August 9, 2007

MEMORANDUM TO: Patrick L. Hiland, Director
Division of Engineering
Office of Nuclear Reactor Regulation

FROM: George A. Wilson, Chief ***/RA/***
Electrical Engineering Branch
Division of Engineering
Office of Nuclear Reactor Regulation

SUBJECT: GENERIC LETTER 2006-02, "GRID RELIABILITY AND THE IMPACT ON PLANT RISK AND THE OPERABILITY OF OFFSITE POWER,": FINAL REPORT

On February 1, 2006, the U.S. Nuclear Regulatory Commission (NRC) issued generic letter (GL) 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power" (Agencywide Documents Access and Management System (ADAMS) Accession No. ML060180352). The purpose of this GL was to determine whether NRC licensees were continuing to comply with the agency's regulatory requirements governing electric power sources and associated personnel training. Specifically, the NRC issued this GL to obtain information from its licensees in four areas:

(1) Use of protocols between the nuclear power plant (NPP) and the transmission system operator (TSO), independent system operator (ISO), or reliability coordinator/authority (RC/RA), as well as the use of transmission load flow analysis tools (analysis tools) by TSOs to assist NPPs in monitoring grid conditions to determine the operability of offsite power systems under plant technical specifications (TS). (The TSO, ISO, or RA/RC is responsible for preserving the reliability of the local transmission system. In this GL, the term TSO is used to denote these entities.)

(2) Use of NPP/TSO protocols and analysis tools by TSOs to assist NPPs in monitoring grid conditions for consideration in maintenance risk assessments.

(3) Offsite power restoration procedures in accordance with Section 2 of Regulatory Guide (RG) 1.155, "Station Blackout," issued August 1988.

(4) Losses of offsite power caused by grid failures at a frequency equal to or greater than once in 20 site-years in accordance with RG 1.155.

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The Electrical Engineering Branch staff has reviewed the information provided by the NPP licensees. The enclosed final report discusses the details of this review. This memorandum and the enclosed safety evaluation complete the NRC staff's review and evaluation efforts for GL 2006-02.

Enclosure:
As stated

P.Hiland

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GRID RELIABILITY AND THE IMPACT ON PLANT RISK AND THE OPERABILITY OF OFFSITE POWER

FINAL REPORT

On February 1, 2006, the U.S. Nuclear Regulatory Commission (NRC) issued generic letter (GL) 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power" (Agencywide Documents Access and Management System (ADAMS) Accession No. ML060180352). The purpose of this GL was to determine whether NRC licensees were continuing to comply with the agency's regulatory requirements governing electric power sources and associated personnel training. Specifically, the NRC issued this GL to obtain information from its licensees in four areas:

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(4) Losses of offsite power caused by grid failures at a frequency equal to or greater than once in 20 site-years in accordance with RG 1.155.

Pursuant to Title 10, Section 50.54(f), of the *Code of Federal Regulations* (10 CFR 50 54(f)), addressees were required to submit a written response to this GL.

On December 5, 2006, the NRC staff forwarded several clarifying questions to licensees (ADAMS Accession No. ML063380308). The staff formulated these additional questions from feedback and discussions with the industry (specifically the Nuclear Energy Institute (NEI) and licensees) during a public meeting held on June 22, 2006. The applicable licensees responded satisfactorily to the agency's request for additional information.

BACKGROUND

Based on information obtained from inspections and risk insights developed by an internal NRC expert panel, the staff was concerned that several conditions associated with assurance of grid reliability may impact public health and safety and/or compliance with applicable regulations. These conditions included use of long-term periodic grid studies and informal communication arrangements to monitor real-time grid operability, potential shortcomings in grid reliability evaluations performed as part of maintenance risk assessments, lack of preestablished arrangements identifying local grid power sources and transmission paths, and potential elimination of grid events from operating experience and training. The NRC staff identified these issues while considering the 2003 blackout event.

On August 14, 2003, the largest power outage in U.S. history occurred in the northeastern United States and parts of Canada. Nine U.S. NPPs tripped. Eight of these facilities lost offsite power, along with one NPP that was already shut down. The length of time until power was available to the switchyard ranged from approximately 1 hour to 6.5 hours. Although the onsite emergency diesel generators (EDGs) functioned to maintain safe-shutdown conditions, this event was significant in terms of the number of plants affected and the duration of the power outage.

The loss of all alternating current (ac) power to the essential and nonessential switchgear buses at an NPP involves the simultaneous loss of offsite power (LOOP), turbine trip, and the loss of the onsite emergency power supplies (typically EDGs). Such an event is referred to as a station blackout (SBO). NPP risk analyses indicate that the SBO can be a significant contributor to the core damage frequency. Although NPPs are designed to cope with a LOOP event through the use of onsite power supplies, such events are considered precursors to SBO. An increase in the frequency or duration of LOOP events increases the probability of core damage.

The NRC issued Regulatory Issue Summary (RIS) 2004-05, “Grid Operability and the Impact on Plant Risk and the Operability of Offsite Power,” dated April 15, 2004, to advise NPP addressees of the requirements in 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants”; 10 CFR 50.63, “Loss of All Alternating Current Power”; General Design Criterion (GDC) 17,[1] “Electric Power Systems”; and plant technical specifications (TS) on the operability of offsite power. In addition, the agency issued Temporary Instruction (TI) 2515/156, “Offsite Power System Operational Readiness,” dated April 29, 2004, and TI 2515/163, “Operational Readiness of Offsite Power,” dated May 5, 2005, which instructed the NRC regional offices to perform followup inspections at plant sites on the issues identified in the RIS.

On April 26, 2005, the Commission was briefed on grid stability and offsite power issues by a stakeholder panel that included representatives of the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC), the National Association of Regulatory Utilities Commissioners, PJM Interconnection (one of the country’s largest transmission system operators), a FirstEnergy Corporation executive representing NEI, and the NRC staff. In light of this briefing, the Commission issued a staff requirements memorandum (SRM) dated May 19, 2005, in which the Commission directed the staff to review NRC programs related to operator examination and training and ensure that these programs adequately capture the importance of grid conditions and offsite power issues to the design, assessment, and safe operation of the plant, including appropriate interactions with grid operators. The SRM further directed the NRC staff to determine whether the operator licensing program needs to be revised to incorporate additional guidance on grid reliability.

On January 9 and 10, 2006, the NRC hosted a public workshop with stakeholders to review the intent and purpose of the questions contained in the draft GL.

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[1] In the GL, GDC 17 includes equivalent plant-specific principal design criteria on electric power systems for those plants that were licensed before issuance of the present GDC.

On February 16, 2006, FERC issued an interpretive order pertaining to its Standards of Conduct (Order No. 2004). The purpose of this interpretive order was to clarify that transmission providers may communicate with affiliated NPPs regarding certain matters related to the safety and reliability of the plants' transmission systems to comply with the NRC requirements described in GL 2006-02.

On March 3, 2006, the NRC issued TI 2515/165, "Operational Readiness of Offsite Power and Impact on Plant Risk." The objective of this TI was to gather information to support the assessment of NPP operational readiness of offsite power systems and the impact on plant risk, in accordance with NRC requirements prescribed in plant TS and 10 CFR 50.65(a)(4). The NRC staff reviewed the TI results and found that the NPPs were prepared for continued safe operation through the summer of 2006.

The NRC reviewed the preliminary results of the GL with stakeholders and addressed the NEI and industry concerns in a public meeting held on June 22, 2006.

APPLICABLE REGULATORY REQUIREMENTS

GDC 17

For NPPs licensed in accordance with Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," GDC 17 provides the design criteria for onsite and offsite electrical power systems. For NPPs not licensed in accordance with the GDC in Appendix A to 10 CFR Part 50, the updated final safety analysis report provides the applicable design criteria. These reports set forth criteria similar to GDC 17, which requires, among other things, that an offsite electric power system be provided to permit the functioning of certain structures, systems, and components (SSCs) important to safety in the event of anticipated operational occurrences and postulated accidents.

The transmission network (grid) is the source of power to the offsite power system. The final paragraph of GDC 17 includes, in part, provisions to minimize the probability of the loss of power from the transmission network given a loss of the power generated by the nuclear power unit(s). Loss of the power generated by the nuclear power unit (trip) is an anticipated operational occurrence. The offsite power circuits must therefore be designed to be available following a trip of the unit(s) to permit the functioning of SSCs necessary to respond to the event.

The trip of an NPP can affect the grid, potentially resulting in a LOOP. Foremost among such effects is a reduction in the plant's switchyard voltage as a result of the loss of the reactive power supplied to the grid from the generator (voltage support) of the NPP. If the voltage is low enough following a unit trip, the plant's degraded voltage protection could actuate and separate the plant safety buses from offsite power causing a LOOP. A trip of an NPP could also cause grid instability, potential grid collapse, and a subsequent LOOP.

Plant Technical Specifications

Plant TS require the offsite power system to be operable as part of the limiting conditions for operation (LCOs) and specify actions to be taken when the offsite power system is not operable.

Plant operators should therefore be aware of (1) the capability of the offsite power system to supply power during operation and (2) situations that can result in a LOOP following a trip of the plant. If the offsite power system is not capable of providing the requisite power in either situation, the system should be declared inoperable and pertinent plant TS provisions followed.

<u>10 CFR 50.65</u>

As required by 10 CFR 50.65(a)(4), licensees must assess and manage the increase in risk that may result from proposed maintenance activities before performing such activities. These activities include, but are not limited to, surveillance, postmaintenance testing, and corrective and preventive maintenance. The licensee may limit the scope of the assessment to SSCs that a risk-informed evaluation process has shown to be significant to public health and safety.

In RG 1.182, "Assessing and Managing Risks Before Maintenance Activities of Nuclear Power Plants," issued May 2000, the NRC endorsed the February 22, 2000, revision to Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 2, issued April 1996, as providing acceptable methods for meeting the requirements of 10 CFR 50.65(a)(4). (Revision 3 of NUMARC 93-01 later incorporated the revised Section 11.) The revised Section 11 addressed grid stability and offsite power availability in several areas. Specifically, Section 11.3.2.8 states the following:

> Emergent conditions may result in the need for action prior to conduct of the assessment, or could change the conditions of a previously performed assessment. Examples include plant configuration or mode changes, additional SSCs out of service due to failures, or *significant changes in external conditions (weather, offsite power availability)* [emphasis added].

Additionally, Section 11.3.4 states that "the assessment for removal from service of a single SSC for the planned amount of time may be limited to the consideration of unusual external conditions that are present or imminent (e.g., severe weather, offsite power instability)."

Accordingly, licensees should perform grid reliability evaluations as part of the maintenance risk assessment required by 10 CFR 50.65 before performing "grid-risk-sensitive" maintenance activities. Such activities are those that could increase risk under existing or imminent degraded grid reliability conditions, including (1) conditions that could increase the likelihood of a plant trip, (2) conditions that could increase the likelihood of a LOOP or SBO, and (3) conditions impacting the plant's ability to cope with a LOOP or SBO, such as out-of-service risk-significant equipment (e.g., an EDG, a battery, a steam-driven pump, an alternate ac power source). The maintenance risk assessment should consider the likelihood of a LOOP and SBO either quantitatively or qualitatively. If the grid reliability evaluation indicates that degraded grid reliability conditions may exist during maintenance activities, the licensee should consider rescheduling any grid-risk-sensitive maintenance activities. If there is some overriding need to perform grid-risk-sensitive maintenance activities under existing or imminent conditions of degraded grid reliability, the licensee should consider alternate equipment protection measures and compensatory actions to manage the risk.

With regard to conditions that emerge during a maintenance activity in progress, Section 11.3.2.8 in the 2000 revision to Section 11 of NUMARC 93-01 states that emergent conditions could change the conditions of a previously performed risk assessment. Offsite power availability is one example of an emergent condition that could change the conditions of a previously performed risk assessment. Licensees should reassess the plant risk in view of an emergent condition that affects an existing maintenance risk assessment, except as discussed below, and should take a worsening grid condition into account. However, as discussed in the Statements of Consideration for 10 CFR 50.65(a)(4) and the revised Section 11 of NUMARC 93-01, this reassessment of the risk should not interfere with or delay measures to place and maintain the plant in a safe condition, in general, or in response to or preparation for the worsening grid conditions.

Note also that, as discussed in the Statements of Consideration for 10 CFR 50.65(a)(4) and in the revised Section 11 of NUMARC 93-01, if the emergent condition (including degrading grid reliability) is corrected (or ceases to exist) before the risk reassessment is completed, the reassessment need not be completed.

10 CFR 50.63

Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate be able to withstand an SBO for a specified duration and to recover from the SBO. RG 1.155 provides guidance for licensees to use in developing their approach for complying with 10 CFR 50.63. A series of tables in the RG define a set of pertinent plant and plant site parameters that have been found to affect the likelihood of a plant experiencing an SBO event of a given duration. Using the tables allows a licensee to determine a plant's relative vulnerability to SBO events of a given duration and identify an acceptable minimum SBO coping duration for the plant.

With regard to grid-related LOOPs, Table 4 in RG 1.155 indicates that plant sites with the following characteristic should be assigned to Offsite Power Design Characteristic Group P3:

> Sites that expect to experience a total loss of offsite power caused by grid failures at a frequency equal to or greater than once in 20 site-years, unless the site has procedures to recover AC power from reliable alternative (nonemergency) AC power sources within approximately one-half hour following a grid failure.

The majority of U.S. NPPs fall into the 4-hour minimum coping capability category set forth in RG 1.155. However, Table 2 in RG 1.155 indicates that a typical plant with two redundant EDGs per nuclear unit should have at least an 8-hour minimum coping duration if it falls into the P3 group. Therefore, plants that have experienced a grid-related LOOP that were evaluated in accordance with the SBO guidance in RG 1.155 may no longer be consistent with that guidance.

Section 2 of RG 1.155 provides guidance on the procedures necessary to restore offsite power, including losses following "grid undervoltage and collapse." Section 2 states, "Procedures should include the actions necessary to restore offsite power and use nearby power sources when offsite power is unavailable." These procedures are a necessary element in minimizing LOOP durations following a LOOP or SBO event.

<u>10 CFR 55.59, "Requalification," and 10 CFR 50.120, "Training and Qualification of Nuclear Power Plant Personnel"</u>

Pursuant to 10 CFR 55.59(c)(2), operator requalification programs must include preplanned lectures on a regular basis throughout the license period in areas that operator and senior operator written examinations and facility operating experience indicate the need for more scope and depth of coverage. The following is a listing of the subjects:

(i) theory and principles of operation
(ii) general and specific plant operating characteristics
(iii) plant instrumentation and control systems
(iv) plant protection systems
(v) engineered safety systems
(vi) normal, abnormal, and emergency operating procedures
(vii) radiation control and safety
(viii) technical specifications
(ix) applicable portions of Title 10, Chapter I, of the *Code of Federal Regulations*

As required by 10 CFR 55.59(c)(3)(i), operator requalification programs must include on-the-job training on a number of control manipulations and plant evolutions if they are applicable to the plant design. The loss of electrical power (or degraded power sources) is just one of the evolutions to be performed annually by each operator. Moreover, 10 CFR 55.59(c)(3)(iv) requires each licensed operator and senior operator to review the contents of all abnormal and emergency procedures on a regularly scheduled basis.

In addition, in lieu of the programs specified in 10 CFR 55.59(c)(2) and 10 CFR 55.59(c)(3) above, the Commission may approve a program developed by using a systems approach to training (SAT).

According to 10 CFR 50.120, each NPP licensee must establish, implement, and maintain a SAT-based program for training and qualifying nonlicensed operators, shift supervisors, and electrical and mechanical maintenance personnel (among several other job categories). The training program must be periodically evaluated and revised as appropriate to reflect industry experience and changes to the facility and procedures (among other things).

SAT-based training programs, which are developed, implemented, and maintained by facility licensees and accredited by the National Nuclear Accrediting Board, should incorporate lessons learned as a result of industry operating events such as the 2003 blackout. The NRC staff routinely monitors the industry's accreditation process, administers the initial operator licensing examinations, conducts biennial licensed operator requalification training program inspections, and retains authority to conduct for-cause training program inspections. However, these activities did not provide the NRC staff with information sufficient to verify that all facility licensee training programs have adequately captured the importance of grid conditions and offsite power issues in advance of the 2006 peak summer cooling season. Accordingly, the NRC staff included questions on operator training.

DEFINITIONS

The following definitions clarify the terms used in the GL.

Adequate Offsite Power

The existence of power from the transmission system of sufficient voltage and capacity to power the safety-related loads under defined NPP load conditions. Sufficient voltage is generally related to the degraded voltage relay setpoints.

Degraded Grid Reliability Conditions

Those conditions on the grid caused by load flow, failure of a transmission element, or maintenance on a transmission element that could significantly increase the probability of an NPP trip or loss of adequate offsite power supply.

Grid Stress or a Stressed Grid

Inadequate generation or transmission paths that require entry into an Alert condition in the context of NERC Emergency Preparedness and Operating Standard EOP-002-0, Attachment 1, "Energy Emergency Alerts."

N-1 Contingency

The projected failure or outage of a single system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. Examples include trip of the NPP unit, trip of the largest generator on the system, trip of a transmission path, or loss of a power transformer.

Stability

The ability of an electrical system to maintain a state of equilibrium during normal and abnormal conditions or disturbances. The GL focuses on adequate offsite voltage, not system stability.

Transmission Load Flow Analysis Tools (Analysis Tools)

Any controlled analysis tool that enables the TSO or the NPP licensee to predict the resultant NPP offsite power voltage during plant operation for any N–1 contingency as defined above. The NRC does not intend for an analysis tool to be a transient analysis program.

DISCUSSION

The discussion that follows is organized around the same four information areas identified at the beginning of this document.

(1) *Use of protocols between the NPP licensee and the TSO, and the use of analysis tools by TSOs to assist the NPP licensee in monitoring grid conditions to determine the operability of offsite power systems under plant TS.*

A licensee's ability to comply with TS for offsite power may depend on grid conditions and plant status; in particular, maintenance on and degraded conditions of key elements of the plant switchyard and offsite power grid can affect the operability of the offsite power system, especially during times of high grid load and high grid stress. A communication interface with the plant's TSO, together with training and other local means to maintain NPP operator awareness of changes in the plant switchyard and offsite power grid, is important to enable the licensee to determine the effects of these changes on the operability of the offsite power system. The NRC staff found a significant variability in the TI 2515/156 and TI 2515/163 responses on the use of these NPP licensee/TSO communication protocols. Some licensees apparently rely on informal NPP licensee/TSO communication arrangements and offline long-term grid studies to ensure offsite power operability. However, the staff also learned that most TSOs serving NPP sites now have, or will have shortly, an analysis tool.

Analysis tools give the TSO the capability to determine the impact of the loss or unavailability of various transmission system elements, or contingencies, on the condition of the transmission system. Transmission systems can generally cope with several contingencies without undue impairment of grid reliability, but it is important that the NPP operator know when the transmission system near the NPP can no longer sustain NPP voltage based on the analysis by the TSO of a reasonable number of contingencies. This knowledge helps the operator understand the general condition of the NPP offsite power system. To satisfy the Maintenance Rule, the NPP operator should know the grid's condition before taking a risk-significant piece of equipment out of service and should monitor this condition for as long as the equipment remains out of service.

It is especially important that the NPP operator know when the trip of the NPP will result in a LOOP to the plant. As stated earlier, a reduction in the NPP switchyard voltage caused by a trip is the main cause of a LOOP event. Transmission systems may be permitted to operate with a wider voltage band than required by plant TS for NPP component operability. As a result, the TSO will not necessarily keep the transmission system voltage above the level needed for the NPP, unless the TSO has been informed of the needed voltage level and agreements have been formalized to maintain the voltage level. The data collected in accordance with TI 2515/156 did not clearly indicate whether the TSO would notify the NPP licensee of inadequate transmission system contingency voltages or inadequate voltages required for the NPP SSC operability.

Inadequate NPP contingency posttrip switchyard voltages will result in TS inoperability of the NPP offsite power system because of actuation of NPP degraded voltage protection circuits during certain events. NPPs of certain designs have occasionally experienced other inoperabilities in these circumstances (e.g., overloaded EDGs or loss of certain safety features caused by interaction with circuit breaker logic). Safety-related motors may also be started more than once under these circumstances, which could result in operation outside the motors' specifications and actuation of overload protection. Unavailability of plant-controlled equipment, such as voltage regulators, transformer auto tap changers, and generator automatic voltage regulation, can contribute to the more frequent occurrence of inadequate NPP posttrip voltages.

Analysis tools in use by the TSOs, together with properly implemented NPP licensee/TSO communication protocols and training, can keep NPP operators better informed about conditions affecting the NPP offsite power system. However, the TSO may not always have access to the analysis tools, as was the case during the period leading up to the August 14, 2003, blackout. Furthermore, events have shown that the data used in the programs sometimes do not represent actual conditions and capabilities. These shortcomings have been offset to some degree by notifying NPP operators of the unavailability of analysis tools. The operators then perform operability determinations to assess posttrip switchyard voltages following inadvertent NPP trips.

(2) *Use of NPP licensee/TSO protocols and analysis tools by TSOs to assist NPP licensees in monitoring grid conditions for consideration in maintenance risk assessments*.

As discussed above (e.g., when warranted by worsening grid conditions), grid reliability evaluations should be performed as part of the maintenance risk assessment required by 10 CFR 50.65 (or in any reassessment). To perform meaningful and comprehensive grid reliability evaluations (or reevaluations as appropriate), it is essential that the NPP licensee communicate with the TSO before and periodically during the performance of grid-risk-sensitive maintenance activities. The communication between the NPP licensee and its TSO should enable the NPP operator to obtain up-to-date information on existing and projected grid conditions for use in maintaining a current and valid maintenance risk assessment and in managing a possible risk change. The communication with the TSO should include a discussion of whether a loss of the NPP electrical output could impact the local grid, as well as activities that increase the likelihood of (1) a plant trip and (2) a LOOP.

With regard to risk management, an internal NRC expert panel found that it is important to have effective NPP configuration risk management (including the maintenance risk management required by 10 CFR 50.65(a)(4)) when grid reliability is degraded or threatened. In particular, a potentially significant increase in NPP risk may occur if the equipment required to prevent and mitigate SBO is unavailable when the grid is degraded. Recent NRC studies have found that since 1997, (1) LOOP events have occurred more frequently during the summer (May through October), (2) the probability of a LOOP event resulting from a reactor trip has also increased during the summer months, and (3) the durations of LOOP events generally have increased. The NRC staff is concerned about extended maintenance activities scheduled for equipment required to prevent and mitigate SBO during periods that may be more susceptible to a LOOP (especially in areas of the country that may also experience a high level of grid stress).

The NRC staff found a significant variability in the data collected in accordance with TI 2515/156 and TI 2515/163 regarding grid reliability evaluations performed, when warranted, as part of the maintenance risk assessment required by 10 CFR 50.65. Some licensees communicate routinely with their TSOs once per shift to determine grid conditions, while others rely solely on the TSOs to inform them of deteriorating grid conditions and do not inquire about grid conditions before performing grid-risk-sensitive maintenance activities. Some licensees do not consider the NPP posttrip switchyard voltages in their evaluations, and some do not coordinate grid-risk-sensitive maintenance with their TSOs. The NPP licensee/TSO communication protocol is a useful tool for obtaining the information necessary for the grid reliability evaluations that should be performed, when warranted, as part of the maintenance risk assessment required by 10 CFR 50.65. The protocol is also useful in effectively implementing the guidance in the 2000 revision of Section 11 of NUMARC 93-01 on reassessing plant risk in light of emergent conditions. As discussed under the previous topic, the analysis tools available to most TSOs give them the capability to determine the impact of various transmission system contingencies on the condition of the transmission system. It is important that the NPP operator know when the transmission system near the NPP cannot sustain a reasonable level of contingencies. In summary, the NPP operator should know and stay informed of the general condition of the NPP offsite power system and be adequately trained to assess and manage risk under the

Maintenance Rule before performing and for the duration of grid-risk-sensitive maintenance activities (i.e., activities that could increase risk under degraded grid reliability conditions).

(3) *Offsite power restoration procedures in accordance with Section 2 of RG 1.155.*

LOOP events can have numerous unpredictable initiators such as natural events, potential adversaries, human error, or design problems. Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate be able to withstand an SBO for a specified duration and to recover from the SBO. RG 1.155 provides licensees with guidance on developing their approaches for complying with 10 CFR 50.63. Section 2 of RG 1.155 provides guidance on the procedures necessary to restore offsite power, including losses following “grid undervoltage and collapse.” Section 2 states, “Procedures should include the actions necessary to restore offsite power and use nearby power sources when offsite power is unavailable.”

Preestablished agreements between NPP licensees and TSOs that identify local power sources and transmission paths that could be made available to resupply NPPs following a LOOP event, in addition to operator training, help to minimize the durations of LOOP events, especially unpredictable LOOP events. Discussions with NPP licensees indicate that some licensees do not have such agreements in place, but instead only attempt restoration of their EDGs following a potential SBO. RIS 2004-05 states that NPP licensees should have procedures available consistent with the guidance in Section 2 of RG 1.155 for restoration of offsite power following a LOOP or SBO event.

(4) *Losses of offsite power caused by grid failures at a frequency equal to or greater than once in 20 site-years in accordance with RG 1.155*.

The data collected in accordance with TI2515/156 indicate that grid failures that caused a total LOOP at some NPPs have occurred since the NPPs were initially analyzed in accordance with the criteria in RG 1.155. The NRC staff is concerned that these NPPs have not been reanalyzed to determine whether their SBO coping durations have remained consistent with the guidance in RG 1.155. The staff is also concerned that some plants may be inappropriately eliminating some grid events from their operating experience database.

NRC STAFF EVALUATION OF REQUESTED INFORMATION

The staff asked addressees to answer the following questions, which are organized into nine topic areas. All but one of these topic areas (question 9) include a number of related questions. The NRC staff’s evaluation of the responses to those questions is also provided below.

<u>Question 1</u>

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

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

(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.

(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.

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

(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.

(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 values in their TS) or LOOP after a trip of the reactor unit(s).

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

The December 5, 2006, NRC staff request for additional information asked licensees to identify the specific minimum switchyard voltage limits that were supplied to the local transmission entity. Specifically, licensees were asked to provide (1) the specific minimum acceptable switchyard voltage included in their protocol agreement with the TSO and its basis, and (2) how the value related to the TS degraded voltage relay setpoints.

NRC Staff Evaluation of Question 1

The NRC staff reviewed the responses to question 1 of GL 2006-02 and identified the following:

- All NPP licensees have formal agreements or protocols with their TSOs.

- NPP operators are trained either through licensed operator qualification/requalification or the SAT on the use of procedures for assessing grid conditions identified in question 1(c).

- All NPP licensees are aware of the low switchyard voltage conditions that would initiate operation of plant degraded voltage protection.

Question 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 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.

(b) Does your NPP 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?

(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 values in their TS) and consequent actuation of plant degraded voltage protection? If not, discuss how such a condition would be identified on the grid.

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

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

(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?

(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?

(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?

(i) If an analysis tool is not available, does your TSO perform periodic studies to verify that adequate offsite power capability, including adequate NPP posttrip 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?

(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.

The December 5, 2006, NRC staff request for additional information asked licensees to identify the actions that would be taken if the online grid analysis tool (i.e., the software program) that is relied upon as an input for offsite power operability became unavailable. Specifically, licensees were asked to describe the actions that would be taken to determine whether posttrip voltages would be acceptable until the posttrip voltage is confirmed to be adequate. The NRC staff stated that the actions may include reliance on a backup (third party) real-time contingency analysis or similar program or reliance on a grid planning study to confirm that the original assumptions bound the existing grid conditions.

The NRC staff also requested additional information regarding the validation of the voltages predicted by the online grid analysis tool. Specifically, the NRC staff requested information related to (1) the range of accuracy for the online grid analysis tool and (2) the basis for confidence that the posttrip voltages calculated by the online grid analysis tool (when it is used to determine operability of the offsite power system) are reasonably accurate and conservative. The NRC staff stated that it is important to verify the accuracy and conservatism of programs used for predicting posttrip voltage.

<u>NRC Staff Evaluation of Question 2</u>

The NRC staff reviewed the responses to question 2 of GL 2006-02 and identified the following:

- All but three NPP sites (Diablo Canyon, Palo Verde, and San Onofre) rely on the results from an online contingency analysis program for determining the adequacy of the NPP offsite power system. These three NPP sites have no plans for using the output of an online contingency analysis tool but instead plan to continue using precalculated engineering analyses.

- D.C. Cook uses a plant-specific application of contingency analysis software that allows near real-time monitoring of offsite power system conditions from the plant control rooms. NERC has identified this application as an Example of Excellence. (This designation was made as a result of the information presented at the March 10–11, 2004, NERC Readiness Audit of American Electric Power.)

- Each NPP TSO uses an analysis tool (either online or offline) as the basis for notifying NPP licensees when grid conditions exist that would make the NPP offsite power system inoperable during various contingencies.

- The analysis tools used by NPP TSOs will identify a condition in which a trip of an NPP will result in switchyard voltages (immediate and/or long term) falling below TS nominal trip reset value requirements (including NPP licensees using allowable values in their TS).

- The online contingency analysis program for 62 NPP sites updates at least once every 15 minutes. The online contingency analysis program for seven NPP sites (Arkansas Nuclear One, Browns Ferry, Grand Gulf, River Bend, Sequoyah, Waterford, and Watts Bar) updates at least once per day, or more frequently, if warranted (e.g., when plant/grid changes are made that could affect the day-ahead analysis).

- All but six NPP sites (Catawba, Ginna, McGuire, Oconee, Palisades, and South Texas Project) have a formal agreement that requires notification by the TSO of periods when the TSO is unable to determine whether offsite power voltage and capacity could be inadequate. The Palisades TSO is required by procedure to notify the NPP operators if the contingency analysis program is not operating or is considered unreliable.

- After an unscheduled inadvertent trip of the NPP, 10 NPP sites (Arkansas Nuclear One, Columbia, Davis-Besse, Fort Calhoun, Grand Gulf, River Bend, St. Lucie, V.C. Summer, Turkey Point, and Waterford) have procedures to formally verify that the resultant switchyard voltages are bounded by the voltages predicted by the analysis tool. Thirty-three of the remaining NPP sites stated that the TSO informally compares the analysis tool results. The rest of the NPP sites stated that the accuracy of the analysis tool is based on conservative inputs and assumptions.

Question 3

Use of criteria and methodologies to assess whether the NPP 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 values in their TS) and would actuate plant degraded voltage protection, is the NPP offsite power system declared inoperable under the plant TS? If not, why not?

(b) If onsite safety-related equipment (e.g., EDGs or safety-related motors) is lost when subjected to a double sequencing (loss-of-coolant accident 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?

(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).

(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.

(e) If you believe your plant TS 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 TS, 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.

(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).

In the December 5, 2006, NRC staff request for additional information, licensees were asked to identify the loss of critical transmission elements, other than the loss of the nuclear unit, that may cause the offsite power system to degrade. Specifically, the NRC staff requested information related to (1) the inclusion of specific critical transmission elements in the N–1 contingency analysis (e.g., other generators, critical transmission line, transformers, capacitor banks, voltage regulators) that could degrade the offsite power system, possibly resulting in inadequate posttrip voltage, and (2) declaring the offsite power supply inoperable when the loss of a transmission element could result in actuation of the NPP degraded voltage grid relay.

<u>NRC Staff Evaluation of Question 3</u>

The NRC staff reviewed the responses to question 3 of GL 2006-02 and identified the following:

- If notified that a trip of the NPP would result in inadequate offsite power voltage, all but two NPP sites (Crystal River and Palo Verde) would take action to determine whether offsite power should be declared inoperable. Crystal River supplies power to a different switchyard than the incoming offsite power supply. Therefore, a trip of the Crystal River NPP would not impact the incoming offsite power supply. Palo Verde has procedures in place that address the actions to take if the offsite power circuits are incapable of providing adequate posttrip voltage.

- No NPP licensee would declare the offsite power system inoperable based on a postulated contingency on the transmission grid without having evaluated the condition first.

- Five NPP sites (Comanche Peak, Farley, Hatch, South Texas Project, and Vogtle) noted that the term “Operable/Operability” is defined in the TS and applied only to TS SSCs in accordance with RIS 2005-20. The licensees for those NPP sites used RIS 2005-20 as the basis for not referring to the transmission grid as operable or inoperable because the grid is not perceived as a TS SSC. The licensees for the aforementioned NPP sites stated that everything that is non-TS is referred to as functional or non-functional. However, TS 3.8.1 for all the above NPP sites requires the offsite power to be “operable.”

- All NPP licensees (except Palo Verde, San Onofre, and Waterford) stated that double sequencing was not part of the licensing basis for their respective plants and therefore they have not studied the full effect of a delayed LOOP.

- Only two NPP licensees (San Onofre and Waterford) appeared to have performed an evaluation to determine the impact of a double-sequencing event. While the licensee for Palo Verde stated that it has not performed an evaluation, the licensee did receive a TS amendment to ensure that the appropriate actions would be taken to prevent double sequencing of safety-related loads.

- Operators are trained on the items relevant to this question through licensed operator training (both initial and requalification) and/or through the SAT. Eight NPP licensees (Arkansas Nuclear One, Diablo Canyon, Fermi, Grand Gulf, River Bend, St. Lucie, Turkey Point, and Waterford) did not identify any compensatory actions in response to question 3, and therefore, no training was credited.

Question 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 plant-monitored equipment (e.g., voltage regulators, auto tap changing transformers, capacitors, static volt-amperes reactive (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.

(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 plant-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 TS, or describe what actions you intend to take to provide such guidance or procedures.

NRC Staff Evaluation of Question 4

The NRC staff reviewed the responses to question 4 of GL 2006-02 and identified the following:

- All but two NPP licensees (Turkey Point and St. Lucie) have guidance in plant TS bases sections, the final safety analysis report, or plant procedures regarding situations in which the condition of plant-controlled or plant-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. Turkey Point and St. Lucie do not have any voltage regulating equipment in ac circuit operability determinations.

<u>Question 5</u>

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 surveillance, postmaintenance 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, or an alternate ac power source, out of service?

(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?

(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.

(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?

(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?

(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.

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

(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.

(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).

(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.

(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.

The December 5, 2006, NRC staff request for additional information asked licensees whether they adjusted the base LOOP frequency in their probabilistic risk assessment and Maintenance Rule evaluations for various seasons. The NRC staff based this information request on the Electric Power Research Institute (EPRI) Report 1011759, Table 4-7, “Grid LOOP Adjustment Factor,” and NUREG/CR-6890, “Reevaluation of Station Blackout Risk at Nuclear Power Plants,” issued December 2005, which indicated that certain regions during certain times of the year (seasonal variations) experience higher grid stress.

The NRC staff also requested additional information regarding licensee interface with their respective TSOs when ongoing maintenance at the NPP that has been previously coordinated with the TSO for a definite timeframe is extended beyond that planned timeframe.

NRC Staff Evaluation of Question 5

The NRC staff reviewed the responses to question 5 of GL 2006-02 and identified the following:

- All NPP licensees perform either a quantitative or qualitative grid reliability evaluation as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4) before performing grid-risk-sensitive maintenance activities.

- All NPPs and/or their respective TSOs monitor grid status for the duration of the grid-risk-sensitive maintenance to confirm the continued validity of the risk assessment and to reassess risk when warranted.

- The licensees of 46 NPP sites noted that there is no significant variation in the stress on the grid in the vicinity of their NPP site caused by seasonal loads or maintenance activities associated with critical transmission elements. One NPP licensee (Palo Verde) stated that it has not performed an analysis and was therefore unable to draw a conclusion. The licensees for the remaining NPP sites stated that there is a significant variation in the stress on the grid in the vicinity of their NPP site caused by seasonal loads or maintenance activities associated with critical transmission elements.

- Forty-six NPP sites only consider real-time conditions in grid-risk-sensitive maintenance evaluations (i.e., no time-related variations). The remaining NPP sites consider known time-related variations in the probability of a LOOP in the grid-risk-sensitive maintenance evaluations.

- All NPP licensees contact their TSOs to determine current and anticipated grid conditions as part of the grid reliability evaluation performed before conducting grid-risk-sensitive maintenance activities.

- All NPP licensees have a formal agreement or protocol with their TSO to ensure that they are promptly alerted to a worsening grid condition that may emerge during a maintenance activity. This action is not limited to maintenance activities.

- Twenty-seven NPP sites contact their TSOs periodically during the performance of grid-risk-sensitive maintenance activities. The remaining 38 NPP sites assume that there are no changes to grid status if they are not contacted by the TSO.

- Twenty-three NPP sites do not formally train and/or test operators on the formal agreement with the TSO. These NPP sites rely on other plant personnel to implement the protocol. The remaining NPP sites train their operators through licensed operator training. Thirty-four NPP licensees do not formally train and/or test maintenance personnel on the formal agreement with the TSO.

Question 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?

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

(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?

(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.)

(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.

(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).

(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).

(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.

(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).

NRC Staff Evaluation of Question 6

The NRC staff reviewed the responses to question 6 of GL 2006-02 and identified the following:

- All NPP TSOs coordinate with the NPP operator when transmission system maintenance activities can impact NPP operation.
- All NPP licensees coordinate with the TSO when NPP maintenance activities can impact the transmission system.
- All NPP licensees consider and, if warranted, implement the rescheduling of grid-risk-sensitive maintenance activities (i.e., activities that could (1) increase the likelihood of a plant trip, (2) increase LOOP probability, or (3) reduce LOOP or SBO coping capability) under existing, imminent, or worsening degraded grid reliability conditions.
- All NPP licensees implement appropriate risk management actions if there is an overriding need to perform grid-risk-sensitive maintenance activities under existing or imminent conditions of degraded grid reliability, or alternatively, continue grid-risk-sensitive maintenance when grid conditions worsen.

Question 7

Procedures for identifying local power sources[2] that could be made available to resupply your plant following a LOOP event.

Note: Section 2 of RG 1.155 states the following:

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

- Grid undervoltage 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 resupply power to your plant following a LOOP event.

(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.

(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.

NRC Staff Evaluation of Question 7

The NRC staff reviewed the responses to question 7 of GL 2006-02 and identified the following:

- All but 10 NPP sites (Arkansas Nuclear One, Browns Ferry, D.C. Cook, Palo Verde, Point Beach, San Onofre, Sequoyah, Vermont Yankee, Watts Bar, and Wolf Creek) did not identify local power sources because of the myriad of possible restoration scenarios. However, all NPPs are given priority restoration by their respective TSO following a LOOP event. The licensees for two NPP sites (Monticello and Prairie Island) stated that the NPP would only get top priority for restoration of offsite power if the EDGs were inoperable. Priority would be given to restoring power to the safe-shutdown equipment, rather than to restarting the plant. The licensee stated that the NPP would not necessarily be the first to have offsite power restored because it is much easier, faster, and safer, from a reactor safety perspective, to restart the fossil units first.

- All NPP licensees stated that operators are trained on restoring offsite power following a LOOP event.

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

Question 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?

(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?

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

(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.

NRC Staff Evaluation of Question 8

The NRC staff reviewed the responses to question 8 of GL 2006-02 and identified the following:

- Ten NPP sites (Davis-Besse, Fermi, FitzPatrick, Indian Point, Nine Mile Point, Palo Verde, Peach Bottom, Perry, Pilgrim, and V.C. Summer) have experienced a total LOOP caused by grid failure since the plants' coping duration was initially determined under 10 CFR 50.63. This does not include the Ginna LOOP event as a result of the August 14, 2003, Northeast blackout. The licensee for Ginna does not believe that the event was a LOOP because plant Operators manually isolated the NPP unit from an unstable grid. However, the NRC staff maintains that a LOOP did exist at Ginna.

- The licensees for six NPP sites (Davis-Besse, FitzPatrick, Nine Mile Point, Palo Verde, Peach Bottom, and Perry) that experienced a total LOOP caused by grid failure since the plants' coping duration was initially determined under 10 CFR 50.63 have reevaluated their NPPs using the guidance in Table 4 of RG 1.155 to determine whether their NPPs should be assigned to the P3 offsite power design characteristic group. The licensees for Indian Point and Pilgrim did not reevaluate their NPPs because Indian Point is already assigned to the P3 offsite power design characteristic group and Pilgrim already has an SBO diesel generator. The licensees for Fermi and V.C. Summer did not use the guidance in Table 4 of RG 1.155 to determine whether their NPPs should be assigned to the P3 offsite power design characteristic group. In response to its decision not to reevaluate the LOOP event using the guidance in Table 4 of RG 1.155, the licensee for V.C. Summer stated that corrective actions have been taken to minimize recurrence of the initiating event and that system stability studies indicate that the grid is stable. The licensee for Fermi used a probabilistic risk assessment to determine the design characteristic group designation for the NPP in lieu of the guidance in RG 1.155.

- Nine of the 10 NPP sites above reported that the coping duration for the NPP did not need to be adjusted. Palo Verde's reevaluation determined that the coping duration needed to be changed from 4 to 16 hours. (The licensee submitted a license amendment request to this effect to the NRC in October 2005.). The licensees for three NPP sites (Davis-Besse, Peach Bottom, and Perry) claimed that no change was warranted because these NPPs had only experienced one grid-related LOOP in more than 20 site-years.

Question 9

If you determine that any action is warranted to bring your NPP into compliance with NRC regulatory requirements, including TS, 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.

`NRC Staff Evaluation of Question 9

The NRC staff reviewed the responses to question 9 of GL 2006-02 and identified the following:

- The licensees for two NPP sites (Duane Arnold and Indian Point) reported corrective actions necessary to bring their NPP sites into compliance with the NRC regulatory requirements. The licensee for Duane Arnold has implemented a change in the operating procedures such that the TS LCO for inoperable offsite circuits will be entered following notification by the TSO that a trip of the NPP would result in switchyard undervoltage conditions. The licensee for Indian Point has implemented a change to declare offsite power inoperable when notified by the TSO of a contingency analysis alarm.

Conclusion and Recommendations

The NRC staff did not identify any safety concerns or compliance issues as a result of its review of GL 2006-02. The NRC staff did, however, identify several items that need to be addressed. These items include clarifying the NRC staff's expectations regarding the validation of online contingency analysis programs, evaluating the implementation of the SBO rule to ensure that changes in the grid environment are being appropriately considered, following up with those NPP licensees that stated that offsite power could not be considered inoperable in accordance with RIS 2005-20, and initiating discussions with the licensee for Ginna to discuss the August 14, 2003, event designation.

Furthermore, the NRC staff has revised Inspection Procedures 71111.01, "Adverse Weather Protection," and 71111.13, "Maintenance Risk Assessments and Emergent Work Control," to include recommended inspection guidance and to incorporate inspections for the offsite power system and the alternate ac power source. In addition to the above, the NRC staff also recommends continued interaction with FERC and NERC. Based on its review, the NRC staff finds that its licensees are continuing to comply with the agency's regulatory requirements governing electric power sources and associated personnel training.