East Kentucky Power Cooperative
(EKPC)

Transmission System Planning Criteria

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Section 1
Overview and General Discussion

The primary purpose of East Kentucky Power Cooperative's (EKPC's) transmission system is to reliably transmit electrical energy from its available generating resources to customers served by its transmission system. Interconnections have been established with other utilities to increase the reliability of the EKPC transmission system, and to provide EKPC customers access to other economic and/or emergency generating resources.

EKPC is a member of the PJM Interconnection Regional Transmission Organization (RTO). EKPC subscribes to and designs it's bulk electric system (BES) and all non-BES PJM monitored facilities to comply with the reliability principles and responsibilities set forth by PJM.

EKPC subscribes to and designs its transmission system to conform to the fundamental characteristics of a reliable interconnected bulk electric system required by the North American Electric Reliability Council (NERC). Additionally, EKPC is a member of the SERC Reliability Corporation (SERC) and subscribes to and designs its transmission system to comply with the reliability principles and responsibilities set forth by SERC.

The Federal Energy Regulatory Commission (FERC) requires all transmission providers that own, operate, or control facilities used for transmitting electric energy in interstate commerce to have on file open access non-discriminatory transmission tariffs. PJM has these tariffs on file on behalf of its transmission-owning members to provide firm and non-firm point-to-point transmission service to other entities, as well as firm network service.

The American National Standards Institute (ANSI), The Institute of Electrical and Electronic Engineers, Inc (IEEE), and The Rural Utilities Services (RUS) all publish standards for power system equipment design and application. EKPC incorporates these standards in the design and application of equipment utilized on its transmission system.

The NERC, SERC and PJM standards and requirements previously referred to above are discussed in Section 2. The EKPC Planning Criteria is presented in Section 3.

Section 2
NERC, SERC and PJM Reliability Standards

NERC in its Reliability Standards states the fundamental requirements for planning reliable interconnected bulk electric systems and the required actions or system performance necessary to comply. The Regions (EKPC is a member of SERC), Subregions, Power Pools, and their members have the responsibility to develop their own appropriate planning criteria and/or guides that are based on the NERC Reliability Standards.

EKPC is a member of PJM. PJM conducts a comprehensive assessment of the ability of the PJM system to meet all applicable reliability planning criteria. Annually, PJM performs comprehensive power flow, short circuit and stability analyses as part of its Regional Transmission Expansion Planning (RTEP) process. This set of analyses assesses the impacts of forecasted firm loads, firm imports from and exports to neighboring systems, existing generation and transmission assets, and anticipated new generation and transmission facilities. The criteria PJM uses in developing the RTEP is set forth in PJM Manual 14B – PJM Region Transmission Planning Process.

Section 3
EKPC Transmission System Planning Criteria

3.1 Overview

As a Transmission Owner (TO), EKPC's planning criteria can impose more stringent standards on its analyses than PJM, NERC, or SERC. These standards often arise to address specific system conditions. TO and PJM planning standards are important to RTEP analyses to supplement and enhance NERC criteria. NERC requires PJM and the TO to specify the critical system conditions to be tested.

In general, EKPC's transmission system is planned to withstand forced outages of generators and transmission facilities, individually and combined. Table 1 describes the contingencies and measurements EKPC utilizes in testing and assessing the performance of its transmission system

For all testing conditions, stability of the network should be maintained, and cascading outages should not occur. Specific modeling considerations are adhered to as part of the testing conditions, and are discussed in Section 3.3.

Table 1: Transmission Planning Contingencies and Measurements

Contingencies[1]	Facility Ratings	Min. Volt Level[2] (P.U.)	Max. Volt Level (P.U.)	Curtail Demand and/or Transfers
None(Base Case)	Normal	0.940	1.060	no
Extreme load due to unusual weather.[3]	Emergency[8]	0.925	1.060	no
Outage of a generator, transmission circuit, or transformer.[4]	Emergency	0.900	1.060	no
Outage of two (2) generators.	Emergency	0.900	1.060	no
Outage of a generator and a transmission circuit or transformer.	Emergency	0.900	1.060	no
Outage of a bus section or a circuit breaker.[5]	Emergency	0.900	1.060	yes
Outage of two (2) transmission circuits.	Emergency	0.900	1.060	yes
Outage of a transmission circuit and a transformer.	Emergency	0.900	1.060	yes
Outage of two (2) transformers.	Emergency	0.900	1.060	yes
Outage of a multiple circuit tower line.[6]	Emergency	0.900	1.060	no
Outage of a generator, transmission circuit, transformer, or bus section.[7]	Emergency	0.900	1.060	yes

[1] All contingencies (except as noted) are single line to ground or 3-phase faults with normal clearing. For all testing conditions, network stability should be maintained and cascading should not occur.

[2] Measured at the high side of the distribution transformer.

[3] Based on a 10% probability load forecast. Fault conditions do not apply.

[4] Includes outages which do not result from a fault.

[5] Single line to ground fault with normal clearing.

[6] Non 3-phase fault, with normal clearing.

[7] Single line to ground fault, with delayed clearing.

[8] Ratings based on the same ambient temperature as the load level based on a 10% probability load forecast.

3.2 Plant Voltage Schedules

For major power plants, the voltage level at the low side of the generator step up transformer (GSU) should be maintained at nominal generator terminal voltage with normal generation and normal transmission system conditions as follows:

Plant Name	Unit Name and Nominal Voltage	Scheduled Voltage (kV)	Scheduled Voltage (Per Unit)
H. L. Spurlock	Unit #1 – 22 kV	22.0	1.000
H. L. Spurlock	Unit #2 – 22 kV	22.0	1.000
H. L. Spurlock	Unit #3 – 18 kV	18.0	1.000
H. L. Spurlock	Unit #4 – 18 kV	18.0	1.000
J. S. Cooper	Unit #1 – 13.8 kV	13.8	1.000
J. S. Cooper	Unit #2 – 20.0 kV	20.0	1.000
W. C. Dale	Unit #3 – 13.8 kV	13.8	1.000
W. C. Dale	Unit #4 – 13.8 kV	13.8	1.000
J. K. Smith	Units #1-#7 – 13.8 kV	13.8	1.000
J. K. Smith	Unit #9-#10 – 13.8 kV	13.8	1.000
Bluegrass C.T.	Unit #1 – 18kV	18.0	1.000
Bluegrass C.T.	Unit #2 – 18kV	18.0	1.000
Bluegrass C.T.	Unit #2 – 18kV	18.0	1.000

3.3 Modeling Considerations

Replacement generation required to offset generating unit outages should be simulated first from all available internal resources. If internal resources are not available or are exhausted, then replacement generation should be simulated from the most restrictive of interconnected companies (PJM or TVA).

A single outage may include multiple transmission components in the common zone of relay protection.

Post-fault conditions and conditions after load restoration should be evaluated. Post-contingency operator initiated actions to restore load service must be simulated. Load that is off-line as a result of the contingency being evaluated may be switched to alternate sources during the restoration process; however, load should not be taken off-line to perform switching.

Transmission capacitor status (on/off) should be simulated consistent with existing automatic voltage control (on/off) settings and operating practice during normal transmission system conditions. Manual on-line switching of capacitors during normal conditions can be simulated provided it is consistent with existing operational practice; however, manual switching should not be simulated following a contingency to eliminate low voltage conditions. The system will be analyzed with all capacitor banks that would normally be on based on automatic voltage control settings to determine if potential voltage collapse conditions would exist post-contingency without any additional capacitor banks switching. System reinforcements will be implemented if system voltages fall below 85% of nominal for these post-contingency conditions.

Addition of transmission capacitor banks to the transmission system will be restricted such that no more than one transmission capacitor bank is installed on a transmission circuit.

The following operational procedures should be avoided:

1) Seasonal adjustment(s) of fixed taps on transmission transformers to control voltage(s) within acceptable ranges.
2) Switching HV and EHV system facilities out of service to reduce off-peak voltage(s).

3.4 Reliability Criteria

Customer Interruptions - Customer interruptions may occur due to an outage of a subtransmission circuit or a distribution substation transformer. To minimize the time and number of customers affected by a single contingency outage, the following criteria should be applied:

(a) Spare Distribution Transformer - To provide for the failure of a distribution substation transformer, a spare transformer should be maintained and available for installation at the affected substation within 10 hours.

(b) Spare Transmission Transformers – To provide for the failure of transmission autotransformers, a spare transformer should be maintained for each voltage class – i.e. 345/138 kV, 161/138 kV, 161/69 kV, 138/69 kV.

(c) Distribution Substation Supply - Transmission radial supply to a distribution substation is acceptable provided that the tap "load-exposure" index, TE, does not exceed 100 MW-miles. When this index is exceeded, multiple source supply should be considered to reduce this index below 100 MW-miles if other system problems are also expected.

(d) Subtransmission Circuit - The circuit "load-exposure" index, CE, should not exceed 2400 MW-miles. When this index is exceeded, solutions to reduce the index should be considered if other system problems are also expected.

Additionally, EKPC's Reliability group evaluates the transmission system based on the past five year outage history to identify the most significant transmission reliability issues. This criterion is based on number of outages, annual outage duration and System Average Interruption Duration Index (SAIDI) impacts.

3.5 Load Level

Future transmission facility requirements should be determined using power flow base cases which model coincident individual substation peak demands (summer and winter) forecasted on a normal weather basis. Future transmission facility requirements should also be determined using summer and winter load flow base cases simulating a 10% probability severe weather load forecast. A severe weather load flow case will be considered in itself as an abnormal system planning condition – i.e., the system will not be designed for contingencies in conjunction with the extreme load levels.

3.6 Facility Rating Methodology

EKPC designs its transmission system to adhere to the EKPC Facility Rating Methodology. For general planning purposes summer ratings are based on a summer peak load coincident ambient temperature of 95°F and winter ratings are based on a winter peak load coincident ambient temperature of 14°F.