Voltage"). Automatic devices that operate within a few cycles, such as static VAR compensators (SVCs), can be used as a means of preventing a voltage deviation violation. As noted in Section 2.4, refer to PJM Manual 14B for planning study parameters. PPL EU study parameters are in line with PJM study parameters.

Table 4.2-2
PPL EU Voltage Criteria

Category	Initial Condition	Outage Event	500 kV Facilities[1]			230, 138, and 115 kV BES and Non-BES Tariff Facilities[1]			69 kV Non-BES Tariff Facilities[1]		
			Min (X)	Max (Y)	Delta (Z)[1]	Min (X)	Max (Y)	Delta (Z)[1]	Min (X)	Max (Y)	Delta (Z)[1]
P0: Normal System	Normal System	None	1.00	1.10	NA	0.95	1.05	NA	0.923	1.019	NA
P1 Single Contingency[2]	Normal System	P1-1: Generator P1-2: Transmission Line P1-3: Transformer P1-4: Shunt Device	0.97	1.10	5.0%	0.92	1.05	8.0%	0.893	1.019	8.0%
P2 Single Contingency	Normal System	P2-1: Opening of Line Section without a Fault[3] P2-2: Bus Section Fault	0.97	1.10	5.0%	0.92	1.05	8.0%	0.893	1.019	8.0%
P3 Multiple Contingencies	One (P1-1) outage event followed by System Adjustments[4]	P3-1: Generator P3-2: Transmission Line P3-3: Transformer P3-4: Shunt Device	0.97	1.10	5.0%	0.92	1.05	8.0%	0.893	1.019	8.0%
P4 Multiple Contingencies Due to Stuck Breaker during Initial Event	Normal System	P4-1: Generator & Stuck Breaker (Non-Bus Tie Breaker) P4-2: Transmission Line & Stuck Breaker (Non-Bus Tie Breaker) P4-3: Transformer & Stuck Breaker (Non-Bus Tie Breaker) P4-4: Shunt Device & Stuck Breaker (Non-Bus Tie Breaker) P4-5: Bus Section & Stuck Breaker (Non-Bus Tie Breaker) P4-6: Bus Section & Stuck Breaker (Bus Tie Breaker)	0.97	1.10	5.0%	0.92	1.05	8.0%	0.893	1.019	8.0%
P6 Multiple Contingencies	One (P1-2, P1-3, or P1-4) outage event followed by System Adjustments[4]	P6-1: Transmission Line P6-2: Transformer P6-3: Shunt Device	0.97	1.10	5.0%	0.92	1.05	8.0%	0.893	1.019	8.0%
P7 Multiple Contingencies Due to a DCT Event	Normal System	P7-1: Double-Circuit Transmission Line	0.97	1.10	5.0%	0.92	1.05	8.0%	0.893	1.019	8.0%

NA = Not Applicable

Note 1: Facility Voltage Must Remain Between Min Voltage X and Max Voltage Y {p.u. of Nominal Voltage}. Voltage Change during Event Shall Not Exceed Z%

Note 2: For P1 events, following system adjustments, facilities must meet Normal System (P0) voltage criteria

Note 3: P2-1 events are not applicable on the PPL EU Non-BES

Note 4: In the case of NERC Category P3 and P6 events, after the initial event followed by system adjustments, facility voltage must be able to recover to within the Normal System (P0) min/max voltage range prior to the 2nd outage event. It is important to note that the maximum delta voltage described for NERC Category P3 and P6 contingencies is measured by calculating the difference between the post-initial event and adjustments (N-1) voltage and the voltage after the entire N-1-1 outage scenario is complete (Post- N-1-1)

4.3 Short Circuit Criteria

When performing short circuit analyses, existing substation breakers shall not be allowed to exceed 100% of their interrupting capability. For new breaker installations, the Planning Engineer shall include an approximate 10% margin above the required fault interrupting current identified in system studies. PPL Planning coordinates with Engineering to ensure that anticipated continuous short circuit current and fault interrupting current from Planning analyses are within all respective facility and equipment ratings.

The following assumptions shall be included in the breaker evaluation:

- All existing generation in service
- The pre-fault voltage shall be one per unit, unless sufficient reason exists to use a higher value
- Breakers shall be evaluated with the system in its normally operated state (i.e. normally open switches open and normally closed switches closed)
- Both single-line-to-ground and three phase faults shall be evaluated

4.4 Stability Criteria

PJM performs stability analysis during the RTEP cycle on PPL EU's behalf according to the methodology and criteria outlined in PJM Manual 14B (Attachment G.1 through G.6 specifically focuses on PJM's stability criteria) to ensure that the planned system can withstand NERC TPL 001-5 criteria disturbances and maintain stable operation throughout the PJM planning horizon. In conjunction, PPL EU also performs in-house stability studies to ensure compliance with NERC TPL-001-5 criteria. Table 4.4-1 identifies the fault types studied for each contingency category.

Critical system conditions for stability analysis include light load and peak load scenarios. Typically, light load study scenarios are assessed to identify potential generator dynamic stability issues. In general, generators tend to be less stable when operating at maximum facility output and when taking MVArs off the power system. The tendency to have fewer units online coupled with lower load levels leads to both of these factors being present during light load scenarios. Peak load stability studies are generally conducted to assess wide-area power system stability issues such as frequency response and system voltage recovery.

In the Northeast Pennsylvania (NEPA) area, studies in the past have shown the potential for generator instability, particularly under light load conditions. As such, all RTEP cycle reliability assessments and PJM generation queue cycle assessments involving stability analyses in the PPL EU footprint must include, at least, a light load study scenario. Engineering judgment will be used to determine if and when peak load scenarios need to be assessed. The load levels studied shall include a load model which represents the expected dynamic behavior of study area loads during the condition being tested (e.g. hour 14 on a hot summer day to represent summer daytime peak load, hour 18 on a winter evening to represent the winter nighttime peak load, or hour 5 on a spring morning to represent minimum load conditions). For PPL EU, a CMLD[3] aggregate load model is used to represent the overall dynamic behavior of the load.

PPL EU's stability analysis ensures the dual objectives of stability of new interconnected projects and system-wide stability. These analyses ensure newly-connecting projects and changes to the system configuration maintain or improve the stability of the project and the system. Study of these projects throughout PPL EU provides a thorough, ongoing review at the project level and system-wide.

[3] CMLD- Composite load model- The dynamic load model being used to model the dynamic response of load in PPL-EU's area is the PSS/E composite load model (CMLD). The composite load model represents the dynamic response of the aggregate load behavior of motor loads (4 distinct types), discharge lighting, and electronic load.

Additionally, PPL EU stability studies may be performed for conditions other than generation additions or the RTEP annual assessment as deemed necessary. The results of the stability studies are used to determine:

- The effectiveness of alternative transmission plans
- The operating restrictions of a transmission configuration
- The required normal primary and backup clearing times
- The protective relay functional requirements

Additional equipment or precautions may be necessary to ensure that the system meets the bulk and non-bulk electric system planning criteria. Such system reinforcements may include protection system enhancements such as tripping by direct transfer trip (DTT), or installation of out-of-step relays to prevent unstable conditions.

<u>Stability Analysis System Representation</u>

The study area close to the unit or units of primary interest is represented in the greatest detail possible. This includes detailed representation of stability models for all machines and loads, and confirmation of the accuracy of the area transmission topology. Power factor of generation in the immediate area of study shall be given particular consideration. A load model which represents the expected dynamic behavior of loads (such as induction motors, etc.) that could impact the study area will be included. For PPL EU, a CMLD aggregate load model is used to represent the overall dynamic behavior of the load.

For machines away from the area of interest, detailed representation should be used on all units for which the information is available. Machine generator, exciter, and governor characteristics shall be obtained from PJM or the Generator Owner directly. If no functional models are available, estimated machine characteristics may be used. Small machines, in relation to the load on the same bus or directly adjacent, may be netted with the load.

<u>Stability Analysis Tests</u>

Stability fault analyses, as described in Table 4.4-1, are conducted during the course of typical PPL EU stability studies to identify stability reliability concerns that must be addressed.

Table 4.4-1
NERC TPL and PPL EU Contingencies Studied During Typical PPL EU Transmission Planning Stability Analyses[1]

Category	Initial Condition	Outage Event	Voltage Class Studied	Fault Type
P0: Normal System	Normal System	None	69 kV & above	None
P1 Single Contingency	Normal System	P1-1: Generator P1-2: Transmission Line P1-3: Transformer P1-4: Shunt Device	69 kV & above	3-phase Normal Clearing
P2 Single Contingency	Normal System	P2-2: Bus Section Fault	100 kV & above	SLG Normal Clearing
P3 Multiple Contingencies	One (P1-1) outage event followed by System Adjustments	P3-1: Generator P3-2: Transmission Line P3-3: Transformer P3-4: Shunt Device	100 kV & above	3-phase Normal Clearing
P4 Multiple Contingencies Due to Stuck Breaker during Initial Event	Normal System	P4-1: Generator & Stuck Breaker (Non-Bus Tie Breaker) P4-2: Transmission Line & Stuck Breaker (Non-Bus Tie Breaker) P4-3: Transformer & Stuck Breaker (Non-Bus Tie Breaker) P4-4: Shunt Device & Stuck Breaker (Non-Bus Tie Breaker) P4-5: Bus Section & Stuck Breaker (Non-Bus Tie Breaker) P4-6: Bus Section & Stuck Breaker (Bus Tie Breaker)	100 kV & above	SLG Delayed Clearing
P5 Multiple Contingencies Due to Relay Failure during Initial Event	Normal System	P5-1: Generator & Relay Failure (Non-Bus Tie Breaker) P5-2: Transmission Line & Relay Failure (Non-Bus Tie Breaker) P5-3: Transformer & Relay Failure (Non-Bus Tie Breaker) P5-4: Shunt Device & Relay Failure (Non-Bus Tie Breaker) P5-5: Bus Section & Relay Failure (Non-Bus Tie Breaker) P5-6: Bus Section & Relay Failure (Bus Tie Breaker)	100 kV & above	SLG Delayed Clearing
P6 Multiple Contingencies	One (P1-2, P1-3, or P1-4) outage event followed by System Adjustments	P6-1: Transmission Line P6-2: Transformer P6-3: Shunt Device	100 kV & above	3-phase Normal Clearing
P7 Multiple Contingencies Due to a DCT Event	Normal System	P7-1: Double-Circuit Transmission Line	100 kV & above	SLG Normal Clearing
NERC Extreme Events [2] Multiple Contingencies Due to Relay Failure during Initial Event	Normal System	E-Stability 2E-H: Transmission Element & Relay Failure	230 kV & above	3-phase Delayed Clearing

Note 1: PPL EU determines and implements upgrade solutions as necessary to resolve reliability concerns identified for the contingency types described in this table

Note 2: 3-phase delayed clearing events are not considered on lines that have dual pilot protection schemes

Acceptable damping is in accordance with PJM Manual 14B, Attachment G.

Judgment must be exercised in selecting the fault and its location because of the different types of bus and breaker arrangements in use. For example, a three-phase fault on one bus of a double-breaker or breaker-and-a-half arrangement is not as severe as a three-phase fault on one of the lines. However, a three-phase fault on the bus of a single bus-single breaker arrangement is more severe than a three phase fault on one of the lines.

The tests above shall be performed on the system at both peak and light load levels. Light load levels will be in alignment with the percentage of peak load PJM uses in their light load studies which is identified in PJM Manual 14B.

Less probable extreme contingency events are also tested at varying voltage classes and locations on the power system to determine the severity of the consequences. Such fault analyses typically include:

- Permanent three-phase fault with stuck breaker or other cause of delayed clearing (i.e. an extreme event version of a NERC TPL-001-4 P4 or P5 event).

- Permanent three-phase fault involving both circuits of a double circuit line with normal clearing and reclosing sequences, if applicable (i.e. an extreme event version of a NERC TPL-001-4 P7 event).

- Permanent three-phase fault on one line with an overtrip of another unfaulted line. Both the overtrip and clearing of the faulted line occur in normal primary clearing time. Reclosing sequences, if applicable, should be included.

If the consequences of these tests are severe and show significant adverse impact to BES system reliability, further tests are performed to determine potential mitigation alternatives, such as, but not limited to those noted below. PPL EU, at its own discretion, will determine if extreme event consequences warrant pursuit of upgrade solutions. The following potential solutions are examples of some options that will be considered, where appropriate, to resolve extreme event stability concerns:

- Independent pole tripping
- High speed breaker failure schemes
- High speed reclosing

Nuclear Stability Analysis Tests

Refer to PJM Manual 14B, Attachment G, Sections G.8 and G.9 for details on nuclear generation stability analysis testing.

Fault Clearing and Reclosing Times

Fault Clearing Times - The following nominal fault clearing times should be used in conducting studies:

PPL Fault Clearing Times		
Voltage Level	**Fault Condition**	**Stability Study Clearing Time (cycles)**
500 kV	Three phase or SLG fault w/ Normal Clearing - All relaying in service	3.5
	SLG fault w/ Delayed Clearing - Due to Failure of primary (Pilot) relaying	24.0
	SLG fault w/Delayed Clearing - Due to Stuck Breaker [1] (at Generating Stations)	12.0
	SLG fault w/Delayed Clearing - Due to Stuck Breaker [1] (at Non-Generating Stations)	14.0
	SLG fault at Bus Section w/ Delayed Clearing - Due to Stuck Breaker [1]	15.0
230 kV	Three phase or SLG fault w/ Normal Clearing - All relaying in service	5.0
	SLG fault w/ Delayed Clearing - Due to Failure of primary (Pilot) relaying	35.0
	SLG fault w/Delayed Clearing - Due to Stuck Breaker [1] (at Generating Stations)	13.0
	SLG fault w/Delayed Clearing - Due to Stuck Breaker [1] (at Non-Generating Stations)	17.0
	SLG fault at Bus Section w/ Delayed Clearing - Due to Stuck Breaker [1]	17.0
115 kV & 138 kV	Three phase or SLG fault w/ Normal Clearing - All relaying in service	5.5
	SLG fault w/ Delayed Clearing - Due to Failure of primary (Pilot) relaying	35.0
	SLG fault w/Delayed Clearing - Due to Stuck Breaker [1] (at Generating Stations)	15.0
	SLG fault w/Delayed Clearing - Due to Stuck Breaker [1] (at Non-Generating Stations)	17.5
	SLG fault at Bus Section w/ Delayed Clearing - Due to Stuck Breaker [1]	17.5
69 kV	Three phase or SLG fault w/ Normal Clearing - All relaying in service	7.5
	SLG fault w/ Delayed Clearing - Due to Failure of primary relaying	38.0
	SLG fault w/Delayed Clearing - Due to Stuck Breaker [1] (at Generating Stations)	38.0
	SLG fault w/Delayed Clearing - Due to Stuck Breaker [1] (at Non-Generating Stations)	38.0
	SLG fault at Bus Section w/ Delayed Clearing - Due to Stuck Breaker [1]	38.0

Note 1: The breaker failure clearing time equals the sum of the worst case local relay delay for a close-in bolted fault, the time to activate CB trip coil, the time delay to initiate breaker failure scheme (relay input debounce time), the breaker failure timer duration setting, the time delay to activate the adjacent circuit breaker's trip coil and the maximum adjacent breaker operate time. Local times are given. For Remote clearing times, assume an additional 1 cycle for DTT scheme operation.

The clearing times listed are nominal values applicable to the standard schemes initiated by various protective schemes and auxiliary relays and for various fault types and locations. If stability is a concern, tests should use actual clearing time settings. Alternate schemes may provide faster times for specific terminals and specific faults if the above times are inadequate.

Where tapped transformers are involved, the low side breaker clearing time is assumed to be the same as the high side breaker clearing time. Judgment must be used for the situation where a transformer connects two voltage levels with generators connected to each voltage level.

Reclosing Times -The following nominal reclosing times should be used in conducting studies:

Table 4.4-3: Relay Reclosing Times for PPL EU Transmission Substations

Station Type	Voltage Class	Terminal selected for right-of-way (R/W)[1, 4]	Follower Terminal [2, 4]
At Generating Stations	69 kV	10 seconds	12 seconds
	138 kV	10 seconds	12 seconds
	230 kV	10 seconds	12 seconds
	500 kV	10 seconds	12 seconds
At Non-Generating Stations[3]	69 kV	1.5 seconds	3 seconds
	138 kV	1.5 seconds	3 seconds
	230 kV	1.5 seconds	3 seconds
	500 kV	0.75 seconds	2.25 seconds

Footnotes for Table 4.4-3

[1] Terminal selected for right-of-way (R/W) – time for first terminal to close and test fault.

[2] Follower Terminal – times listed are from when the terminal trips until the transmission path is restored.

[3] Terminal remote from a generating station and all lines not connected to a generating station.

[4] The listed values are the immediate reclosing times (first reclose). Times listed are minimum reclosing times. Because of variations in the system, actual reclosing times may be longer than stated.

Out-of-Step Relaying - Connection of generation into a relatively weak transmission system can pose unique stability issues. With the ability of current stability programs to analyze transient (first swing) and dynamic (swings after first swing) response, such programs may predict unstable operation for disturbances on transmission facilities. The resulting analysis may require specific relaying to be equipped with "out-of-step" protective relay functions. These protective relay functions may include:

- Out-of-step tripping relays on the unit transformer
- Out-of-step blocking of high-speed, non-synchrocheck reclosing
- Out-of-step tripping and/or blocking of tripping to assure controlled separation in case of instability
- Relay characteristic load carrying capability to prevent tripping for severe but stable swing.

4.5 Load Loss Criteria

PJM’s Transmission Planning Criteria, “PJM Region Transmission Planning Process” (Manual 14B), specifies that it is not permissible to have a planned loss of load (consequential load loss + controlled load loss due to automatic schemes) in excess of 300 MW (excluding extreme events). In addition to the aforementioned PJM Load Loss criteria, the PPL EU Load Loss criteria described in table 4.5-1 are also applicable within the PPL EU service territory.

Table 4.5-1
PPL EU Networked Transmission Outage Event Maximum Load Loss Criteria [1]

Category	Initial Condition	Outage Event	BES Facility Outage Shall Not Result in More Than X MW of Consequential Load Loss and Shall Not Exceed Y MW of Non-Consequential Load Loss		Non-BES Networked Tariff Facilities Outage Shall Not Result in More Than X MW of Consequential Load Loss and Shall Not Exceed Y MW of Non-Consequential Load Loss	
			Consequential (X)	Non-Consequential (Y)	Consequential (X)	Non-Consequential (Y)
P0: Normal System	Normal System	None	0	0	0	0
P1 Single Contingency	Normal System	P1-1: Generator	300	0	300	0
		P1-2: Transmission Line	300	0	300	0
		P1-3: Transformer	300	0	300	0
		P1-4: Shunt Device	300	0	300	0
P2 Single Contingency	Normal System	P2-1: Opening of Line Section without a Fault	300	0 or 300 [2]	300	
		P2-2: Bus Section Fault	300	0 or 300 [2]	300	
P3 Multiple Contingencies	One (P1-1) outage event followed by System Adjustments	P3-1: Generator	300	0	300	0
		P3-2: Transmission Line	300	0	300	0
		P3-3: Transformer	300	0	300	0
		P3-4: Shunt Device	300	0	300	0
P4 Multiple Contingencies Due to Stuck Breaker during Initial Event	Normal System	P4-1: Generator & Stuck Breaker (Non-Bus Tie Breaker)	300	0 or 300 [2]	300	
		P4-2: Transmission Line & Stuck Breaker (Non-Bus Tie Breaker)	300	0 or 300 [2]	300	
		P4-3: Transformer & Stuck Breaker (Non-Bus Tie Breaker)	300	0 or 300 [2]	300	
		P4-4: Shunt Device & Stuck Breaker (Non-Bus Tie Breaker)	300	0 or 300 [2]	300	
		P4-5: Bus Section & Stuck Breaker (Non-Bus Tie Breaker)	300	0 or 300 [2]	300	
		P4-6: Bus Section & Stuck Breaker (Bus Tie Breaker)	300		300	
P6 Multiple Contingencies	One (P1-2, P1-3, or P1-4) outage event followed by System Adjustments	P6-1: Transmission Line	300		300	
		P6-2: Transformer	300		300	
		P6-3: Shunt Device	300		300	
P7 Multiple Contingencies Due to a DCT Event	Normal System	P7-1: Double-Circuit Transmission Line	300		300	

Note 1: The 300 MW load limit referenced in various cells in this table does not include load that is immediately restored via automatic switching to adjacent substations

Note 2: For NERC contingency types P2-2, P4-1, P4-2, P4-3, P4-4, and P4-5, if the outage event occurs on facilities above 300 kV, Non-Consequential Load-Loss must be 0 MW. If the outage event occurs on facilities at or below 300 kV, the maximum allowable Non-Consequential Load-Loss is 300 MW. Consequential plus Non-Consequential load loss shall not exceed 300 MW

4.6 End of Life Criteria

"End of life" is defined as the point at which infrastructure is at risk of failure, and continued maintenance and/or refurbishment of the infrastructure is no longer a valid option to extend the life of the facilities consistent with Good Utility Practice and PPL EU Transmission Planning Criteria. The infrastructure to be evaluated under this end-of-life criteria are all regional transmission lines operated at 500 kV and above.

The decision point of this criterion is based on:

Facility is nearing, or has already passed, its end of life:

- **Condition of the facility, taking into consideration**:
  - Industry recommendations on service life for the particular type of facility
  - The facility's performance history
  - Documented evidence indicating that the facility has reached the end of its useful service life
  - The facility's maintenance and expense history

- **Third-party assessment** - While not required, PPL EU has the option of seeking a third-party assessment of a facility to determine if industry specialists agree the facility has reached the end of its useful service life

This criterion mandates either replacing these facilities with in-kind infrastructure that meets current PPL EU standards or employing an alternative solution to ensure the PPL EU transmission system satisfies all applicable reliability criteria.

5.0 References

5.1 "PJM Region Transmission Planning Process" (M-14B)

5.2 "PJM New Services Request Process" (M-14A)

5.3 "PJM Transmission Operations" Manual (M-3)

5.4 PPL EU Rules For Electric Service (Tariff Rule 4D)

5.5 NERC TPL-001-4 Standard

5.6 NERC CIP-014-1 Standard

5.7 Susquehanna Nuclear NPIR (Revision 2)

5.8 "PJM Manual 39: Nuclear Plant Interface Coordination" (M-39)

6.0 Responsibilities

6.1 This document is under the control of the Manager – Transmission Planning.

7.0 Compliance and Regulatory Requirements

7.1 All PPL Electric Utilities Asset Management employees are expected to fully comply with this Practice which serves to ensure that PPL EU remains in compliance with NERC TPL-001-4.

7.2 The Transmission Planning Practice complies with and supports the PPL EU NERC Compliance Program. Revisions of this document should be reviewed with the PPL EU NERC Compliance Manager.

8.0 Record of Revisions

Revision History		
Prepared By:	Michael Mullin Michael Mullin Engineer II - Transmission Planning	
Reviewed By:	George Khoury George Khoury Supervisor - Transmission Planning	
Approved By:	Christopher Szmodis Christopher Szmodis Manager - Transmission Planning	
Revision	**Effective Date**	**Revision Comments**
6	6/1/2011	The “Reliability Principles & Practices” document was originally issued on 05/11/1971, and subsequently revised five times on 11/24/1975, 8/31/1984, 2/10/1989, 12/29/1995, and 1/31/2004. Records are not available that detail the various changes that were made to the document during each revision cycle. The contents of this document were originally part of those previous revisions, but now have been separated to create this stand-alone document. This latest revision has been labeled number 6.
7	4/1/2016	PPL EU Transmission Planning Criteria updated to align with new NERC TPL 001-4 Criteria.
8	4/1/2017	PPL EU Transmission Planning Criteria updated to include most recent clearing and reclosing times in Stability Criteria section along with additional clarity added on types of faults analyzed during PPL stability analyses. Review and update of outdated references and correction of minor typographical errors.

0	4/1/2018	New document number to eliminate conflicts with a similarly numbered internal PPL document. Rev history restarted at 0 as a result of document renumbering. Minor text and grammar edits / clean up. Simplified thermal and voltage criteria tables by combining rows that had similar information. Removed specific references to number of hours and replaced with "Emergency". Moved unity power factor requirement from high side to low side of load-serving transformers. Changed Delta V for PPL 69 kV to 8% when taps and capacitors locked. Modified PPL 69 kV min and max voltage magnitudes to match values in PJM Manual 3.
1	4/1/2019	Minor text and grammar edits / clean up. Updated stability clearing times table.
2	4/1/2020	Minor text and grammar edits / clean up. Remove 7% NEPA margin paragraph since there is no longer a single NEPA interface limit value in PJM Manual 3. Remove Note 3 from Table 4.1-1. Remove Note 4 from Table 4.2-2. Remove 3PH breaker failures from Table 4.4-1.
3	4/1/2021	Updated Table 3-1, 4.1-1, and 4.2-2 to note that P2-1 events are not applicable on PPL EU Non-BES
4	4/1/2022	Minor edits to add clarity on PPL planning process. Updated Table 1-1 Note 6, and Table 3-1 Note 3 regarding the treatment of extreme events. Updated stability section discussion on dynamic load models to reflect use of CMLD load model.
5	4/1/2023	Minor edits to add clarity on PPL planning process. Updated section 4.4 Stability Criteria for further clarification on why stability analysis should be performed in different conditions and when stability analysis should be performed.
6	4/1/2024	Minor edits to add clarity on PPL planning process.
7	12/15/2024	Added section 4.6 - End of Life Criteria. Added note 2 to table 4.1-1 to match table 4.2-2.