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SOUTHERN COMPANY

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U.S. Nuclear Regulatory Commission
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Southern Nuclear Operating Company
Vogtle Electric Generating Plant Units 3 and 4 Combined License Application
Response to Request for Additional Information Letter No. 025

Ladies and Gentlemen:

By letter dated March 28, 2008, Southern Nuclear Operating Company (SNC) submitted an application for combined licenses (COLs) for proposed Vogtle Electric Generating Plant (VEGP) Units 3 and 4 to the U.S. Nuclear Regulatory Commission (NRC) for two Westinghouse AP1000 reactor plants, in accordance with 10 CFR Part 52. During the NRC's detailed review of this application, the NRC identified a need for additional information, involving the offsite electrical power system, required to complete their review of the COL application's Final Safety Analysis Report (FSAR) Section 8.2, "Offsite Power System." By letter dated December 19, 2008, the NRC provided SNC with Request for Additional Information (RAI) Letter No. 025 concerning this offsite electrical power system information need. This RAI letter contains nine RAI questions numbered 08.02-1 thru -9. The enclosure to this letter provides the SNC response to these RAIs.

If you have any questions regarding this letter, please contact Mr. Wes Sparkman at (205) 992-5061.

D092
NRO

Mr. J. A. (Buzz) Miller states he is a Senior Vice President of Southern Nuclear Operating Company, is authorized to execute this oath on behalf of Southern Nuclear Operating Company and to the best of his knowledge and belief, the facts set forth in this letter are true.

Respectfully submitted,

SOUTHERN NUCLEAR OPERATING COMPANY

JAMiller

Joseph A. (Buzz) Miller

Sworn to and subscribed before me this 16 *day of* January, *2009*

Notary Public: Gloria H. Buie

My commission expires: 05/06/09

JAM/BJS/lac

Enclosure: Response to NRC RAI Letter No. 025 on the VEGP Units 3 & 4 COL Application Involving the Offsite Electrical Power System

cc: Southern Nuclear Operating Company
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Southern Nuclear Operating Company

ND-09-0009

Enclosure

Response to NRC RAI Letter No. 025

on the VEGP Units 3 & 4 COL Application

Involving the

Offsite Electrical Power System

FSAR Section 8.2, Offsite Power System

eRAI Tracking No. 1596

NRC RAI Number 08.02-1:

In order for the NRC staff to confirm that the single offsite power circuit provided from the transmission network satisfies the requirements of GDC (General Design Criterion) 17, provide the voltage and frequency variations expected at all switchyards. Confirm that these voltage and frequency limits are acceptable for auxiliary power system equipment operation and Class 1E battery chargers during different operating conditions. The confirmation should include the following calculations: load flow analysis (bus and load terminal voltages of the station auxiliary system); short circuit analysis; equipment sizing studies; protective relay setting and coordination; and motor starting with minimum and maximum grid voltage conditions. A separate set of calculations should be performed for each available connection to an offsite power supply. In addition, discuss how the results of the calculations will be verified before fuel loading.

SNC Response:

It is recognized extensively throughout the FSER (NUREG-1793) that there is no requirement for functionality of the offsite power to accomplish safe shutdown of the AP1000. Section 8.2.3.2 of the NRC FSER for the AP1000 addresses the AP1000 partial exemption from GDC 17 and states "The AP1000 design does not rely on power from the offsite system to accomplish safety functions, and therefore, the underlying purpose of the rule is met without the need for two independent offsite circuits."

With regard to GDC 17, Regulatory Guide 1.206, Section C.III.1, Position C.I.8.2.1 states that for passive designs "the applicant should provide information on the single offsite power source with sufficient capacity and capability from the transmission network designed to power the safety-related systems and other auxiliary systems under normal, abnormal, and accident conditions. The design of this offsite power source should minimize to the extent practical the likelihood of its failure under normal, abnormal, and accident conditions."

The results of the grid stability studies performed for each available connection to an offsite power supply demonstrate the offsite source capacity and capability to power plant components during normal, shutdown, startup, and turbine trip conditions.

For the VEGP Units 3 and 4 grid voltage evaluation, the 500-kV voltage was set to 517-kV (1.03p.u.) and the 230-kV voltage was set to 235-kV (1.02p.u.). This is the anticipated voltage schedule to be set by VEGP Operations, and is consistent with standard practice for grid studies at VEGP.

The conclusion that the voltage and frequency variations expected at all VEGP switchyards are acceptable for auxiliary power system equipment operation during steady-state and transient operating conditions is based on stability studies which include the most critical contingencies, such as simulation of turbine trip events, loss of the most critical transmission line, loss of the largest load and loss of the largest unit in the area. The acceptance criteria for voltage and frequency are provided by Westinghouse.

The table below summarizes the worst case voltage and frequency swings that envelope all the cases stated above.

Parameter	Condition	Worst Case Values				Westinghouse Requirements
		Turbine Trip	Loss of Line	Loss of Largest Load	Loss of Largest Unit	
Switchyard Voltage	Steady-State	1.022 – 1.044 pu	1.0217 - 1.0217 pu	1.0217 - 1.0217 pu	1.0217 - 1.0217 pu	0.95 - 1.05 pu
	Transient	+/- 5%	-18.3% / +9.8%	-.1% / +.1%	-6.2% / +3.6%	+/- 20%
Generator Bus Voltage	Steady-State	0.98 - .99 pu	.98 - .98 pu	.98 - .98 pu	.99 - .98 pu	0.95 - 1.05 pu
	Transient	+/- 6%	-19.5% / +9.9%	-.06% / +.15%	-6.4% / +3.3%	+/- 20%
Frequency	Steady-State	60.0 - 59.98 Hz	60.0 - 60.0 Hz	60.0 - 60.0 Hz	60.0 - 59.98 Hz	+/- 0.5 Hz indefinite
	Transient	+/- 0.15 Hz	+/- .25 Hz	-0 / +0 Hz	-.12Hz / +.06 Hz	+/- 0.5 Hz indefinite

The above grid voltage evaluation results are verified during the preoperational testing identified in DCD subsection 14.2.10 which includes the following tests.

- 100 Percent Load Rejection (14.2.10.4.21)
- Plant Trip from 100% Power (14.2.10.4.24)
- Loss of Offsite Power (14.2.10.4.26)

NRC RAI Number 08.02-2:

RG 1.206, C.III.1, Position C.I.8.2.1 states that a COL applicant for passive design should provide a discussion in the FSAR of how the single designated offsite power circuit from the transmission network conforms with the requirements of GDCs 2, 4, 5, 17 and 18 (also see guidance in Standard Review Plan Section 8.2.II). Discuss how the FSAR addresses this consideration or justifies an alternative, as well as how Southern Nuclear Operating Company intends to meet the requirements of 10 CFR 50.65 with respect to maintenance of onsite and offsite power system components.

<u>SNC Response</u>:

There is no portion of the single required offsite circuit required to conform with GDC's 2, 4, 5, and 18. These GDC's are for structures, systems and components important to safety. For the AP1000, the single offsite circuit does not perform a safety-related function as stated in DCD Subsection 8.1.4. The required offsite circuit interface with the safety related batteries is through the class 1E battery chargers. These battery chargers are located within the Nuclear Island which is designed in accordance with GDC's 2 and 4.

Environmental effects are considered in the design of the offsite power circuit. For example, conductors are designed to withstand a particular high temperature (normally 100 degrees C) before violating sag clearances, and transmission lines are designed for high winds, typically 110 mph for the VEGP site area, and for appropriate levels of snow and ice. Additionally, transmission lines include overhead ground wires and, in an area with a history of lightning strikes or an area of high ground resistivity, have lightning arrestors installed.

The transmission lines and switchyard are designed so the full output of the plants can be carried out to the network, and the capacity is more than sufficient for any incoming power requirements.

Maintenance and testing of the offsite power circuits is discussed in the response to question 08.02-07.

With regard to GDC 17, Regulatory Guide 1.206, Section C.III.1, Position C.I.8.2.1 states that for passive designs "the applicant should provide information on the single offsite power source with sufficient capacity and capability from the transmission network designed to power the safety related systems and other auxiliary systems under normal, abnormal, and accident conditions. The design of this offsite power source should minimize to the extent practical the likelihood of its failure under normal, abnormal, and accident conditions."

The results of the grid stability analysis demonstrate the offsite source capacity and capability to power plant components during normal, shutdown, startup, and turbine trip conditions. The VEGP grid stability analysis specifically examined two conditions: Normal Running and Turbine Trip. Other conditions (i.e., startup and normal shutdown) are bounded by these analyses. The results of the failure modes and effects analysis demonstrate the reliability of the offsite source which minimizes the likelihood of its failure under normal, abnormal and accident conditions.

FSAR Section 17.6 describes implementation of the requirements of 10 CFR 50.65. As indicated therein, implementation of the NEI 07-02 program description will determine the applicability of the maintenance requirements for the offsite power circuit.

NRC RAI Number 08.02-3:

The final paragraph of GDC 17 requires, in part, provisions to minimize the probability of the loss of power from the transmission network given a loss of the power generated by the nuclear power unit(s). Describe any limits on the main generator MVAR output such that loss of the main generator will not result in an unacceptable voltage in the switchyards. Describe any auxiliary transmission system equipment, such as capacitor banks, static VAR compensators that may be necessary to offset loss of MVAR support on loss of the main generator.

SNC Response:

The VEGP site is currently a two unit site with plans to add two new AP1000 units. A transmission planning analysis was performed utilizing existing transmission system data and projections for the time that the new units will be placed on-line. For conservatism, the existing or forecasted local area generation that could significantly enhance the voltage at the VEGP 230kV switchyard was modeled off-line. Also, the existing 230kV capacitor bank and 500kV shunt reactors were initially modeled off-line. The turbine-generators were modeled to operate within their ratings with no limitations. For the cases that were run, after the third unit is placed on-line, but prior to Unit 4 being in service, there was one case, Unit 1 in a LOCA, Units 2 and 3 tripped, where the capacitor bank would be required in order to maintain voltage at the acceptable level for Unit 1 and 2 offsite power. The analysis concluded that the existing capacitors at the VEGP site are adequate for system operations should there be a need to increase the 230kV bus voltage above the minimum acceptable value of 100% required for Units 1 and 2. The offsite power supply transformers for Units 3 and 4 are equipped with load tap changers and will allow a lower minimum acceptable voltage in the switchyard. After Unit 4 is on-line, all studied scenarios had at least one other VEGP unit on-line and the capacitor bank was not required. All scenario results indicated that the bus voltages could be maintained above the criteria for the unit and line contingencies studied. There were no limitations on the main generator MVAR output.

NRC RAI Number 08.02-4:

Section 8.2.1.1 of the FSAR discusses the results of the Failure Mode and Effects Analysis (FMEA) of the Vogtle Electric Generating Plant switchyards. In order for the staff to evaluate the FMEA, describe in detail how each event (a breaker not operating during a fault on an offsite line; fault on a switchyard bus; a spurious relay trip; and a loss of control power) in the FMEA was evaluated to conclude that the offsite power to each unit is not lost.

SNC Response:

The FMEA was based on the design of the switchyard and the interconnecting transmission system as shown in FSAR Figure 8.2-201. The evaluation of each failure mode was a qualitative assessment at the major component level. For example, for a fault on a transmission line or switchyard bus, the associated breakers are credited for tripping to isolate the fault. For that same scenario with a failed closed breaker, the next breaker in line is credited to open. Each failure mode addressed in the FMEA was done at this level. FSAR Subsection 8.2.1.1, Failure Analysis, provides the results of the FMEA for each failure evaluated. A quantitative evaluation was not performed on each component. If a single failure was assumed to occur, then the remaining associated component was assumed to operate properly.

NRC RAI Number 08.02-5:

Standard Review Plan (SRP, NUREG-0800) Section 8.2.III.F states that "[t]he results of the grid stability analysis must show that loss of the largest single supply to the grid does not result in the complete loss of preferred power. The analysis should consider the loss, through a single event, of the largest capacity being supplied to the grid, removal of the largest load from the grid, or loss of the most critical transmission line." Describe how your design satisfies the SRP, and provide the analysis results, or justify an alternative.

SNC Response:

For verification of conformance of VEGP 3 and 4 design to SRP Section 8.2.III.F requirements, the stability studies were performed using Siemens PTI PSS/E (Power System Simulator for Engineering) software version 30.2.1. The 2015 summer off-peak case was used as a starting point for the stability study. The Southern Control Area load was scaled down to a valley load condition of ~38% of peak and the generation was dispatched for this loading condition. Valley load conditions give the most conservative stability results for nuclear units. VEGP Units 1 and 2 were each assumed to have been up-rated to 1280 MW gross output and the station service load for these two units was modeled explicitly. New Units 3 and 4 were assumed to produce 1262 MW each. Each new unit's station service load was assumed to be 78.2 MW and 41.7 Mvars served from the generator bus (based on Westinghouse information pertaining to AP1000 plant house loads including major loads such as 4 RCS pumps, 3 FWS pumps, 2 CDS pumps and 3 CWS pumps).

The VEGP switchyards are connected to eight transmission lines. No single transmission line is designated as the preferred circuit, but analysis shows that with any one of these transmission lines out of service, the transmission grid can supply the switchyard with sufficient power for safety related systems and other auxiliary loads for normal, abnormal, and accident conditions. The grid stability study considered normally-cleared three-phase faults on the transmission system and three-phase faults followed by breaker failure at the VEGP 500 kV switchyard. A 500 kV line out for maintenance with a normally cleared fault on another 500 kV line was also studied. It was found that the most critical 500 kV line is the Vogtle – W. McIntosh line and the most critical 230 kV line is the Vogtle – South Carolina Electric and Gas (SCEG) line. For the most critical contingencies with all four units assumed to be on line, the study produced following results:

- <u>Loss of the most critical transmission lines (three-phase fault on W. McIntosh 500 kV line or three-phase fault on SCEG 230 kV line):</u> after the fault is cleared in 6 cycles, the generator bus voltage immediately recovers to a value above 0.8 pu. This is within the Westinghouse requirement of +/- 20% for transient events.

- <u>Loss of the largest load in the area of the VEGP units (loss of Augusta Newsprint load):</u> the generator bus voltages are not affected by this contingency.

- <u>Loss of the largest unit in the area [three-phase fault on the low side of GSU for VEGP Unit 3; three-phase fault on the low side of GSU for VEGP Unit 4 (tripping VEGP 1 or 2 rather than VEGP 3 or 4 would not change the results for loss of the largest unit in the area)]:</u> after the fault is cleared in 6 cycles, the generator bus voltage immediately recovers to a value above 0.9 pu. This is within the Westinghouse requirement of +/- 20% for transient events.

The VEGP grid stability study concluded that the grid remains stable for the loss of the most critical transmission line, the loss of the largest load, and the loss of the largest generating unit. For these contingencies, the generator bus voltages and switchyard voltages (after fault clearing) remain well within the required limits.

NRC RAI Number 08.02-6:

Section 8.2.1.1 of the applicant's FSAR, Subsection "Transmission System Operator (TSO)," describes the VEGP's relationship with its TSO, Southern Company Transmission (SCT). It also describes the entire hierarchy of entities involved in the transmission grid operations and the communication protocols among them: "Southern Company Transmission (SCT) is the TSO within the SBAA and is responsible for the safe and reliable operation of the SBAA transmission grid. The SBAA is located within the SERC Reliability Corporation, one of the regional corporations within the North American Electric Reliability Corporation (NERC). SCT has responsibility for Transmission Planning and Operation of the bulk power transmission system. The Operation is performed by the Georgia Transmission Control Center (GCC) in Atlanta, Georgia and Bulk Power Operations (BPO) organization. The BPO control center is also known as the Power Coordination Center (PCC) and is located in Birmingham, Alabama ... The PCC/GCC continuously monitors and evaluates grid reliability and switchyard voltages, and informs plant operations of any potential grid instability or voltage inadequacies ... If a condition arises where the SBAA transmission grid cannot supply adequate offsite power, plant operators are notified and appropriate actions are taken ... In addition, plant operators inform the PCC/GCC of changes in generation ramp rates and notify them of any developing problems that may impact generation."

As offsite power is shared between the existing VEGP, Units 1 and 2, how is the above notification coordinated between the system operator and the operators of VEGP, Units 3 and 4? In addition, does the interface agreement require that the operators be notified of periods when the system operator is unable to determine if offsite power voltage and capacity is inadequate?

SNC Response:

Offsite power is not shared between Units 1 & 2 and Units 3 & 4. However a common transmission grid is shared. Offsite power circuits in some cases originate at a similar electrical point in the common grid. Specifically:

- Units 1 & 2 offsite power comes from two circuits which originate in the existing VEGP Units 1 & 2 230kV switchyard.

- VEGP Unit 3 offsite power is available from two sources. The preferred offsite power source is from the Unit 3 Unit Auxiliary Transformers (UATs) which are normally powered from the output of the main electrical generator and can be back fed through the Generator Step-up Transformer (GSU) which is connected to the 230kV switchyard. A second source for maintenance is available from the Reserve Auxiliary Transformers (RATs) which are powered from a new 230kV switchyard located on the Plant Vogtle to Augusta Newsprint 230 kV line.

- VEGP Unit 4 offsite power is also available from two sources. The preferred offsite power source is from the Unit 4 UATs which are normally powered from the output of the main electrical generator and can be backfed through the GSU which is connected to the new Unit 4 500kV Switchyard. A second source for maintenance is available from RATs which are powered from a new 230kV switchyard located on the Plant Vogtle to Augusta Newsprint 230 kV line.

Currently VEGP Units 1 and 2 communications related to grid issues are described in the Plant Vogtle Power Quality Guide. The description of communication protocols provided in FSAR Subsection 8.2.1.1 for Units 3 and 4 is based on a similar expected process. Since the time that the FSAR was submitted to the NRC, NERC has released NERC NUC-001-1. At the present time, Southern Company intends to perform a significant revision to the Power Quality Guide such that it is structured to follow the NUC-001-1 requirements. However, it does not appear, at this time, that the restructuring will materially change the intent or processes for communications described in the present Power Quality Guide. Therefore, a similar restructured guide is expected for VEGP Units 3 and 4. However, due to the passive safety system design of Units 3 and 4, the Nuclear Plant Interface Requirements (NPIRs) may differ in some areas.

The present Vogtle Units 1 and 2 Power Quality Guide addresses the Transmission Operations notification responsibilities as follows:

"Notification to Vogtle Shift Supervisor if the grid monitoring tools (EMS, System Security, Automatic Generation Control, etc.) are to be taken out of service, or become degraded or non-functional, for greater that 8 hours."

In the NERC NUC-001 standard, this is addressed as requirement R4.3. The upcoming revision to the Vogtle Units 1 and 2 Power Quality Guide will address the required notifications with similar actions to the existing guide. It is anticipated that if monitoring of the grid is required for Units 3 and 4, this requirement will be noted as one of the plant's NPIRs per NUC-001-1. This would result in Southern Company Transmission providing the necessary communication to the Vogtle Shift Supervisor per NUC-001-1 in a manner similar to what is done currently for Units 1 and 2.

NRC RAI Number 08.02-7:

Section 8.2.1.4 of the FSAR discusses maintenance, testing, and calibration practices that SCT follows. It states that PD follows its own field test manuals, vendor manuals, industry's maintenance practices, and observes NERC reliability standards. Explain what is meant by 'observes'? Explain whether this statement is intended to indicate that SCT will follow the NERC standards for switchyard maintenance and testing.

SNC Response:

In Subsection 8.2.1.4 of the VEGP Units 3 and 4 FSAR, the phrase "observes NERC reliability standards" is meant to indicate that it is the intention of Southern Company Transmission to follow the NERC standards for switchyard maintenance and testing.

NRC RAI Number 08.02-8:

Section 8.2.2 of the applicant's FSAR discusses grid stability studies for load flow, transient stability, and fault analysis. In this regard, please provide the following additional information:

a) Provide the assumptions and conditions used in the analysis.

b) Provide the switchyard voltages assumed in the study.

c) Does this analysis include worst-case disturbances for which the grid has been analyzed to remain stable?

d) Did the analysis include station auxiliary loads for all four units?

e) Identify the software used for this study.

f) How often is this study performed?

SNC Response:

a) In addition to major assumptions already listed in the FSAR Subsection 8.2.2, the following assumptions are also used in the VEGP analysis:

- Study assumptions that provided the most conservative results were used.
- All of the local area transmission enhancements identified in the study to support VEGP Units 3 and 4 are in service.
- The system short-circuit model included all future generation typically assumed for planning horizon cases.
- VEGP Units 1 and 2 were each assumed to have been up-rated to 1280 MW gross output and the station service load for these two units was modeled explicitly. New Units 3 and 4 were assumed to produce 1262 MW each. Each new unit's station service load was modeled at 78.2 MW and 41.7 Mvars, as provided by Westinghouse.

The VEGP grid stability analysis examined two conditions: Normal Running and Turbine Trip. Other conditions (i.e., startup and normal shutdown) are bounded by these analyses.

The grid stability analysis for Normal Running condition utilized an appropriate load flow case while considering various fault conditions. The most critical contingencies considered in the study are:

- Loss of the most critical transmission lines (three-phase fault on W. McIntosh 500 kV line; three-phase fault on South Carolina Electric and Gas (SCEG) 230 kV line; three-phase fault on W. McIntosh 500 kV line followed by breaker failure at the VEGP 500 kV switchyard)
- Loss of the largest load in the area of the VEGP units (loss of Augusta Newsprint load)
- Loss of the largest unit in the area [three-phase fault on the low side of GSU for VEGP Unit 3; three-phase fault on the low side of GSU for VEGP Unit 4 (tripping VEGP 1 or 2 rather than VEGP 3 or 4 would not change the results for loss of the largest unit in the area)]
- A 500 kV line (Warthen) out for maintenance with a normally cleared fault on another 500 kV line (W. McIntosh) was also studied.

The grid stability analysis for Turbine Trip condition included simulations of turbine trip events for VEGP Unit 3 and for VEGP Unit 4. These simulations included scenarios when the station service load is fed from the unit auxiliary transformers (UATs) and from the reserve auxiliary transformers (RATs).

b) For the VEGP Units 3 and 4 grid voltage evaluation, the 500-kV voltage was set to 517-kV (1.03p.u.) and the 230-kV voltage was set to 235-kV (1.02p.u.).

c) The grid stability analysis considered worst-case disturbances for which the grid has been analyzed to remain stable. The worst-case disturbances analyzed include the loss of the largest capacity being supplied to the grid, removal of the largest load from the grid, or loss of the most critical transmission line. The results of the study demonstrate that for these worst-case contingencies, the generator bus voltages (after fault clearing) remain within the Westinghouse requirement of +/- 20% for transient events.

d) The grid stability analysis included station auxiliary loads for all four units. VEGP Units 1 and 2 were each assumed to have been up-rated to 1280 MW gross output and the station service load for these two units was modeled explicitly. New Units 3 and 4 were assumed to produce 1262 MW each. Each new unit's station service load was modeled at 78.2 MW and 41.7 Mvars, as provided by Westinghouse.

e) The load flow and stability studies were performed using Siemens PTI PSS/E (Power System Simulator for Engineering) software version 30.2.1. The short circuit analysis was conducted using Electrocon International Inc. CAPE (Computer-Aided Protection Engineering) software version March 2005.

f) Grid stability studies, short circuit analysis and load flow studies are performed to support changes to plant and system configurations through periodic updates. The load flow studies are performed every year. The grid stability study and short circuit analysis are performed only when changes in the system warrant it (typically about every 5 years).

NRC RAI Number 08.02-9:

Section 8.2.2 of the FSAR states that "[i]n order to maintain Reactor Coolant Pump (RCP) operation for three seconds following a turbine trip as specified in DCD Subsection 8.2.2, the grid voltage at the highside of the GSU, and RATs cannot drop more than 15 percent from the pre-trip steady-state voltage." In this regard, provide the following information:

Is this voltage based on worst expected switchyard voltage?

SNC Response:

As discussed in FSAR Subsection 8.2.2:

"The study analyzes transient stability utilizing an appropriate load flow case while considering various fault contingencies. In order to complete the forward looking study, the following assumptions are made:

- Grid voltage is 235 kV and 517 kV
- Unit 3 GSU voltage ration 230/26 kV with a 1.05 p.u. tap setting
- Unit 4 GSU voltage ratio 525/26 kV with a 1.0 p.u. tap setting"

The switchyard voltages of 235 kV and 517 kV are the lowest expected values of the voltage schedules at the VEGP site. After the completion of VEGP Units 3 and 4, there will be two units tied to the 500 kV switchyard and two units tied to the 230 kV switchyard. With one unit off-line, the other unit will be able to hold scheduled voltage even if a transmission line is also out. Therefore, the worst expected voltage would be the scheduled voltage, which is what was used in the grid stability study.