Implementation of the NPIR for Planning Analysis

PJM is required to incorporate the Nuclear Plant Interface Requirements (NPIRs) into its planning processes according to the applicable NERC standards. PJM performs these planning analyses consistent with the NPIR planning requirements and its Regional Transmission Planning requirements. PJM Manuals 14B and 39 are the two principal sources that document these requirements, among various other planning and operating process business rules. It the responsibility of the Planning engineer to monitor changes to the planning requirements contained in the NPIR source documents (kept in confidence by PJM System Operating) and Manual 39 and to update this manual to reflect changes as appropriate per the protocols of Manual 39 section 3.1.

The following material are the excerpted planning requirements and criteria contained in the NPIR's that must be incorporated into PJM Planning analyses. This material must only be changed to be consistent with the source documents.

Braidwood Station, Units 1 and 2 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: Periodic analysis of the expected Braidwood switchyard voltages following a unit trip (Unit 1 or 2) shall be performed for various transmission system load levels and contingencies based on the study template provided by Exelon Nuclear. Exelon Nuclear will periodically request these studies from the ComEd transmission entity on a periodic basis to support compliance with GDC 17. The results of the studies are to be provided to Exelon Nuclear by the ComEd Transmission Entity.

PJM Planning and Operations transmission studies shall incorporate the Braidwood voltage and stability requirements that follow. Exelon Nuclear shall be notified by the Planning Authority if planning study results identify that the Braidwood requirements are not met by current or future system configurations, load levels, and contingencies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for Braidwood and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following Braidwood requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements:

The Braidwood Voltage Operating Limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level, are as follows:

345kV: Normal Low (actual voltage evaluations) – 349.2kV (1.0122)

Emergency Low (contingency voltage evaluations) – 349.2kV (1.0122)

Note:

a. The limits above are applicable for Braidwood Units 1 and 2. It is acceptable that the Normal Low limit be conservatively adjusted upward by .1kV to allow for design limitations of the transmission entity state estimators. Some state estimator designs do not allow a Normal Low limit and an Emergency Low limit to be the same value.

b. For the purposes of the planning studies only the Braidwood unit trip contingency voltage limit requires evaluation. Other transmission system contingencies do not require evaluation.

Stability:

Braidwood generating units 1 and 2 are to be stable for the following conditions (the following are included in PJM standard stability testing):

a. A three-phase line fault with normal clearing of the line protective systems.
b. A phase-to-ground fault with abnormal (delayed) clearing involving the failure of a relay or circuit breaker.
c. A double line tower fault.

Exelon Nuclear shall be notified by the Planning Authority if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if the system stability studies pertinent to the Braidwood generators, the Braidwood switchyard, or the lines connecting the Braidwood switchyard to the transmission system indicate that stability requirements contained in the PJM, NERC or ComEd Transmission Entity standards are not met.

Byron Station, Units 1 and 2 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: Periodic analysis of the expected Byron switchyard voltages following a unit trip (Unit 1 or 2) shall be performed for various transmission system load levels and contingencies based on the study template provided by Exelon Nuclear. Exelon Nuclear will periodically request these studies from the ComEd transmission entity on a periodic basis to support compliance with GDC 17. The results of the studies are to be provided to Exelon Nuclear by the ComEd Transmission Entity.

PJM Planning and Operations transmission studies shall incorporate the Byron voltage and stability requirements that follow. Exelon Nuclear shall be notified by the Planning Authority if planning study results identify that the Byron requirements are not met by current or future system configurations, load levels, and contingencies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for Byron and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following Byron requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements:

The Byron Voltage Operating Limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level, are as follows:

345kV: Normal Low (actual voltage evaluations) – 341.0kV (.9885 pu)
Emergency Low (contingency voltage evaluations) – 341.0kV (.9885 pu)

Notes:

a. The limits above are applicable for Byron Units 1 and 2. It is acceptable that the Normal Low limit be conservatively adjusted upward by .1kV to allow for design limitations of the transmission entity state estimators. Some state estimator designs do not allow a Normal Low limit and an Emergency Low limit to be the same value.

b. For the purposes of the planning studies only the Byron unit trip contingency voltage limit requires evaluation. Other transmission system contingencies do not require evaluation.

Stability:

Byron generating units 1 and 2 are to be stable for the following conditions (the following are included in PJM standard stability testing):

a. A three-phase line fault with normal clearing of the line protective systems.
b. A phase-to-ground fault with abnormal (delayed) clearing involving the failure of a relay or circuit breaker.
c. A double line tower fault.

Exelon Nuclear shall be notified by the Planning Authority if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if the system stability studies pertinent to the Byron generators, the Byron switchyard, or the lines connecting the Byron switchyard to the transmission system indicate that stability requirements contained in the PJM, NERC or ComEd Transmission Entity standards are not met.

LaSalle Station, Units 1 and 2 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: Periodic analysis of the expected LaSalle Station switchyard voltages following a unit trip (Unit 1 or 2) shall be performed for various transmission system load levels and contingencies based on a study template provided by Exelon Nuclear. Exelon Nuclear will periodically request these studies from the ComEd Transmission Entity on a periodic basis to support compliance with GDC 17. The results of the studies are to be provided to Exelon Nuclear by the ComEd Transmission Entity.

PJM Planning and Operations transmission studies shall incorporate the LaSalle voltage and stability requirements that follow. Exelon Nuclear shall be notified by the Planning Authority if planning study results identify that the LaSalle requirements are not met by current or future system configurations, load levels, and contingencies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for LaSalle and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following LaSalle requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements:

The LaSalle Voltage Operating Limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level, are as follows:

345 kV: Normal low (actual voltage evaluations) – 353.0 kV (1.0232 pu)
Emergency Low (contingency voltage evaluations) – 353.0 kV (1.0232 pu)

Note:

a. The limits above are applicable for LaSalle Units 1 and 2. It is acceptable that the Normal Low limit be conservatively adjusted upward by .1kV to allow for design limitations of the transmission entity state estimators. Some state estimator designs do not allow a Normal Low limit and an Emergency Low limit to be the same value.

b. For the purposes of the planning studies only the LaSalle unit trip contingency voltage limit requires evaluation. Other transmission system contingencies do not require evaluation.

Stability:

LaSalle generating units 1 and 2 are to be stable for the following conditions (the following are included in PJM standard stability testing):

a. A three-phase line fault with normal clearing of the line protective systems.
b. A phase-to-ground fault with normal clearing and with abnormal (delayed) clearing involving the failure of a relay or circuit breaker.
c. A double line tower fault.

d. A phase-to-ground fault during planned transmission line maintenance outages

Exelon Nuclear shall be notified by the Planning Authority if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if the system stability studies pertinent to the LaSalle generators, the LaSalle switchyard, or the lines connecting the LaSalle switchyard to the transmission system indicate that stability requirements contained in the PJM, NERC or ComEd Transmission Entity standards are not met.

Quad Cities Nuclear Power Station Units 1 and 2 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: Periodic analysis of the expected Quad Cities switchyard voltages following a unit trip (Unit 1 or 2) shall be performed for various transmission system load levels and contingencies based on the study template provided by Exelon Nuclear. Exelon Nuclear will periodically request these studies from the ComEd Transmission Entity to support compliance with GDC 17. The results of the studies are to be provided to Exelon Nuclear by the ComEd Transmission Entity.

PJM Planning and Operations transmission studies shall incorporate the Quad Cities voltage and stability requirements that follow. Exelon Nuclear shall be notified by the Planning Authority if planning study results identify that the Quad Cities requirements are not met by current or future system configurations, load levels, and contingencies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for Quad Cities and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following Quad Cities requirements shall be utilized for the planning studies.

Voltage and Offsite Source Load Capacity Requirements:

The Quad Cities Voltage Operating Limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level, are as follows:

345kV: Normal Low (actual voltage evaluations) – 348.2 kV (1.0093 pu)
Emergency Low (contingency voltage evaluations) – 348.2 kV (1.0093 pu)

Note:

a. The limits above are applicable for Quad Cities Units 1 and 2.
b. For the purposes of the planning studies only the Quad Cities unit trip contingency voltage limit requires evaluation. Other transmission system contingencies do not require evaluation.
c.

Power flow and Stability Testing:

The following design requirements of the Quad Cities UFSAR are to be annually verified through the battery of transmission tests performed by PJM and ComEd. All of the Quad Cities requirements are embodied in the standard NERC, PJM and ComEd transmission criteria applied during PJM and ComEd studies related to the Regional Transmission Expansion Plan and generation interconnections. These tests ensure the Quad Cities and ComEd system are in compliance with the applicable criteria.

The transmission system is designed to withstand the sudden outage of large amounts of generating capacity. The system shall be designed to compensate for the simultaneous loss of any two generating units and maintain all transmission network flows within short term emergency limits, and all 345kV and 138kV voltages within steady state limits. This is required at all load levels up to the 50/50 load forecast. PJM testing examines the non-simultaneous outage of any two units. ComEd testing examines the most critical combination of simultaneous outages of two units.

Quad Cities Station and the transmission system is designed for stability and circuit isolation that will prevent the sudden loss of one unit at Quad Cities from causing the second unit to trip. This is confirmed by power flow and stability studies. The system shall be stable for situations involving a three phase fault on the most critical generating element with normal clearing, or a three phase fault on the most critical generating element with delayed clearing, or the loss of the most critical single facility with no fault.

Assuming one or both of the Quad Cities units are tripped when carrying full load, the high voltage

lines at the station will continue to be energized from the transmission system. The transmission system shall be designed to withstand the outage of any one generator and maintain all network flows within emergency ratings (up to 50/50 load) or short term emergency ratings (up to 90/10 load).

Exelon Nuclear shall be notified by the Planning Authority (PJM) if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if the system stability studies pertinent to the Quad Cities generators, the Quad Cities switchyard, or the lines connecting the Quad Cities switchyard to the transmission system indicate that stability requirements contained in the PJM, NERC or ComEd Transmission Entity standards are not met.

Dresden Units 2 and 3 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: Periodic analysis of the expected Dresden Station switchyard voltages following a unit trip (Unit 2 or 3) shall be performed for various transmission system load levels and contingencies based on a study template provided by Exelon Nuclear. Exelon Nuclear will periodically request these studies from the ComEd Transmission Entity on a periodic basis to support compliance with GDC 17. The results of the studies are to be provided to Exelon Nuclear by the ComEd Transmission Entity.

PJM Planning and Operations transmission studies shall incorporate the Dresden voltage and stability requirements that follow. Exelon Nuclear shall be notified by the Planning Authority if planning study results identify that the Dresden requirements are not met by current or future system configurations, load levels, and contingencies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for Dresden and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following Dresden requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements:

The Dresden Voltage Operating Limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level, are as follows:

345 kV: Dresden Unit 2 (Blue Bus);
Normal low (actual voltage evaluations) – 332.9 kV (0.9650 pu) with Tr 86 LTC in auto, 346.2 kV (1.0035 pu) with Tr 86 LTC in manual
Emergency Low (contingency voltage evaluations) – 332.9 kV (0.9650 pu) with Tr 86 LTC in auto, 346.2 kV (1.0035 pu) with Tr 86 LTC in manual

345 kV: Dresden Unit 3 (Red Bus);
Normal low (actual voltage evaluations) – 338.8 kV (0.9821 pu) with RAT 32 LTC in auto, 345.3 kV (1.0009 pu) with RAT 32 LTC in manual
Emergency Low (contingency voltage evaluations) – 338.8 kV (0.9821 pu) with RAT 32 LTC in auto, 345.3 kV (1.0009 pu) with RAT 32 LTC in manual

Note: For the purposes of the planning studies only the Dresden unit trip contingency voltage limit requires evaluation. Other transmission system contingencies do not require evaluation.

Stability:

Dresden generating units 2 and 3 are to be stable for the following conditions (the following are included in PJM standard stability testing):

a. A three-phase fault on any transmission or generation element with normal clearing of the protective systems.
b. A three-phase fault on any transmission or generation element with abnormal (delayed) clearing involving the failure of a relay or circuit breaker. The fault is cleared in delayed time by back-up equipment. If the protective device which fails to operate is an independent pole operated (IPO) breaker, only one phase will be assumed to fail to clear in the primary clearing attempt which will leave only a single phase fault during the delayed clearing time. Mitigation for unstable scenarios may include generator tripping.
c. A three phase fault on any transmission or generation element accompanied by the failure of a special protection scheme to detect, clear, or properly respond to the fault. The fault is cleared in delayed time by back-up equipment, or the special protection scheme may fail to operate as designed. Mitigation for unstable scenarios may include generator tripping.
d. A three phase fault on all transmission lines installed on a multiple circuit tower. No relay or circuit breaker failure is assumed for this contingency.
e. A three phase fault on any transmission or generation element during the scheduled outage of any other transmission or generation element. No relay, circuit breaker, or special protection scheme failure is assumed for this contingency. Mitigation for unstable scenarios may include generator tripping.

Exelon Nuclear shall be notified by the Planning Authority if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if the system stability studies pertinent to the Dresden generators, the Dresden switchyard, or the lines connecting the Dresden switchyard to the transmission system indicate that stability requirements contained in the PJM, NERC or ComEd Transmission Entity standards are not met.

Oyster Creek Unit 01 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: (FirstEnergy responsibility) Periodic analysis of the expected station switchyard voltages following a unit trip shall be performed for various transmission system load levels and contingencies to support station compliance with GDC 17. The bulk transmission system must be examined for performance during system disturbances; using normal case load flows, transient stability studies, and post-transient load flow studies. The studies are to confirm that the system performs adequately for the predicted worst case single contingency (one line or other failure) on the bulk transmission system with normal system adjustments, followed by the loss of the Oyster Creek generator. For these conditions, the studies must confirm that there was no loss of load in the system, the Oyster Creek 230kV substation is not interrupted, and a predicted minimum grid (substation) voltage is determined . Once per year any changes made to the transmission system that would affect voltage stability at Oyster Creek must be reviewed and if necessary, a new value for the minimum expected/predicted grid voltage is to be provided to Exelon Nuclear. Results of the studies are to be provided to Exelon Nuclear.

Transmission Planning studies (PJM responsibility) shall incorporate the voltage and stability requirements of the station. These studies shall include those performed for Operations and for future transmission and generation interconnection. Exelon Nuclear shall be notified if planning study results identify that the station requirements are not met by current or future system configurations, load levels, and contingencies. The following station requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements:

The Oyster Creek voltage limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level, are as follows:

	230kV Oyster Creek Switchyard Voltage
Normal Low (actual voltage evaluations)	227kV (0.9869 p.u.)
Emergency Low (contingency voltage evaluations)	223.7kV (0.9726 p.u)

Note: For the purposes of the planning studies only the Oyster Creek unit trip contingency voltage limit requires evaluation. Other transmission system contingencies do not require evaluation.

Planning assessments enforce nuclear voltage criteria at the Transmission System level, including any voltage drop criteria. Criteria are enforced on a post-contingency basis without system adjustments but allowing generation reactive supply within normal reactive limits, except as may be explicitly noted below.

Oyster Creek system normal (reference case conditions) 230 kV low voltage limit is 227 kV (.987 pu) and, under contingency conditions it is 223.7 kV (.973 pu). In addition, frequency will be monitored for all studied contingencies and verified to be maintained above 57.5 Hz.

Stability Requirements:

The system shall remain stable and perform within voltage and other applicable criteria following:

1. A 3 phase fault with primary clearing on the most critical of the 230 kV lines emanating from Oyster Creek. (standard PJM test)

2. A 3 phase fault with primary clearing on the most critical of the 34.5 kV lines emanating from Oyster Creek. (standard PJM test applied to lower voltage than PJM's standard testing)

3. A 1 phase fault on the most critical of the two 230 kV lines emanating from Oyster Creek, followed by a stuck breaker and clearing in backup clearing time. (standard PJM test)

4. The simultaneous loss of the Oyster Creek generating unit and the largest generating unit in New Jersey (Salem Unit 2) with no faults. (not part of standard testing)

5. 3 phase close-in fault on the most critical 230 kV and above lines from the station (double circuit tower outage, specifically both Manitou-Oyster Creek lines) and loss of the Oyster Creek generator (verify Oyster Creek unit trips based on out-of-step relay protection), (standard PJM test)

Exelon Nuclear shall be notified by the Planning Authority if the results of system stability studies identify that any of the stability requirements discussed above are not met.

Three Mile Island Unit 1 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: (FirstEnergy responsibility) Periodic analysis of the expected Station switchyard voltages following a unit trip shall be performed for various transmission system load levels and contingencies to support Station compliance with GDC 17. The bulk transmission system must be examined for performance during system disturbances; using normal case load flows, transient stability studies, and post-transient load flow studies. The studies are to confirm that the system performs adequately for the predicted worst case single contingency (one line or other failure) on the bulk transmission system with normal system adjustments, followed by the loss of the TMI generator. For these conditions, the studies must confirm that there was no loss of load in the system, the TMI 230kV substation is not interrupted, and a predicted minimum grid (substation) voltage is determined . Once per year any changes made to the transmission system that would affect voltage stability at TMI must be reviewed and if necessary, a new value for the minimum expected/predicted grid voltage is to be provided to Exelon Nuclear. Results of the studies are to be provided to Exelon Nuclear.

Transmission Planning studies (PJM responsibility) shall incorporate the voltage and stability requirements of the Station. These studies shall include those performed for Operations and for future transmission and generation interconnection. Exelon Nuclear shall be notified if planning study results identify that the Station requirements are not met by current or future system configurations, load levels, and contingencies. The following Station requirements shall be utilized for the planning studies:

Voltage:

The TMI Station voltage limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level, are as follows:

	2 Auxiliary Transformer Operation	Single Auxiliary Transformer Operation	Manual Load Tap Changer Operation
Normal Low	223 (0.9710 pu)	223 (0.9710 pu)	223 (0.9710 pu)
Emergency Low	223 (0.9710 pu)	223 (0.9710 pu)	223 (0.9710 pu)

Planning assessments enforce nuclear voltage criteria at the Transmission System level, including any voltage drop criteria. Criteria are enforced on a system normal and post-contingency basis after allowance for full system adjustments that can be available within 30 minutes following a disturbance.

Stability:

Three Mile Island generating unit stability is to be analyzed according to the applicable NERC, Regional Entities of NERC, and PJM criteria for transient stability.

Exelon Nuclear shall be notified if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if the system stability studies pertinent to the TMI generator, the TMI switchyard, or the lines connecting the TMI switchyard to the transmission system indicate that any of the stability requirements are not met.

Limerick Generating Station Units 1 and 2 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: Periodic analysis of the expected Limerick switchyard voltages following a unit trip (Unit 1 or 2) shall be performed for various transmission system load levels and contingencies based on the study template provided by Exelon Nuclear. Exelon Nuclear will periodically request these studies from the PECO Transmission Entity to support compliance with NRC licensing commitments for Limerick. The results of the studies are to be provided to Exelon Nuclear by the PECO Transmission Entity.

PJM Planning and Operations transmission studies shall incorporate the Limerick voltage and stability requirements that follow. Exelon Nuclear shall be notified by the Planning Authority if planning study results identify that the Limerick requirements are not met by current or future system configurations, load levels, and contingencies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for Limerick and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following Limerick requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements:

The Limerick Voltage Operating Limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level are as follows:

230kV: Normal Low (actual voltage evaluations) – 225kV (.9783 p.u.)

Emergency Low (contingency voltage evaluations) – 225kV (.9783 p.u.)

Voltage drop: 2.5% (Post contingency voltage drop limit to be applied for a contingency trip of Limerick Unit 1 or Unit 2).

500kV: Normal Low (actual voltage evaluations) – 500kV (1.0 p.u.)

Emergency Low (contingency voltage evaluations) – 500kV (1.0 p.u.)

Voltage drop: 2.5% (Post contingency voltage drop limit to be applied for a contingency trip of Limerick Unit 1 or Unit 2).

69kV: Normal Low (actual voltage evaluations) – 67.5kV (.9783 p.u.)
Voltage drop: 3.4% (Post contingency voltage drop limit to be applied for a contingency trip of Limerick Unit 1 or Unit 2).

Note: The 69kV voltage limits are to be activated when notification is received from Exelon Nuclear that the Limerick 69kV source is in operation.

Note: For the purposes of the planning studies only the Limerick unit trip contingency voltage limit requires evaluation. Other transmission system contingencies do not require evaluation.

Stability Requirements:

Limerick Generating Station (LGS) Units 1 and 2 are to be stable for the following conditions:

a. A three-phase fault on any single 500 kV or 230 kV circuit terminating in the Limerick 500kV or 230kV switchyards that is cleared by primary protective equipment (standard PJM test.)
b. A three-phase fault on any single 500 kV or 230 kV circuit terminating in the Limerick 500kV or 230kV switchyards, where the most critical LGS circuit breaker fails to open and the fault is cleared at LGS by backup protective equipment. (beyond standard PJM testing.)
c. A three-phase fault on the transformer connecting the LGS 500 kV and 230 kV buses that is cleared by primary protective equipment (standard PJM test.)
d. A three-phase fault on the transformer connecting the LGS 500 kV and 230 kV buses, where the most critical circuit breaker fails to open and the fault is cleared at LGS by backup protective equipment. (beyond standard PJM testing.)
e. Simultaneous three-phase faults on both LGS to Whitpain 500 kV circuits that are cleared by primary protective equipment (beyond standard PJM testing.)

In addition, The transmission system shall remain stable for the following three cases with either one or both LGS units in service. (All the following are beyond standard PJM testing):

a. Loss of the largest generating station (i.e., loss of Peach Bottom Atomic Power Station (PBAPS) Units 2 and 3) (No faults applied).
b. Loss of the largest load (No faults applied).
c. Loss of the most critical right-of-way (i.e., four simultaneous three-phase faults on the four transmission lines on the 130-30 right-of-way):

1. Cromby-Perkiomen (130-30) 138 kV Line
2. Cromby-Upper Providence (220-62) 230 kV Line
3. Limerick-Whitpain (5030) 500kV Line
4. Limerick-Whitpain (5031) 500kV Line

Exelon Nuclear shall be notified by the Planning Authority if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if PJM system stability studies pertinent to the Limerick generators, the Limerick switchyards, or the lines connecting the Limerick switchyards to the transmission system indicate that any of the stability requirements contained in the PJM, NERC or PECO Transmission Entity standards are not met.

Peach Bottom Station Units 2 and 3 Planning Requirements

Nuclear Plant Voltage Adequacy Studies:

Periodic analysis of the expected Peach Bottom offsite power source voltages following a unit trip (Unit 2 or 3) shall be performed for various transmission system load levels and contingencies based on a study template provided by Exelon Nuclear. Exelon Nuclear will periodically request these studies from the PECO Transmission Entity to support compliance with NRC licensing commitments for Peach Bottom. The results of the studies are to be provided to Exelon Nuclear by the PECO Transmission Entity.

PJM Planning and Operations transmission studies shall incorporate the Peach Bottom voltage and stability requirements that follow. Exelon Nuclear shall be notified by the Planning Authority if planning study results identify that the Peach Bottom requirements are not met by current or future system configurations, load levels, and contingencies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for Peach Bottom and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following Peach Bottom requirements shall be utilized for the planning studies:

Voltage and Offsite Source Load Capacity Requirements:

The Peach Bottom Station Voltage Operating Limits, which are based upon internal plant limitations reflected at the transmission system voltage limit level are as follows:

2SU: (Peach Bottom Tap on 220-08 line)

Normal Low (actual voltage conditions)- 225kV (.9783 p.u.)

Emergency Low (contingency voltage conditions)- 225kV (.9783 p.u.)

Voltage Drop: 1.8% (Post contingency voltage drop limit to be applied for a contingency trip of Peach Bottom Unit 2 or 3).

Maximum- 242kV (1.05 p.u.)

343SU: (Peach Bottom 230kV; Peach Bottom terminal of 220-34 line)

Normal Low (actual voltage conditions)- 225kV (.9783 p.u.)

Emergency Low (contingency voltage conditions)- 225kV (.9783 p.u.)

Voltage Drop- 2.6% (Post contingency voltage drop limit to be applied for a contingency trip of Peach Bottom Unit 2 or 3).

Maximum- 242kV (1.05 p.u.)

3SU: (13kV tertiary of Peach Bottom #1 transformer)

Normal Low (actual voltage conditions)- 13.5kV

Emergency Low (contingency voltage conditions)- 13.5kV

Voltage Drop- 2.5% (Post contingency voltage drop limit to be applied for a contingency trip of Peach Bottom Unit 2 or 3).

Maximum – 538kV (1.0760 p.u.)(on 500kV side of Peach Bottom #1 Autotransformer)

Note: The limits above are applicable for Peach Bottom Units 2 and 3.

Stability Requirements:

Stability studies shall have simulated 500 kV and 230 kV transmission line faults, the loss of each of the Peach Bottom generators, and the loss of the largest generator on the 500 kV grid. The studies must show that the transmission system is stable and there will be no cascading transmission outages for the simulated transmission line faults. The studies must show that continuous offsite power is assured for the simulated transmission system contingencies. This requirement is demonstrated by showing that offsite power sources 2SU, 343SU, and 3SU are maintained in service unless the simulated transmission system contingency is the direct supply to the offsite power source.

Exelon Nuclear shall be notified by the Planning Authority if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, Exelon Nuclear shall be notified if PJM system stability studies pertinent to the Peach Bottom generators, the Peach Bottom switchyards, the lines connecting the Peach Bottom switchyards to the transmission system, or the 220-08 line indicate that any of the stability requirements contained in the PJM, NERC or PECO Transmission Entity standards are not met.

Susquehanna Station units 1 & 2 Planning Requirements

Nuclear Plant Voltage Adequacy Studies: Periodic analysis of the expected Susquehanna switchyard voltages following a unit trip (Unit 1 or 2) shall be performed considering peak transmission system load levels with the system normal or altered by contingencies. Results of the studies are to be provided to PPL Susquehanna. To satisfy this requirement, the PJM normal course of planning studies fulfills this requirement.

Transmission Planning studies shall incorporate the voltage and stability requirements of Susquehanna. These studies shall include those performed to evaluate future transmission and generation interconnection. PPL Susquehanna shall be notified if planning study results identify that the Susquehanna requirements are not met by current or future system configurations, load levels, and contingencies.

The Transmission Planner or Transmission Owner will perform voltage analysis using a "current year + 5" planning horizon 50-50 peak summer load flow case considering N-1, stuck breaker and tower outage contingencies on 230 kV facilities and above and a stability study (following transmission normal stability criteria along with the special stability cases identified in the FSAR (Section 8.2)). These studies are to be completed on a three year cycle by the Transmission Planner and on a two year cycle by the Transmission Owner, or sooner, if system changes dictate. The Transmission Planner or Transmission Owner will communicate the results of these studies to PPL SSES. These studies may include load flow, voltage and/or stability related work analyses.

The following Susquehanna requirements shall be utilized for the planning studies:

SSES Transformer Loading

	T-10	T-20	T-11	T-12
Normal Plant Loading	5 + J3	5 + J3	42 + J24	42 + J24
Post Unit 1 Trip Loading both Start-up transformers in-service	27.1 +J14.65	27.1 +J14.65		42 + J24
Post Unit 2 Trip Loading both Start-up transformers in-service	27.1 +J14.65	27.1 +J14.65	42 + J24	
Post Unit 1 Trip Loading T-10 Start-up transformer in-service	54.2 +J 29.3			42 + J24

Post Unit 2 Trip Loading T-10 Start-up transformer in-service	54.2 +J 29.3		42 + J24	
Post unit 1 Trip Loading T-20 Start-up transformer in-service		54.2 +J 29.3		42 + J24
Post Unit 2 Trip Loading T-20 Start-up transformer in-service		54.2 +J 29.3	42 + J24	

Monitor offsite circuits with/without one S/U transformer in service.

With **both** Start-up Transformers (T-10 & T-20) in-service

Minimum Voltage	Allowable Voltage Drop*****
212kV (0.9217)	5%

With **one** Start-up Transformer (T-10 or T-20) in-service

Minimum Voltage	Allowable Voltage Drop*****
216.7kV (0.9421)	2%

*****Post contingency voltage drop limit to be applied for a contingency trip of Susquehanna unit 1 or unit 2.

NOTE: Voltage excursions below the Susquehanna voltage limits with durations expected to be greater than 9 seconds will result in the affected unit or units transferring from offsite power to the onsite power distribution system. Therefore, the transmission Entities shall take into consideration actions that will mitigate voltage excursions below the Susquehanna minimum voltage limits with durations greater than 9 seconds and provide notification when proposed actions can not mitigate the voltage excursion.

Stability:

Susquehanna generating units 1 and 2 are to be stable for the following conditions:

In general, the stability requirements are that the system shall be maintained without loss of non-consequential load during and after the following types of contingencies based on the latest light load forecast prepared annually by the PJM Load Analysis Subcommittee.

Standard NERC criteria contingencies (identified as R-* cases of FSAR Table 8.2-1):

- Single contingency outage conditions
- Double circuit tower line outage or single stuck circuit breaker conditions Three phase faults with normal clearing time
- Single line to ground faults with a stuck breaker or other cause for delayed clearing

The NERC TPL Standard reliability criteria also requires an evaluation of the ability of the bulk electric system to withstand abnormal or extreme system disturbances (identified as the N-* cases of FSAR Table 8.2-1). The NERC TPL Standard reliability criteria does not require that the bulk electric system be planned and constructed to withstand these abnormal or extreme disturbances due to their low probability of occurrence. However, it is PPL SSES position to maintain stability for these FSAR Table 8.2-1 cases as well. These abnormal system disturbances are analyzed not on the basis of their likelihood of occurrence but rather as a practical means to study the system for its ability to withstand disturbances beyond those that can be reasonably expected.

A total of six (6) contingencies identified in the FSAR Table 8.2-1 are required by NERC standards. Seventeen (17) other contingencies are not required by NERC standards but analyzed to assure a high level of transmission system reliability. FSAR table 8.2-1 is attached with the list of stability cases performed for PPL Susquehanna LLC. PPL Susquehanna shall be notified if the results of system stability studies identify that any of the stability requirements discussed above are not met. In addition, PPL Susquehanna shall be notified if the system stability studies indicate that any of the stability requirements contained within the attached stability summary tables is not met.

CASE	DESCRIPTION	
Fault Tests **R**equired to be Stable (8.2.1.5.C)		
R-1	3 phase fault at Susquehanna 500 kV on the Sunbury 500 kV line. Fault cleared in primary clearing time.	Stable
R-5	Phase-ground fault at Susquehanna 500 kV on Sunbury 500 kV line with Sunbury South 500 kV circuit breaker stuck. Clear remote terminal in primary time. Delayed clearing of Susquehanna.	Stable
R-6	3 phase fault at Susquehanna 230 kV on the Susquehanna 500/230 kV transformer. Fault cleared in primary clearing time.	Stable
R-7	3 phase fault at Montour 230 kV on Susquehanna 230 kV line. Fault cleared in normal primary clearing time.	Stable
R-13	Phase-ground fault at Susquehanna 500 kV on Susquehanna-Wescosville-Alburtis 500 kV line with Wescosville South 500 kV circuit breaker stuck. Clear remote terminal in primary time. Delayed clearing at Susquehanna.	Stable
R-18	3 phase fault at Susquehanna 230 kV on Harwood #1 & #2 Double Circuit. Fault cleared in primary clearing time.	Stable
Fault Tests **N**ot Required to be Stable (8.2.1.5.C)		
N-2	3 phase fault at Susquehanna 500 kV on the Sunburn 500 kV line with one breaker pole stuck at Sunbury. Clear Susquehanna in primary time. Delayed clearing at remote terminal.	Stable
N-3	3 phase fault at Susquehanna 500 kV on the Susquehanna-Wescosville-Alburtis 500 kV line with one Susquehanna 500/230 kV transformer breaker pole stuck. Clear remote terminal in primary time. Delayed clearing of Susquehanna.	Stable
N-4	3 phase fault at Susquehanna 500 kV on the Sunbury 500 kV line with one Susquehanna 500/230 kV transformer breaker pole stuck. Clear remote terminal in primary time . Delayed clearing of Susquehanna.	Stable
N-8	3 phase fault at Susquehanna 230 kV on Montour line with stuck west bus breaker. Clear remote terminal in primary time, clear Susquehanna with delay (lose Stanton-Susquehanna #2 230 kV line).	Stable

N-9	3 phase fault at Susquehanna 230 kV on Jenkins line with stuck east bus breaker. Primary clearing at remote terminal. Delayed clearing at Susquehanna.	Stable
N-10	3 phase fault at Susquehanna 230 kV on the 500/230 kV transformer with stuck west bus breaker pole. Clear two poles in primary time. Primary clearing at remote terminal (Susquehanna 500 kV Switchyard). Clear stuck pole in delayed clearing time (lose Stanton-Susquehanna #2 230 kV line).	Stable
N-11	3 phase fault at Susquehanna 230 kV on Harwood #1 line with stuck tie breaker pole. Clear two poles in primary time. Clear stuck pole in delayed clearing time (lose Sunbury-Susquehanna 230 kV line).	Stable
N-12	3 phase fault at Susquehanna 230 kV on Harwood #2 line with one pole stuck on west bus breaker. Clear two poles in primary time. Clear stuck pole in delayed clearing time (lose Stanton-Susquehanna #2 230 kV line).	Stable
N-14	Susquehanna-Wescosville-Alburtis 500 kV and Susquehanna-Harwood #1 & #2 Double Circuit 230 kV crossing failure (3 phase fault on all circuits). Automatically trip Susquehanna Unit #1. Clear Susquehanna-Wescosville-Alburtis 500 kV line in primary time. Clear Susquehanna- Harwood #1 & #2 230 kV lines in primary time.	Stable
N-15	3 phase fault near E. Palmerton on all lines in E. Palmerton-Harwood R/W corridor. Clear Susquehanna-Wescosville-Alburtis 500 kV line in primary time. Primary clearing of E. Palmerton- Harwood and Harwood-Siegfried 230 kV lines.	Stable
N-16	3 phase fault near Susquehanna on both lines in Sunbury-Susquehanna R/W corridor. Clear Sunbury-Susquehanna #2 500 kV line in primary time. Primary clearing of Sunbury-Susquehanna #1 230 kV line.	Stable
N-17	3 phase fault near Susquehanna 500 kV at Sunbury 230 kV line crossing. Trip Susquehanna –Wescosville-Alburtis 500 kV, Sunbury-Susquehanna #2 500 kV, and Unit #2 in primary time. Trip Sunbury-Susquehanna #1 230 kV in primary clearing time.	Stable
N-19	3 phase fault at Columbia-Frackville 230 kV line crossing. Trip Sunbury-Susquehanna #2 500 kV line in primary time. Trip Columbia-Frackville and Sunbury-Susquehanna #1 230 kV lines in primary time.	Stable

N-20	3 phase fault on 230 kV side of Unit #1 main transformer. Trip Unit #1 main transformer. Trip Unit #1 and overtrip Unit #2 in primary time.	Stable
N-21	3 phase fault at Susquehanna 230 kV on Unit #1 generator leads with a stuck west bus breaker. Trip Unit #1 and Stanton #2 line.	Stable
N-23	Sudden loss of all lines from Susquehanna 230 kV Switchyard	Stable
N-24	3 Phase fault on Susquehanna-Jenkins 230 kV line 80% towards Jenkins with pilot relaying out. Fault cleared in Zone 2 (backup) time at Susquehanna and Zone 1 time at Jenkins.	Stable

Calvert Cliffs Units 1 and 2 (CCNPP) Planning Requirements

Nuclear Plant Voltage Adequacy Studies

At the request of CCNPP, BGE shall perform periodic analysis of expected Calvert Cliffs 500 kV Switchyard post Unit trip voltages. These studies are typically performed on an annual frequency, but could be needed on a more frequent basis. The results of these studies shall be provided to CCNPP by BGE.

Planning and Operations Transmission Studies

PJM planning and operations transmission studies shall incorporate the Calvert Cliffs 500 kV Switchyard voltage, frequency and capacity requirements in switchyard voltage section below. CCNPP shall be notified by the Planning Coordinator (PJM) if planning study results identify that the Calvert Cliffs 500 kV Switchyard requirements are not met by current or future system configurations, load levels, or contingencies. Transmission study violations based on standard PJM criteria testing will be dispositioned in accordance with the applicable PJM agreements and manuals. Resolution of study violations based on criteria that are specific to CCNPP and are beyond standard PJM criteria testing will be CCNPP responsibility. The following Calvert Cliffs 500 kV Switchyard requirements shall be utilized for the planning studies:

- Voltage and Offsite Source Load Capacity Requirements: Refer to Section 1 for the voltage and load capacity requirements.
- Stability Requirements: Stability studies shall have simulated transmission line faults, the loss of each of the CCNPP main generators, and the loss of the largest generator on the 500 kV system. The studies must show that the transmission system is stable and there will be no cascading transmission outages for the simulated transmission line faults. They must also show continuity of offsite power at the Calvert Cliffs 500 kV Switchyard for the simulated transmission system contingencies by ensuring voltage limits defined in section 1.3 are not violated. CCNPP shall be notified by the Planning Authority (PJM) if the results of system stability studies identify if any of the stability requirements are not met.

Calvert Cliffs 500 kV Switchyard Voltage and CCNPP Frequency Requirements

1.3.1 Operating Voltage Limits for the Calvert Cliffs 500 kV Switchyard

Calvert Cliff Voltage Limits		
Plant Service Transformers (P-13000-2 & P-13000-2)	**Pre-Contingency**	**Post-Contingency**
Both xfmrs in service	500kV – 550kV	475kV – 550kV
Only one xfmr in service	520kV – 550kV	510kV – 550kV

Note: See maximum post-trip voltage drop below for loss of a CCNPP unit.

Calvert Cliffs 500 kV Switchyard Voltage Drop Limit

Maximum post-trip voltage drop (Post-contingency for a single CCNPP unit): Voltage drop of 5% of the pre-trip bus voltage with either one or both P-13000 transformers in service. The 5% post contingency voltage drop limit is to be applied at the Calvert Cliffs 500 kV Switchyard for a contingency trip of CCNPP Unit 1 or Unit 2.

Short Circuit Calculations

BGE and SMECO shall provide to CCNPP available short circuit current data at the points of interconnection, when requested for use in the CCNPP distribution system short circuit calculations.

Beaver Valley Units 1 and 2 Planning Requirements

Nuclear Station Voltage Adequacy studies: Per Service Agreement No. 1668, Schedule F, paragraph 12: "ATSI (American Transmission Systems Incorporated) will perform a probability study, at FENOC's (FirstEnergy Nuclear Operating Company) expense, by June 1 of each year to determine the frequency of grid voltage outside of values identified in this schedule. This study will include expected power flow transfers through the region that would influence grid voltages." Results of the studies are to be provided to FENOC.

Transmission Planning studies: The Transmission Planner shall incorporate the voltage and stability requirements of BVPS. These studies shall include those performed to evaluate future transmission and generation interconnection in accordance with applicable NERC and Regional Entities of NERC standards. Both FENOC (Akron) and the BVPS Design Engineering staff shall be notified if planning study results identify that the BVPS requirements are not met by current or future system configurations, load levels, and contingencies by the Transmission Planner performing the studies. Transmission study violations based on standard PJM criteria testing will be handled by the procedures described in the PJM agreements and manuals. Study violations based on criteria that are specified specifically for BVPS and are beyond standard PJM criteria testing will require remedies that will be the plant owner's responsibility. The following BVPS requirements shall be utilized for the planning studies:

Voltages:

The voltage limit requirements are as stated below.

The Station voltage limits are as follows:

Beaver Valley Switchyard 345kV Voltage Limits
EL (Emergency Low) 341 kV (0.9850 p.u.)
NL (Normal Low) 343 kV (0.9942 p.u.)
NH (Normal High) 355 kV (1.0290 p.u.)

Beaver Valley Switchyard 138kV Voltage Limits
EL (Emergency Low) 131 kV (0.9493 p.u.)
NL (Normal Low) 136 kV (0.9855 p.u.)
NH (Normal High) 142 kV (1.0289 p.u.)

Planning assessments enforce nuclear voltage criteria at the Transmission System level, including any voltage drop criteria. Criteria are enforced on a system normal and post-contingency basis after allowance for full system adjustments that can be available within 30 minutes following a disturbance.

Frequency:

Both BVPS-1 and BVPS-2 require a stable grid frequency of 59.9 to 60.1 Hz.

Stability:

BVPS generating unit stability is to be analyzed according to the applicable NERC, and Regional Entities of NERC, criteria for transient stability. The analyzed contingencies that are evaluated against Beaver Valley's voltage requirements include:

- Loss of a significant generating unit (standard PJM testing)
- Loss of a significant transmission line (standard PJM test), or
- Loss of a Beaver Valley unit (standard PJM test)

BVPS and FENOC (Akron) shall be notified by the Transmission Planner performing the studies if the results of system stability studies identify that any of the stability requirements discussed above are not met.

Cook Unit 1 and 2 Planning Requirements

The following requirements are derived from Cook Plant Design Information Transmittal DIT-B-03036-00. The information in this DIT is to be used to perform transmission studies that support Cook Plant Operation.

This DIT looks at case reports for Mode 1 and LOCA. The purpose is to allow a comparison between plant data and the model (Mode 1). and make adjustments to the model if appropriate. These values will be transmitted to Transmission planning as input for their studies.

Depending on the preferred power line up (split = Transformer #4 and Transformer #*5;* Transformer #4 only; or Transformer #*5* only) different values for transfer must be considered. The "split" lineup will transfer the IA & l B or 2A & 2B busses to Transformer #*5* and the IC & ID or 2C & 2D busses to Transformer #4. The transfer includes the associated T-busses. These groups of loads (load groups) are called Division AB and Division CD for each unit. When the preferred power lineup is Transformer #4 only or Transformer #*5* only; then both divisions (AB and CD) will transfer to the applicable single transformer. The single transformer load group is called "Entire Plant" and consists of the Division AB and Division CD for a single unit. This DIT also looks at 69kv power requirements.

3. Design Value Determination

3.1. The values determined above are increased to allow increased use of power within the plant and for margin. The amount of the increase was determined by engineering judgement considering weld receptacles and desired margins. All power magnitudes are assumed to be at 0.8 power factor. This is reasonable since the current plant model shows power factor slightly above 0.8.

	Accident Megawatt Load		
	AB Division	CD Division	Entire Plant
Unit 1	22	22	42
Unit 2	20	24	42.5

3.2. The division power levels should be used for the normal split lineup of the switchyard when the AB division will be powered via transformer 5 and the CD division will be powered via transformer 4. The division power levels cannot be added together to represent the entire plant because the division power values are representative of different plant lineups where depending on which pumps are in service power can be shifted from one division to another. The total power levels should be used when the switchyard is lined up in either the Transformer4 only or transformer 5 only lineups.

4. 69kv System Determination

4.1. Power for the 69kv system is procedurally limited to 600 amperes at the 4kv level for each unit (Ref 4). This power would be in addition to the normal load seen on 69kv. The normal load consists of power to other buildings at the site such as the Training Center and the Visitors Center. Actual power factor is expected to be between 0.8 and 0.9. The value which results in the lowest voltage should be selected for conservatism.

4.2. Since the primary result from determining these values is the evaluation of voltage adequacy and the limitation is an absolute value for current; available power will reduce with available voltage.

4.3. The bounding case of determining minimum adequate voltage will be when system conditions are such that the minimum acceptable voltage results from applying the power allowed at that voltage via the EP (69kv source).

4.4. The lowest allowable voltage is cited in the TRM as 91%.

4.5. The power for the bounding case is 1200*0.91*4160*1.73*pf=7.86*pf (MW)

5. Conclusions for Transmission Planning Studies

5.1. The power transferred to our 34kv system will depend on the lineup of the system. The normal lineup is split so that the AB division will transfer to TR5 and the CD division will transfer to TR4. If either transformer is out of service then the entire unit will transfer to the remaining transformer (TR5 and TR4 only lineups). The following table prescribes the value to be used for transmission studies. The power factor associated with these loads is 0.80.

	Megawatt Load Transferred at Unit Trip		
	AB Division (TR5 split)	CD Division (TR4 split)	Entire Plant (TR5 or TR4 only)
Unit 1	22	22	42
Unit 2	20	24	42.5

5.2. The power that can be transferred to the 69kv system is 7.86* power factor (MW). The power factor between 0.80 and 0.90 which provides the lowest voltages should be selected.

Using the input data described above, periodic planning studies are conducted of the transmission and subtransmission networks surrounding the D. C. Cook Plant to determine worst-case offsite power voltage conditions that could credibly exist during a plant shutdown scenario, as well as minimum and maximum voltage and short circuit levels that may be experienced. These studies determine the impact of the most significant factors including transmission and subtransmission network contingencies, Cook Plant generating unit configurations, status of other generation near Cook Plant, 765 kV switched shunt reactor status, and transmission network power flows and take into account the various possible reserve auxiliary switchyard lineups. Available historic data for EHV flows and voltages is utilized in preparation of power flow models used in the studies and for independent validation of study results.

Typically Planning studies will be requested by Cook Plant personnel and performed by AEP Transmission with results provided to Cook Plant and to PJM Planning.

Voltage Requirement

TABLE 1
Maximum switchyard voltage swing requirements to reset the degraded voltage relays with the Main Generator Synchronized to the Transmission Network and the buse(s) are powered from the Unit Auxiliary Transformer(s) source:

Cook Offsite Power Source	34 kV Switchyard Source Breaker position	345 kV System Swyd Swing Limit (Value @ DGR reset.) % of 345kV				TR4 Tertiary 34.5 kV System Swyd Swing Limit (Value @ DGR reset) % of 34.5kV			
		Unit 1		Unit 2		Unit 1		Unit 2	
		Limit Note 1	**Alarm** Setpoint	**Limit** Note 1	**Alarm** Setpoint	**Limit** Note 1	**Alarm** Setpoint	**Limit** Note 1	**Alarm** Setpoint
TR5 & TR4	BD – Open BE & BC – Closed	**5.0%** Note 3	**4.5%** Note 2	**3.7%** Note 3	**3.2%** Note 2	**5.3%** Note 3	**4.8%** Note 2	**3.6%** Note 3	**3.1%** Note 2
TR5	BD & BE - Closed BC – Open	**1.1%**	**0.6%** Note 2	**0.0%**	**-0.5%** Note 2	N/A	N/A	N/A	N/A
TR4	BD & BC – Closed BE – open	N/A	N/A	N/A	N/A	**4.3%**	**3.8%** Note 2	**2.5%**	**2.0%** Note 2
The BOLDED values indicate the limits and alarm values.									

TABLE 2
Maximum switchyard voltage swing requirements to reset the degraded voltage relays with the Main Generator Synchronized to the Transmission Network and the buse(s) are powered from the Reserve Auxiliary Transformer(s) source:

Cook Offsite Power Source	34 kV Switchyard Source Breaker position	345 kV System Swyd Swing Limit (Value @ DGR reset.) % of 345kV				TR4 Tertiary 34.5 kV System Swyd Swing Limit (Value @ DGR reset) % of 34.5kV			
		Unit 1		Unit 2		Unit 1		Unit 2	
		Limit Note 1	**Alarm** Setpoint	**Limit** Note 1	**Alarm** Setpoint	**Limit** Note 1	**Alarm** Setpoint	**Limit** Note 1	**Alarm** Setpoint
TR5 & TR4	BD – Open BE & BC – Closed	**1.6%**	**1.1%** Note 2	**1.1%**	**0.6%** Note 2	**2.4%**	**1.9%** Note 2	**2.0%**	**1.5%** Note 2
TR5	BD & BE - Closed BC – Open	**1.0%**	**0.5%** Note 2	**0.7%**	**0.2%** Note 2	N/A	N/A	N/A	N/A
TR4	BD & BC – Closed BE – open	N/A	N/A	N/A	N/A	**1.5%**	**1.0%** Note 2	**1.1%**	**0.6%** Note 2
The BOLDED values indicate the limits and alarm values.									

North Anna Units 1 and 2 Planning Requirements

The Dominion System Operator must notify the station in a timely manner if any of the GDC-17 limits stated in item 1 above may potentially be impacted by the results of Operations Planning studies.

It is the responsibility of Transmission Planning to develop a long-range transmission plan which provides for orderly and timely modifications to the transmission system in order to insure an adequate, economical and reliable supply of electric power. The system must be planned, designed, and constructed to operate reliably within thermal, voltage, and stability limits. Dominion's Transmission Planning performs a wide variety of specific studies to ensure the GDC-17 requirements are met.

These include:

- Power Flow Studies
- Stability Studies

PJM and Dominion Electric Transmission Planning will design the system to meet the GDC-17 requirements. Steady state voltage limits will use the "Emergency Limit Low" and "Emergency Limit High" voltage limits of section 1. Only the following contingency scenarios will be evaluated:

Transmission Condition	Unit 1	Unit 2
All lines in	On	On
All lines in	Trip	On
All lines in	On	Trip
All lines in	Trip	Trip
Worst case N-1 contingency	On	On
Worst case N-1 contingency	Trip	On
Worst case N-1 contingency	On	Trip

PJM/Dominion Electric Transmission Planning will notify Dominion Nuclear of any NPIR criteria violations. Transmission study violations based on standard PJM/Dominion planning criteria will be handled through the normal planning processes described in the PJM agreements and manuals. Upgrades for study violations based on the more stringent Dominion Nuclear NPIR criteria will be the responsibility of the plant owner.

Voltage Limits:

The NAPS 500 kV switchyard voltage must be maintained between 505kV and 535 kV to ensure compliance with GDC-17 voltage analysis. The Dominion System Operator must notify the station in a timely manner (within 15 minutes) when one of the following conditions occurs:

- The 500 kV or 230 kV voltage or frequency limits are exceeded, and the steps taken or being taken to mitigate the exceeded limit.

Bus Name	Normal Limit Low	Emergency Limit Low
500 kV	510.0 kV (1.02 pu)	505.0 kV (1.01 pu)
230 kV	226.3 kV (0.984 pu)	224.0 kV (0.974 pu)

Bus Name	Normal Limit High	Emergency Limit High
500 kV	530.0 kV (1.06 pu)	535.0 kV (1.07 pu)
230 kV	239.2 kV (1.04 pu)	242.0 kV (1.052 pu)

Bus Name	Normal Voltage Drop	Emergency Voltage Drop
500 kV	3.5 %	3.5 %
230 kV	3.5 %	3.5 %

Bus Name	Frequency Limit Low	Frequency Limit High
500 kV	59.5 Hz	60.5 Hz
230 kV	59.5 Hz	60.5 Hz

- A contingency analysis study indicates the normal or emergency limit for the station will be exceeded if a single contingency occurs and the Transmission Operator cannot effectively mitigate the condition to avoid the violation.

- Both the Dominion and the PJM Real Time Contingency Analysis (RTCA) are not available.

- The real time telemetry between Dominion System Operator and the station is known to be out of service.

- The system conditions return to normal.

Surry Units 1 and 2 Planning Requirements

The Dominion System Operator must notify the station in a timely manner if any of the GDC-17 limits stated in item 1 above may potentially be impacted by the results of Operations Planning studies.

It is the responsibility of Transmission Planning to develop a long-range transmission plan which provides for orderly and timely modifications to the transmission system in order to insure an adequate, economical and reliable supply of electric power. The system must be planned, designed, and constructed to operate reliably within thermal, voltage, and stability limits. Dominion's Transmission Planning performs a wide variety of specific studies to ensure the GDC-17 requirements are met. These include:

- Power Flow Studies
- Stability Studies

PJM and Dominion Electric Transmission Planning will design the system to meet the GDC-17 requirements. Steady state voltage limits will use the "Emergency Limit Low" and "Emergency Limit High" voltage limits of section 1. Only the following contingency scenarios will be evaluated:

Transmission Condition	Unit 1	Unit 2
All lines in	On	On
All lines in	Trip	On
All lines in	On	Trip
All lines in	Trip	Trip
Worst case N-1 contingency	On	On
Worst case N-1 contingency	Trip	On
Worst case N-1 contingency	On	Trip

PJM/Dominion Electric Transmission Planning will notify Dominion Nuclear of any NPIR criteria violations. Transmission study violations based on standard PJM/Dominion planning

criteria will be handled through the normal planning processes described in the PJM agreements and manuals. Upgrades for study violations based on the more stringent Dominion Nuclear NPIR criteria will be the responsibility of the plant owner.

Voltage Limits:

The SPS 500 kV switchyard voltage must be maintained between 505 kV and 535 kV to ensure compliance with GDC-17 voltage analysis. Similarly, the 230 kV switchyard voltage must be maintained between 220 kV and 245 kV. The Dominion System Operator must notify the station in a timely manner (within 15 minutes) when one of the following conditions occurs:

- The 500 kV or 230 kV voltage or frequency limits are exceeded, and the steps taken or being taken to mitigate the exceeded limit.

Bus Name	Normal Limit Low	Emergency Limit Low
500 kV	510.0 kV (1.02 pu)	505.0 kV (1.01 pu)
230 kV	222.3 kV (0.967 pu)	220.0 kV (0.957 pu)

Bus Name	Normal Limit High	Emergency Limit High
500 kV	530.0 kV (1.06 pu)	535.0 kV (1.07 pu)
230 kV	239.2 kV (1.04 pu)	245.0 kV (1.065 pu)

Bus Name	Normal Voltage Drop	Emergency Voltage Drop
500 kV	4.5 %	4.5 %
230 kV	6.0 %	6.0 %

Bus Name	Frequency Limit Low	Frequency Limit High
500 kV	59.67 Hz	60.33 Hz
230 kV	59.67 Hz	60.33 Hz

- A contingency analysis study indicates that the normal or emergency limit for the station will be exceeded if a single contingency occurs and the Transmission Operator cannot effectively mitigate the condition to avoid the exceeded limit.

- Both the Dominion and the PJM Real Time Contingency Analysis (RTCA) are not available.

- The real time telemetry between Dominion System Operator and the station is known to be out of service.

- The system conditions return to normal.