FPL

Florida Power & Light Company, 700 Universe Boulevard, P.O. Box 14000, Juno Beach, FL 33408-0420

April 3, 2006

L-2006-073
10 CFR 50.54(f)

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

RE: Florida Power and Light Company
St. Lucie Units 1 and 2
Docket Nos. 50-335 and 50-389
Turkey Point Units 3 and 4
Docket Nos. 50-250 and 50-251

FPL Energy Seabrook, LLC
Seabrook Station
Docket No. 50-443

FPL Energy Duane Arnold, LLC
Duane Arnold Energy Center
Docket No. 50-331

NRC Generic Letter 2006-02 60-Day Response

Florida Power and Light Company (FPL), the licensee for the St. Lucie Nuclear Plant, Units 1 and 2, and the Turkey Point Nuclear Plant, Units 3 and 4, and FPL Energy Seabrook, LLC (FPL Energy Seabrook), the licensee for Seabrook Station, and FPL Energy Duane Arnold, LLC (FPL Energy Duane Arnold), the licensee for Duane Arnold Energy Center (hereafter referred to collectively as FPL), hereby submit their 60-day response to NRC Generic Letter (GL) 2006-02, *Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power.*

Attachment 1 provides the response for St. Lucie Units 1 and 2. Attachment 2 provides the response for Turkey Point Units 3 and 4. Attachment 3 provides the response for Seabrook Station. Attachment 4 provides the response for Duane Arnold Energy Center.

Questions 2(a) through 2(g) and questions 5(c), 5(f), 6(a), and 7(a) in GL 2006-02 seek information about Transmission System Operator (TSO) analyses, procedures, and activities concerning grid reliability about which FPL, FPL Energy Seabrook and FPL Energy Duane Arnold, has either little or no first-hand knowledge and must, therefore, rely on the TSO to provide appropriate response information. Accordingly, in providing information responsive to these questions, where TSO information is provided, FPL makes no representation as to the accuracy or completeness of their response. Although there is no reason to doubt the accuracy of information provided by the TSO, FPL, FPL Energy Seabrook and FPL Energy Duane Arnold have no authority over the TSO regarding such information.

Although the following information is not directly requested in the Generic Letter, FPL Energy Seabrook believes that it is germane to the overall issue of grid reliability. The New England ISO has directed Seabrook Station to back down in power to less than 1200 MWe on nineteen occasions in 2006. The directions to commence the downpower come with very short notice,

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e.g., on the order of 30 minutes, and are not of a long duration, e.g., two to three hours. The downpowers are reported to be required to support grid reliability. It is FPL Energy Seabrook's understanding that the majority of the downpower requirements are related to transmission issues in the New York ISO. FPL Energy Seabrook believes that it is not in the best interest of grid stability for the region for both the New England and New York ISOs to be frequently requiring a large plant such as Seabrook Station to quickly maneuver and decrease or increase power. FPL Energy Seabrook has pursued, and will continue to pursue, the resolution of this issue with the New England and New York ISOs and with the Federal Energy Regulatory Commission in the overall interests of grid stability and grid reliability. FPL Energy Seabrook believes that it is prudent for the NRC to have this information to more effectively evaluate the entire grid reliability issue.

This letter makes the following commitment, as described in Attachment 4, in response to Items 3(a), 3(e), and Item 9:

> FPL Energy Duane Arnold will implement a change in operating procedure such that the TS LCO for inoperable offsite circuits will be entered following notification by the TSO that a trip of the DAEC would result in switchyard under-voltage conditions.

If there are any questions regarding this letter, please contact Rajiv S. Kundalkar at (561) 694-4848.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on the 3rd day of April 2006

Sincerely yours,

J.A. Stall
Senior Vice President Nuclear and
Chief Nuclear Officer

Attachments: (4)

cc: Regional Administrator, Region I
Regional Administrator, Region II
Regional Administrator, Region III
USNRC Project Manager, St. Lucie and Turkey Point
USNRC Project Manager, Seabrook Station
USNRC Project Manager, Duane Arnold Energy Center

ATTACHMENT 1

St. Lucie Units 1 & 2 Response to 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 Technical Specifications.	
(a) Do you have a formal agreement or protocol with your TSO?	Yes, St. Lucie has a formal interface agreement with the Florida Power and Light Company (FPL) Transmission System Operator (TSO). The agreement, *Power Systems And St Lucie Plant Transmission Switchyard Interface Agreement*, is included in St. Lucie Plant Procedure ADM-16.01, *PSL Switchyard Access / Work Control,* as Attachment 1. Compliance with GDC 17, as documented in St. Lucie Units 1 & 2 licensing basis and plant TS is not predicated on such an agreement. Note that the TSO is comprised of FPL's Power Supply and Transmission & Substation Area Operations departments.
(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	Per Procedure ADM-16.01, Attachment 2, the TSO notifies St. Lucie if a condition exists or is forecasted to exist (i.e. due to the contingency analysis program) that could result in switchyard low or high voltage limits to be exceeded. The time for notification is within 15 minutes of a condition or forecast of a possible condition. The notification includes information on the nature of the problem, remedial actions being taken, and expected time of restoration to normal voltage limits. The TSO also notifies St. Lucie if the contingency analysis program is unavailable for a period longer than 4 hours for reasons other than scheduled maintenance. The TSO immediately communicates the following information to St. Lucie in accordance with of Procedure ADM-16.01, Attachment 2: • Any clearance work on the transmission grid impacting the reliability or serviceability of power to the nuclear plants. • Any unplanned transmission outage impacting the reliability of the nuclear plants. • Any action which threatens or could potentially lead to degradation of grid reliability or stability. • Notification of weather related threats, such as hurricanes, tornados, or severe weather activity that could jeopardize the plant or switchyard. • Notification of terrorist or other threats to the electrical facilities that could potentially impact service to the switchyard or jeopardize the stability or reliability of the bulk transmission network. Responses to notification of a transmission system problem are outlined in St. Lucie Plant Procedures 1-ONP-53.01and 2-ONP-53.01, *Main Generator*.
(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.	St. Lucie plant operators will contact the TSO under the following conditions: • If switchyard voltage is outside of the normal operating range • If there are abnormal switchyard voltage fluctuations or main generator MW/MVAR oscillations. • Loss of one of the three transmission lines between the St. Lucie switchyard and Midway substation. Procedures ADM-16.01 and 1(2)-ONP-53.01 are associated with these communications.

St. Lucie Units 1 & 2 Response to Generic Letter 2006-02

1. (continued)	
(d) Describe how NPP operators are trained and tested on the use of the procedures or assessing grid conditions in question 1(c).	St. Lucie Licensed Operators are trained in both the classroom and simulator on INPO SOER 99-01, *Loss of Grid.* The classroom and simulator takes into account aspects of notification of off-site personnel, emergency plan implementing procedures, as well as dealing with loss of power to station equipment. This is performed on a recurring (2 year) cycle, with the most recent performance during segment 4 of 2005. Additionally, simulator practice and evaluation scenarios performed more frequently challenge the operators in severe weather conditions, resulting in either a partial loss of power or complete LOOP conditions.
(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.	St. Lucie has a formal agreement with the TSO. Therefore, this question is not applicable.
(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).	The St. Lucie interface agreement with the TSO requires prompt notification of actual or predicted conditions (i.e. contingency analysis program) that could cause a degraded voltage condition below the minimum allowable value. There is no low voltage setpoint for the switchyard specified in the TS. The minimum allowable switchyard voltage (actual, post-trip or transient) is the value assumed for calculating the plant degraded voltage setpoints which are specified in the TS. Maintaining the switchyard voltage above the minimum allowable value ensures that safety-related equipment has sufficient voltage to perform the required functions and that the degraded voltage relays will not actuate and transfer to the emergency diesel generators in the event of a unit trip due to a design basis accident. This notification requirement is described in Procedures ADM-16.01 and 1(2)-ONP-53.01.
(g) Describe the low switchyard voltage conditions that would initiate operation of plant degraded voltage protection.	Both St. Lucie Units 1 & 2 have been analyzed for a minimum switchyard voltage of 230 kV following a unit trip. Below this switchyard voltage, the degraded voltage relays could actuate assuming worst-case accident loading conditions. Note that the low switchyard voltage condition (less than 230 kV) must persist for a time greater than the time delay settings specified in the TS for the degraded voltage relays.

St. Lucie Units 1 & 2 Response to Generic Letter 2006-02

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.	Yes, as described in Procedure ADM-16.01, the TSO operates the grid using an on-line contingency analysis software program that continuously calculates the NPP switchyard voltage assuming various "contingencies" occur, such as plant trips or transmission line or substation faults. When the St. Lucie switchyard voltage (actual or post-contingency) falls below the minimum allowable value (230 kV), an alarm is initiated at the TSO control center to alert the TSO to take corrective action and notify St. Lucie within 15 minutes. In response to the Generic Letter, the TSO has provided the following information: "FPL's contingency analysis program evaluates the impact of outages of all FPL transmission lines and transformers to identify any overload conditions or voltage problems. It also evaluates the loss of 700 MW class generating units and most 400 MW class generating units. Outages of 500 kV, 230 kV and selected lower voltage lines are looked at for foreign systems; none of which tie directly to or support FPL nuclear switchyards."
(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?	Yes, as described in Procedure ADM-16.01, Attachment 2, the TSO uses the contingency analysis program as the basis for notifying St. Lucie of potential degraded conditions.
(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.	In response to the Generic Letter, the TSO has provided the following information: "The TSO contingency analysis program identifies conditions which would result in a switchyard voltage that could actuate the St. Lucie degraded voltage protection relays and initiate separation from offsite power upon a St. Lucie unit trip."

St. Lucie Units 1 & 2 Response to Generic Letter 2006-02

2. (continued)	
(d) If your TSO uses an analysis tool, how frequently does the analysis tool program update?	In response to the Generic Letter, the TSO has provided the following information: "The TSO contingency analysis program calculates the expected post-trip St. Lucie switchyard voltage for the various contingencies approximately every 5 minutes."
(e) Provide details of analysis tool-identified contingency conditions that would trigger an NPP licensee notification from the TSO.	As specified in the interface agreement, Attachment 1 to Procedure ADM-16.01, the TSO will notify St. Lucie if the contingency analysis (CA) program determines that the postulated contingency event would result in switchyard voltage outside the allowable operating range as specified in the interface agreement. The low limit is 230 kV and high limit is 244 kV. If one of the unit's loads is being supplied from the startup transformer, the high limit is 241 kV. The TSO will also notify St. Lucie if the CA program determines there is potential or developing grid instabilities.
(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?	Yes, the agreement with the TSO, Attachment 1 to Procedure ADM-16.01, requires St. Lucie to be notified when the contingency analysis program is unavailable for a period longer than four hours for reasons other than scheduled maintenance. St. Lucie would continue to rely on the TSO to notify them of any change in grid conditions which could affect the quality or reliability of offsite power. In response to the Generic Letter, the TSO has provided the following information; "In the event that the FPL CA program is unavailable, the responsibility to monitor the grid is turned over to a back-up Reliability Coordinator which is Progress Energy for FPL. Progress Energy has a CA program which would be used to monitor the Florida transmission system. Additionally, FPL system operator has available support studies that identify critical operating limits, an on-line power flow program with which he can model changing systems conditions, and access to support personnel to run off-line studies."
(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?	Yes, as part of the post trip review, St. Lucie Plant Procedure 0030119, *Post Trip Review*, requires that the actual post-trip voltage be compared against the predicted post-trip voltage calculated by the contingency analysis program. The actual voltage is to be verified as bounded by the predicted voltage.
(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?	This question is not applicable since TSO currently uses a contingency analysis program to monitor grid conditions.

St. Lucie Units 1 & 2 Response to Generic Letter 2006-02

2. (continued)	
(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? (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? (b) If the bounds of the analyses are exceeded, does this condition trigger the notification provisions discussed in question 1 above?	This question is not applicable since TSO currently uses a contingency analysis program to monitor grid conditions.
(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.	Not applicable to St. Lucie. The TSO uses a real time contingency analysis program to monitor real time grid conditions. St. Lucie is notified by the TSO if the contingency analysis program identifies grid conditions that could compromise the quality or reliability of offsite power. St. Lucie is in compliance with GDC 17 and no compensatory actions are required.

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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?	Yes, if the TSO notifies St. Lucie that a postulated contingency condition would result in a switchyard voltage below minimum allowed value (230 kV), both offsite AC power circuits are declared inoperable and the applicable TS action is entered, as specified in Procedures 1(2)-ONP-53.01.
(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?	Double sequencing (LOCA with delayed LOOP) is not part of the licensing bases for St. Lucie. The UFSAR accident analyses assume a concurrent LOOP and LOCA. The ability for onsite safety-related equipment to respond to a double sequencing event is not a requirement for operability. Note that St. Lucie emergency diesel generators and safety related motors are not expected to be lost during double sequencing event based on review of the load sequencer and breaker logic.

St. Lucie Units 1 & 2 Response to Generic Letter 2006-02

3. (continued)	
(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).	Not applicable. Since a double sequencing event is not part of St. Lucie licensing bases, an evaluation has not been performed for St. Lucie to determine the overall impact on safety related equipment response for such an event. Note that electrical design considerations for a double sequencing event were evaluated for St. Lucie Unit 2 in response to the third request for additional information (RAI) regarding a proposed license amendment to allow operation of St. Lucie Unit 2 with a reduced reactor coolant system (RCS) flow, corresponding to a steam generator tube plugging level of 30% per steam generator. The response of electrical equipment was found to be acceptable. The RAI response is provided in FPL letter (L-2005-007) to the NRC dated January 7, 2005.
(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.	No, the TS action statement would only be entered if the grid conditions results in postulated contingency switchyard voltages below the minimum allowed value. When notified of the specifics of other degraded grid conditions, St. Lucie would perform appropriate operational decision making to determine if offsite power should be considered inoperable and the applicable TS action statement entered.
(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.	The offsite AC power circuits are declared inoperable and the applicable TS action is entered when postulated contingency conditions could result in a switchyard voltage below minimum allowed value (230 kV), assumed for the degraded voltage actuation setpoint. St. Lucie is in compliance with GDC 17 and no compensatory actions are required.
(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).	Not applicable. No compensatory actions are required.

St. Lucie Units 1 & 2 Response to Generic Letter 2006-02

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.	Not applicable. There is no voltage regulating equipment included in the determinations of offsite AC circuit operability required by TS. None of the analyses prepared for the onsite AC power distribution systems at St. Lucie take credit for automatic tap changers, capacitor banks, or other reactive power compensating equipment. The main generator voltage regulator is normally operated in "ON" position (automatic) in accordance with the *Florida Power & Light Company Facility Connection Requirements*, dated July 30, 2001 and St. Lucie Plant Procedures 1(2)-GOP-201, *Reactor Plant Startup-Mode 2 to Mode 1*. The TSO monitors the status of the voltage regulator and evaluates the impact of grid conditions when any of the units' voltage regulators is placed in manual.
(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.	St. Lucie AC power distribution system operability takes no credit for automatic tap changers, capacitor banks or reactive power compensation equipment. The main generator voltage regulator of each unit is operated in automatic. The TSO monitors the status of the transmission grid and models possible contingencies that could affect the switchyard voltage. Failure of the main generator voltage regulator is included and enveloped by the possible contingencies. If a contingency is discovered that could lower the switchyard voltage below 230.0 kV, St. Lucie is notified within 15 minutes and TS actions will be addressed as required. Therefore, St. Lucie is in compliance with GDC 17 and no compensatory actions are required.

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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?	Yes, St. Lucie procedures contain requirements for coordination of plant systems and switchyard maintenance and testing to minimize the risk of a loss of offsite or onsite power: St. Lucie Plant Procedure ADM-10.03, *Work Week Management,* requires that risk assessments be performed for safety related or risk significant components or systems including the emergency diesel generators, startup transformers, or station blackout cross-tie breakers, for pre-planned and emergent activities. In addition, St. Lucie Plant Procedure ADM-17.16, *Implementation of the Configuration Risk Assessment Program,* requires consideration of potential grid degradation/instability as part of the Configuration Risk Management Program.
(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?	Yes, grid status is continuously monitored by the TSO, including during the performance of grid-risk-sensitive maintenance. As required by the St. Lucie and TSO interface agreement, the TSO will immediately notify St. Lucie of potential or developing grid instabilities. Procedure ADM-17.16 requires that the current risk assessment be reassessed if there is any potential increased in grid instability reported by the TSO or as a result of severe weather conditions.

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5. (continued)	
(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?	Yes, seasonal loads have an impact on grid stress and also influence the scheduling for plant maintenance outages. In general, peak load conditions usually occur during the summer months in south Florida. However, plant availability is also maintained at a maximum during the summer months to ensure grid and service reliability. Grid conditions can be stressed during the summer months if unplanned plant or transmission line outages occur. Similar grid stress conditions can also occur during other seasons if unexpected cold or hot periods occur when there are multiple planned plant outages.
Is there a seasonal variation (or the potential for a seasonal variation) in the LOOP frequency in the local transmission region?	Yes, for St. Lucie, the potential of a LOOP is higher in the late summer and early fall months due to the increased probability of severe weather (e.g. hurricanes, tornadoes).
If the answer to either question is yes, discuss the time of year when the variations occur and their magnitude.	Peak system load conditions resulting in potential grid stress would have a greater potential for occurring during the summer months.
(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?	No. There is no specific change made to the On Line Risk Monitor during summer months. However, if severe weather conditions are expected and one of the following conditions is planned, the Core Damage Frequency (CDF) on the On Line Risk Monitor will be forced to at least an ORANGE condition: • An EDG on either unit is out of service (OOS), or • The blackout crosstie is OOS A specific evaluation must then be performed to determine the acceptability of the proposed maintenance/surveillance with the severe weather condition. With severe weather conditions expected, St. Lucie Plant Procedure 0005753, *Severe Weather Preparations*, specifies that an EDG or blackout crosstie would only be removed from service for corrective maintenance (i.e. maintenance required to ensure or restore operability). If an EDG or blackout crosstie is unavailable, they would be restored to service as soon as possible.

St. Lucie Units 1 & 2 Response to Generic Letter 2006-02

5. (continued)	
(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.	Yes, Work Control Procedures and Guidelines ADM-10.01, *Critical Maintenance Management*, ADM-10.03, *Work Week Management*, and WCG-016, *Online Work Management*, requires the Work Week Manager to contact the TSO Load Dispatcher prior to performing planned grid risk significant maintenance activities. In the event of an emergent or anticipated change in the maintenance activity or grid conditions, an initial communication is conducted between Load Dispatch and the Shift Manager or Unit Supervisor followed by a communication to the Work Control Manager.
(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.	The formal interface agreement (Procedure ADM-16.01, Attachment 1) between St. Lucie and TSO requires the TSO to provide early warning to St. Lucie of potential or developing grid instabilities. The agreement also requires TSO emergent activities, as well as the detailed conduct of planned activities, to be coordinated on a real time basis with St. Lucie. These activities include, but are not limited to: • TSO removing from service any transmission line terminating in the switchyard; • TSO breaker switching which can affect power supply (e.g. switching of line identified in item (a) above; • TSO maintenance activities that can affect power supply.
(g) Do you contact your TSO periodically for the duration of the grid-risk-sensitive maintenance activities?	No, St. Lucie would only contact the TSO if plant conditions change that could impact offsite power or increase the probability of a unit trip. The plant relies on the TSO to monitor grid conditions and contact St. Lucie of potential grid instabilities.
(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.	Training for St. Lucie operators is discussed in the response to Question 1(d). Work Control (maintenance) personnel are trained in accordance with WCG-017, *Work Control Departmental Training Plan*, which requires training in St. Lucie plant procedures (e.g. ADM-16.01, ADM-10.03, WCG-016, and ADM-10.01) governing maintenance activities and include the requirements for coordination and communications with FPL Power Supply/System Dispatcher (TSO).
(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).	Not applicable. St. Lucie does have a formal agreement for communication with the TSO to facilitate risk assessments required by 10 CFR 50.65(a)(4).

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5. (continued)	
(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.	As described in Procedure ADM-17.16, risk is assessed (when warranted) when plant conditions have changed; upon notification from the TSO of potential grid instabilities; or the onset of severe weather conditions. As previously discussed in response to Item 1(b), the TSO uses a real time contingency analysis program to continuously monitor grid conditions. St. Lucie's formal interface agreement with the TSO requires that St. Lucie be contacted if there is change in switchyard status or a potential for grid instability. Therefore, St. Lucie has adequately implemented the provisions of the endorsed industry guidance associated with the maintenance rule.
(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.	No additional actions are required.

St. Lucie Units 1 & 2 Response to Generic Letter 2006-02

<table>
<tr><td colspan="2">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).</td></tr>
<tr><td>(a) Does the TSO coordinate transmission system maintenance activities that can have an impact on the NPP operation with the NPP operator?</td><td>Yes, the St. Lucie interface agreement with the TSO, which is included in Procedure ADM-16.01 requires the following coordination activities:
• The TSO will coordinate planned outages and planned load reductions with St. Lucie. TSO and St. Lucie maintenance and testing activities should be coordinated between the parties to prevent inadvertent reductions in nuclear plant defense-in-depth.
• St. Lucie will inform the Power Supply system dispatcher of planned outages and planned load reductions.
• TSO will coordinate with St. Lucie the activities that may affect the off-site power supply to the nuclear plants. As a minimum, the TSO system dispatcher and/or the TSO maintenance crew will inform St. Lucie while planning these activities.
• Emergent activities, as well as the detailed conduct of planned activities, will be coordinated on a real time basis with St. Lucie. These activities include, but are not limited to: removing from service any transmission line terminating in the switchyard; TSO breaker switching which can affect power supply (e.g. switching of line identified above); TSO maintenance activities that can affect power supply.</td></tr>
<tr><td>(b) Do you coordinate NPP maintenance activities that can have an impact on the transmission system with the TSO?</td><td>Yes, work performed at the St. Lucie nuclear plant is controlled through Procedure ADM-10.03. This procedure references Work Control Guideline WCG-016 for details for performance of on-line maintenance work scheduling. Appendix J of WCG-016 details requirements for communication between the plant Work Control daily organization and the System Load Dispatcher. The scheduling of activities which will result in a down power and/or the possibility of a removal of a unit from service (Load Threat) shall be communicated to the Load Dispatcher in a timely manner to ensure a stable, cost effective power supply to our customers. The primary notification to the System Dispatcher of a scheduled change or emergent change of unit megawatt output shall be the on-shift Unit Supervisor or Shift Manager, immediately prior to the change if possible. In the event of an emergent change, notification will occur as soon as possible. Any evolution that meets the criteria of a planned down power or load threat is communicated to the System Dispatcher at least 72 hours prior to the evolution and communications maintained if the System Dispatcher is uncertain of changing conditions.</td></tr>
<tr><td>(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?</td><td>Yes, Procedure ADM-17.16 requires load threatening surveillance or maintenance activities, including EDG or SBO tie breaker maintenance, be deferred if the potential for increased grid instability exists or hurricane warning has been issued. If emergent conditions exist that increase the potential for grid instability when the EDG or SBO tie breaker are unavailable, the EDG or SBO tie breaker would be restored as soon as possible.

Procedures 1(2)-ONP-53.01 also require load threatening activities be terminated if in progress, or deferred if planned, for degraded switchyard voltage conditions.</td></tr>
</table>

St. Lucie Units 1 & 2 Response to Generic Letter 2006-02

6. (continued)	
(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.)	Yes, if grid-risk-sensitive maintenance was required or in progress with degraded grid conditions, the Core Damage Frequency (CDF) associated with the On Line Risk Monitor would be forced to at least an ORANGE condition. As described in Procedure ADM-17.16, alternate equipment protection measures and compensatory actions would be considered. In general, the primary action would be to restore the System, Structure, or Component (SSC) that is out of service to operable status as soon as possible. Other compensatory actions taken, if any, would be dependent on the nature of the grid condition and what SSC was out of service.
(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.	The Maintenance Rule risk assessment process and actions for the coordination of maintenance activities between St. Lucie and the TSO are governed by the following procedures: ADM-16.01: • Communications between the TSO and St. Lucie plant regarding switchyard or grid activities that could affect the availability of offsite power to St. Lucie. • Interface agreement between Power Systems and St. Lucie. ADM-10.03 & Work Control Guideline WCG-016: • Notification and coordination with the System Dispatcher (TSO) for plant maintenance activities that are load-threatening or affect grid risk sensitive equipment. • Coordination of planned outages and load reductions. ADM-17.16: • Risk assessment of load threatening or grid risk sensitive equipment. • Consideration for deferral of risk significant maintenance if potential for grid instability or adverse weather conditions. 1(2)-ONP-53.01: • Coordination of degraded switchyard voltage conditions. • Deferral of risk significant maintenance if potential for grid instability. These actions have proved to be effective during recent grid-risk-sensitive activities associated with the hurricanes of 2004 and 2005 that affected the FPL transmission grid.

St. Lucie Units 1 & 2 Response to Generic Letter 2006-02

6. (continued)	
(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).	Work Control personnel training is defined in Guideline WCG-017. Required reading on all procedures applicable to Work Control Group and on the job training provides instruction on the functions and responsibilities of the WCG personnel. The effectiveness of the training is determined through periodic self-assessments and supervisory monitoring of job performance. Training for St. Lucie operators is discussed in the response to Question 1(d).
(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).	There is effective coordination between the NPP operator and the TSO regarding transmission system maintenance or NPP maintenance activities. Such coordination is in accordance with established protocols. Therefore, St. Lucie is compliance with 10 CFR 50.65(a)(4).
(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.	As discussed in questions 6(a) through 6(d), the St. Lucie plant effectively implements appropriate risk management actions.
(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).	No alternative actions are required.

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7. Procedures for identifying local power sources (this includes items such as nearby or onsite gas turbine generators, portable generators, hydro generators, and black-start fossil power plants) 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 under-voltage and collapse - Weather-induced power loss - 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 re-supply power to your plant following a LOOP event.	St. Lucie does not have an agreement with the TSO to provide a specific local power source in the event of LOOP. St. Lucie has an agreement in place with the TSO to restore power to St. Lucie on a priority basis using any and all transmission lines and power sources available and provide an estimate of when offsite power will be restored to within normal limits.
(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.	Not applicable. St. Lucie does not rely on specific local power sources to restore power following a LOOP.
(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.	Not applicable. St. Lucie does not take credit or rely on any local power sources to restore power following a LOOP or SBO event. St. Lucie is in compliance with 10 CFR 50.63. In response to the Generic Letter, the TSO has provided the following information; "The TSO will utilize the best sources available for specific events to restore offsite power and to determine the specific power sources and paths, since there is no way to predict the extent and characteristics of a specific blackout. The TSO has many options available to restore offsite power and would not be limited to any specific local power sources."

St. Lucie Units 1 & 2 Response to Generic Letter 2006-02

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?	There have been no LOOP events caused by grid failure since St. Lucie's original coping duration was determined under 10 CFR 50.63.
(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?	Not applicable.
(c) If so, what were the results of this reevaluation, and did the initially determined coping duration for the NPP need to be adjusted?	Not applicable.
(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.	Not applicable.

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9. Actions to ensure compliance	
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.	St. Lucie is in compliance with the referenced NRC requirements. No action is required.

ATTACHMENT 2

Turkey Point Response to 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 Technical Specifications.	
(a) Do you have a formal agreement or protocol with your TSO?	Yes, Turkey Point has a formal interface agreement with the Florida Power and Light Company (FPL) Transmission System Operator (TSO). The agreement, *Power Systems, Turkey Point Nuclear, and Turkey Point Fossil Plants Transmission Switchyard Interface Agreement*, is included in Turkey Point Nuclear Plant Procedure 0-ADM-216, *PTN and PTF Shared System Work Control and Switchyard Access*, as Attachment 4. Compliance with GDC 17, as documented in Turkey Point Units 3 & 4 licensing basis and plant Technical Specifications (TS) is not predicated on such an agreement. Note that the TSO is comprised of FPL Power Supply and Transmission & Substation Operations departments.
(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.	The following notification are described in the Turkey Point Nuclear Plant Basis Document 0-BD-ONOP-004.6, *Degraded Switchyard Voltage*, for Turkey Point Nuclear Plant Procedure 0-ONOP-004.6, *Degraded Switchyard Voltage*: The TSO notifies the Turkey Point control room if conditions exist or are forecasted to exist (i.e., contingency analysis (CA) program) that result in exceeding switchyard low or high voltage limits as established in the interface agreement. The time for notification is within 15 minutes. The TSO also notifies the Turkey Point control room if the CA program is unavailable for a period longer than 4 hours for reasons other than scheduled maintenance. Turkey Point would continue to rely on the TSO to notify them of any change in grid conditions that could affect the quality or reliability of offsite power. In addition, the TSO immediately communicates the following information to Turkey Point: 1. Any clearance work on the transmission grid impacting the reliability or serviceability of power to the nuclear plants. 2. Any unplanned transmission outage impacting the reliability of power to the nuclear plants. 3. Any action which threatens or could potentially lead to degradation of grid reliability or stability. 4. Notification of weather related threats, such as hurricanes, tornados, or severe weather activity that could jeopardize the plant or switchyard. 5. Notification of terrorist or other threats to the electrical facilities that could potentially impact service to the switchyard or jeopardize the stability or reliability of the bulk transmission network.

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1. (continued)	
(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.	The Turkey Point control room will contact the TSO if switchyard voltage is outside of the normal operating range in accordance with Procedure 0-ONOP-004.6. Main generator MW/MVAR oscillations will be communicated to the TSO in accordance with Turkey Point Nuclear Plant Procedures 3/4-ONOP-090, *Abnormal Generator MW/MVAR Oscillation.*
(d) Describe how NPP operators are trained and tested on the use of the procedures or assessing grid conditions in question 1(c).	Turkey Point control room operators are trained annually on Procedures 0-ONOP-004.6 and 3/4-ONOP-090 during licensed operator continuing training (LOCT). Training on Institute of Nuclear Power Operations Significant Operating Experience Report 99-1, *Loss of Grid,* is conducted every three years. Simulator practice and evaluation scenarios challenge operators in loss of offsite power (LOOP) conditions.
(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.	Not applicable. Turkey Point has a formal agreement with the TSO.
(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).	The Turkey Point interface agreement with the TSO requires prompt (within 15 minutes) notification of actual or predicted conditions (i.e., CA program) that could cause a voltage condition below the minimum allowable value or greater than the maximum allowable value. The minimum allowable switchyard voltage (actual or post-contingency) is the value assumed for calculating the plant undervoltage/degraded voltage setpoints that are specified in the TS. Maintaining the switchyard voltage above the minimum allowable value ensures that the undervoltage/degraded voltage relays will not actuate in the event of a unit trip concurrent with a design basis accident. There are no safety-related requirements for voltage being above the maximum allowable value. This notification requirement is described in Procedure 0-ONOP-004.6 and the associated basis document, 0-BD-ONOP-004.6.

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1. (continued)	
(g) Describe the low switchyard voltage conditions that would initiate operation of plant degraded voltage protection.	If switchyard voltage drops below 232 kV following a unit trip, the undervoltage/degraded voltage relays could actuate assuming worst case accident loading conditions. Note that the low switchyard voltage condition (less than 232 kV) must persist for a time greater than the time delay settings specified in the TS for the undervoltage/degraded voltage relays to actuate.

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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.	Yes, as described in Basis Document 0-BD-ONOP-004.6, the TSO operates the grid using an online CA software program that continuously calculates the NPP switchyard voltage assuming various "contingencies" occur, such as plant trips or transmission line faults. When the Turkey Point switchyard voltage (actual or post-contingency) falls below the minimum allowable value (232 kV), an alarm is initiated at the TSO control center to alert the TSO to take corrective action and notify the NPP within 15 minutes. In response to the Generic Letter, the TSO has provided the following information: "FPL's CA program evaluates the impact of outages of FPL transmission lines and transformers to identify any overload conditions or voltage problems. It also evaluates the loss of 700 MW class generating units and most 400 MW class generating units. Outages of 500 kV, 230 kV and selected lower voltage lines are looked at in systems outside of FPL's service territory, none of which tie directly to or support FPL nuclear switchyards."
(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?	Yes, as described in Basis Document 0-BD-ONOP-004.6, the TSO uses the contingency analysis program as the basis for notifying Turkey Point of potential degraded conditions.
(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.	In response to the Generic Letter, the TSO has provided the following information: "The TSO CA program identifies conditions which would result in a switchyard voltage that could actuate the Turkey Point undervoltage/degraded voltage protection relays and initiate separation from offsite power upon a Turkey Point unit trip."
(d) If your TSO uses an analysis tool, how frequently does the analysis tool program update?	In response to the Generic Letter, the TSO has provided the following information: "The TSO CA program calculates the expected Turkey Point switchyard voltage for the various contingencies, including a Turkey Point unit trip, approximately every 5 minutes."

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2. (continued)	
(e) Provide details of analysis tool-identified contingency conditions that would trigger an NPP licensee notification from the TSO.	As described in Turkey Point Basis Document 0-BD-ONOP-004.6, the TSO will notify Turkey Point if the CA program determines that the postulated contingency event would result in switchyard voltage outside the allowable operating range as specified in the interface agreement. With Units 3 and 4 on line and on the auxiliary transformer, the low limit is 232 kV and the high limit is 244 kV. If the loads of one of the units are being supplied from the startup transformer, the low limit is 232 kV and the high limit is 241.5 kV. The TSO will also notify the Turkey Point control room if the CA program determines there are potential or developing grid instabilities.
(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?	Yes, the interface agreement with the TSO does require Turkey Point to be notified when the CA program is unavailable for a period longer than 4 hours for reasons other than scheduled maintenance. Turkey Point would continue to rely on the TSO to notify them of any change in grid conditions which could affect the quality or reliability of offsite power. In response to the Generic Letter, the TSO has provided the following information: "In the event that the FPL CA program is unavailable, the responsibility to monitor the grid is turned over to a back-up Reliability Coordinator which is Progress Energy for FPL. Progress Energy has a CA program which would be used to monitor the Florida transmission system. Additionally, the FPL system operator has available support studies that identify critical operating limits, an online power flow program with which he can model changing systems conditions, and access to support personnel to run off line studies."
(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?	Yes, as part of a unit post trip review, Turkey Point Plant Procedure 0-ADM-511, *Post Trip Review (PTR)*, requires that the actual post trip voltage be compared against the predicted post trip voltage calculated by the CA program. The actual voltage is verified to be bounded by the predicted voltage.
(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?	Not applicable. The TSO uses a CA program to monitor grid conditions.

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2. (continued)	
(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? (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? (b) If the bounds of the analyses are exceeded, does this condition trigger the notification provisions discussed in question 1 above?	Not applicable. The TSO uses a CA program to monitor grid conditions.
(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.	Not applicable. The TSO uses a real time CA program to monitor grid conditions. Turkey Point is notified by the TSO if the CA program identifies grid conditions that could compromise the quality or reliability of offsite power. Turkey Point is in compliance with GDC 17 and no compensatory actions are required.

Turkey Point Response to Generic Letter 2006-02

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?	Yes, if the TSO notifies Turkey Point that a postulated contingency condition would result in a switchyard voltage below the minimum allowed value (232 kV), both startup transformers are declared inoperable and the applicable TS action is entered in accordance with Procedure 0-ONOP-004.6.
(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?	Double sequencing [loss of coolant accident (LOCA) with delayed LOOP] is not part of the licensing bases for Turkey Point. The UFSAR accident analyses assume a concurrent LOOP and LOCA. The ability of safety related equipment to respond to a double sequencing event is not a requirement for operability. Turkey Point emergency diesel generators and safety related motors are not expected to be lost during a double sequencing event based on review of the load sequencer and breaker logic.

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3. (continued)	
(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).	Not applicable. Since a double sequencing event is not part of Turkey Point licensing bases, an evaluation has not been performed to determine the overall impact on safety related equipment response to such an event. However, a review of the load sequencer and breaker logic indicates that safety related motors are not expected to be lost during a double sequencing event.
(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.	No, a TS action would only be entered if the grid conditions result in actual or postulated contingency switchyard voltages below the minimum allowed value. When notified of the specifics of the degraded grid conditions, Turkey Point would perform appropriate operational decision making to determine if offsite power should be considered available and whether the TS for inoperable startup transformers should be entered.
(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.	The applicable TS is entered when Turkey Point is notified by the TSO that a Turkey Point unit trip will result in a switchyard voltage below the minimum value (232 kV), assumed for the degraded voltage actuation setpoint. Turkey Point is in compliance with GDC 17 and no compensatory actions are required.
(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).	Not applicable. No compensatory actions are required.

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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.	Not Applicable. There is no voltage regulating equipment included in the determinations of startup transformer operability required by TS or for determining if offsite power is functional. None of the analyses prepared for the onsite AC power distribution systems at Turkey Point take credit for automatic tap changers, capacitor banks, main generator voltage regulators, or other reactive power compensating equipment. The main generator voltage regulator is normally operated in automatic in accordance with *Florida Power & Light Company Facility Connection Requirements*, dated July 30, 2001 and Turkey Point Plant Procedures 3/4-GOP-301, *Hot Standby to Power Operation.* The TSO monitors the status of the voltage regulator and evaluates the impact of grid conditions when any of the units' voltage regulators is placed in manual. Conditions which require the voltage regulator to be placed in manual are closely coordinated with the TSO in accordance with Procedures 3/4-ONOP-090. Operators are required to review Procedures 3/4-ONOP-090 annually.
(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.	Turkey Point is in compliance with GDC 17 and no compensatory actions are required.

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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?	Yes, Turkey Point procedures contain requirements for coordination of plant systems and switchyard maintenance and testing to minimize the risk of a loss of offsite or onsite power: Turkey Point Plant Procedure 0-ADM-068, *Work Week Management* requires that risk assessments be performed for safety related or risk significant components or systems including the emergency diesel generators (EDG), startup transformers, or station blackout (SBO) cross-tie breakers, for pre-planned and emergent activities. In addition, Turkey Point Plant Procedure 0-ADM-225, *Online Risk Assessment and Management*, requires consideration of potential grid degradation/instability as part of the Configuration Risk Management Program.
(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?	Yes, grid status is continuously monitored by the TSO, including during the performance of grid-risk-sensitive maintenance. As required by the Turkey Point and TSO interface agreement, the TSO will immediately notify Turkey Point of potential or developing grid instabilities. Procedure 0-ADM-225 requires that the current risk assessment be reassessed if there is any potential increase in grid instability reported by the TSO or as a result of severe weather conditions.

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5. (continued)	
(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?	Yes, seasonal loads have an impact on grid stress and also influence the scheduling for plant maintenance outages. In general, peak load conditions usually occur during the summer months in South Florida. However, plant availability is also maintained at a maximum during the summer months to ensure grid and service reliability. Grid conditions can become stressed during any season if unplanned plant or transmission line outages occur. Similar grid stress conditions can also occur if unexpected cold or hot periods occur when there are multiple planned plant outages.
Is there a seasonal variation (or the potential for a seasonal variation) in the LOOP frequency in the local transmission region?	Yes, for Turkey Point, the potential for a LOOP is higher in the late summer and early fall months due to the increased probability of severe weather (i.e., hurricanes, tornadoes).
If the answer to either question is yes, discuss the time of year when the variations occur and their magnitude.	Peak system load conditions resulting in potential grid stress would have a greater potential for occurring during the summer months.
(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?	No, there is no specific change made to the On Line Risk Monitor (OLRM) during summer months. However, if severe weather conditions are expected and one of the following conditions is planned, the Core Damage Frequency (CDF) on the OLRM will be forced to an ORANGE condition. • An EDG on either unit is Out-of-Service (OOS), or • The SBO cross-tie is OOS, A specific evaluation must then be performed to determine the acceptability of the proposed maintenance/surveillance with the severe weather condition. With severe weather conditions expected, Turkey Point Plant Procedures 0-ONOP-103.3, *Severe Weather Preparations*, and 0-EPIP-20106, *Natural Emergencies*, provide appropriate risk management actions to minimize risk.
(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?	Yes, Procedure 0-ADM-068 requires the Work Week Manager (WWM) to ensure that the TSO is notified of planned grid-risk-sensitive maintenance activities no less than 72 hours prior to the work activity. The WWM will evaluate rescheduling the work activity if the TSO grid risk evaluation indicates that degraded grid reliability conditions may exist during the maintenance activity. Procedure 0-ADM-225 requires the Turkey Point control room to communicate the "start and stop" of grid-risk-sensitive maintenance activities to the TSO.

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5. (continued)	
(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.	The formal Interface Agreement between Turkey Point and the TSO requires the TSO to provide early warning to Turkey Point of potential or developing grid instabilities. The Interface Agreement also requires TSO emergent activities, as well as the detailed conduct of planned activities, to be coordinated on a real time basis with Turkey Point. These activities include, but are not limited to: a. TSO removing from service any transmission line terminating in the switchyard; b. TSO breaker switching which can affect power supply (e.g. switching of line identified in item (a) above; c. TSO maintenance activities that can affect power supply.
(g) Do you contact your TSO periodically for the duration of the grid-risk-sensitive maintenance activities?	No, in accordance with the Interface Agreement, Turkey Point relies on the TSO to monitor grid conditions and contact the control room of potential grid instabilities. Turkey Point will contact the TSO if plant conditions change that could impact offsite power or increase the probability of a unit trip.
(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.	The formal Interface Agreement between Turkey Point and FPL TSO is included in Procedure 0-ADM-216, as Attachment 4. Training is provided in initial training for licensed and non-licensed operators. Additionally, training was provided in licensed operator continuing training for the 2005 segments. There is no formal method for periodic review of this document.
(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).	Not applicable. Turkey Point does have a formal agreement for communication with the TSO to facilitate risk assessments required by 10 CFR 50.65(a)(4).

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5. (continued)	
(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.	Risk is assessed when plant conditions have changed, notification is received from the TSO of potential grid instabilities, or severe weather conditions are imminent. The TSO uses a real time CA program to continuously monitor grid conditions. Turkey Point's formal agreement with the TSO requires that Turkey Point be contacted if there is a change in switchyard status or a potential for grid instability. Therefore, Turkey Point has adequately implemented the provisions of Section 11 of NUMARC 93-01, *Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants*, the endorsed industry guidance associated with the maintenance rule.
(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.	No additional actions are required.

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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?	Yes, the Turkey Point interface agreement with the TSO, which is included in Procedure 0-ADM-216, requires the following coordination activities: • The TSO will coordinate planned outages and planned load reductions with Turkey Point. TSO and Turkey Point maintenance and testing activities should be coordinated between the parties to prevent inadvertent reductions in nuclear plant defense-in-depth. • Turkey Point will inform the TSO system dispatcher of planned outages and planned load reductions. • TSO will coordinate with Turkey Point the activities that may affect the offsite power supply to the nuclear plants. As a minimum, the TSO system dispatcher and/or the TSO maintenance crew will inform the Turkey Point control room while planning these activities. • Emergent activities, as well as the detailed conduct of planned activities, will be coordinated on a real time basis with Turkey Point. These activities include, but are not limited to: removing from service any transmission line terminating in the switchyard; TSO breaker switching which can affect power supply (e.g. switching of line identified above); TSO maintenance activities that can affect power supply.
(b) Do you coordinate NPP maintenance activities that can have an impact on the transmission system with the TSO?	Yes, see response to 5(e).
(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?	Yes, Procedure 0-ADM-225 considers the deferral of load threatening surveillances or maintenance activities if a potential for increased grid instability exists or a hurricane warning has been issued. Additionally, this Procedure states that the SBO cross-tie breaker or an EDG should be removed from service only for corrective maintenance, e.g., maintenance required to ensure or restore operability. If emergent conditions exist that increase the potential for grid instability when the EDG or SBO cross-tie breaker are unavailable, the EDG or SBO cross-tie breaker would be restored, as a priority work activity, as soon as possible. Plant Procedure 0-ONOP-004.6 also requires load threatening activities to be terminated if in progress or deferred if planned for degraded switchyard voltage conditions.

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6. (continued)	
(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.)	Yes, if grid-risk-sensitive maintenance was required or in progress with degraded grid conditions, the CDF associated with the OLRM would be forced to an Orange condition. Alternate equipment protection measures and compensatory actions would be considered. In general, the primary action would be to restore the Structure, System, or Component (SSC) that is out of service to operable status as soon as possible. Other compensatory actions taken, if any, would be dependent on the nature of the grid condition and what SSC was out of service.
(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.	The maintenance rule risk assessment process and actions for the coordination of maintenance activities between Turkey Point and the TSO are governed by the following Plant Procedures: 0-ADM-216: • Coordination of planned outages and load reductions • Coordination of emergent activities that could affect offsite power to Turkey Point 0-ADM-068: • Notification and coordination of Turkey Point maintenance activities that affects grid-risk-sensitive equipment 0-ADM-225: • Risk assessment of load threatening or grid-risk-sensitive equipment. • Deferral of load threatening surveillances or maintenance activities if a potential for increased grid instability exists or a hurricane warning has been issued. 0-ONOP-004.6: • Coordination of degraded switchyard voltage conditions. • Deferral of risk significant maintenance if potential for grid instability These actions have proved to be effective during recent grid-risk-sensitive activities associated with 2005 Hurricanes Katrina and Wilma.
(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).	Work Control and Operations personnel are trained to utilize the OLRM during daily online schedule development. They received initial training from the FPL Probabilistic Safety Assessment (PSA) group. The Work Control Department and/or Operations will contact the PSA group when a risk assessment is outside the bounds of Procedure 0-ADM-225 or doubt exists as to the validity of the assessment. Continuing training is primarily on-the-job.

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6. (continued)	
(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).	There is effective coordination between the Turkey Point control room and the TSO regarding transmission system maintenance or Turkey Point maintenance activities. Such coordination is in accordance with established protocols. Therefore, Turkey Point is in compliance with 10 CFR 50.65(a)(4).
(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.	As discussed in questions 6(a) through 6(d), Turkey Point effectively implements appropriate risk management actions.
(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).	No alternative actions are required.

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7. Procedures for identifying local power sources (this includes items such as nearby or onsite gas turbine generators, portable generators, hydro generators, and black-start fossil power plants) 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 under-voltage and collapse
> - Weather-induced power loss
> - 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 re-supply power to your plant following a LOOP event.	Turkey Point does not have an agreement with the TSO to provide a specific local power source in the event of a LOOP. Turkey Point has an agreement in place with the TSO to restore power to Turkey Point on a priority basis using any and all transmission lines and power sources available. The Turkey Point switchyard is connected to the state transmission network through eight (8) 230 kV circuits.
(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.	Not applicable. Turkey Point does not rely on specific local power sources to restore power following a LOOP.
(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.	Not applicable. Turkey Point does not take credit or rely on any local power sources to restore power following a LOOP or SBO event. In response to the Generic Letter, the TSO has provided the following information; "The TSO will utilize the best sources available for specific events to restore offsite power and to determine the specific power sources and paths, since there is no way to predict the extent and characteristics of a specific LOOP. The TSO has many options available to restore offsite power and would not be limited to any specific local power sources." Turkey Point is in compliance with 10 CFR 50.63.

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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?	There have been no LOOP events caused by grid failure since the Turkey Point's original coping duration was determined under 10 CFR 50.63.
(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?	Not applicable.
(c) If so, what were the results of this reevaluation, and did the initially determined coping duration for the NPP need to be adjusted?	Not applicable.
(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.	Not applicable.

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9. Actions to ensure compliance	
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.	Turkey Point is in compliance with all referenced requirements. No action is required.

ATTACHMENT 3

Seabrook Response to 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 Technical Specifications.	
(a) Do you have a formal agreement or protocol with your TSO?	Yes, Seabrook Station has formal agreements with the TSO (ISO-NE) in the form of a Service Agreement and with the Transmission Owner in the form of an Interconnection Agreement. Compliance with GDC 17, as documented in the Seabrook Station licensing basis and plant Technical Specifications (TS), is not predicated on such an 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.	Per the ISO-NE Transmission Operating Guides, the TSO will make notifications, as soon as practical, upon identification of any of the following conditions: • Overall system wide warning or alert conditions. • If the computerized contingency monitoring program (Real Time Contingency Analysis Program) determines that the post-trip off-site voltage could degrade below a value specified by Seabrook. • In the event that the ISO-NE Control Center's and the Local Control Center's Real Time Contingency Analysis Program becomes unavailable. • A local system configuration, which would cause Seabrook Station to become unstable in the event of a potential transmission system contingency.
(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.	Seabrook Station monitors local grid conditions (e.g. voltage, frequency, breaker position and voltage regulator mode), which may require the TSO or its Local Control Center to be notified. Conditions that would cause Seabrook Station to contact the TSO include: • changes in capability (power uprate) • changes to Switchyard Voltage, Switchyard Breaker alignment, Generator VAR loading • modifications resulting in changes to generator electrical characteristics • changes in post trip power loading • changes in status of offsite power voltage regulating devices (such as voltage regulators in manual versus auto.) Examples of procedures that require contacting the ISO or the ESCC (Electric System Control Center) include: alarm response procedures D6667, *345 Kv Line Sys 2 Trouble*, B8470, *345 Kv Line 394 Voltage Low*, and D6670, *345 Kv Line Voltage Loss*. Any required notifications are made using dedicated communication equipment.
(d) Describe how NPP operators are trained and tested on the use of the procedures or assessing grid conditions in question 1(c).	Several industry events involving the electrical grid have been incorporated into simulator and classroom training lesson plans. Licensed operator requalification training lesson plans include training/simulations and/or demonstrations of loss of off-site power. Requalification program simulator lessons are updated and presented repetitively over several years per the training program description. The operators are examined in accordance with NUREG 1021 guidance. Examination methods use simulator and written examinations and job performance measures. All three methods test operator response to off-site electrical power (grid) disturbances.

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1. (continued)	
(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.	Seabrook Station does have a formal agreement with the TSO. Therefore, this question is not applicable.
(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).	Seabrook Station's agreement with the TSO does require notification of actual or predicted conditions (i.e. contingency analysis program) that could cause a degraded voltage condition below the minimum allowable value.
(g) Describe the low switchyard voltage conditions that would initiate operation of plant degraded voltage protection.	If the voltage on a 4.16 kV emergency bus is below that required to ensure the continued operation of safety-related equipment, the second level undervoltage protection scheme is activated. If the activation occurs coincidentally with an accident signal, then the unit auxiliary transformer and reserve auxiliary transformer incoming line breakers are automatically tripped after a time delay to prevent spurious operation due to transients such as starting of large motors. If the second level undervoltage protection scheme is activated without the coincident presence of an accident signal, then only an alarm is received. Established plant procedures require the operator to take specific steps to assess the magnitude and expected duration of the disturbance causing the undervoltage. If the operator is not assured that the disturbance is transitory, and that recovery is imminent, the operator may choose to manually trip the offsite power circuit breakers after ensuring that further deterioration of safety will not result from his proposed action. The minimum anticipated post-contingency switchyard voltage at Seabrook Station is 345 kV. A voltage below this value is required to operate the degraded voltage relays. The minimum switchyard value of 345 kV ensures that required safety systems operate without actuation of safety bus degraded voltage protection relays.

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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.	Yes, the TSO and its Local Control Centers (LCC) employ a Real Time Contingency Analysis (RTCA) Program. As provided by ISO-NE this Program utilizes real-time transmission system information and Seabrook Station specific shutdown loads and minimum voltage requirements. The program creates a real-time network model starting with bus/branch connectivity, branch impedance and ratings, and steady state generator models. The program then superimposes real-time switch and breaker status to determine network topology. Real-time generation and bus loads are also applied to this model. Statistical techniques are used to resolve telemetering inconsistencies (state estimation). The result forms the basis upon which contingent events (contingencies) are tested. A pre-defined list of contingencies includes loss of each generator (including each NPP) and transmission events. Contingency results are automatically compared to limits; if any limit is violated, alarms are generated and Seabrook Station would be notified. Additionally, online monitoring is performed every 60 seconds by ISO-NE to verify that predetermined interface limits are not exceeded. This monitoring program totals the fundamental quantities (line flows, VAR output, etc.) and compares this total to a limit that was determined through offline studies.
(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?	Yes, the TSO uses the contingency analysis program as the basis for notifying Seabrook Station of potential degraded conditions.
(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.	Yes, ISO-NE's analysis tool has this function.

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2. (continued)	
(d) If your TSO uses an analysis tool, how frequently does the analysis tool program update?	As provided by ISO-NE, the online Real Time Contingency Analysis calculations are performed at least every 5 minutes at the ISO-NE and at least every 10 minutes at the LCC. In addition, online monitoring is performed every 60 seconds by ISO-NE to verify that predetermined interface limits are not exceeded.
(e) Provide details of analysis tool-identified contingency conditions that would trigger an NPP licensee notification from the TSO.	See the response to question 2(a). As discussed in the response to question 2(a), the real time on-line AC contingency monitor program will determine if existing conditions coupled with a trip of the nuclear generator would result in adequate or inadequate post trip voltages.
(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?	Yes, the TSO has an Operating Procedure, which requires the TSO to notify Seabrook Station if they are unable to determine if offsite power voltage and capacity could be inadequate. This is considered an unlikely event because: • This analysis capability exists at multiple ISO-NE locations. • The analysis capability also exists at the ESCC. • There are multiple methods to determine offsite voltage adequacy both automatic real-time and system operator manual analysis. • With minimum system real-time data the ISO-NE and ESCC operators can provide Seabrook Station with an experience based opinion on the capability of the offsite source. Seabrook Station would continue to rely on the TSO to notify them of any change in the grid conditions which could affect the quality or reliability of offsite power.
(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?	No, the post trip switchyard voltages are not verified by procedure to be bounded by the analysis tool. If, before the trip, the analysis tool were to predict a post trip voltage below the allowable level the TSO would notify Seabrook Station. ISO-NE occasionally benchmarks analysis results with data collected after actual events.
(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?	This question is not applicable since the TSO currently uses a contingency analysis program to monitor grid conditions.

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2. (continued)	
(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? (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? (b) If the bounds of the analyses are exceeded, does this condition trigger the notification provisions discussed in question 1 above?	This question is not applicable since TSO currently uses a contingency analysis program to monitor grid conditions.
(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.	This question is not applicable to Seabrook Station as the TSO uses a real time contingency analysis program to monitor grid conditions. Seabrook Station is in compliance with GDC 17 and no compensatory actions are required.

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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?	Yes, Main Plant Evolution Procedure OS1000.10, *Operation at Power*, requires: "If notified by the Dispatcher that Post Contingency Voltage is less than 345 kV, entry in TS 3.8.1.1 for loss of two physically independent circuits is required. Post Contingency Voltage is the calculated grid voltage expected after a Seabrook Station trip. The Dispatcher is responsible for realigning the grid within 30 minutes to raise the Post Contingency Voltage to greater than 345 kV". Seabrook Station does not declare offsite power inoperable for a postulated trip of another unit or transmission line.
(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?	Double sequencing (LOCA with delayed LOOP event) is not part of the licensing bases for Seabrook Station. The UFSAR accident analysis does not assume double sequencing. No consideration of double sequencing is appropriate at Seabrook Station for operability due to the licensing bases.

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3. (continued)	
(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).	Not applicable for Seabrook Station. See response to 3(b).
(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.	No, TS are not entered for grid conditions that might occur. Per Operating Procedure OS1000.10, *Operation at Power*, Seabrook Station declares offsite power inoperable when the predicted voltage following a Seabrook Station trip is low enough to cause actuation of the degraded voltage relays and a consequential LOOP. Postulated contingencies on the transmission grid are not used as a basis for operability determinations since: • such events are only postulated and have not actually occurred, • the offsite power circuits remain capable of effecting a safe shutdown and mitigating the effects of an accident, and the GDC 17 criterion discussed in the Generic Letter are still met, i.e., loss of power from the transmission network would not occur as a result of loss of power generated by the nuclear power unit. The TSO contingency analysis program analyzes various types of bounding single contingencies including plant trips or transmission line faults. If any contingency results in a switchyard voltage below the minimum allowed value, then the TSO will notify Seabrook Station, per the ISO-NE Transmission Operating Guides.
(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.	The applicable TS are entered when Seabrook Station is notified by the TSO that a single contingency, including a unit trip, will result in a switchyard voltage below the minimum value. Seabrook Station is in compliance with GDC 17 and no compensatory actions are required.

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3. (continued)	
(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).	Several industry events involving the electrical grid have been incorporated into lesson plans for licensed operator requalification training. Licensed operator requalification training lesson plans include training/simulations and/or demonstrations of loss of off-site power. Requalification program simulator lessons are updated and presented repetitively over several years per the training program description. The operators are examined in accord with NUREG-1021 guidance. Examination methods use simulator and written examinations and job performance measures. All three methods test operator response to various aspects of off-site electrical power interruption. The simulator training lessons and both simulator and written examinations include TS evaluations of grid conditions and their effect on the operability of in-plant equipment.

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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.	Yes, Seabrook Station procedures require TSO notification any time that the voltage regulator is operated in manual. Seabrook Station has no auto tapping transformers or VAR compensators. The operators are not specifically trained or tested on the guidance and procedures. Procedure compliance, use and application are considered operator skills. No knowledge elements are required.
(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.	Seabrook Station Operating Procedure OS1000.10 provides the necessary guidance on how to operate the main generator voltage regulator. Seabrook Station is in compliance with GDC 17 and no compensatory actions are required.

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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?	Yes, all scheduled activities are procedurally required to be reviewed to determine if the activities could increase the probability of a plant trip or LOOP, impact LOOP or SBO coping capability before taking risk impact equipment out of service. In accordance with Procedures WM10.1, *Online Maintenance*, and RM-201, *Risk Evaluation Process for Online Maintenance*, a qualitative grid reliability evaluation is performed prior to removing equipment from service when the TSO has notified Seabrook Station of grid related activities. If an activity impacts a "component" that is modeled in the Seabrook Station PRA (e.g. a 345 kV line) or if the activity is judged to have a potential impact on the frequency of LOOP, a quantitative evaluation is performed using the Safety Monitor model.
(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?	Yes, the grid status is continuously monitored by the TSO, including during the performance of grid-risk-sensitive maintenance. A qualitative grid reliability evaluation is performed prior to removing equipment from service when the TSO has notified Seabrook Station of grid related activities. If an activity impacts a "component" that is modeled in the Seabrook Station PRA (e.g. a 345 kV line) or if the activity is judged to have a potential impact on the frequency of LOOP, a quantitative evaluation is performed using the Safety Monitor model.

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5. (continued)	
(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.	Yes, as provided by ISO-NE, entry into alert conditions in the context of NERC Emergency Preparedness and Operating Standard EOP-002-0 is more prevalent in the summer months. There is not a significant variation in the stress on the grid in the vicinity of Seabrook Station in regard to maintenance activities. Based on the limited number of LOOP events there is no seasonal variation in the LOOP frequency in the local transmission region. Appendix B of WCAP-16316, *Lessons Learned from the August 14, 2003 Loss of Offsite Power Events in North America*, identifies 7 events described as "major disturbances and unusual occurrences" that impacted ISO New England from 1999 to 2003. Two of these events occurred in Summer (July, August), one in the fall (November), three in Winter (December and 2 in March), and one in Spring (June). This shows no seasonal variation in this limited data set. Also note that these events impacted only a small area of the ISO New England grid or resulted in only a voltage reduction. These events may be identified as precursor events to a LOOP at Seabrook Station, but were not significant with regard to actual Seabrook Station-area grid performance.
(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?	No, there are no known time related variations in the probability of a LOOP at Seabrook Station.
(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?	Yes, there are normal communication protocols with the TSO (ISO-NE) per established procedures. All grid related work performed at Seabrook Station is planned and scheduled with the ISO and the ESCC. A one-year look-ahead schedule is provided to the ESCC every month. Seabrook Station's schedule is then reviewed for conflict, integrated with the rest of the ESCC district and forwarded to the TSO for area integration and posting on the Long Term Transmission Operation Plan.
(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.	The TSO has Operating Procedures which require ISO-NE or its Local Control Center to notify Seabrook Station if grid conditions are under stress. This notification takes place regardless of whether maintenance is taking place. Important alerts such as the one suggested by this question would be made to all generators in the control area.

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5. (continued)	
(g) Do you contact your TSO periodically for the duration of the grid-risk-sensitive maintenance activities?	No, the TSO is not periodically contacted during maintenance work. As discussed in response to question 5.b, the grid conditions are continuously monitored by ISO-NE and the Local Control Center (ESCC). Seabrook Station is notified of changing grid conditions in accordance with ISO-NE and Local Control Center (ESCC) procedures.
(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.	Seabrook Station trains maintenance personnel on conduct of work activities that the plant has agreed to, such as requesting TSO tags for the LP cutout when we add SF6 gas in the switchyard. We train the electricians on requirements for immediate notification of ESCC and ISO for identified problems with transmission equipment, even if no line outage is anticipated. This includes delays in returning equipment to service. Licensed and non-licensed operators receive on-the-job training on ESCC and ISO procedures, switching orders and communications. This training is documented in qualification guides. Licensed operator training and examination includes simulated communication with ESCC and ISO. Training on the interface agreement is covered in initial and continuing Switching and Tagging training, which is attended by Operations and Maintenance department personnel.
(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).	The question is not applicable to Seabrook Station, as Seabrook Station has a communications arrangement with the TSO.
(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.	Not applicable for Seabrook Station. Risk is assessed/reassessed, by Seabrook Station, using the Safety Monitor Program when warranted based on communication from the TSO or changing weather conditions (see answer to 5b). Risk assessment under 10CFR50.65(a)(4) is not intended to be a numerical exercise, but rather to highlight the condition of the plant and ensure that the plant staff is aware of the safety implications of the work so that the proper risk management actions can be taken.

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5. (continued)	
(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.	Not applicable for Seabrook Station. No additional actions are required.

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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?	Yes, outages of lines supplying the Seabrook Station switchyard are discussed before implementation. The long term maintenance schedule (12-month look-ahead) for Seabrook Station is communicated to the TSO each month and becomes part of the integrated long range schedule.
(b) Do you coordinate NPP maintenance activities that can have an impact on the transmission system with the TSO?	Yes, see response to question 6a. Short of inducing a trip of the main generator, no work at Seabrook Station is able to make a significant change to the status of the grid in the vicinity of the plant or the grid at-large. For switchyard work the long term maintenance schedule (12-month look-ahead) for Seabrook Station is communicated to the TSO each month and becomes part of the integrated long range schedule.
(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?	Yes, Seabrook Station has rescheduled maintenance activities after contact from the TSO regarding potential degraded grid conditions.
(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.)	Yes, the risk assessment required by 10CFR50.64(a)(4) would consider all of the parameters of interest, including the risk impact of the condition of overriding need, the actual condition of the grid, duration of the proposed maintenance or duration left to complete maintenance or restore equipment, etc. If the risk assessment yields a result above 1E-06 ICDP, then risk management actions would be implemented as required by the guidance. In accordance with the Seabrook Station Work Management Manual, the actual actions implemented would depend on the specific circumstances, however, such things as restoration or cessation of maintenance in progress, confirmation and protection of alternate equipment would be considered.

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6. (continued)	
(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.	6(a), 6(b), and 6(c) are governed by the agreement with the TSO. 6(d) is governed by WM10.1, *On-Line Maintenance*. The actions comply with the industry guidance in NEI 93-01, Rev 3, as endorsed by N.R.C. Regulatory Guide 1.182.
(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).	Electrical Maintenance coordinates with the TSO for work effecting transmission through their clearance request process. Maintenance receives specific training on the clearance requesting process at ESCC. Operations assesses risk when warranted by communication with the TSO, thus allowing proper risk management actions to be taken by the plant staff. Training in the use of the Safety Monitor software for risk assessment was initially presented to all crews in on-shift briefings. Safety Monitor training is included in licensed operator initial and continuing training.
(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).	Not applicable for Seabrook Station. There is effective coordination between the Seabrook Station operator and the TSO regarding transmission system maintenance and station maintenance activities. Such coordination is in accordance with the protocols.
(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.	Not applicable for Seabrook Station. As discussed in questions 6(a) through 6(d), Seabrook Station effectively implements appropriate risk management actions.
(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).	Not applicable to Seabrook Station.

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7. Procedures for identifying local power sources (this includes items such as nearby or onsite gas turbine generators, portable generators, hydro generators, and black-start fossil power plants) 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 under-voltage and collapse* - Weather-induced power loss - 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 re-supply power to your plant following a LOOP event.	The TSO has a detailed system blackout recovery procedure (OP6) which describes the process by which the New England electric system would be re-established if power was lost to part or the entire ISO-NE region. Included in this procedure (OP6) is notification to the Local Control Centers of the importance of re-establishing power to the NPPs as a priority action. Based on the recovery procedure (OP6), the TSO will utilize the best sources available for specific events to restore offsite power and to determine the specific power sources and paths, since there is no way to predict the extent and characteristics of a specific blackout. The NPPs in the ISO-NE region have participated as an active player in the annual system recovery exercises. During this exercise the NPPs and TSO have discussed the NPPs off-site power requirements and restart limitations.
(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.	Seabrook Station's 345 kV switchyard has no "local power sources" capable of re-supplying it following a LOOP event. Restart of the plant under these conditions is dependent upon 345 kV power being restored by the TSO. When off-site power is restored, Seabrook Station's EOPs and AOPs for LOOP contain recovery actions for the in-plant distribution system. Operators are trained and tested on these procedures. See item 1.d. (above) for a description of operator training and testing. Electrical Maintenance trains electricians on the procedure for aligning alternate control power to switchyard equipment, thus allowing 345 kV restoration following a LOOP.
(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.	Not applicable for Seabrook Station; an agreement with the TSO exists. Our TSO has agreements with and has verified the adequacy of regional units which have black-start capability. These units are started and dispatched under the direction of TSO, in accordance with TSO (OP6) system recovery process. NPPs are considered a priority to have power restored.

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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?	Seabrook Station has not experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10CFR 50.63.
(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?	Not applicable to Seabrook Station.
(c) If so, what were the results of this reevaluation, and did the initially determined coping duration for the NPP need to be adjusted?	Not applicable to Seabrook Station.
(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.	Not applicable to Seabrook Station.

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9. Actions to ensure compliance	
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.	Not applicable to Seabrook Station.

ATTACHMENT 4

Duane Arnold Energy Center Response to 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 Technical Specifications.	
(a) Do you have a formal agreement or protocol with your TSO?	Yes, Duane Arnold Energy Center (DAEC) does have a formal agreement with the TSO (American Transmission Company (ATC)) and the Midwest Independent System Operator (Midwest ISO). The agreement is documented in Procedure ACP 101.16, *Midwest ISO Real-Time Operations Communication and Mitigation Protocols for Nuclear Plant/Electrical System Interfaces* (Note this is MISO procedure RTO-OP-03). Compliance with GDC 17, as documented in the DAEC license bases and plant TS, is not predicated on such an 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.	The TSO is required to notify DAEC whenever an impaired or potentially degraded grid condition is recognized by the TSO. Specific examples of known potentially degrading conditions identified in the agreement include: 1. Midwest ISO Real-Time Operations Communication and Mitigation Protocols for Nuclear Plant/Electrical System Interfaces states "Transmission Operator (ATC) will immediately initiate communication with the Nuclear Plant and the Midwest ISO if the Transmission Operator verifies an actual violation to the operating criteria [system limits] affecting the Nuclear Plant. The Transmission Operator and the Midwest ISO will immediately initiate steps to mitigate the actual violation." 2. Midwest ISO Real-Time Operations Communication and Mitigation Protocols for Nuclear Plant/Electrical System Interfaces states: "The Midwest ISO or the Transmission Operator will initiate communication with each other to verify study results that indicate a post-contingent violation of operating criteria [system limits]. Upon verification, the Transmission Operator and the Midwest ISO will immediately initiate steps to mitigate the pre and post contingent operating criteria violation. If the violation is not mitigated within 15 minutes of the verification of the study results, the Transmission Operator shall immediately notify the Nuclear Plant." 3. In response to this Generic Letter the ATC provided the following information: "ATC will notify FPL-Duane Arnold within 15 minutes after verification whenever the real time voltage on the Duane Arnold 161 kV bus goes lower than 156 kV or higher than 169 kV. ATC will notify FPL-Duane Arnold within 15 minutes after verification whenever the loss of any single transmission element or generator connected to the IP&L [Interstate Power and Light] transmission system will cause the Duane Arnold 161 kV bus voltage to go lower than 153 kV or higher than 177 kV. When notified by FPL, ATC will change the real time and post-contingent low voltage limits to 158 kV in response to in-plant configuration changes. ATC will notify FPL-Duane Arnold of forced outages to either end of any 345 kV or 161 kV transmission line connected to the Duane Arnold Substation."

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1. (continued)	
(b)	4. In response to this Generic Letter, the Midwest ISO provided the following information: The Midwest ISO Communication Protocol, RTO-OP-03 states "Midwest ISO will monitor the appropriate system conditions and notify the nuclear plant's operating personnel via the local transmission operator when operating conditions are outside of established limits, as well as, when they are restored to within acceptable criteria. This communication shall take place within 15 minutes of verification of the results." The occurrence of a grid contingency that impacts DAEC requires immediate DAEC notification.
(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.	The observable grid parameters of the DAEC operator include; voltage and frequency, generator reactive output, breaker status, line status and certain switchyard alarm points. Procedure AOP 304, *Grid Instability*, is entered whenever the grid reaches a limited reserve condition, essential bus voltage reaches 95%, main generator reaches 200 MVAR, when the main transformer loading is greater than 95%, when the local transmission lines are heavily loaded or at the discretion of the OSM. This procedure directs communication with the local grid operator to assess grid conditions. Procedure ACP 101.16, *Midwest ISO Real-Time Operations Communications and Mitigation Protocols for Nuclear Plant/Electric System Interfaces*, is the protocol established for such communications.
(d) Describe how NPP operators are trained and tested on the use of the procedures or assessing grid conditions in question 1(c).	DAEC operators are trained and tested on the following: • LOOP • System Restoration • Degraded voltage conditions • VARs • Breaker status • Offsite power trip • Notification by TSO of changed conditions. Procedures associated with this training and testing include; AOP 301, *Loss of Essential Power*, AOP 301.1, *Station Blackout*, AOP 304, *Grid Instability*, and AOP 304.1, *Loss of Non-essential Power*. These procedures are covered in the Initial License Training program, as well as the Licensed Operator Continuing Training program on a once per two year basis.

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1. (continued)	
(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.	DAEC does have a formal agreement with the TSO. Therefore, this question is not applicable.
(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) <u>or</u> LOOP after a trip of the reactor unit(s).	As previously stated, DAEC does have a formal TSO agreement. Prompt notification and a pre-trip analysis of post-trip voltage are included. Procedures associated with these communications are in Procedure ACP 101.16, *Midwest ISO Real-Time Operations Communication and Mitigation Protocols for Nuclear Plant/Electrical System Interfaces.* In response to this Generic Letter, the Midwest ISO provided the following information: "The Midwest ISO Communication Protocol, RTO-OP-03 states; the Midwest ISO or the Transmission Operator will initiate communication with each other to verify study results that indicate a post-contingent violation of operating criteria. Upon verification, the Transmission Operator and the Midwest ISO will immediately initiate steps to mitigate the pre and post contingent operating criteria violation. If the violation is not mitigated within 15 minutes of the verification of the study results, the Transmission Operator shall immediately notify the Nuclear Plant".
(g) Describe the low switchyard voltage conditions that would initiate operation of plant degraded voltage protection.	The DAEC degraded voltage protection is set so that sufficient power will be available for starting large ECCS motors without risking damage to the motors that could disable the ECCS function. Power supply to the bus is transferred from offsite power to the onsite DG power when the voltage on the bus drops below the Degraded Voltage Function Allowable Values, i.e., 92.2% of 4.16 kV for 8.5 seconds. The 92.2% of 4.16 kV equates to 98.8% voltage on the 161 kV switchyard buses with the essential buses under load.

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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.	Yes, the TSO makes use of analysis tools to predict grid conditions that would affect the DAEC offsite power system. The tools presently used by the TSO to manage the grid programs, control the transmission related activities, and monitor grid actions are outside the control of the DAEC. In response to this Generic Letter the ATC provided the following information: "ATC uses both offline (PSSE, Areva, POM/OPM, VSAT, etc.) and online (Areva energy management system) analytical tools to determine grid conditions under a variety of situations. The online analysis is performed approximately once every 5 minutes while the offline analysis is performed on an as needed basis." In response to this Generic Letter, the Midwest ISO provided the following information: "Midwest ISO Energy Management System (EMS) includes a State Estimator (SE) that currently runs every 90 seconds and Real-Time Contingency Analysis (RTCA) programs that analyzes over 7000 contingencies based on the transmission owner's criteria. One of the contingencies analyzed by the MISO EMS is the trip of the NPP. The analysis provides results with respect to thermal, voltage, and voltage drop limit violations."
(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?	Yes, the TSO and ISO uses the above analysis tools, in conjunction with procedures, as the basis for determining when conditions warrant DAEC notification. In response to this Generic Letter, the Midwest ISO provided the following information: "The results of the MISO RTCA program application contain the specific contingency of the nuclear power plant tripping as the contingent element. Operation outside of the voltage limits for a unit trip contingency would result in notification to the NPP per MISO Procedure RTO-OP-03. If Midwest ISO determines the transmission system is outside of operating criteria, the Midwest ISO will notify the local transmission operator." Refer to the response to question 1(b).
(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.	Yes, the TSO analysis tool, in conjunction with DAEC plant analysis, identifies conditions which would actuate the DAEC degraded voltage protection logic and initiate separation from an offsite power source upon a DAEC trip. In response to this Generic Letter, the ATC provided the following information; "The analysis tools identify when a trip of the Duane Arnold unit would result in switchyard voltages falling below the values provided to ATC by FPL." In response to this Generic Letter, the Midwest ISO provided the following information: "Midwest ISO RTCA program simulates the loss of NPP and analyzes the post-trip condition against the criteria provide by the transmission owner. If the conditions were exceeded, the Midwest ISO RC would notify the local transmission operator per MISO Procedure RTO-OP-03".

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2. (continued)	
(d) If your TSO uses an analysis tool, how frequently does the analysis tool program update?	In response to this Generic Letter, the ATC provided the following information; "ATC's on line analysis tool updates approximately every 5 minutes, immediately following the operation of any breaker 100 kV or greater, or as initiated by the system operator. ATC completes off line studies on an as needed basis." In response to this Generic Letter, the Midwest ISO provided the following information; "Midwest ISO State Estimate runs every 90 seconds and Real-Time Contingency Analysis program runs every 5 minutes or by Midwest ISO Reliability Coordinator Action."
(e) Provide details of analysis tool-identified contingency conditions that would trigger an NPP licensee notification from the TSO.	The notification from the TSO is based upon the predicted post-trip switchyard voltage given actual (RTCAs) grid conditions. In response to this Generic Letter, the ATC provided the following information; "The contingencies that are modeled and studied include the loss of any single transmission line or transformer as well as [large] generator (including the Duane Arnold unit) connected to the Alliant West system. FPL Energy Duane Arnold is notified whenever any activated contingency results in voltages outside of predefined limits [per MISO protocol]." In response to this Generic Letter, the Midwest ISO provided the following information; "If Midwest ISO observes the transmission system is in real-time or has post-contingent analysis, which indicates the system would be outside of operating criteria, the Midwest ISO will notify the local transmission operator. The Midwest ISO criterion for contingency analysis is to monitor all generators greater than 100 MW, all non-radial lines above 100 kV, and all transformers with two windings greater than 100 kV. This contingency list is validated with the local transmission operator to ensure inclusion of all critical contingencies, and may include lower voltage facilities and smaller generators if deemed critical." Refer to the response to question 1(b).

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2. (continued)	
(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?	Yes, the agreement does specifically require DAEC notification for periods of time when grid conditions are indeterminate. Procedure ACP 101.16 states: "Should the Transmission Operator lose its ability to monitor or predict the operation of the transmission system affecting off-site power to the Nuclear Plant, the Transmission Operator shall notify the Midwest ISO, validate Midwest ISO's ability to monitor and predict the operation of the transmission system and then communicate to the Nuclear Plant. Transmission Operator will communicate to the Nuclear Plant and Midwest ISO when this capability is restored. This communication should be as soon as practicable or per established agreements with the Transmission Operator". In response to this Generic Letter, the ATC provided the following information; "Yes, ATC will notify FPL-Duane Arnold per the MISO Communication and Mitigation Protocols for Nuclear Plant/Electric System Interfaces." Should Midwest ISO lose its ability to monitor or predict the operation of the transmission system affecting off-site power to the Nuclear Plant, MISO shall notify the Transmission Operator. In response to this Generic Letter, the Midwest ISO provided the following information; "Per the Midwest ISO Nuclear Plant Communication protocol, should the Transmission Operator lose its ability to monitor or predict the operation of the transmission system affecting off-site power to the Nuclear Plant, the Transmission Operator shall notify the Midwest ISO, validate Midwest ISO's ability to monitor and predict the operation of the transmission system and then communicate to the Nuclear Plant. Transmission Operator will communicate to the Nuclear Plant and Midwest ISO when this capability is restored. This communication should be as soon as practicable or per established agreements with the Transmission Operator. Should Midwest ISO lose its ability to monitor or predict the operation of the transmission system affecting off-site power to the Nuclear Plant, MISO shall notify the Transmission Operator. The Midwest ISO has developed Abnormal Operating Procedures (AOP) to guide its transmission system operation for failures of different components of analytical and communication tools. For loss of the MISO RTCA, Midwest ISO will consider the results of the local transmission operator's analytical tools. For loss of both sets of tools, Midwest ISO Operating Engineer will attempt to use off-line power flow tools to replicate operating conditions and predict contingent operation."

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2. (continued)	
(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?	No, for post event analysis, the TSO does not verify by procedure the switchyard voltages are bounded by the analysis tools. In response to this Generic Letter, the Midwest ISO provided the following information: "There is no formal process for comparing the actual post-trip voltages to the post-trip contingency voltage results calculated by the MISO RTCA program. Because many [of] the MISO transmission owning member companies have similar RTCA programs, there are many opportunities to compare the results. This results in a high confidence that the RTCA results are accurate. However, if the resultant voltages are outside of the criteria, when they are predicted to be within, MISO would be initiating an investigation".
(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?	This question is not applicable to DAEC, since TSO analysis tools are presently in use.
(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? (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? (b) If the bounds of the analyses are exceeded, does this condition trigger the notification provisions discussed in question 1 above?	This question is not applicable to DAEC, since TSO analysis tools are presently in use. Specifically, the TSO performs periodic studies for DAEC in addition to the offsite power analysis tool.

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2. (continued)	
(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.	This question is not applicable to DAEC, since the TSO utilizes analysis tools and communicates the applicable conclusions to the DAEC.

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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?	As outlined in DAEC's response to question (9) below, FPL Energy Duane Arnold will implement a change in operating procedure such that the TS LCO for inoperable offsite circuits will be entered following notification by the TSO that a trip of the DAEC would result in switchyard under-voltage conditions.
(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?	No, double sequencing events (LOCA with a delayed LOOP) are not part of the DAEC current licensing basis. As stated in the DAEC UFSAR (Chapter 15.2.1), loss-of-offsite power is concurrent with the postulated LOCA, not subsequent to it. Therefore, plant safety equipment was not specifically designed to cope with "double sequencing events" and thus, such capability does not constitute "operability" requirements for this equipment.
(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).	As stated in the response to question 3(b) above, such scenarios are not part of the DAEC design or licensing basis. Therefore, no such evaluation has been performed for the DAEC.

Duane Arnold Energy Center Response to Generic Letter 2006-02

3. (continued)	
(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.	No, as committed to in the response to question 3(a) above, only a condition where the trip of the NPP itself would lead to degraded switchyard voltage would cause the TS actions for offsite circuits to be entered. Other "N-1 contingencies" would not cause the offsite circuits to be declared inoperable.
(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.	As outlined in DAEC's response to question (9) below, FPL Energy Duane Arnold will implement a change in operating procedure such that the TS LCO for inoperable offsite circuits will be entered following notification by the TSO that a trip of the DAEC would result in switchyard under-voltage conditions. The DAEC switchyard design meets the intent of GDC 17 (Note: DAEC was issued its Operating License before the GDC were issued as "final."). The DAEC switchyard design has the requisite number of lines of AC power from the transmission network (i.e., more than 2), that are appropriately independent of each other, and the associated transfer breakers, disconnects, etc., are all currently capable of performing their intended safety function, i.e., meet the TS definition of Operability. The DAEC switchyard (offsite circuits), upon a trip of the DAEC turbine/generator, has been analyzed to demonstrate this event does not lead to a grid instability (UFSAR 8.2.2.2), under the most probable "N-1" scenarios, as specified in GDC 17. The current Loss-of-Power (LOP) instrumentation (TS LCO 3.3.8.1) is capable of detecting actual degraded grid voltages and transferring offsite sources from the preferred to the alternate preferred source when required and in the extreme event, disassociation from the offsite sources and starting and loading of essential equipment onto the on-site, standby AC sources (Emergency Diesel Generators), i.e., they meet their TS definition of Operability. However, as discussed in the Reponses to questions 5 and 6 below, compensatory measures are taken to ensure that overall plant risk is managed, as required by 10 CFR 50.65(a)(4).
(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).	When DAEC operators are notified by the TSO of potential grid problems, DAEC enters and executes Procedure AOP 304, *Grid Instability*. Procedure AOP 304 lists a probable indication of potential grid instability as notification from the System Operating Center (SOC). Procedure AOP 304 is trained on in both Initial License Training and License Operator Requalification Training on a once per two year basis.

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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.	DAEC TS do not address voltage regulating equipment. Due to the fact that a trip of a 345 kV transmission line in Wisconsin (King-Eau Claire- Arpin) had the potential of tripping the DAEC offline a capacitor bank was installed in the DAEC switchyard in 2001. This capacitor bank is operated by the TSO to provide voltage support when required. The main generator voltage regulator is operated in accordance with Operating Instruction OI-698, *Main Generator System*. The voltage regulator is normally operated in the automatic mode of operation. The automatic voltage regulator contains over excitation and under excitation (Under Excited Reactive Ampere Limit) limiters integral to the regulator. These limiters are not installed in the manual voltage regulator. Operating Instruction OI-698 directs coordinating with the local grid operator to limit reactive loading of the generator when the unit is operated in manual. Additionally, Operating Instruction OI-698 and Procedure ARP 1C08C B-3, *Generator and Auxiliary Power Annunciator Procedure*, directs informing the grid operator of the voltage regulator operating mode, auto or manual. DAEC has no auto tapping transformers or static VAR compensators. Training is provided in both Initial License Training and License Requalification Training for the Main Generator Tasks that would require operators to contact the TSO. The tasks covering these procedures are 57.02, *Prepare Main Generator System to Be Placed on the Grid*, and 57.03, *Place Main Generator on the Grid*. The Initial License Training lesson plan for the main generator covers both of these tasks, and also covers Operating Instruction OI-698 and Procedure ARP 1C08C B-3. These two tasks are also selected for License Requalification Training. These tasks were trained in Cycle 2005A. This task is trained on a once per two year basis.

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4. (continued)	
(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.	DAEC complies with the NERC Standard (VAR-001-0-Voltage and Reactive Control) requirements of reporting the voltage regulator and power system stabilizer status to the local grid operator. Per this standard: "Each Generator Operator shall provide information to its Transmission Operator on the status of all generation reactive power resources, including the status of voltage regulators and power system stabilizers." Also per this standard, "When a generator's voltage regulator is out of service, the Generator Operator shall maintain the generator field excitation at a level to maintain Interconnection and generator stability."

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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?	Yes, per Guideline WPG-2, *On-line Risk Management Guideline*, the Control Room Supervisor/Operations Shift Manager is responsible for ensuring the grid operator is contacted to verify grid stability prior to taking the following equipment out of service for maintenance or testing: • Emergency Diesel Generators • Startup Transformer • Standby Transformer • HPCI • RCIC • 125 Volt Battery • 250 Volt Battery
(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?	Yes, the grid is monitored by the grid operator, during these times. Procedure ACP 101.16 contains communications requirements. In addition Plant Shift Orders dated March 20, 2006 states: "...when we have risk significant equipment out of service, contact ATC once per day on nights for predicted grid status regarding stability and log it in the control room logs."

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5. (continued)	
(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?	No, in response to this Generic Letter, the ATC provided the following information: "Grid stress varies, but there is not necessarily a correlation between stress and season. ATC does not track the frequency of LOOP at Duane Arnold and therefore cannot report on the variation of LOOP frequency with season. Transmission outages are typically scheduled when overall grid stress is low. However, scheduled outages increase the stress on the remaining in service elements."
Is there a seasonal variation (or the potential for a seasonal variation) in the LOOP frequency in the local transmission region?	In response to this Generic Letter, the Midwest ISO provided the following information; "After review of Energy Emergency Alerts within the Midwest ISO Reliability Footprint, there is no correlation between grid stress and seasonal load or maintenance activities. Part two of the question should be answered by the nuclear power plant and local transmission operator."
If the answer to either question is yes, discuss the time of year when the variations occur and their magnitude.	EPRI TR-1011759, dated December 2005, has shown that there is no statistically significant seasonal-regional variation in recorded LOOP events from 1997 to 2004. Some observations from EPRI TR-1011759 indicate: • a LOOP in the fall is rare • Several grids regions appeared to be more stable than other grids. To gather a statistically significant sample of LOOP events by region for EPRI TR-1011759, the national grid is subdivided into the major North American Electric Reliability Council regions. This grouping keeps events at "remote plants" from skewing the LOOP counted as appropriate to any particular plant.

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5. (continued)	
(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?	As part of the DAEC's risk management process, time related variations (e.g., grid instability, severe weather) are always considered as follows: • Severe weather is routinely considered separately as an emergent condition. • Switchyard maintenance and test activities are considered within the SENTINEL risk tool. • Other events (not only grid specific) outside the plant are under heightened risk conditions considered separately. The DAEC's procedures require increased controls on maintenance during the described conditions. Risk is usually not calculated solely due to changes in grid reliability (i.e., assessed in conjunction with plant equipment being out of service). According to preliminary work by the Westinghouse Owners Group (WOG), (Note: WOG data on LOOP frequency would also pertain to BWRs) there is no statistically significant time-of-day or day-of-week variation in the frequency of LOOP at nuclear power plants. This is largely a result of a small number of LOOP events. The analysis has yet to normalize factors such as: • most tasks are done on the day-shift, and • most tasks are performed from Monday to Friday. Thus, the risk assessment for the purposes of 10 CFR 50.65(a)(4) does not vary the LOOP frequency strictly as a function of "time-related" issues.
(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?	Yes, per Guideline WPG-2, the Control Room Supervisor/Operations Shift Manager is responsible for ensuring the grid operator is contacted to verify grid stability prior to taking the following equipment out of service for maintenance or testing: • Emergency Diesel Generators • Startup Transformer • Standby Transformer • HPCI • RCIC • 125 Volt Battery • 250 Volt Battery Typically, the TSO uses pre-evaluated nomographs or computer programs to identify conditions where the minimum grid voltage could not be maintained. As a result of the dynamic nature of loads and active generation on the power-grid, the TSO is only able to comment on the grid conditions shortly before (on the order of hours) maintenance tasks commence. Obviously, the TSO can provide commentaries on grid conditions at anytime maintenance tasks are underway. The same dynamic nature of loads and active generation make prediction of grid conditions days or weeks ahead of time highly uncertain.

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5. (continued)	
(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.	Per the Midwest ISO Communications Protocol, RTO-OP-03, the Transmission Operator will immediately initiate communication with the nuclear plant and the Midwest ISO if the Transmission Operator verifies an actual violation to the operating criteria affecting the nuclear plant. The Midwest ISO or the Transmission Operator will initiate communication with each other to verify study results that indicate a post-contingent violation of operating criteria. Upon verification, the Transmission Operator and the Midwest ISO will immediately initiate steps to mitigate the pre and post contingent operating criteria violation. If the violation is not mitigated within 15 minutes of the verification of the study results, the Transmission Operator shall immediately notify the nuclear plant. Notification occurs whether or not maintenance is on-going. The type of alerts provided to the DAEC conform to the accepted practice promulgated by the NERC. Important alerts such as the one suggested by this question would be made to all generators in the control area.
(g) Do you contact your TSO periodically for the duration of the grid-risk-sensitive maintenance activities?	Plant Shift Orders dated March 20, 2006 states; "...when we have risk significant equipment out of service, contact ATC once per day on nights for predicted grid status regarding stability and log it in the control room logs."

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5. (continued)	
(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.	The Midwest ISO Real-Time Operations: Communication And Mitigation Protocols For Nuclear Plant/Electric System Interfaces (DRAFT) was introduced during Licensed Operator Requalification Training 2005 Cycle B, SOER 99-01, *Loss of Grid*. The introduction of this draft agreement was NOT formal training (no objectives based upon the draft agreement). At the time, this communications agreement was NOT formally agreed upon between DAEC and MISO. Since then, it has been formally accepted by both DAEC and MISO. This document has been incorporated into our procedures as Administrative Control Procedure (ACP) 101.16. A corrective action item has been assigned to perform Job Task Analysis for Procedure ACP 101.16 for inclusion into the Initial License and License Requalification programs (OTH011965). This action will be complete by April 30, 2006. Maintenance personnel are NOT trained in this protocol since the Operations personnel are the interface between DAEC and MISO. Operations personnel contact the TSO about maintenance activities that may be affected by grid conditions.
(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).	Most of the PRA analyses to assess the viability of planned maintenance tasks are run days and weeks prior to the actual work to help plan the sequencing of tasks. At this rolling maintenance planning stage, the TSO can provide no statistically valid input to the process. Once degraded grid conditions are identified, the degraded grid conditions will be considered a change in plant configuration and a 10 CFR 50.65(a)(4) risk assessment will be triggered. This assessment will result in a review of available plant equipment out of service. A higher priority is placed on: • repairing grid-risk-sensitive equipment • ensuring grid-risk-sensitive equipment is not removed from service and • post-poning optional maintenance activities on trip sensitive equipment.

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5. (continued)	
(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.	Plant configuration maintenance and PRA personnel are well aware of the importance of LOOP sequences and how they are impacted by plant configuration. The communication with the TSO, including the associated process, is a plant-specific and situation-specific attribute. 10 CFR 50.65(a)(4) is a risk informed performance based rule; it is not intended to be prescriptive with regard to "one size fits all" risk assessment and management actions. The point of risk assessment under 10 CFR 50.65(a)(4) is not intended to be a numerical exercise but rather to highlight the condition of the plant and ensure the plant staff is aware of the safety implications of maintenance work so that the proper risk management actions can be taken. Once the implications of the work are known, well rehearsed risk management practices can be implemented. Sometimes, the risk management action is to defer the work to another time.
(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.	No alternative actions.

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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?	Yes, the TSO informs the plant of transmission system maintenance activities. The TSO sends DAEC a schedule of transmission work which includes; current activities in progress, work scheduled for the upcoming weeks as well as proposed future work activities. Per Guideline WPG-2, Engineering is responsible for ensuring that the Switchyard System Engineer or Maintenance Engineer reviews the weekly transmission outage schedule and notifying the Operations Shift Manager/Control Room Supervisor and the Scheduling Team Leader of potential impacts to offsite power circuits terminating at the DAEC substation. Additionally as transmission system maintenance pertains to equipment located within the DAEC switchyard, Procedure ACP 1408.23, *Controls to the DAEC Switchyard*, states: "The Operation and Maintenance Agreement between FPL Energy Duane Arnold, LLC and Interstate Power and Light Company (IP&L) specifies the scope, responsibilities, and requirements for coordination and control of access, design, operation, and maintenance of the DAEC switchyard, associated equipment, and transmission lines. It requires that IP&L obtain FPL Energy Duane Arnold review and approval of any procedure changes, design changes, tests, and changes to other activities that might affect compliance with DAEC's Operating License or regulatory commitments involving DAEC's switchyard and associated equipment and transmission lines." Any work performed by the DAEC staff in the switchyard, in accordance with Procedure ACP1408.23, is coordinated with the TSO. If required both the Alliant Request for Clearance and the DAEC tagout program control the work activities per Procedure ACP 1410.5, *Tagout Procedure*. Work activities on Alliant Energy transmission lines, switchyards, and substations are controlled from the DDC and SOC by use of the Request for Clearance tagout system. Tagouts within the DAEC switchyard and substations may impact plant/ISFSI operations and therefore are controlled by DAEC Tagout Program in addition to the Request for Clearance. The long term work schedule of work performed in the DAEC switchyard by DAEC personnel is transmitted to the TSO in the spring as part of the summer readiness policy. Required requests for clearance for scheduled work is coordinated several weeks in advance. At DAEC access to the plant switchyard is controlled by the Operations Shift Manager/Control Room Supervisor. Procedure ACP 1408.23 directs switchyard access and controls switchyard activities. The Control Room Supervisor shall be informed of what work is to be performed and of potential effects on the plant. Thus, the outside entity and the on-shift personnel jointly coordinate transmission system maintenance activities in the switchyard. Success of such activities is verified by the plant operator rounds that routinely include tours of the switchyard and other high-voltage equipment.

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6. (continued)	
(a) Continued	In response to this Generic Letter the Midwest ISO provided the following information; "Midwest ISO is responsible for approving *maintenance schedule of transmission facilities and coordinating* the scheduling of generation facilities. The decision to approve transmission and generation facility maintenance schedules is based on the ability of the Midwest ISO to operate the transmission system within the criteria set forth by the transmission owner and NERC and the applicable regional reliability organization. Outage scheduling process analyzes the outages under expected operating conditions. On the day prior and on the outage start day, the system is analyzed by MISO before permitting the equipment to be switched out of service. Once the equipment is switched out of service, grid status is automatically captured by the MISO State Estimator and continually evaluated by the MISO RTCA program." In response to this Generic Letter, the ATC provided the following information: *"Alliant Energy Service, through it's contact with ATC, coordinates transmission system maintenance activities that have an impact on the DAEC operation."* Specific high-voltage circuit outages or substation work is not directly indicative of "grid conditions" that are relevant to determining offsite power operability. The reason is that the power-grid outages affect transmission, which is only one factor affecting the quality of voltage available in the plant switchyard. Besides transmission, the quality of voltage is affected by the amount of generating resources and the load on the network. The TSO has no means of predicting voltage in the DAEC switchyard more than a few hours in advance. Thus, whether or not the TSO coordinates transmission system maintenance activities with the DAEC has little bearing on the operation of the DAEC, except in the case of the plant switchyard. When the transmission system maintenance activities involve the plant switchyard or an important substation in the immediate vicinity, then there are some effective risk management actions available, i.e., deferring work on auxiliary feedwater pumps or postponing testing.
(b) Do you coordinate NPP maintenance activities that can have an impact on the transmission system with the TSO?	See response 5(e).

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6. (continued)	
(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?	Yes, Procedure AOP 304, states: 1. In order to minimize the possibility of a plant trip or reduced electric output: a. *Surveillance tests which cause half scrams or half group one isolations should be stopped and rescheduled if possible.* b. Maintenance which may reduce plant electric output or has the potential to trip the plant should be postponed. c. Maintenance or surveillance tests which could force the plant into *a required shutdown condition of less than 72 hours should be* postponed. d. If any surveillance or maintenance is postponed, contact the Work Week Coordinator to reschedule. NOTE:The maximum excitation limiter and the URAL (Under-excited Reactive Amperes Limit) are only part of the AUTO VOLTAGE REGULATOR and are not in operation when the Regulator is in MANUAL. 2. If the Auto Voltage Regulator is operable verify the generator is in the AUTO Voltage Regulator Mode. 3. Limit electrical distribution system work, especially on the SBDGs, batteries, and in the switchyard. 4. Return Safety equipment to service, if available to do so. 5. Verify SBDGs are in standby readiness. This may be accomplished by a review of the NSPEO logs. 6. As available, non-essential site loads may be secured in order to minimize site electrical usage. This load reduction should be based upon the condition of the grid as well as the economic worth of doing so. It shall NOT negatively affect the operation of the plant." Rescheduling is not in the Maintenance Rule definitions, the risk informed Maintenance Rule allows many choices for the DAEC. Grid-risk sensitive maintenance is performed when the on-shift DAEC personnel conclude that the risk of the work is small compared to the safety benefit. When the maintenance work is done in response to a TS, the risk assessment is informative for sequencing tasks, but not controlling. Emergent issues with the grid are managed to maintain a high level of plant safety. At times appropriate management means rescheduling activities. At other times, the shift-supervisor will order the on-shift DAEC staff to back-out of the task and restore the safety-related function of the equipment.

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6. (continued)	
(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.)	Yes, per Guideline WPG-2, Section 6.4, when the overall risk result presented by SENTINEL is ORANGE or RED, the Cycle Scheduler, Work Week Coordinator or Operations Shift Manager (OSM) should attempt to reduce the color to GREEN or YELLOW by separating maintenance activities. When reducing the color is not possible or practical, appropriate compensatory actions and/or contingency plans shall be discussed and agreed upon at the management challenge board meeting. The Scheduling Department is then responsible for maintaining separation between activities and communicating compensatory actions to the Control Room and other affected organizations. Definition of SENTINEL colors and recommended response to colors are summarized in the WPG. Per Guideline WPG-2, Section 6.3, Emergent and Fill In Work Activities: "Emergent and/or Fill-in work activities shall not be added to the schedule without first verifying their risk significance. When emergent work affects risk-significant equipment, the OSM should have the STA perform a SENTINEL risk analysis prior to authorizing start of the scheduled work. The PSA Significant Train Interactions Matrix...may also be used for this analysis. The assessment should also consider qualitatively, the impact of potentially adverse external conditions such as high winds, flooding, or degraded offsite power availability if such conditions are imminent or have a high probability of occurring during the planned out of service duration. The OSM has final authority for this decision." Guideline WPG-2, Section 6.3, goes on to state: "Activities that would require an overall risk of orange or red should be evaluated by the management team for an IPTE per Procedure ACP 102.17. When emergent activities occur that have placed or will place the plant in an overall risk of orange or red, the Operations Shift Manager will dictate what compensatory actions are required, and will determine the plant's priorities for return-to-service of the risk significant systems/components."
(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.	Procedure AOP 304 and Guideline WPG-2 govern the actions to be taken, see discussion in the responses to questions 6(c) and 6(d) above.

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6. (continued)	
(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).	For Procedure AOP 304; Task 94.48 is titled "Respond to Grid Instability" and is trained and evaluated per the Initial License Training Program Description. Specifically, this task is covered in Lesson Plan 94.47 and Simulator Exercise Guide 24. This task is also trained and evaluated per the License Operator Requalification Training Program Description. It is selected in the two-year plan, and was covered in Cycle 2005B in both the classroom setting and the simulator. This task is trained on a once per two-year basis. The actions described above are taken by Operations personnel, therefore, Maintenance personnel are NOT trained on these actions. For Guideline WPG-2; Task 1.11; Ensure the Conduct of Plant Operations and Maintenance are in Compliance with Administrative Procedures, is covered in the Initial Senior License Operator program. The lesson plan where Guideline WPG-2 is covered is LP 1.13, Administrative Control Procedures.
(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).	There is effective coordination between the DAEC operator and the TSO regarding transmission system maintenance or DAEC maintenance activities. Such coordination is in accordance with the protocols.
(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.	As discussed in the responses to questions 6(a) through 6(d), the DAEC effectively implements appropriate risk management actions.
(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).	No alternative actions.

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<table>
<tr><td colspan="2">7. Procedures for identifying local power sources (this includes items such as nearby or onsite gas turbine generators, portable generators, hydro generators, and black-start fossil power plants) 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 under-voltage and collapse
- Weather-induced power loss
- Preferred power distribution system faults that could result in the loss of normal power to essential switchgear buses</td></tr>
<tr><td>(a) Briefly describe any agreement made with the TSO to identify local power sources that could be made available to re-supply power to your plant following a LOOP event.</td><td>The Large Generator Interconnection Agreement among Midwest Independent Transmission System Operator, Inc. and Interstate Power and Light Company and FPL Energy Duane Arnold, LLC states "Interconnection Customer, Transmission Provider, Transmission Owner or their designated agents, as applicable, shall comply with applicable NRC Requirements and Commitments, concerning offsite supply of energy to nuclear units and station black out recovery action." The current Black start plan's primary objectives list "Supply off-site power to DAEC within 4 hours."

In response to this Generic Letter, the Midwest ISO provided the following information; "The Midwest ISO restoration process coordinates the development of individual Transmission Owner Restoration Plans. Midwest ISO conducts reviews, workshops and drills to ensure the effectiveness of the restoration plan.

The Midwest ISO restoration process will provide updates to the TSO and NPP on transmission system status during emergency restoration, and will give the highest priority to restoring power to essential affected nuclear facilities, per NERC standard EOP-005-0.

However, due to the myriad of possible restoration scenarios, no specific power sources to resupply NPPs are identified. The MISO restoration process allows for the fact that the blacked out area may or may not be separated from the remainder of the system. The MISO restoration process allows to the use of black start unit or cranking path from non-blacked out areas. Regardless of the scenario, there is a clear recognition of the importance of expeditious restoration of an NPP offsite power source."

Existing plant procedures and commitments are adequate. The TSO will utilize the best sources available for specific events to restore offsite power and to determine the specific power sources and paths, since there is no way to predict the extent and characteristics of a specific blackout.</td></tr>
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7. (continued)	
(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.	Yes, DAEC Procedure AOP 301.1, *Station Blackout*, directs operator response to the LOOP and also offsite power recovery. Operators are trained and tested on this procedure in both Initial License Training and License Operator Requalification Training on a once per two year basis. NOTE: on October 12, 2005, DAEC participated in a Midwest ISO loss of grid drill. DAEC's participation included Engineering and Operations representation. The drill included a table top walkthrough of DAEC site procedures and communications with the drilling participants of the TSO and Midwest ISO. The drill simulated a loss of power to the DAEC switchyard and subsequent restoration. Power was restored to the switchyard in 3 hours and 8 minutes.
(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.	Not applicable; an agreement exists. The TSO has the responsibility to restore offsite power to the NPP as a priority. Details are available in the protocol that exists between the NPP and the TSO. Identifying local power sources that could be made available to resupply power to the NPP following a LOOP is not part of the NPP licensing bases.

Duane Arnold Energy Center Response to Generic Letter 2006-02

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?	The plant's initial coping duration was initially determined in the early 1990s. Since that time, DAEC has not experienced a total LOOP caused by a grid failure.
(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?	There have been no grid related events, not applicable.
(c) If so, what were the results of this reevaluation, and did the initially determined coping duration for the NPP need to be adjusted?	There have been no grid related events, not applicable.
(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.	There have been no grid related events, not applicable.

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<table>
<tr><td colspan="2">9. Actions to ensure compliance</td></tr>
<tr><td>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.</td><td>As discussed in the responses above, FPL Energy Duane Arnold will implement a change in operating procedure such that the TS LCO for inoperable offsite circuits will be entered following notification by the TSO that a trip of the DAEC would result in switchyard under-voltage conditions. Actions associated with implementation are as follows:
• A TS Bases change will be developed to implement this commitment;
• Applicable procedures will be revised to reflect the TS Bases change; and,
• Licensed Operator notification on the TS Bases and procedure changes will be conducted.
These actions will be completed by June 15, 2006.</td></tr>
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