Progress Energy

Crystal River Nuclear Plant
Docket No 50-302
Operating License No. DPR-72

Ref: 10 CFR 50.54(f)

April 3, 2006
3F0406-06

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
11555 Rockville Pike
Rockville, Maryland 20852

Subject: Crystal River Unit 3 – 60-Day Response to NRC Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power"

Reference: Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," dated February 1, 2006

Dear Sir:

On February 1, 2006, the Nuclear Regulatory Commission (NRC) issued Generic Letter (GL) 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power," which requested licensees to provide information within 60 days of the date of the GL. Florida Power Corporation (FPC), doing business as Progress Energy Florida, Inc., hereby provides the requested 60-day response to GL 2006-02 for the Crystal River Unit 3 Nuclear Plant.

This letter establishes no new regulatory commitments.

If you have any questions regarding this submittal, please contact Mr. Paul Infanger, Supervisor, Licensing and Regulatory Programs at (352) 563-4796.

Sincerely,

Dale E Young

Dale E. Young
Vice President
Crystal River Nuclear Plant

DEY/dar

Attachment:
60-Day Response to NRC Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power"

xc: NRR Project Manager
Regional Administrator, Region II
Senior Resident Inspector

A123

Progress Energy Florida, Inc.
Crystal River Nuclear Plant
15760 W. Powerline Street
Crystal River, FL 34428

STATE OF FLORIDA

COUNTY OF CITRUS

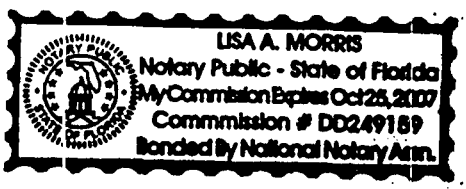
Dale E. Young states that he is the Vice President, Crystal River Nuclear Plant for Florida Power Corporation, doing business as Progress Energy Florida, Inc.; that he is authorized on the part of said company to sign and file with the Nuclear Regulatory Commission the information attached hereto; and that all such statements made and matters set forth therein are true and correct to the best of his knowledge, information, and belief.

Dale E Young

Dale E. Young
Vice President
Crystal River Nuclear Plant

The foregoing document was acknowledged before me this 3rd day of April, 2006, by Dale E. Young.

Lisa A Morris



Signature of Notary Public
State of Florida

LISA A MORRIS

(Print, type, or stamp Commissioned
Name of Notary Public)

Personally Known X -OR- Produced Identification _____

PROGRESS ENERGY

CRYSTAL RIVER UNIT 3

DOCKET NUMBER 50-302 / LICENSE NUMBER DPR -72

ATTACHMENT

60-Day Response to NRC Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power"

Responses to Questions from Generic Letter 2006-02

1. Use of protocols between the NPP licensee and the TSO, ISO, or RC/RA to assist the NPP licensee in monitoring grid conditions to determine the operability of offsite power systems under plant TS.

   (a) Do you have a formal agreement or protocol with your TSO?

   Response:

   Yes. Progress Energy nuclear plants (which include Crystal River Unit 3 [CR3]), manage interfaces to the Transmission Department and System Planning and Operations Department via a formal Interface Agreement, NGGM-IA-0003, "Transmission Interface Agreement for Operation, Maintenance, and Engineering Activities at Nuclear Power Plants." The nuclear power plant and transmission system operations are conducted under a vertically integrated utility business model. Under this business model, the transmission system is not in a Regional Transmission Organization (RTO) or operated by an ISO as is the case in other parts of the country. Instead, under the vertically integrated utility business model, the System Operators (Grid Operators) operate both the transmission and generation systems (nuclear and non-nuclear) and work in the same company that holds the licenses to operate the Nuclear Power Plants. Nuclear Power Plant offsite power reliability is jointly managed by the System Operators, Transmission Personnel, and licensed Nuclear Plant Personnel through communications and actions governed and coordinated by the formal Interface Agreement.

   (b) Describe any grid conditions that would trigger a notification from the TSO to the NPP licensee and if there is a time period required for the notification.

   Response:

   With respect to potential grid problems which may be anticipated in advance, the Interface Agreement requires both daily and weekly communications between Nuclear Plant Operations and System Operations to discuss the status of the plant and the transmission system, review upcoming work activities, and discuss the operating conditions scheduled or anticipated for the current day and the next seven days.

   In addition to normal operational communications, the System Operators initiate communications to the Nuclear Plant Operators for the following infrequent or off-normal situations:

   - **Plant Transmission Line Out (Tier 1 Line Out):** ***When a transmission line directly connected to the plant switchyard is taken out.***

   - **Grid Condition "Red" (Red Light On):** ***A "Grid Condition Red" situation occurs if a single contingency (possible failure) could result in a generation – load imbalance that may require load curtailments or firm load shedding to correct. This imbalance could be due to insufficient system resources, insufficient off-system resources or transmission import limitations. Plant personnel should curtail activities that increase***

the risk of tripping a unit or may cause any loss of generation. Plants should be notified of an anticipated "Grid Condition Red" as early as practical.

- **Anticipated Loss of Coolant Accident (LOCA) Voltage Support Problem:** *A grid condition where offsite power voltage support is expected to degrade at some time in the future and become inadequate for the plant to remain connected to offsite power during post-trip LOCA load sequencing. In this scenario, post-trip LOCA voltage support from offsite power would still be good.*

- **Actual LOCA Voltage Support Problem:** *A grid condition where offsite power voltage support is already inadequate such that the plant would not remain connected to offsite power during post-trip LOCA load sequencing due to actuation of the degraded grid voltage relays. Under these conditions, post-trip LOCA voltage support from offsite power would not be good.*

- **Significant Grid Frequency Problem:** *When the grid experiences frequency problems to the extent that continued safe operation of the generator may be jeopardized. Under these circumstances, conditions will need to be monitored closely.*

- **Substation Problem (Plant Impacting Substation Equipment Status Change)**

- **Severe Weather Conditions**

- **Sabotage**

- **Terrorism**

No specific time period is applied. The requirement is to make the notification promptly.

(c) Describe any grid conditions that would cause the NPP licensee to contact the TSO. Describe the procedures associated with such a communication. If you do not have procedures, describe how you assess grid conditions that may cause the NPP licensee to contact the TSO.

Response:

CR3 has developed a new Abnormal Procedure AP-730, Grid Instability. This new procedure will be issued when Cycle 6 of Licensed Operation Requalification Training is complete. This cycle has specific classroom and simulator training associated with the new procedure.

AP-730, Grid Instability, includes the following "Entry Conditions":

- **System Dispatcher notification of 230 KV voltage <236.4 KV or > 243.6 KV**

- **System Dispatcher notification of existing or imminent grid instability**

- **ES 4160V bus voltage < 4150V or > 4400V**

- **Unstable grid frequency**

The last two entry conditions would be cause for initiation of communication from CR3 to the Energy Control Center (ECC) if the ECC had not already been aware of degraded conditions. The first two conditions fall under the ECC's area of responsibility.

Compliance Procedure CP-253, Power Operation Risk Assessment and Management, describes the process used to perform risk assessments of online Maintenance activities in the plant and to manage these activities' risks. Part of this management is the consideration of availability and reliability of offsite power. Specifically, this document states that when emergent risk changes occur that increase the importance of offsite power reliability, grid operators at the ECC should be notified.

Emergency Procedure EM-220, Violent Weather, provides guidance of activities during violent weather to ensure plant safety. The document states that the status of the grid as determined by discussions with the ECC and other fossil units should be taken into consideration before placing the plant in Mode 3 when the plant is in Modes 1 or 2 during a Category 1 or 2 hurricane.

Under most conditions the ECC by nature of his or her function would identify or be knowledgeable of conditions that could challenge the operability of offsite power systems under plant TS and would initiate by procedure communications with CR3. The thresholds for action/notification are above limits necessary to ensure operability of the ES 4160V power supplies. This process is described below:

Administrative Instruction AI-500, Conduct of Operations Department Organization and Administration, requires communications from CR3 to the TSO to request ECC to provide time and duration estimate when:

- Grid condition is red (red light is on)
- Energy Emergency Alert (EEA levels 1 – 3)
- Grid contingency voltage support problem
- Actual LOCA voltage support problem
- Significant grid frequency problem
- Other grid-related problems such as ECC prediction tool or computer problems, key transmission lines out of service, substation problems, neighboring utility problem , sabotage, or terrorism

AI-500 also requires the Control Room to notify the CR3 PTAC (CR3 Engineering interface between CR3 and the TSO) whenever any of the above conditions arise.

Surveillance Procedure SP-321, Power Distribution Breaker Alignment and Power Availability Verification, currently list CR3's actual operability voltage numbers. This procedure also list times when actual low voltage is verified in communications with the dispatcher.

(d) Describe how NPP operators are trained and tested on the use of the procedures or assessing grid conditions in question 1(c).

Response:

Initial training on communication between the NPP and the TSO was performed with an Operations Study Book Entry (OSB) 0503-04. This OSB discussed the North American Electric Reliability Council (NERC) Readiness Audit and the use of NGGM-IA-0003, "Transmission Interface Agreement for Operation, Maintenance, and Engineering Activities at Nuclear Plants," specifically steps 6.2.1 and 6.2.2.

Further training of actions for point of discharge temperature or grid voltage control were issued in Short Term Instructions (STI) 05-018 (8/24/05) and 05-019 (9/7/05) which were reissued as STI 05-027 (11/24/05). STI 05-027 discusses actions for a potential degraded voltage condition if high MWe and MVAR loading are combined with a loss of fossil plants supplying the 230 KV grid. STI-05-027 has sections that have been incorporated in AI-500, Conduct of Operations Department Organization and Administration, and AI-1300, Engineering, Maintenance and Support Interfaces. These changes will be reflected in classroom lesson plan OPS-5-38, Administrative Instructions, AI-500, OPS-NGGC-1306, OPS-NGGC-1303, AI-506 and AI-513. OPS-5-38 is in all operator initial and continuing training programs.

Discussion of communications with the TSO has also been added to classroom lesson plan OPS-4-88, Switchyard and Transformers, Section 1-8.0 C., Grid Reliability. This section includes discussion of AP-770, Emergency Diesel Generator Actuation, OP-707, Operation of the ES Emergency Diesel Generators, and EM-220, Violent Weather. Training Department tracking mechanisms are in place to add further information concerning AP-730, Grid Instability, when issued.

Simulator lesson plan LOR-1-026, "Low Power Operations/ISLOCA/Grid Instability," has been written and includes AP-730 training along with appropriate TS training. Training Department tracking mechanisms are in place to place LOR-1-026 in the Licensed Operator Continuing Training (LOCT) "backbone" schedule. During Cycle 6 LOCT of 2006 (March 6 through April 7), training will be performed on AP-730. A similar simulator lesson plan will be generated for initial training.

Once trained, operator testing occurs per the normal initial and continuing training programs based on NUREG 1021 standards and training departmental procedures.

(e) If you do not have a formal agreement or protocol with your TSO, describe why you believe you continue to comply with the provisions of GDC 17 as stated above, or describe what actions you intend to take to assure compliance with GDC 17.

Response:

Not applicable, a formal agreement is used as described in the response to question 1.a.

(f) If you have an existing formal interconnection agreement or protocol that ensures adequate communication and coordination between the NPP licensee and the TSO, describe whether this agreement or protocol requires that you be promptly notified when

the conditions of the surrounding grid could result in degraded voltage (i.e., below TS nominal trip setpoint value requirements; including NPP licensees using allowable value in its TSs) or LOOP after a trip of the reactor unit(s).

Response:

The Interface Agreement requirements that are in place are accomplished by the System Operators who monitor key grid parameters and use predictive analysis tools. The procedure used by the System Operators directs them to promptly notify Nuclear Plant Operators of conditions for which there would not be adequate switchyard voltage, including predicted post nuclear plant trip conditions. Separate procedural steps are included in these procedures for both conditions which currently exist and conditions which are anticipated to occur. The intent of these separate steps is to provide as much early warning to Nuclear Plant Operations of problem conditions as is possible.

(g) Describe the low switchyard voltage conditions that would initiate operation of plant degraded voltage protection.

Response:

If the switchyard voltage is low enough to result in a safety bus voltage of 3969V, the top end of the degraded grid voltage relaying (DVR) actuation set point, (227.7 KV in the switchyard) for greater than 5 seconds, the second level undervoltage relays will actuate disconnecting the safety buses from offsite power and transferring the loads to the onsite emergency diesel generators. However, the minimum required switchyard voltage provided to the grid operators to run the system (232.4 KV) is high enough to prevent this from occurring during post-trip load sequencing.

The preferred and alternate sources of offsite power for the 4160V ES buses are the Offsite power transformer (OPT) and Back-up Engineered Safeguards ES transformer (BEST) which are both powered from the 230 KV switchyard. The normal operating voltage range of the 230 KV switchyard is 238 KV to 242 KV which is conservatively enveloped by electrical design basis calculations by using 240 KV ± 1.5 %, i.e., 236.4 KV to 243.6 KV. For degraded grid voltage conditions, the ES 4160V buses voltage level must contain sufficient margin to accommodate the addition of Engineered Safeguards (ES) loads and still remain above the reset voltage of the DVR in order to prevent the DVR from transferring the ES buses to the Emergency Diesel Generators. If prior to ES actuation the ES buses voltage was 4150 V or higher, the addition of ES loads will cause this voltage to drop due to additional voltage drop through OPT and BEST but will remain above 4009 V, the top end of the DVR reset setpoint. The 230 KV switchyard voltage corresponding to the ES buses voltage of 4150V, with some margin, is 232.4 KV. The DVR has a reset set point of 3992V ± 17V and an actuation set point of 3952V ± 17V. The 230 KV switchyard voltage corresponding to 3969V, the top end of the DVR actuation set point is 227.7 KV.

2. Use of criteria and methodologies to assess whether the offsite power system will become inoperable as a result of a trip of your NPP.

(a) Does your NPP's TSO use any analysis tools, an online analytical transmission system studies program, or other equivalent predictive methods to determine the grid conditions that would make the NPP offsite power system inoperable during various contingencies?

If available to you, please provide a brief description of the analysis tool that is used by the TSO.

Response:

Yes, the System Operators use monitoring / predictive analysis computer programs that can predict nuclear plant switchyard voltages expected to occur upon realization of any one of a number of possible losses to the grid, such as a trip of the nuclear plant generator, a trip of another large generator, or the loss of an important transmission line. This monitoring / predictive analysis computer program tool operates based on raw data from transducers across the system which is processed through a state estimator to generate a current state snapshot of the system. This output is then processed through a contingency analysis program that generates a set of new results with various single elements of the system out of service (OOS). These results are then screened against a predetermined set of acceptance limits. Postulated scenarios which then do not meet the acceptance limits are listed for review by the System Operator.

(b) Does your NPP's TSO use an analysis tool as the basis for notifying the NPP licensee when such a condition is identified? If not, how does the TSO determine if conditions on the grid warrant NPP licensee notification?

Response:

Yes, notifications are made based on unsatisfactory monitoring / predictive analysis computer program tool results.

(c) If your TSO uses an analysis tool, would the analysis tool identify a condition in which a trip of the NPP would result in switchyard voltages (immediate and/or long-term) falling below TS nominal trip setpoint value requirements (including NPP licensees using allowable value in its TSs) and consequent actuation of plant degraded voltage protection? If not, discuss how such a condition would be identified on the grid.

Response:

Yes, monitoring / predictive analysis tools and procedures are in place for this purpose. However, CR3 output goes to the 500 KV substation. Offsite power is fed from the 230 KV substation. A plant trip has little or no impact on the capability of the offsite power system to supply necessary voltage support to the plant.

(d) If your TSO uses an analysis tool, how frequently does the analysis tool program update?

Response:

The analysis tool updates every 5 minutes.

(e) Provide details of analysis tool-identified contingency conditions that would trigger an NPP licensee notification from the TSO.

Response:

Monitoring / predictive analysis computer program validated results that do not meet the predetermined acceptance limit for minimum required switchyard voltage would trigger a notification. The analyzed contingencies that are evaluated against the Nuclear Power Plant (NPP) voltage requirements include loss of another generator, loss of a significant transmission line, loss of a transformer, or loss of the NPP itself.

The same minimum required switchyard voltage limit bases that are used in the grid operating procedures are also used in the predictive analysis computer programs. A communications protocol has been established between the TSO and the CR3 Operator to ensure that more frequent communication exchange occurs between the TSO and CR3 if the N-1 Real Time Contingency Analysis predicts that a potential loss of a generating unit or transmission line feeding into the 230 KV switchyard could cause the 230 KV switchyard voltage to fall below 232.4 KV.

(f) If an interface agreement exists between the TSO and the NPP licensee, does it require that the NPP licensee be notified of periods when the TSO is unable to determine if offsite power voltage and capacity could be inadequate? If so, how does the NPP licensee determine that the offsite power would remain operable when such a notification is received?

Response:

Yes, if analysis tools are OOS to such an extent that system conditions are indeterminate, then implementing procedures used by the System Operators require notification to be made because a condition would exist which is not within the guidelines of the procedure. Upon such notification, the NPP licensee will make an offsite power operability determination under the plant TSs. In addition, the System Operator will continue efforts to determine by alternate method(s) (e.g., off-line studies) if NPP voltage requirements are satisfied or not.

(g) After an unscheduled inadvertent trip of the NPP, are the resultant switchyard voltages verified by procedure to be bounded by the voltages predicted by the analysis tool?

Response:

No, not by procedure. However, if a disturbance causes a large perturbation in voltage, further analysis would be performed. Crystal River Unit 3 trips have not caused a large enough perturbation in voltage to justify further investigation and analysis. This is primarily due to the output of the generator being connected to the 500 KV switchyard, while offsite power uses the 230 KV switchyard as its source.

(h) If an analysis tool is not available to the NPP licensee's TSO, do you know if there are any plans for the TSO to obtain one? If so, when?

Response:

Not applicable, an analysis tool is available.

(i) If an analysis tool is not available, does your TSO perform periodic studies to verify that adequate offsite power capability, including adequate NPP post-trip switchyard voltages (immediate and/or long-term), will be available to the NPP licensee over the projected timeframe of the study?

Response:

Not applicable, an analysis tool is available.

(a) Are the key assumptions and parameters of these periodic studies translated into TSO guidance to ensure that the transmission system is operated within the bounds of the analyses?

Response:

Not applicable.

(b) If the bounds of the analyses are exceeded, does this condition trigger the notification provisions discussed in question 1 above?

Response:

Not applicable.

(j) If your TSO does not use, or you do not have access to the results of an analysis tool, or your TSO does not perform and make available to you periodic studies that determine the adequacy of offsite power capability, please describe why you believe you comply with the provisions of GDC 17 as stated above, or describe what compensatory actions you intend to take to ensure that the offsite power system will be sufficiently reliable and remain operable with high probability following a trip of your NPP.

Response:

Not applicable, a predictive analysis tool is used.

3. Use of criteria and methodologies to assess whether the NPP's offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.

(a) If the TSO notifies the NPP operator that a trip of the NPP, or the loss of the most critical transmission line or the largest supply to the grid would result in switchyard voltages (immediate and/or long-term) below TS nominal trip setpoint value requirements

(including NPP licensees using allowable value in its TSs) and would actuate plant degraded voltage protection, is the NPP offsite power system declared inoperable under the plant TSs? If not, why not?

Response:

No. For CR3, the plant output goes to the 500 KV substation and the offsite power is fed from the 230 KV substation. A plant trip has little or no impact on the capability of the offsite power system to supply necessary voltage support to the plant to meet TSs because the two transmission systems are not connected together at the plant.

The offsite power system is not declared inoperable per the TS when a contingency analysis indicates that the post-contingency switchyard voltage would lower below 232.4 KV because the contingencies that can yield this result are not nuclear plant trip contingencies and would not have actually occurred at the time. Should such a contingency actually occur, safety bus voltage is used to determine operability of the post contingency offsite power source. As long as actual ES 4160V bus voltage is maintained within limits, the offsite power system remains operable. In summary, due to the configuration of CR3 generation and offsite power sources (plant output to 500 KV system with offsite supply from 230 KV system), operability of offsite power can be directly monitored at the safety buses and actual safety bus voltage can be used to determine operability in regard to voltage support adequacy provided from offsite power. Non-nuclear plant trip contingencies which have not actually occurred trigger increased monitoring at the plant but do not require entry into TSs.

If actual switchyard voltage is maintained ≥ 232.4 KV, calculations show that in the event of a plant trip, an Engineered Safeguards actuation, and the addition of essential manual loads, that ES 4160V bus voltages are maintained sufficiently high to prevent actuation of degraded voltage protection and thus the offsite power system is able to perform its design function.

In accordance with ITS 3.8.1, the offsite power system remains Operable as long as proper voltage and frequency is maintained on the ES 4160V buses. Per SP-321, Power Distribution Breaker Alignment and Power Availability Verification, if ES 4160V bus voltage is maintained ≥ 4150 V or switchyard voltage is maintained ≥ 236.4 KV, then the offsite power system remains Operable per the TSs.

(b) If onsite safety-related equipment (e.g., emergency diesel generators or safety-related motors) is lost when subjected to a double sequencing (LOCA with delayed LOOP event) as a result of the anticipated system performance and is incapable of performing its safety functions as a result of responding to an emergency actuation signal during this condition, is the equipment considered inoperable? If not, why not?

Response:

No formal plant specific evaluation of record exists for this scenario (LOCA with delayed Loss of Offsite Power [LOOP] event) at CR3 because a LOCA followed by a delayed LOOP is not a part of the CR3 Licensing basis.

The CR3 Licensing basis is a simultaneous LOCA and LOOP event coincident with one worst case single failure. However, the Emergency Diesel Generator (EDG) calculations have been performed to evaluate a LOOP followed by a delayed LOCA event, coincident with one worst case single failure. This scenario is more severe than a LOCA followed by delayed LOOP event, coincident with one worst case single failure, with regard to EDG

voltage dips response, frequency dips response and loading. The worst case single failure which is assumed to occur coincident with a simultaneous LOOP and LOCA event or a LOOP followed by a delayed LOCA event is the complete loss (and therefore inoperability) of one entire train of ES equipment including the EDG for that train. The results of this analysis for CR3 are acceptable. Double sequencing as a result of a LOCA followed by a delayed LOOP event is not postulated to coincide with more than one worst case single failure. Based on the above, onsite safety-related equipment is not expected to be lost when subjected to a double sequencing (LOCA with delayed LOOP), and consequently is not declared inoperable due to any anticipated system performance events.

(c) Describe your evaluation of onsite safety-related equipment to determine whether it will operate as designed during the condition described in question 3(b).

Response:

No formal plant specific evaluation of record exists for this scenario (LOCA with delayed LOOP event) at CR3 because a LOCA followed by a delayed LOOP is not a part of the CR3 Licensing basis. However, the CR3 EDG loading calculations evaluate a LOOP followed by a delayed LOCA event, coincident with one worst case single failure. The worst case single failure is the complete loss (and therefore inoperability) of one entire train of ES equipment including the EDG for that train. Since LOOP occurs first, the analysis postulates that the operator manually applies all essential loads, needed to achieve a natural circulation cool down condition, to the EDG. After the operator has manually applied these loads, the delayed LOCA occurs and causes the EDG to respond to and carry the motor starting loading imposed by ES load sequencing as well as continuing to carry the already running manually applied essential loads. The essential loads are not stripped prior to ES load sequencing because the EDG was maintaining the bus voltage prior to the LOCA and therefore no under voltage condition, needed to strip these loads, occurred. The results of this analysis for CR3 are acceptable. In a LOCA followed by a delayed LOOP event, the first load sequencing occurs when the ES buses are on the offsite power sources. The delayed LOOP causes under voltage conditions which strip all loads including essential manual loads. When the subsequent load sequencing occurs, the EDG is called upon to carry only the loading imposed by ES load sequencing as there are no already running essential manual or other loads. Thus a LOCA followed by a delayed LOOP, coincident with one worst case single failure, is not as severe an event as a LOOP followed by a delayed LOCA event, coincident with one worst case single failure, with regard to EDG voltage dips response, frequency dips response and transient loading.

(d) If the NPP licensee is notified by the TSO of other grid conditions that may impair the capability or availability of offsite power, are any plant TS action statements entered? If so, please identify them.

Response:

The operability of the offsite power systems, as described in the TS LCO 3.8.1 Bases, is maintained if each offsite circuit is capable of maintaining rated frequency and voltage, and accepting required loads during an accident while connected to the ES 4160V buses. The 230 KV and 500 KV substations, while part of the offsite network, are not considered part of the circuit required by this LCO. The Operability of the offsite power systems is

supported by the substation provided the substation is capable of supplying the required post accident loads.

If actual switchyard voltage is maintained ≥ 232.4 KV, calculations show that in the event of a nuclear plant trip, an Engineered Safeguards actuation, and the addition of essential manual loads, that ES 4160V bus voltages are maintained sufficiently high to prevent actuation of degraded voltage protection and thus the offsite power system is able to perform its design function.

Per SP-321, "Power Distribution Breaker Alignment and Power Availability Verification," if ES 4160V bus voltage is maintained ≥ 4150 V or switchyard voltage is maintained ≥ 236.4 KV, then the offsite power system remains Operable.

If the TSO notifies CR3 of other grid conditions that may impair the capability of offsite power, then CR3 evaluates the specific conditions against the criteria above and makes a determination of whether or not the offsite power systems remain Operable per the TSs.

The offsite power system is not declared inoperable per the TSs when a contingency analysis indicates that the post-contingency switchyard voltage would lower below 232.4 KV because the contingencies that can yield this result are not nuclear plant trip contingencies as described in the response to question 3.a, and would not have actually occurred at the time. Should such a contingency actually occur, safety bus voltage is used to determine operability of the post contingency offsite power source as described in the response to question 3.a.

(e) If you believe your plant TSs do not require you to declare your offsite power system or safety-related equipment inoperable in any of these circumstances, explain why you believe you comply with the provisions of GDC 17 and your plant TSs, or describe what compensatory actions you intend to take to ensure that the offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.

Response:

The design and construction of the CR3 electrical system preceded 10 CFR 50 Appendix A. CR3 was constructed to the Principal Architectural and Design Criteria contained in FSAR Section 1.4. However, the general design criteria (GDCs) issued in 1971 were considered in the design and construction of CR3. The electric power system for CR3 is in compliance with the intent of 10 CFR 50 Appendix A, GDC 17, "Electric Power Systems," in that it provides independence and redundancy to ensure an available source of power to the Engineered Safeguards systems. CR3 TS Bases state that two qualified circuits are required to be operable to satisfy LCO 3.8.1 (AC Sources-Operating):

- **The offsite power transformer, cabling through breakers 3211, and 3212, connecting to ES bus 3A and 3B respectively.**
- **The BEST transformer, BEST Auxiliary Bus 3, cabling and nonsegregated-phase bus through breakers 3205, and 3206, connecting to ES bus 3A and 3B respectively.**

The 230 KV and 500 KV substations, while part of the offsite network, are not considered part of the circuit required by LCO 3.8.1. The operability of the circuit is supported by the substation provided the substation is capable of supplying the required post accident loads.

If actual switchyard voltage is maintained ≥ 232.4 KV, calculations show that in the event of a plant trip, an Engineered Safeguards actuation, and the addition of essential manual loads, that ES 4160V bus voltages are maintained sufficiently high to prevent actuation of degraded voltage protection and thus the offsite power system is able to perform its design function.

In accordance with ITS 3.8.1, the offsite power system remains Operable as long as proper voltage and frequency is maintained on the ES 4160V buses. Per SP-321, if ES 4160V bus voltage is maintained ≥ 4150 V or switchyard voltage is maintained ≥ 236.4 KV, then the offsite power system remains Operable per the TSs.

The offsite power system is not declared inoperable per the TSs when a contingency analysis indicates that the post-contingency switchyard voltage would lower below 232.4 KV because the contingencies that can yield this result are not nuclear plant trip contingencies and would not have actually occurred at the time. Should such a contingency actually occur, safety bus voltage is used to determine operability of the post contingency offsite power source. As long as actual ES 4160V bus voltage is maintained within limits, the offsite power system remains operable. In summary, due to the configuration of CR3 generation and offsite power sources (plant output to 500KV system with offsite supply from 230 KV system), operability of offsite power can be directly monitored at the safety buses and actual safety bus voltage can be used to determine operability in regard to voltage support adequacy provided from offsite power. Non-nuclear plant trip contingencies which have not actually occurred trigger increased monitoring at the plant but do not require entry into TSs.

(f) Describe if and how NPP operators are trained and tested on the compensatory actions mentioned in your answers to questions 3(a) through (e).

Response:

Training for TSs is covered in the classroom for both initial and continuing training using OPS-5-01, "Technical Specifications." OPS-5-01 is an overview of the use of TS and their Bases. The TS Bases clearly define what is required for "operable" equipment. Application of TS and their Bases are practiced in many Simulator Scenarios both in initial and continuing training. Simulator lesson plan LOR-1-026, "Low Power Operations/ISLOCA/Grid Instability," has been written and includes AP-730 training along with appropriate TS application. Safety system component operability is handled in the same methodology.

Annunciator response, which is covered in both initial and continuing classroom and simulator training, assists in operability determination. AR-702, "SSF Q Annunciator Response," as an example, contains alarms that indicate conditions of an inoperable offsite power supply.

Once trained, operator testing occurs per the normal initial and continuing training programs based on NUREG 1021 standards and training departmental procedures.

4. Use of criteria and methodologies to assess whether the offsite power system will remain operable following a trip of your NPP.

(a) Do the NPP operators have any guidance or procedures in plant TS bases sections, the final safety analysis report, or plant procedures regarding situations in which the

condition of plant-controlled or -monitored equipment (e.g., voltage regulators, auto tap changing transformers, capacitors, static VAR compensators, main generator voltage regulators) can adversely affect the operability of the NPP offsite power system? If so, describe how the operators are trained and tested on the guidance and procedures.

Response:

Yes. Of the equipment identified in the question, the main generator voltage regulator is the only one applicable to CR3. However, there are no consequences to the off-site power source following a trip of the plant. CR3 output is provided to the 500 KV switchyard. The power to both the preferred and alternate sources of offsite Power (OPT and BEST) is provided from the 230 KV switchyard. The two switchyards are electrically separate and loss of CR3 will only affect the voltage for the 500 KV switchyard, not the 230 KV switchyard. Hence, the 230 KV switchyard and the two offsite power sources (OPT and BEST) are unaffected by the loss of CR3 generator output.

Training for TSs is covered in the classroom for both initial and continuing training using OPS-5-01, "Technical Specifications." OPS-5-01 is an overview of the use of TS and their Bases. The TS Bases clearly define what is required for "operable" equipment. Application of TS and their Bases are practiced in many Simulator Scenarios both in initial and continuing training. Simulator lesson plan LOR-1-026, "Low Power Operations/ISLOCA/Grid Instability," has been written and includes AP-730 training along with appropriate TS application.

Annunciator response, which is covered in both initial and continuing classroom and simulator training assists in operability determination. AR-702, SSF Q Annunciator Response, as an example, contains alarms that indicate conditions of an inoperable offsite power supply.

Once trained, operator testing occurs per the normal initial and continuing training programs based on NUREG 1021 standards and training departmental procedures.

(b) If your TS bases sections, the final safety analysis report, and plant procedures do not provide guidance regarding situations in which the condition of plant-controlled or -monitored equipment can adversely affect the operability of the NPP offsite power system, explain why you believe you comply with the provisions of GDC 17 and the plant TSs, or describe what actions you intend to take to provide such guidance or procedures.

Response:

Not applicable. Guidance is provided.

5. Performance of grid reliability evaluations as part of the maintenance risk assessments required by 10 CFR 50.65(a)(4).

(a) Is a quantitative or qualitative grid reliability evaluation performed at your NPP as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4) before performing grid-risk-sensitive maintenance activities? This includes surveillances, post-maintenance testing, and preventive and corrective maintenance that could increase the probability of a plant trip or LOOP or impact LOOP or SBO coping capability, for example, before

taking a risk-significant piece of equipment (such as an EDG, a battery, a steam-driven pump, an alternate AC power source) out-of-service?

Response:

Yes. Procedure CP-253, "Power Operation Risk Assessment and Management," directs this review in Section 4.4, Determination of Risk Management Actions, Step 4.4.3.

- **Actions should consider the current status of the offsite power system when risk is initially assessed and respond to a change in the status of the offsite power system that requires risk re-evaluation (grid "red light on").**
- **Grid operators at the ECC should be notified when emergent risk changes occur that increase the importance of offsite power reliability to the plant.**
- **Low risk transmission related work can be allowed with minimal restrictions while moderate and high risk tasks continue to be scrutinized and controlled by the work management process. The PTAC will be relied upon to evaluate individual tasks and categorize them appropriately to the Work Week Manager (WWM).**

(b) Is grid status monitored by some means for the duration of the grid-risk-sensitive maintenance to confirm the continued validity of the risk assessment and is risk reassessed when warranted? If not, how is the risk assessed during grid-risk-sensitive maintenance?

Response:

Yes. Interface Agreement NGGM-IA-0003, "Transmission Interface Agreement for Operation, Maintenance, and Engineering Activities at Nuclear Plants," Section 6.2, discusses the day-to-day Operations communications between the TSO and the plant. For instance, it requires System Operations to contact Nuclear Plant Operations – Control Room each business day to discuss plant status, grid status, and to review upcoming work activities for the day.

Risk reassessment regarding changes in the condition of the grid is conducted as described in plant procedure CP-253, Section 4.4.3 which states:

"Risk Management Actions consider the availability and reliability of offsite power.

- **"Actions should consider the current status of the offsite power system when risk is initially assessed and respond to a change in the status of the offsite power system that requires risk re-evaluation (grid "red light on").**
- **"Grid operators at the energy control center should be notified when emergent risk changes occur that increase the importance of offsite power reliability to the plant.**
- **Low risk transmission related work can be allowed with minimal restrictions while moderate and high risk tasks continue to be scrutinized and controlled by the work management process. The PTAC will be relied upon to evaluate individual tasks and categorize them appropriately to the WWM.**

(c) Is there a significant variation in the stress on the grid in the vicinity of your NPP site caused by seasonal loads or maintenance activities associated with critical transmission elements? Is there a seasonal variation (or the potential for a seasonal variation) in the LOOP frequency in the local transmission region? If the answer to either question is yes, discuss the time of year when the variations occur and their magnitude.

Response:

Yes, variations in grid stress do occur when load peaks during the summer months (June through September) as well as when spring and fall maintenance outage activities are planned. These variations are predictable, planned for, and managed. The magnitude of the variations results in less margin in the system to provide adequate voltage support. For this reason, additional analytical studies are used to ensure adequate voltage support is maintained during these periods.

CR3 has never had a total LOOP event. However, seasonal variation regarding partial LOOP events is shown below. These were plant-centered or severe weather related and not indicative of the reliability of the grid in the local transmission region.

CR3 Partial LOOPs as a Function of Season

Plant	Spring Mar.-May	Summer June-Aug.	Fall Sept.-Nov.	Winter Dec.-Feb.
CR3	5	5	2	1

Note: Six of the above partial LOOP events occurred during severe weather -- one in the spring, three in the summer, one in the fall and one in the winter. Additional information on these events is provided in the following documents:

- **Letter number 3F0103-06, dated January 10, 2003, "Crystal River Unit 3 – Response to Request for Additional Information, Proposed License Amendment Request, "Emergency Diesel Generator Allowed Outage Time Extension (TAC No. MB5616)"**
- **Letter number 3F1004-06, dated October 29, 2004, "Licensee Event Report 50-302 / 2004-003-00"**

(d) Are known time-related variations in the probability of a LOOP at your plant site considered in the grid-risk-sensitive maintenance evaluation? If not, what is your basis for not considering them?

Response:

No, not based on the time of year. Variations in the probability of a LOOP are addressed based on notification protocols with the TSO and local weather predictions regardless of the time of year. The grid around CR3 typically experiences higher levels of grid loading during some portions of the summer or winter months. System Operators evaluate grid load stress and notify CR3 accordingly through grid condition red alerts. When such notifications are made, plant risk evaluations are adjusted as described in plant procedure

CP-253, Section 4.4.3. These alerts are generally predictable in advance and are thus considered in weekly maintenance planning. CP-253, Enclosure 3 has Event Frequency Adjustments which take factors into consideration that may affect the grid. It provides additional guidance on how much frequency of an event would increase when certain activities are occurring such as switchyard work, secondary plant surveillance (PT, calibration, etc.), and a failure during trip breaker testing.

Guidance is also provided to reduce the risk of a LOOP during periods of sever weather. Additionally, EM-220, Violent Weather, describes different steps to take to reduce the risk of a LOOP during sever weather such as switchyard debris control.

(e) Do you have contacts with the TSO to determine current and anticipated grid conditions as part of the grid reliability evaluation performed before conducting grid-risk-sensitive maintenance activities?

Response:

Yes. Interface agreement NGGM-IA-0003, "Transmission Interface Agreement for Operation, Maintenance, and Engineering Activities at Nuclear Plants," Section 6.2, discusses the day-to-day Operations communications between the TSO and the plant.

(f) Describe any formal agreement or protocol that you have with your TSO to assure that you are promptly alerted to a worsening grid condition that may emerge during a maintenance activity.

Response:

Interface Agreements are in place to establish the interfaces between the System Operators and the Nuclear Plant Operators. The agreements, along with the operating procedures used by the System Operators, ensure that early notification of worsening grid conditions take place. This occurs whether or not a specific maintenance activity is in progress at the plant.

With respect to potential grid problems which may be anticipated in advance, the agreement requires both daily and weekly communications between Nuclear Plant Operations and System Operations to discuss the status of the plant and the transmission system, review upcoming work activities, and discuss the operating conditions scheduled or anticipated for the next day and the next seven days. This communication provides a means for the grid and plant operators to know what is going on with each others systems.

With respect to potential grid problems which may occur with little or no advance warning, the System Operator is in a unique position to anticipate and assess grid problems via information obtained from the grid Supervisory Control and Data Acquisition System (SCADA System), communications with field personnel, communications with neighboring utilities, and timely reports from various weather services. Implementing procedures require that System Operations monitor system conditions and promptly notify Nuclear Plant Operations of any existing or anticipated conditions which would result in inadequate voltage support.

(g) Do you contact your TSO periodically for the duration of the grid-risk-sensitive maintenance activities?

Response:

Yes. Interface agreement NGGM-IA-0003, "Transmission Interface Agreement for Operation, Maintenance, and Engineering Activities at Nuclear Plants," Section 6.2, discusses the day-to-day Operations communications between the TSO and the plant.

(h) If you have a formal agreement or protocol with your TSO, describe how NPP operators and maintenance personnel are trained and tested on this formal agreement or protocol.

Response:

Training on communication between the NPP and the TSO for operators was performed with an Operations Study Book Entry (OSB) 0503-04. This OSB discussed the NERC Readiness Audit and the use of NGGM-IA-0003, "Transmission Interface Agreement for Operation, Maintenance, and Engineering Activities at Nuclear Plants," specifically Steps 6.2.1 and 6.2.2.

NPP operators and maintenance personnel have not been "formally" trained on SORMF-TD-08, Crystal River 230 KV and 500 KV Voltage Criteria. Action Request AR 00186193 has been generated in the CR3 Corrective Action Program with action to present this issue at the Training Program Committee (TPC) meetings for maintenance, operations and supervisor enhancement programs. CR3 maintenance personnel do not work on offsite power supplies.

Transmission Maintenance personnel are responsible for maintenance on transmission lines, switchyard equipment (i.e., breakers and relaying), and transformers that supply offsite power into the plant. These personnel receive initial and annual refresher training in accordance with the Interface Agreement.

(i) If your grid reliability evaluation, performed as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4), does not consider or rely on some arrangement for communication with the TSO, explain why you believe you comply with 10 CFR 50.65(a)(4).

Response:

Not applicable. A grid reliability evaluation is performed as part of maintenance risk assessments at CR3.

(j) If risk is not assessed (when warranted) based on continuing communication with the TSO throughout the duration of grid-risk-sensitive maintenance activities, explain why you believe you have effectively implemented the relevant provisions of the endorsed industry guidance associated with the maintenance rule.

Response:

Not applicable. Risk is assessed based on periodic communication with the Transmission System Operator throughout the duration of grid-risk-sensitive maintenance activities at CR3.

(k) With respect to questions 5(i) and 5(j), you may, as an alternative, describe what actions you intend to take to ensure that the increase in risk that may result from proposed grid-risk-sensitive activities is assessed before and during grid-risk-sensitive maintenance activities, respectively.

Response:

Not applicable. CR3 does not intend to take any alternative actions.

6. Use of risk assessment results, including the results of grid reliability evaluations, in managing maintenance risk, as required by 10 CFR 50.65(a)(4).

(a) Does the TSO coordinate transmission system maintenance activities that can have an impact on the NPP operation with the NPP operator?

Response:

Yes, the TSO coordinates transmission system maintenance activities that can have an impact on the NPP operation with the NPP operator and PTAC. The Interface Agreement (NGGM-IA-0003) defines and controls the Interfaces for Operation, Maintenance, and Engineering Activities at Nuclear Plants. The PTAC serves as the single point of contact for transmission engineering, construction, and maintenance activities impacting the nuclear plant. The PTAC is a full time position.

(b) Do you coordinate NPP maintenance activities that can have an impact on the transmission system with the TSO?

Response:

Yes. Coordination of testing and maintenance activities at CR3 that could affect electrical supply diversity is performed by the CR3 Outage and Scheduling organization and the PTAC, in accordance with NGGM-IA-0003. These activities are integrated into the online and outage scheduling processes per applicable site procedures. On line maintenance risk evaluations are performed for each work week as schedule changes occur. Safe shutdown risk assessments are also performed to evaluate each outage schedule prior to the outage. These reviews include representatives from the applicable Transmission Area Maintenance staff. This provides direct attention to transmission outage activities and aids in assessing their effects on defense in depth for electrical power supply.

(c) Do you consider and implement, if warranted, the rescheduling of grid-risk-sensitive maintenance activities (activities that could (i) increase the likelihood of a plant trip, (ii)

increase LOOP probability, or (iii) reduce LOOP or SBO coping capability) under existing, imminent, or worsening degraded grid reliability conditions?

Response:

Yes. Guidance concerning grid conditions are monitored by the TSO and are reported to the Unit Control Operator when a condition outside analyzed boundaries exists or is anticipated to occur. This guidance is documented in "System Operations Reference Manual - Florida SORMF-TD-08".

In addition, Section 6.2 of NGGM-IA-0003 discusses the "day-to-day operations" responsibilities and communications between TSO and the NPP Operations-Control Room. Section 7.2.8 describes the process for deferring previously scheduled work when needed.

Although there is no quantitative process for evaluating 'grid stability', CR3 does a qualitative assessment of risk, considering activities that may be scheduled for the switchyard or switching operations, grid manipulations that could affect the CR3 end of the grid. This risk assessment is described in response to question 6(d).

AI-500, Conduct of Operations Department Organization and Administration, describes what is done when the grid condition is red meaning there is not enough reserve capacity should CR3 have to come off line. Under these conditions, the ECC Coordinator calls the plant, informs them of the status, and the SSO does the following:

- **Notify the WWM to review the workweek schedule and FIN team work. This review should determine if there are any high-risk evolutions that are either in progress or scheduled. High risk evolutions include evolutions that increase the potential for loss of generation or have the potential to cause entry into a short duration LCO, and should be curtailed. The Superintendent Shift Operations and the Manager of Outage and Scheduling will determine whether the work will be performed.**
- **Notify the PTAC.**
- **Turn the red light on in the Control Room.**
- **Notify the Manager of Shift Operations if scheduled work is deferred / delayed as a result of the grid conditions.**
- **Discuss the Grid Red Light status at each crew turnover meeting.**
- **Contact the ECC and discuss the expected duration of the current grid condition.**

(d) If there is an overriding need to perform grid-risk-sensitive maintenance activities under existing or imminent conditions of degraded grid reliability, or continue grid-risk-sensitive maintenance when grid conditions worsen, do you implement appropriate risk management actions? If so, describe the actions that you would take. (These actions could include alternate equipment protection and compensatory measures to limit or minimize risk.)

Response:

Yes. Procedure CP-253, "Power Operation Risk Assessment and Management," directs this review in Section 4.4, Determination of Risk Management Actions. This entire section describes the actions that will be taken.

Section 4.4.7 provides instructions for: Risk Management Actions aimed at minimizing the risk magnitude. These actions include:

- **Minimize work in other areas that could impact event initiators.**
- **Minimize work in areas that could impact redundant components to further ensure their availability ("Protect" components).**
- **Establish alternate success paths for the OOS equipment.**
- **Use of designated personnel to restore equipment or accomplish alternate success paths.**

(e) Describe the actions associated with questions 6(a) through 6(d) above that would be taken, state whether each action is governed by documented procedures and identify the procedures, and explain why these actions are effective and will be consistently accomplished.

Response:

These are required Maintenance Rule processes governed by plant procedures; as such, the effectiveness and consistency is continually assessed and monitored. Interface Agreement NGGM-IA-0003 is the primary document which establishes the interfaces between the Grid Operators and the Nuclear Plant Operators. This agreement, along with the operating procedures used by the Grid Operators, ensures compliance. This agreement is binding in that it has been approved at the company Department level and periodic assessments are conducted to ensure compliance. In regards to identifying offsite power requirements, the importance of meeting these requirements, and recognizing that nuclear plants have high priority when restoring power, all of these attributes are included in the agreement and implemented as described.

(f) Describe how NPP operators and maintenance personnel are trained and tested to assure they can accomplish the actions described in your answers to question 6(e).

Response:

Training for the above mentioned topics is presented to NPP operators, maintenance and other "need-to-know" personnel by the Transmission Department.

Once trained, operator (NPP operations only) testing occurs per the normal initial and continuing training programs based on NUREG 1021 standards and training departmental procedures.

The PTAC has a common Engineering Support Personnel (ESP) Training Guide ESG0072N which they are qualified to. Upon successful completion of the ESP Training Guide, the candidate will possess the knowledge and skills necessary to independently perform the tasks associated with PTAC.

Transmission Maintenance personnel are responsible for maintenance on transmission lines, switchyard equipment (i.e., breakers and relaying), and transformers that supply

offsite power into the plant. These personnel receive initial and annual refresher training in accordance with the Interface Agreement.

(g) If there is no effective coordination between the NPP operator and the TSO regarding transmission system maintenance or NPP maintenance activities, please explain why you believe you comply with the provisions of 10 CFR 50.65(a)(4).

Response:

Not applicable. Effective coordination between the NPP operator and the TSO regarding transmission system maintenance or NPP maintenance activities is in accordance with the Interface Agreement NGGM-IA-0003.

(h) If you do not consider and effectively implement appropriate risk management actions during the conditions described above, explain why you believe you effectively addressed the relevant provisions of the associated NRC-endorsed industry guidance.

Response:

Not applicable. CR3 implements appropriate risk management actions per applicable procedures and the Interface Agreement.

(i) You may, as an alternative to questions 6(g) and 6(h) describe what actions you intend to take to ensure that the increase in risk that may result from grid-risk-sensitive maintenance activities is managed in accordance with 10 CFR 50.65(a)(4).

Response:

Not applicable. CR3 does not intend to take any alternative actions.

7. Procedures for identifying local power sources[1] that could be made available to resupply your plant following a LOOP event.

Note: Section 2, "Offsite Power," of RG 1.155 (ADAMS Accession No. ML003740034) states:

Procedures should include the actions necessary to restore offsite power and use nearby power sources when offsite power is unavailable. As a minimum, the following potential causes for loss of offsite power should be considered:

- Grid undervoltage and collapse

- Weather-induced power loss

[1] This includes items such as nearby or onsite gas turbine generators, portable generators, hydro generators, and black-start fossil power plants.

- Preferred power distribution system faults that could result in the loss of normal power to essential switchgear buses

(a) Briefly describe any agreement made with the TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event.

Response:

An agreement is in place to restore power to the NPPs as soon as possible. In addition, a system operations procedure provides instructions for prompt NPP offsite power restoration. The procedure specifies various means of accomplishing the required power restoration. System operators train on this procedure annually per NERC training requirements.

(b) Are your NPP operators trained and tested on identifying and using local power sources to resupply your plant following a LOOP event? If so, describe how.

Response:

Yes, while the grid operator is restoring offsite power using non-CR3 power sources following a LOOP event, the immediate concern of the plant operator is to ensure power to the Emergency Buses from the onsite EDGs.

Operators have classroom and simulator training on the following procedures that identify alternate power supplies: AP-730 (soon to be issued), "Grid Instability," AP-770, "Emergency Diesel Generator Actuation," and EOP-12, "Station Blackout." Multiple classroom and simulator training activities also cover annunciator response procedures which reference alternate power supplies. Multiple simulator scenarios cover these particular topics. In addition to the classroom lesson plans for the procedures listed above, there are lesson plans which discuss electrical distribution and cross-connections between on and offsite sources: OPS-4-88, "Switchyard and Transformers," OPS-4-89, "6900 V, 4160V And 480 V Unit Distribution," and OPS-4-90, "4160V and 480 V ES Distribution."

Once trained, operator testing occurs per the normal initial and continuing training programs based on NUREG 1021 standards and training departmental procedures.

(c) If you have not established an agreement with your plant's TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event, explain why you believe you comply with the provisions of 10 CFR 50.63, or describe what actions you intend to take to establish compliance.

Response:

Not applicable, the necessary agreement and implementing procedure are in place.

8. Maintaining SBO coping capabilities in accordance with 10 CFR 50.63.

(a) Has your NPP experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63?

Response:

No. Based on a review of LOOP events at CR3, a total LOOP caused by grid failure has not occurred at CR3 since the SBO rule under 10CFR50.63 was adopted.

(b) If so, have you reevaluated the NPP using the guidance in Table 4 of RG 1.155 to determine if your NPP should be assigned to the P3 offsite power design characteristic group?

Response:

Not applicable, based on response to 8.a above.

(c) If so, what were the results of this reevaluation, and did the initially determined coping duration for the NPP need to be adjusted?

Response:

Not applicable, based on response to 8.a above.

(d) If your NPP has experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63 and has not been reevaluated using the guidance in Table 4 of RG 1.155, explain why you believe you comply with the provisions of 10 CFR 50.63 as stated above, or describe what actions you intend to take to ensure that the NPP maintains its SBO coping capabilities in accordance with 10 CFR 50.63.

Response:

Not applicable, based on response to 8.a above.

9. If you determine that any action is warranted to bring your NPP into compliance with NRC regulatory requirements, including TSs, GDC 17, 10 CFR 50.65(a)(4), 10 CFR 50.63, 10 CFR 55.59 or 10 CFR 50.120, describe the schedule for implementing it.

Response:

Not applicable. No additional action is required to bring the plant into compliance with regulatory requirements regarding the topics included in this generic letter.