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DOMINION ENERGY KEWAUNEE, INC. (DEK)
DOMINION NUCLEAR CONNECTICUT, INC (DNC)
VIRGINIA ELECTRIC AND POWER COMPANY (DOMINION)
KEWAUNEE POWER STATION
MILLSTONE POWER STATION UNITS 2 AND 3
NORTH ANNA POWER STATION UNITS 1 AND 2
SURRY POWER STATION UNITS 1 AND 2
RESPONSE TO GENERIC LETTER 2006-02, GRID RELIABILITY AND THE IMPACT ON PLANT RISK AND THE OPERABILITY OF OFFSITE POWER

On February 1, 2006, the NRC issued Generic Letter 2006-02 to determine if compliance is being maintained with the NRC regulatory requirements governing electric power for the nuclear power plants. The generic letter requests information in the following four areas:

- 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) and the use of real-time contingency analysis (RTCA) software or an equivalent state-of-the-art software program by TSOs to assist NPPs in monitoring grid conditions to determine the operability of offsite power systems under plant technical specifications. (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);
- use of NPP/TSO protocols and RTCA programs by TSOs to assist NPPs in monitoring grid conditions for consideration in maintenance risk assessments;
- offsite power restoration procedures in accordance with Section 2 of NRC Regulatory Guide (RG) 1.155, "Station Blackout;" and
- 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.

In accordance with 10 CFR 50.54(f), DEK, DNC, and Dominion are providing the requested information in the attachments to this letter for Kewaunee, Millstone, North Anna and Surry Power Stations.

If you have any questions or require additional information, please contact Mr. Thomas Shaub at (804) 273-2763.

Very truly yours,

Eugene S. Grecheck
Vice President - Nuclear Support Services

Dominion Energy Kewaunee, Inc.
Dominion Nuclear Connecticut, Inc.
Virginia Electric and Power Company

Attachments
1. Kewaunee Power Station Response
2. Millstone Power Station Response
3. North Anna and Surry Response

Commitments made by this letter: None

COMMONWEALTH OF VIRGINIA)
)
COUNTY OF HENRICO)

The foregoing document was acknowledged before me, in and for the County and Commonwealth aforesaid, today by Eugene S. Grecheck who is Vice President - Nuclear Support Services for Dominion Energy Kewaunee, Inc., Dominion Nuclear Connecticut, Inc. and Virginia Electric and Power Company. He has affirmed before me that he is duly authorized to execute and file the foregoing document in behalf of these Companies, and that the statements in the document are true to the best of his knowledge and belief.

Acknowledged before me this 3rd day of April, 2006.

My Commission Expires: May 31, 2006.

Vicki L. Hull
Notary Public

(SEAL)

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ATTACHMENT 1

KEWAUNEE POWER STATION
Docket No. 50-305

(SERIAL NO. 06-103)

RESPONSE TO GENERIC LETTER 2006-02
GRID RELIABILITY AND THE IMPACT ON PLANT RISK AND THE OPERABILITY OF OFFSITE POWER

DOMINION ENERGY KEWAUNEE, INC. (DEK)

KEWAUNEE RESPONSE TO REQUESTED INFORMATION FOR GL 2006-02
GRID RELIABILITY AND THE IMPACT ON PLANT RISK AND THE OPERABILITY OF OFFSITE POWER

Use of protocols between the NPP licensee and the TSO, ISO, or RC/RA and the use of analysis tools by TSOs to assist NPP licensee in monitoring grid conditions to determine the operability of offsite power systems under plant Technical Specifications.

GDC 17, 10 CFR Part 50, Appendix A, requires that licensees 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).

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.*

Question	Response
1(a) Do you have a formal agreement or protocol with your TSO?	Yes. Kewaunee Power Station (Kewaunee) does have a formal agreement with the TSO, the American Transmission Company (ATC). ATC, Dominion Energy Kewaunee, Inc. (DEK), and Midwest Independent Transmission System Operator (MISO) have a 3-party Generator to Transmission Interconnection Agreement for Kewaunee filed with the Federal Energy Regulatory Commission (FERC). Additionally, ATC, Kewaunee, and MISO have developed and implemented the Communication and Mitigation Protocols for Nuclear Plant/Electric System Interfaces. The agreement is documented in RTO-OP-03 Rev. 10 "MIDWEST ISO Real-Time Operations: Communication and Mitigation Protocols for Nuclear Plant/Electric System Interfaces."
1(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 Midwest ISO Communication Protocol states that Midwest ISO will monitor the appropriate system conditions and notify the nuclear plant's operating personnel via the ATC. ATC will notify Kewaunee 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 with MISO. ATC will notify Kewaunee within 15 minutes after verification whenever the real time voltage on the Kewaunee 138 kV bus goes lower than 140 kV or higher than 143 kV. ATC will notify Kewaunee within 15 minutes after verification whenever the loss of any single transmission element or generator connected to the ATC transmission system will cause the Kewaunee 138 kV bus voltage to go lower than 140 kV or higher than 143 kV. ATC will also notify Kewaunee of forced outages to either end of any 345 kV or 138 kV transmission line connected to the Kewaunee substation as well as other transmission lines identified in the Point Beach/Kewaunee Stability Study.
1(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,	The grid conditions that would cause Kewaunee to contact ATC (the TSO) include a change in breaker status for the offsite transmission lines, main generator (grid) frequency less than 59.3 Hz, 138 kV transmission line voltages outside normal operating range of 140-143 kV, or 345 kV transmission line voltage outside normal operating range

describe how you assess grid conditions that may cause the NPP licensee to contact the TSO.	of 330-360 kV. The abnormal operating procedure associated with abnormal grid conditions and alarm response procedures associated with a substation major alarm and generator under frequency alarm address these conditions. Additionally, Kewaunee would contact ATC for abnormal safeguards bus voltages per abnormal operating procedures associated with the 4160V AC supply and distribution system and the 480V AC supply and distribution system. The plant process computer monitors the safeguards busses voltage and alarms are generated for the following conditions: • 4160V Bus 5 or Bus 6 voltage >4400 VAC or <4000 VAC • 480V Bus 51 or Bus 61 voltage >525 VAC or <430 VAC • 480V Bus 52 or Bus 62 voltage 509 VAC or <430 VAC
1(d) Describe how NPP operators are trained and tested on the use of the procedures or assessing grid conditions in question 1(c).	Kewaunee operators are trained and tested during initial and re-qualification training on the following: • Loss of Offsite Power (LOOP) • System Restoration • Degraded voltage conditions • Voltage less than 4160V AC on Bus 5 or 6 • VARs • Breaker status • Notification by TSO of changed conditions
1(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. Kewaunee does have a formal agreement with the TSO.
1(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	The Midwest ISO Communication Protocol 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 (ATC) 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 (ATC) shall immediately notify the Nuclear Plant (Kewaunee).

allowable value in its TSs) or LOOP after a trip of the reactor unit(s).	
1(g) Describe the low switchyard voltage conditions that would initiate operation of plant degraded voltage protection.	Criteria for voltages have been provided to the ATC to maintain real-time and post contingent voltages within a band of 140 kV to 143 kV. Alarms exist to alert the operators before exceeding these valves. Kewaunee operators monitor grid conditions, and enter an abnormal procedure when the 138 kV systems voltage is below 140 kV or when abnormal 4160 V or 480 V bus voltages exist, due to grid voltage abnormalities. The procedure instructs Kewaunee operations to contact the ATC for review of contingencies. The following low voltage conditions initiate degraded voltage protection: • Low voltage, <85.0% for one second or 93.6% for six seconds, on 4160 V Bus 1-5. • Low voltage, <85.0% for one second or 93.6% for six seconds, on 4160 V Bus 1-6.

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.	
Question	**Response**
2(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.*	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, immediately following the operation of any breaker 100 kV or greater, or as initiated by the system operator. The offline analysis is performed on an as-needed basis. 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.
2(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. Refer to the response to question 2(a). 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. If Midwest ISO determines the transmission system is outside of operating criteria, the Midwest ISO will notify the local transmission operator. ATC will notify Kewaunee within 15 minutes after verification whenever the real time voltage on the Kewaunee 138 kV bus goes lower than 140 kV or higher than 143 kV. ATC will notify Kewaunee within 15 minutes after verification, whenever the loss of any single transmission element or generator connected to the ATC transmission system will cause the Kewaunee 138 kV bus voltage to go lower than 140 kV or higher than 143 kV. In addition, ATC will notify Kewaunee of forced outages to either end of any 345 kV or 138 kV transmission line connected to the Kewaunee substation as well as other transmission lines identified in the Point Beach/Kewaunee Stability Study.
2(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?	Yes. The analysis tools identify when a trip of the Kewaunee unit would result in switchyard voltages falling below the values provided to ATC by Kewaunee. Midwest ISO RTCA program simulates the loss of NPP and analyzes the post-trip condition against the criteria provided by the transmission owner. If the conditions were exceeded, the Midwest ISO RC would notify the local transmission operator.

If not, discuss how such a condition would be identified on the grid.	
2(d) If your TSO uses an analysis tool, how frequently does the analysis tool program update?	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. 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.
2(e) Provide details of analysis tool-identified contingency conditions that would trigger an NPP licensee notification from the TSO.	If Midwest ISO observes that 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 100MW, all non-radial lines above 100kV, and all transformers with two windings greater than 100kV. 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. The contingencies that are modeled and studied include the loss of any single ATC transmission line or transformer, as well as, any generator connected to the ATC system. The contingency definition for the loss of the Kewaunee unit includes the transfer of auxiliary load from the main auxiliary transformer to the reserve auxiliary transformer. Kewaunee is notified whenever any activated contingency results in voltages outside of predefined limits.
2(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. If the Transmission Operator loses the 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. The 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 RTP-OP-03. 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. ATC will notify Kewaunee per the MISO Communication and Mitigation Protocols for Nuclear Plant/Electric System Interfaces. When Kewaunee is notified that the TSO (ATC) is unable to determine if offsite power voltage and capacity could be adequate, Kewaunee would enter the condition into the corrective action program. This would begin the operability and reportability determination processes. Additionally, it is the TSO's position that if they could not predict Kewaunee's post-trip voltages, this would be the result of significant grid disturbances that would initiate communications between the TSO and Kewaunee. Kewaunee would enter the abnormal procedure to assess these conditions.
2(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. 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. For post-event analysis, the TSO does not verify by procedure the switchyard voltages are bounded by the analysis tools.
2(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 to Kewaunee, since TSO analysis tools are presently in use.
2(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?*	Not applicable to Kewaunee, since TSO analysis tools are presently in use.

(b) If the bounds of the analyses are exceeded, does this condition trigger the notification provisions discussed in question 1 above?	
2(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 Kewaunee, since the TSO utilizes analysis tools and communicates the applicable conclusions to Kewaunee.

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.*	
Question	**Response**
3(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?	If ATC notifies Kewaunee that a trip of Kewaunee would cause the 138 kV supply line voltage to drop below the degraded grid setpoint, Kewaunee declares the offsite power system inoperable for contingent unit trip. Also, if notified that a Kewaunee trip would drive voltage below the degraded voltage protection setpoint, Kewaunee would enter the TS standard shutdown sequence. If ATC notifies Kewaunee that a loss of the most critical transmission line or the largest supply to the grid would cause the 138 kV supply line voltage to drop below the degraded grid setpoint Kewaunee would not declare the offsite power system inoperable, but would enter the condition into the corrective action program. Postulated contingencies on the transmission grid are not used as a basis for functional 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 is still met, i.e., loss of power from the transmission network would not occur as a result of loss of power generated by Kewaunee.
3(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 is not in the Kewaunee licensing basis and Kewaunee is not designed or analyzed for double sequencing scenarios. As stated in the USAR section 8: "Electric power from the transmission network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights-of-way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all on-site alternating current power supplies and the other off-site electric power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a loss-of-coolant accident to assure that core cooling, containment integrity, and other vital safety functions are maintained."

	"Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the on-site electric power supplies."
3(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).	Double sequencing is not in the Kewaunee licensing basis and Kewaunee is not designed or analyzed for double sequencing scenarios.
3(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.	As noted in 3(a) above. Kewaunee declares offsite power inoperable when the predicted voltage following a Kewaunee 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 is 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.
3(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.	Double sequencing (LOCA with delayed LOOP event) is not part of the licensing bases for Kewaunee. As noted in 3(d), entry into TS action statements is evaluated on a case-by-case bases. Kewaunee will declare equipment inoperable when the inoperability occurs. That is, if the 138 kV system becomes degraded, alarms will be initiated and appropriate responses will be taken. 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 is 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.
3(f) Describe if and how NPP operators are trained and tested on the compensatory actions	The Kewaunee operators are trained and tested during initial and re-qualification training on the following:

mentioned in your answers to questions 3(a) through (e).	• LOOP • System Restoration • Degraded voltage conditions • Voltage less than 4160V AC on Bus 5 or 6 • VARs • Breaker status • Notification by TSO of changed conditions

4. Use of criteria and methodologies to assess whether the offsite power system will remain operable following a trip of your NPP.	
Question	**Response**
4(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. Procedural guidance is available to Kewaunee operators. Operation of the Main Generator voltage regulator is contained in the normal operating procedure, as well as limits for Main Generator VAR loading. KPS has the ability to monitor voltage on the 345 kV and 138 kV transmission systems, voltage on the 4160 VAC and 480 VAC safeguards busses, grid/main generator frequency, and off-site transmission line breaker position. Alarms are provided for abnormal (high and low) safeguards bus voltages, low main generator (grid) frequency, and opening of offsite power supply breakers located in the KPS substation. Abnormal operating procedures direct the KPS operators to contact ATC to restore from the abnormal condition, as well as assess the impact on off-site power operability. Licensed operators are trained and tested on the design and operating characteristics for Main Generator Excitation and Voltage Regulation system including: • Automatic/Manual Voltage Regulation and • Generator capability limits. Simulator training / evaluation on main generator operating procedures includes: • Startup and shutdown of main generator excitation and voltage regulation system, • Normal operation and control of generator voltage regulation, • Coordination of reactive load sharing and the simulated TSO, and • Abnormal operation / annunciator response to voltage regulator malfunctions. Training is provided on grid instability and loss of electrical busses on a periodic basis in the simulator and classroom as part of continuing training.
4(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.	Not applicable, since guidance is provided in plant procedures. See response to question 4(a).

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

The Maintenance Rule (10 CFR 50.65(a)(4)) requires that licensees assess and manage the increase in risk that may result from proposed maintenance activities before performing them.

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

Question	Response
5(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. A quantitative grid reliability evaluation is performed as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4) before performing grid-risk-sensitive maintenance activities. Upon notification by the system operator of grid instability, or observed off-normal conditions from the control room, a procedure is entered, which requires the (a)(4) analysis to be updated to reflect any entry into the grid instability procedure, as well as continuous monitoring of grid conditions by communication with the transmission owner, American Transmission Company. Therefore, an appropriate process is in place for continuous monitoring of the grid by two independent parties, with procedural requirements to update the (a)(4) assessment during off-normal conditions. This process does not perform a specific check at the time of equipment tagout because the grid is continuously monitored for potential (a)(4) impact before and during all evolutions.
5(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 TSO continuously monitors grid status and is required to report changes to grid status affecting the off-site power supply to Kewaunee as previously described. Kewaunee's abnormal procedures provide guidance for evaluating continuing maintenance activities during periods of abnormal grid conditions and updating the (a)(4) risk assessment.
5(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.*	No. 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. There is no seasonal variation in the LOOP frequency. Seasonal variations are dominated by switchyard maintenance during the spring and fall refueling outages, and by weather-related effects. Switchyard maintenance is explicitly modeled. Severe weather is handled by the (a)(4) program in the same way as grid instability; the severe weather procedure requires an update of the risk assessment. The severe weather scope includes thunderstorms (electrical activity), high winds up to and including tornadoes, ice storms and earthquakes.

5(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. The known, time-related variations in LOOP probability are explicitly accounted for in the (a)(4) process. These time-dependent factors are dominated by grid instability, severe weather and switchyard maintenance. When either of these first two conditions exists, the Operations staff enters procedures that include an update of the 10 CFR 50.65(a)(4) risk analysis. The (a)(4) program directs risk management actions when any regulatory risk threshold is crossed. In the case of switchyard maintenance, this activity is monitored by careful communication between the (a)(4) staff and the system operator; all switchyard maintenance is likewise accounted for in the (a)(4) configuration analyses. Therefore, all of the dominant contributors to time-dependent LOOP frequency are specifically monitored to ensure that the risk analyses are updated and any required risk management actions are performed. These risk management actions are designed to protect and restore the affected key safety functions. In this case, the applicable function is electrical power, which is supported by its power supplies, busses and breakers. Risk management actions can include delays in scheduled maintenance or the early recovery of necessary support equipment. As a result, there is no need for a "summer" LOOP penalty. The summer LOOP risk increase is dominated by potential grid instability and severe weather, both of which are already accounted for in the station procedures.
5(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. For Maintenance activities performed by the TSO all communications are through the Outage Coordinator at our TSO. This communication process starts in the planning phase of the work and continues until the work is completed. As part of the planning phase, Kewaunee staff evaluates the conditions that Kewaunee may experience during the work and plan contingencies for those conditions and contingencies if there are additional problems encountered during the maintenance activity. Kewaunee's administrative procedure for substation and transformer bay maintenance or modification requires that prior written notification shall be provided at least ninety days in advance of commencement of work for modification or new construction. This notification is in accordance with the Generation-Transmission Interconnect Agreement. Maintenance, which is non-intrusive, is excluded from the notification requirement.
5(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.	Midwest ISO has established a communication protocol for nuclear plants that requires the Midwest ISO to communicate to the local transmission owner whenever the Midwest ISO has determined that the pre- and post-contingent voltage is outside of the acceptable voltage range. Additionally, per the MISO Nuclear Communication Protocol, ATC will notify Kewaunee

	anytime real-time or post-contingent voltages go outside of predetermined bandwidths. Additionally, ATC will notify Kewaunee whenever a forced outage occurs to the networking capability of any 138 kV or 345 kV transmission line that terminates at the Kewaunee Switchyard, as well as, any other transmission line identified in the Point Beach/Kewaunee Stability Study.
5(g) Do you contact your TSO periodically for the duration of the grid-risk-sensitive maintenance activities?	Yes. Once the activity is scheduled, a responsible contact person is assigned to communicate with the TSO (periodically for the duration of maintenance activity) on the maintenance activities. Typically, this is the Outage and Planning Department representative, as they are aware of the other plant work activities and what affect this work will have on the plant risk profile for the day. During periods of maintenance on transmission lines that affect Kewaunee operation, daily schedule updates are provided to the station by the TSO. Additionally, the TSO is contacted twice daily (approximately 0100 and 1300) to verify operability of the off-site power supply.
5(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.	Kewaunee System Engineering, Operations, and Outage and Planning groups have been briefed on the protocols. Activities have been initiated to conduct future continuing training on MISO procedure RTP-OP-03, "Communication and Mitigation Protocols for Nuclear Plant/Electric System Interface," and on the appropriate sections of the Generation-Transmission Interconnection Agreement. This training will have objectives developed and an evaluation will be performed to confirm understanding of the objectives. The Kewaunee operators are trained to use the abnormal operating procedure associated with abnormal grid conditions, and the Kewaunee workweek coordinators and Shift Technical Advisors are trained in the use of plant procedures associated with risk assessment for plant configurations. This training has objectives developed and a post-training evaluation is performed to gauge understanding of the objectives.
5(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).	Risk is re-assessed either when the TSO notifies the station staff of grid stability concerns, or when the control room staff sees indications of an off-normal grid condition. In both cases, they will enter the applicable procedure, which requires an update of the (a)(4) evaluation.
5(j) If risk is not assessed (when warranted) based on continuing communication with the TSO throughout the duration of grid-risk-sensitive	Risk is re-assessed when the TSO notifies the station staff of grid stability concerns. This requirement is written into the station procedures.

maintenance activities, explain why you believe you have effectively implemented the relevant provisions of the endorsed industry guidance associated with the maintenance rule.	
5(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.	There is no need for an alternative method. The current method procedurally ensures that off-normal conditions are identified and the (a)(4) assessment is updated.

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).	
Question	**Response**
6(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 coordinates transmission system maintenance activities that can have an impact on the NPP operation with the NPP operator and Midwest ISO.
6(b) Do you coordinate NPP maintenance activities that can have an impact on the transmission system with the TSO?	Yes. When Kewaunee schedules any work that may affect the output of the plant, Kewaunee communicates what the affect on generation may be to the marketing organization. Once Dominion Energy Marketing, Inc. (DEMI) communicates this with the TSO, Kewaunee staff coordinates with the TSO to determine best available conditions to perform the work and based on the evaluation by DEMI, TSO and Kewaunee determine what is the available window for the work activity.
6(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. If the maintenance was determined to increase risk to an unacceptable level on the station or transmission system, the work would be rescheduled to a mutually acceptable time.
6(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. Kewaunee procedures provide the risk management actions that would be implemented. Examples of risk management actions include pre-job briefings, establishing protected equipment, establish a contingency plan to restore out of service equipment, or establishing other compensatory measures. The level of risk management actions would be selected commensurate with the risk.
6(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.	Actions taken, as discussed in 6(a) through 6(d), are implemented by procedures. These activities/protocol/procedures have been reviewed and approved by station management. Procedure compliance is discussed in station administrative procedures and station personnel are trained to follow procedures. Kewaunee procedure GNP-08.21.01, "Risk Assessment for Plant Configuration," provides direction on performing 10 CFR 50.65(a)(4) risk calculations.
6(f) Describe how NPP operators and maintenance personnel are trained and tested to	Kewaunee workweek coordinators and Shift Technical Advisors are trained in the use of risk assessment tools. Kewaunee electrical maintenance personnel are trained on

assure they can accomplish the actions described in your answers to question 6(e).	the coordination of maintenance that may affect the offsite power supply.
6(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. There is effective and carefully prescribed coordination between station operations and planning individuals and the TSO regarding transmission system maintenance and NPP maintenance activities.
6(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. Kewaunee adequately uses risk assessment results, including grid reliability evaluation results, in managing maintenance risk, as required by 10 CFR 50.64(a)(4).
6(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. Kewaunee adequately uses risk assessment results, including grid reliability evaluation results, in managing maintenance risk, as required by 10 CFR 50.64(a)(4).

Offsite power restoration procedures in accordance with 10 CFR 50.63 as developed in Section 2 of RG 1.155. **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 recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches for complying with 10 CFR 50.63.**	
7. Procedures for identifying local power sources[1] that could be made available to resupply your plant following a LOOP event *Note: Section 2, "Offsite Power," of RG 1.155 (ADAMS Accession No. ML003740034) states:* *Procedures should include the actions necessary to restore offsite power and use nearby power sources when offsite power is unavailable. As a minimum, the following potential causes for loss of offsite power should be considered:* *- Grid 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.*	
Question	**Response**
7(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.	ATC participates in the development and implementation of the black start and system restoration plan established for the loss of all or part of the transmission system with the MISO Power System Restoration Working Group (PSRWG) to re-supply the Kewaunee switchyard following a LOOP event. The MISO PSRWG includes ATC and Wisconsin Public Service Corp, as well as, MISO and other utilities in the ATC footprint.
7(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. The NRC reviewed these offsite power restoration procedures during SBO Rule implementation inspections. Kewaunee has emergency/abnormal operating procedures for LOOP and offsite power recovery. The Kewaunee operators are trained and tested on these procedures. Kewaunee has an onsite SBO diesel generator that is the credited AC source pursuant to 10 CFR 50.63. Use of local grid power sources is not credited as part of Kewaunee 10 CFR 50.63 response.
7(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.

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

Losses of offsite power caused by grid failures at a frequency of equal to or greater than once in 20 site-years in accordance with Table 4 of Regulatory Guide 1.155 for complying with 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 recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches for complying with 10 CFR 50.63.**	
8. Maintaining SBO coping capabilities in accordance with 10 CFR 50.63.	
Question	**Response**
8(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?	No.
8(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.
8(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.
8(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.

Actions to ensure compliance.
9. If you determine that any action is warranted to bring your NPP into compliance with NRC regulatory requirements, including TSs, GDC 17, 10 CFR 50.65(a)(4), 10 CFR 50.63, 10 CFR 55.59 or 10 CFR 50.120, describe the schedule for implementing it.
Response Not Applicable. Kewaunee complies 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.

ATTACHMENT 2

MILLSTONE POWER STATION
UNITS 2 AND 3
Docket Nos. 50-336/423

(SERIAL NO. 06-103)

RESPONSE TO GENERIC LETTER 2006-02
GRID RELIABILITY AND THE IMPACT ON PLANT RISK AND THE OPERABILITY OF OFFSITE POWER

DOMINION NUCLEAR CONNECTICUT, INC. (DNC)

MILLSTONE RESPONSE TO REQUESTED INFORMATION FOR GL 2006-02
GRID RELIABILITY AND THE IMPACT ON PLANT RISK AND THE OPERABILITY OF OFFSITE POWER

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

GDC 17, 10 CFR Part 50, Appendix A, requires that licensees 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).

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

Question	Response
1(a) Do you have a formal agreement or protocol with your TSO?	Yes. The ISO-New England (ISO-NE) Market Participant Service Agreement and the Interconnection Agreement requires Dominion Nuclear Connecticut, Inc. (DNC), ISO-NE and the Local Control Center to comply with approved ISO-NE procedures and instructions.
1(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.	ISO-NE will notify Millstone control rooms, as soon as practical, in accordance with good utility practice 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) determines that the predicted post-trip off-site voltage is below FSAR requirements; • In the event that the Real-Time On-line AC Contingency Monitor programs become unavailable; and • If local system configuration exists which would cause the Millstone generators to become unstable in the event of certain transmission system contingencies. These notifications are made when the conditions are identified by the ISO-NE.
1(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 plant operators monitor 345 kV switchyard voltages and breaker alignments and would contact ISO-NE and/or CONVEX, the Local Control Center, if abnormal conditions are identified in the switchyard. Millstone station operating and alarm response procedures contain instructions to contact ISO-NE and CONVEX through a dedicated telephone line when abnormal conditions are identified.
1(d) Describe how NPP operators are trained and tested on the use of the procedures or assessing grid conditions in question 1(c).	Plant operators are trained in the use of operating and alarm response procedures in accordance with the initial and normal re-qualification program. Operators and Shift Technical Advisors (STAs) receive training on Performing Risk Reviews as part of

	licensed operator training. The STAs receive specific training in the use of a risk monitor computer program (EOOS), which can be used to assess the impact of TSO notifications of abnormal grid conditions.
1(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.	As described in response 1(a), Millstone has a formal agreement with ISO-NE and the Local Control Center (CONVEX).
(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).	ISO-NE operating procedures require that the Millstone control rooms be notified, as soon as practical, in accordance with good utility practice in the event of degraded grid voltage less than the FSAR limits as a result of a Millstone reactor trip.
1(g) Describe the low switchyard voltage conditions that would initiate operation of plant degraded voltage protection.	The emergency bus 4.16 kV degraded voltage protection relay dropout setting ensures adequacy of the voltages at the emergency loads. Following a transient, if voltage at the 4.16 kV emergency bus drops below the dropout value, the voltage must recover to the reset value within a set time delay to prevent degraded voltage protection actuation. The reset value of the relay corresponds to slightly below 345 kV at the Millstone Unit 2 and Unit 3 switchyard. A minimum switchyard voltage of 345 kV will ensure that required safety systems operate without actuation of safety bus degraded voltage protection relays. If the minimum 345 kV is not available for the worst-case analyzed plant scenario, the plant degraded voltage protection scheme will be initiated to separate the emergency busses from the grid and the loads will sequence onto the emergency diesel generators.

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.	
Question	**Response**
2(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. ISO-NE and the CONVEX Local Control Center employ a real-time contingency analysis program. As provided by ISO-NE, the program utilizes real-time transmission system information and NPP unit specific shutdown loads and minimum voltage requirements. The program creates a real-time network model starting with bus/branch connectivity, branch impedances 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 NPPs are notified. Additionally, an on-line 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.
2(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. ISO-NE uses an analysis tool. See response to 1(b) for conditions on notification.
2(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 does this function.
2(d) If your TSO uses an analysis tool, how frequently does the analysis tool program update?	As provided by ISO-NE, on-line real-time contingency analyzer calculations are performed at least every 5 minutes at ISO-NE and at the CONVEX Local Control Center.

	In addition, on-line monitoring is performed every 60 seconds by ISO-NE to verify that predetermined interface limits are not exceeded.
2(e) Provide details of analysis tool-identified contingency conditions that would trigger an NPP licensee notification from the TSO.	As discussed in response 2(a), the real-time on-line AC contingency monitor program will determine if existing system conditions, coupled with a trip of a nuclear generator, would result in adequate or inadequate post trip voltages. ISO-NE has identified some transmission system configurations that require Millstone to take a predetermined action (i.e., down-power) to prevent the trip of Millstone units following a transmission system design contingency. Millstone is aware of these operating limiting configurations and required actions. Millstone is required to respond upon notification from the ISO or the Local Control Center (CONVEX).
2(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. There is an agreement and notification is required. Loss of voltage prediction tools alone has no impact on operability. If ISO-NE had previously determined that the grid was in a degraded or stressed condition and/or if ISO-NE notified Millstone that, based on changing system conditions and their operating experience, a stressed condition has developed during the loss of voltage prediction tools, operability would be assessed.
2(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. ISO-NE has no formal verification procedure, but does occasionally benchmark analysis results with data collected after actual events.
2(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?	An analysis tool is available to ISO-NE.
2(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,*	An analysis tool is available to ISO-NE.

does this condition trigger the notification provisions discussed in question 1 above?	
2(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.	An analysis tool is available to ISO-NE.

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.	
Question	**Response**
3(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?*	If ISO-NE notifies the Millstone control rooms that a trip of a Millstone unit would result in switchyard voltages below the FSAR minimums, the offsite power system is declared inoperable under plant Technical Specifications (TS). Notification by ISO-NE that a loss of the most critical transmission line or the largest supply to the grid that would result in switchyard voltages below FSAR minimums has no impact on the operability of plant TS equipment. 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; • The GDC 17 criterion discussed in the Generic Letter is still met, i.e., a loss of power from the transmission network would not occur as a result of loss of power generated by the nuclear power unit.
3(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 Millstone station. The FSAR accident analyses do not assume double sequencing. No compensatory actions are required and no consideration of double sequencing is appropriate at Millstone station for operability due to the licensing bases established at the time of issuance.
3(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).	No evaluation has been completed and none is required due to the licensing bases established at the time of issuance.

3(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.*	As noted in 3(a) above. However, plant TS action statements would be identified on a case-by-case basis. There are no pre-established degraded grid Limiting Conditions for Operability other than low voltage.
3(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.	Double sequencing (LOCA with delayed LOOP event) is not part of the licensing bases for Millstone station. As noted in 3(d) entry into TS action statements is evaluated on a case-by-case basis. 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 is 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.
3(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).	Plant operators are trained in the use of Millstone procedures that describe actions in questions 3(a) through (e) in accordance with the normal licensed operator re-qualification program. Operators and STAs receive training on performing risk reviews as part of licensed operator training. STAs receive specific training in the use of a risk monitor computer program (EOOS), which can be used to assess the impact of TSO notifications of abnormal grid conditions. Licensed operators were trained on INPO SOER 99-1. As part of continuing operator training, in April/May of 2006, operators are scheduled to attend training on the SOER 99-1 Addendum. Licensed operators were trained in 2005 on transmission and offsite power. This presentation covered the design and operation of Millstone's connection to the grid and how it supports our offsite power reliability. Material covered provisions of GDC 17, NUREG-0800 and TS applicability. Objectives included: • Design basis for offsite power sources, • Design and configuration of the Switchyard and offsite transmission lines, • System voltage and frequency control,

	• Methods utilized to protect system stability, and • Purpose and design of SLOD.

4. Use of criteria and methodologies to assess whether the offsite power system will remain operable following a trip of your NPP.	
Question	**Response**
(4a) 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. Operation of the Millstone station main generator voltage regulators is covered in plant operating procedures and ISO-NE procedures. The plant operators are trained on operating procedures in accordance with the normal licensed operator training program. Licensed operators are trained and tested on the design and operating characteristics for Main Generator Excitation and Voltage Regulation system including: • Automatic/Manual Voltage Regulation, • Generator capability limits. Simulator training/evaluation on main generator operating procedures includes: • Startup and shutdown of main generator excitation and voltage regulation system, • Normal operation and control of generator voltage regulation, • Coordination of reactive load sharing between units and the simulated TSO, and • Abnormal operation/annunciator response to voltage regulator malfunctions. Licensed operators are trained and evaluated on procedure C OP 200.8, "Response to ISO New England/CONVEX Emergencies and Alerts." Additionally both units' licensed operators are trained and evaluated during initial and continuing training in the performance of "Degraded Voltage" and "Emergency Generation Reduction."
4(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.	Not applicable. Guidance is provided to the operators as identified in question 4(a).

Use of NPP licensee/TSO protocols and analysis tool by TSOs to assist NPP licensees in monitoring grid conditions for consideration in maintenance risk assessments. **The Maintenance Rule (10 CFR 50.65(a)(4)) requires that licensees assess and manage the increase in risk that may result from proposed maintenance activities before performing them.**	
5. Performance of grid reliability evaluations as part of the maintenance risk assessments required by 10 CFR 50.65(a)(4).	
Question	**Response**
5(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. A quantitative grid reliability evaluation is performed as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4) before performing grid-risk-sensitive maintenance activities. Upon notification by the system operator of grid instability, or observed off-normal conditions from the control room, a procedure is entered which requires the (a)(4) analysis to be updated to reflect any entry into the grid instability procedure, as well as, continuous monitoring of grid conditions by communication with the transmission owner.
5(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 ISO-NE and the Local Control Center (CONVEX). Millstone station is notified in accordance with ISO-NE procedures whenever grid conditions change. Upon notification by the system operator of grid instability or observed off-normal conditions from the control room, a procedure is entered which requires the (a)(4) assessment to be updated to reflect any entry into the grid instability procedure. Continuous monitoring of grid conditions is established by communication with the transmission owner.
5(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.*	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 no seasonal variation in the LOOP frequency in the local transmission region. According to data provided by ISO-NE, abnormal condition alerts and actions during a capacity deficiency are much more common in the summer.

5(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?	The known, time-related variations in the probability of a LOOP are explicitly accounted for in the (a)(4) process at Millstone. These time-dependent factors are dominated by grid instability alerts issued by the TSO, severe weather (high winds) and switchyard maintenance. When either of the first two conditions exists, operators enter procedures that include an update to the 10 CFR 50.65(a)(4) risk analysis. The (a)(4) program directs risk management actions when risk to the availability of offsite power increases due to an abnormal condition. In the case of switchyard maintenance, the activity is carefully reviewed before being approved by Millstone; procedural guidance is then applied to update the (a)(4) risk profile before the switchyard maintenance has commenced. Therefore, all of the dominant contributors to time-dependent LOOP frequency are specifically monitored to ensure that the risk assessment is updated and any required risk management actions are performed. These risk management actions are designed to protect and restore the affected key safety functions. In this case, the applicable function is electrical power, which is supported by its power supplies, buses and breakers. Risk management actions can include delays in scheduled maintenance or the early recovery of necessary support equipment. As a result, there is no need for a "summer" LOOP penalty. The summer LOOP risk increase is dominated by potential grid instability and severe weather, both of which are already accounted for in the station procedures.
5(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. Millstone does have contacts with the ISO and the Local Control Center (CONVEX).
5(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.	As discussed in response 1(a), the Market Participants Service Agreement provides assurance that ISO-NE will follow their procedures and promptly notify Millstone station of a worsening grid condition that may emerge during a maintenance activity.
5(g) Do you contact your TSO periodically for the duration of the grid-risk-sensitive maintenance activities?	No. As discussed in response 5(b), the grid conditions are continuously monitored by ISO-NE and the Local Control Center (CONVEX). Millstone station is notified of changing grid conditions in accordance with ISO-NE and the Local Control Center (CONVEX) procedures. In addition, as required by plant TS, the forecasted grid conditions are discussed with ISO-NE before utilizing the extended emergency diesel generator LCO action statement for on-line maintenance.
5(h) If you have a formal agreement or protocol	The plant operators are trained on operating procedures in accordance with the

with your TSO, describe how NPP operators and maintenance personnel are trained and tested on this formal agreement or protocol.	normal licensed operator training program. Operators and STAs receive training on performing risk reviews as part of licensed operator training. STAs receive specific training in the use of a risk monitor computer program (EOOS), which can be used to assess the impact of TSO notifications of abnormal grid conditions. A 2006 simulator session for Unit 2 continuing operator training modeled the events of August 14, 2003. Operators were trained on the ISO-NE notifications for "Abnormal Condition Alert" and "Nuclear Plant Transmission Operations." Training covered the impact on Probabilistic Risk Assessment (PRA) and TS applicability. This session also required the operators to coordinate with the simulated TSO for switching activities to support restoration of power from offsite sources. Unit 3 will be running a similar session in cycle 3 of this year, which starts in April 2006. Operations personnel and STAs successfully responded to those conditions in the simulated environment. Maintenance personnel are not trained on the plant risk management programs. However, operations support and work management plan maintenance work to minimize plant risk.
5(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. Risk is re-assessed either when the ISO-NE notifies the station of grid stability concerns or when the control room staff sees indications of an off-normal grid condition. In both cases, the station will enter the applicable procedure, which requires an update of the (a)(4) risk evaluation.
5(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. Risk is re-assessed when the TSO notifies the station of grid stability concerns. This requirement is written into the station procedures.
5(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. There is no need for an alternative method. The current method procedurally ensures that off-normal conditions are identified and the (a)(4) assessment is updated.

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).	
Question	**Response**
(6a) Does the TSO coordinate transmission system maintenance activities that can have an impact on the NPP operation with the NPP operator?	Yes. Millstone has a procedure that defines the process used to identify and schedule transmission facility maintenance within the switchyard. ISO-NE also has a procedure to govern transmission outages.
6(b) Do you coordinate NPP maintenance activities that can have an impact on the transmission system with the TSO?	Yes. Millstone has a procedure in place to coordinate maintenance activities between and among ISO-NE, CONVEX, and CL&P, the owner of the transmission grid.
6(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. If the maintenance was determined to be detrimental to grid reliability, the maintenance would be rescheduled as agreed upon between Millstone and the grid operator.
6(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 Millstone station risk management program specifies that risk calculation results be managed to pre-approved levels. If conditions require work activities that challenge these levels, the procedure requires that additional station management approval be obtained and compensatory actions to mitigate the increase in risk are developed.
6(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.	Millstone risk review procedure provides direction on performing 10 CFR 50.65(a)(4) risk analysis. The procedure provides detailed guidance on grid conditions and ISO notifications that are factored into the analysis. The results of these reviews are used to coordinate and schedule in-plant and offsite transmission system maintenance and testing such that plant risk is managed to meet Millstone requirements. ISO-NE procedure, Abnormal Conditions Alert, guides the ISO-NE notification of the Millstone station and the rest of the New England power plant operators of the conditions on the grid. The 345 kV transmission system outages are used to coordinate and authorize transmission system maintenance activities that could affect grid reliability.

6(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).	The plant operators are trained on operating procedures in accordance with the normal licensed operator training program. Maintenance personnel are not trained on the plant risk management programs. However, operations support and work management plan maintenance work and manage plant risk. Operators and STAs receive training on performing risk reviews as part of licensed operator training. STAs receive specific training in the use of a risk monitor computer program (EOOS), which can be used to assess the impact of TSO notifications of abnormal grid conditions. A 2006 simulator session for Unit 2 continuing operator training modeled the events of August 14, 2003. Operators were trained on the ISO-NE (TSO) notifications for "Abnormal Condition Alert" and "Nuclear Plant Transmission Operations." Training covered the impact on Probabilistic Risk Assessment (PRA) and TS applicability. This session also required the operators to coordinate with the simulated TSO for switching activities to support restoration of power from offsite sources. Operations personnel and STAs successfully responded to those conditions in the simulated environment.
6(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 as noted in 6(a) and (b) activities.
6(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. Millstone adequately uses risk assessment results, including the results of grid reliability evaluations, in managing maintenance risk as required by 10 CFR 50.65(a)(4).
6(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. Millstone adequately uses risk assessment results, including the results of grid reliability evaluations, in managing maintenance risk as required by 10 CFR 50.65(a)(4).

Offsite power restoration procedures in accordance with 10 CFR 50.63 as developed in Section 2 of RG 1.155 **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 recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches for complying with 10 CFR 50.63.**	
7. Procedures for identifying local power sources[1] that could be made available to resupply your plant following a LOOP event. *Note: Section 2, "Offsite Power," of RG 1.155 (ADAMS Accession No. ML003740034) states:* *Procedures should include the actions necessary to restore offsite power and use nearby power sources when offsite power is unavailable. As a minimum, the following potential causes for loss of offsite power should be considered:* *- Grid 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*	
Question	**Response**
7(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.	In accordance with ISO-NE procedures, restoration of offsite power to nuclear power plants receives priority attention.
7(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.	No. Millstone station has an onsite SBO diesel generator that is the credited AC source in accordance with 10 CFR 50.63. Use of local grid power sources is not credited as part of Millstone 10 CFR 50.63 response.
7(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.	Millstone station has an onsite SBO diesel generator that is the credited AC source in accordance with 10 CFR 50.63. Use of local grid power sources is not credited as part of Millstone 10 CFR 50.63 response.

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

Losses of offsite power caused by grid failures at a frequency of equal to or greater than once in 20 site-years in accordance with Table 4 of Regulatory Guide 1.155 for complying with 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 recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches for complying with 10 CFR 50.63.**	
8. Maintaining SBO coping capabilities in accordance with 10 CFR 50.63.	
Question	**Response**
8(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?	No. Millstone has not experienced a total LOOP.
8(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.
8(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.
8(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.

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

ATTACHMENT 3

NORTH ANNA AND SURRY POWER STATIONS
UNITS 1 AND 2

(SERIAL NO. 06-103)

RESPONSE TO GENERIC LETTER 2006-02
GRID RELIABILITY AND THE IMPACT ON PLANT RISK AND THE OPERABILITY OF OFFSITE POWER

VIRGINIA ELECTRIC AND POWER COMPANY
(DOMINION)

NORTH ANNA AND SURRY RESPONSE TO REQUESTED INFORMATION FOR GL 2006-02
GRID RELIABILITY AND THE IMPACT ON PLANT RISK AND THE OPERABILITY OF OFFSITE POWER

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

GDC 17, 10 CFR Part 50, Appendix A, requires that licensees 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).

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

Question	Response
1(a) Do you have a formal agreement or protocol with your TSO?	Yes. The Transmission Owner (TO) providing interconnection services to the North Anna and Surry NPPs is Dominion. Dominion, North Anna and Surry (the NPPs) agree to abide by the requirements contained in the Nuclear-Electric Transmission Interface Agreement. Dominion is a member of PJM. North Anna and Surry Power stations are located in the service territory of PJM Interconnection, L.L.C. (PJM). PJM is the Transmission System Operator (TSO) for North Anna and Surry. All members of PJM execute the PJM Operating Agreement, which details the obligations and responsibilities of PJM to the members and vice versa. In the Operating Agreement, each member agrees to abide by the requirements contained in the PJM Manuals. The TOs are also signatories to a PJM Transmission Owners Agreement (TOA). The TOA requires the TOs to operate and maintain their Transmission Facilities in accordance with, among other things, the PJM Manuals. Moreover, the TOs are required under that section of the TOA to conform to PJM's operating instructions as they apply to the TOs' Transmission Facilities. Also, the TOs agree to follow PJM's operating instructions during an emergency.
1(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.	Requirements for notification of NPPs for specific grid conditions are contained in Dominion's System Operations Procedures Manual and in Dominion's Nuclear-Electric Transmission Interface Agreement – Addendum 2. Notification is required for: • Any transmission switching (inside or outside the switchyard) that may affect the availability of offsite power. • Any changes to the voltage schedule or variations in station voltage that exceed the schedule by specified limits. • Actual WARNING LIMIT voltage violations that cannot be mitigated within 15

minutes (within 1% of nominal voltage within the emergency limit).

- EMERGENCY LIMIT voltage violations (analyzed GDC 17 limits). Notification required as soon as practical, but no later than 15 minutes.
- Contingency WARNING LIMIT or EMERGENCY LIMIT violations that cannot be mitigated within 15 minutes.
- Operating under very heavy load conditions with the Load Curtailment Plan in effect. This notification is required as soon as practical, but no later than 15 minutes from the initial event.
- When system conditions return to normal.
- The Real-Time Contingency Analysis (RTCA) is not available.
- When real time telemetry between the stations and the System Operations Center is known to be out of service.

The PJM Manual requires PJM to initiate notification to an NPP through its respective transmission owner's control center if PJM identifies an NPP switchyard voltage violation. The PJM manual states: "This notification should occur within 15 minutes for voltage contingency violations and immediately for actual voltage violations. To the extent practical, PJM shall direct operations such that the violation is remedied within 30 minutes."

In addition, the PJM Manual identifies a series of alerts, warnings, and actions that PJM issues to PJM members depending on the identified grid condition. The PJM message is communicated to the NPP by their generation dispatcher for a variety of system conditions, including:

- Capacity Emergencies
- Maximum Emergency Generation Loading
- Load Management Curtailment
- Voltage Reduction Initiation
- Manual Load Dump Initiation
- Light Load Emergencies
- Minimum Generation Emergency
- Local Minimum Generation Emergency
- Weather/Environmental Emergency
- Hot/cold weather alerts
- Thunderstorms and Tornadoes
- Solar Magnetic Disturbances
- Sabotage/Terrorism Emergencies

1(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 Shift Manager (SM) shall notify the TO in a timely manner in accordance with the following: • When the plant's voltage schedule cannot be met due to plant limitations. • When the voltage regulator is being operated in manual mode or returned to automatic after being in manual. • To determine the cause of the possible transmission system operation that affected plant output. Example would be megawatt swings greater than 40 peak to peak that are not due to governor valve control system outputs. • Entrance into and exit of Abnormal Procedure(s) for Grid Instability.
1(d) Describe how NPP operators are trained and tested on the use of the procedures or assessing grid conditions in question 1(c).	Operators are trained and evaluated on the abnormal procedures associated with grid instability in initial and requalification training classes.
1(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.	As described in response to 1(a), North Anna and Surry have a formal agreement with the TO and TSO.
1(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).	Dominion's System Operations Procedures Manual and Nuclear-Electric Transmission Interface Agreement–Addendum 2 specify notifications required for contingency and actual nuclear station voltage limit violations. The System Operations Procedures Manual states, "The Supervisor – System Operations or designee shall notify the nuclear station's Shift Supervisor as soon as practical, but no later than 15 minutes after the event…" In addition, the PJM Manual requires PJM to initiate notification to an NPP through its respective transmission owner's control center if PJM identifies an NPP switchyard voltage violation.
1(g) Describe the low switchyard voltage conditions that would initiate operation of plant degraded voltage protection.	For North Anna and Surry, it is difficult to relate switchyard voltage directly to the Degraded Voltage relay setting. The Reserve Station Service Transformers (RSST) have automatic load tap changers (LTC) that regulate Emergency Bus voltage, via the Transfer Buses, within a relatively small band. As switchyard voltage fluctuates, the RSST automatic LTCs compensate. Emergency bus voltage is constant throughout the entire range of acceptable switchyard voltages.

	The minimum and maximum switchyard voltage limits correspond to the worst case expected voltages. The actual operating range is much smaller. The switchyard voltage level and the switchyard voltage drop are design inputs into the 10 CFR 50 Appendix A General Design Criterion 17 (GDC 17) analyses. The Transmission Planning department makes several worse case assumptions in their analyses in an attempt to model the worse case conditions, regarding other generation unit status, power transfers, and system load. Corporate Nuclear Engineering uses those results as an input to GDC 17 accident analyses. Nuclear Engineering does not establish a minimum required switchyard voltage drop by working back from the equipment ratings. The Degraded Voltage (DV) relay setting is normally approached only during transient conditions. When modeling an accident, emergency bus voltage frequently drops down near or below the DV relay setting. Prior to separation from offsite power, voltage is restored above the DV relay setting preventing transfer of the emergency buses to the EDGs. Subsequently, the RSST automatic LTCs continue to raise voltage, typically to normal levels.

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.*	
Question	**Response**
2(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 Dominion Energy Management System (EMS) includes Security Analysis which runs at least every 5 minutes and processes over 400 contingencies on Dominion's system plus several on external systems. Security Analysis reports violations of thermal, voltage, voltage drop and reclosing power angle limits for system-wide contingencies including loss of North Anna and Surry. Contingencies for loss of NPPs include emergency load switching where applicable. The PJM Energy Management System (EMS) includes a Security Analysis application which currently runs approximately every 1 minute and analyzes ~4,000 contingencies on the PJM system. The analysis provides results with respect to thermal, voltage, and voltage drop limit violations. One of the contingencies analyzed by the PJM EMS is the trip of the NPP.
2(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. Dominion's Security Analysis analyzes contingencies for loss of the NPPs as well as for loss of transmission devices that may affect the NPP. The results of the PJM Security Analysis application also contain the specific contingency of the NPP tripping as the contingent element. Violation of the unit trip contingency voltage limit would result in notification to the NPP. See response 1(b) for other conditions of notification.
2(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 trip of the NPP is one of the contingencies analyzed by the Dominion and PJM Security Analysis applications.
2(d) If your TSO uses an analysis tool, how frequently does the analysis tool program update?	Dominion's Security Analysis application updates automatically on a time trigger every 5 minutes and is also triggered if a transmission circuit breaker trips anywhere on the system. It also can be triggered manually. The PJM Energy Management System includes a Security Analysis application, which updates approximately every 1 minute.
2(e) Provide details of analysis tool-identified contingency conditions that would trigger an NPP licensee notification from the TSO.	For any contingency that predicts a violation of the warning voltage limits for the NPP, Dominion TO will notify North Anna or Surry if the system operator cannot effectively mitigate the conditions to avoid the violation. Dominion will notify North Anna and

	Surry for any contingency that predicts an emergency voltage limit violation, as soon as possible, but no later than 15 minutes from the initial event. PJM notifies the NPP through its respective transmission owner's control center whenever actual or post-contingency voltages are determined to be below the NPP switchyard voltage limits provided by the NPP. This requirement applies to all contingencies involving the tripping of the NPP or any transmission facility as the contingent element. The notification is required even if the voltage limits are the same as the standard PJM voltage limits. See response 1(b) for other conditions of notification.
2(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 System Operator is required to notify the NPP "as soon as practical, but no later than 15 minutes after the event" if both Dominion's and PJM's Security Analysis tools are unavailable. North Anna and Surry unit trip contingency voltage calculations are performed by the PJM EMS and the Dominion Security Analysis application. The PJM and Dominion EMS consist of a primary and backup system. If the PJM EMS fails, the Dominion Security Analysis application continues to analyze the North Anna and Surry unit trip contingency voltage. North Anna and Surry are notified if the real time contingency analysis capability of PJM and Dominion is lost simultaneously. If North Anna and Surry are notified that PJM and Dominion have lost their real-time contingency analysis capability, North Anna and Surry would request PJM and Dominion to provide an assessment of the current condition of the grid based on the tools that PJM and Dominion have available. The determination of the operability of the offsite sources would consider the assessment provided by PJM and Dominion and whether the current condition of the grid is bounded by the grid studies previously performed for North Anna and Surry. The Shift Manager (SM) will enter the Abnormal Procedural for grid instability and assess the operability of the offsite power supplies using the guidance of the abnormal procedure.
2(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. There is no formal process for comparing the actual post-trip voltages to the post-trip contingency voltage results calculated by the PJM and Dominion Security Analysis applications. Because Dominion has a similar Security Analysis program to PJM, there are many opportunities to compare the results of the respective Security Analysis programs.

	Dominion communicates with PJM whenever discrepancies are discovered in the Security Analysis results and resolves the issue. In this manner, there is high confidence that the Security Analysis results are accurate within the precision of the calculations.
2(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 has an analysis tool.
2(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 has an analysis tool.
2(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 has an analysis tool.

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.	
Question	**Response**
3(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?*	North Anna and Surry declare the offsite power system inoperable per Technical Specifications (TS) for a system contingency analysis that determines an emergency limit alarm for low voltage will occur from a trip of the subject nuclear unit. North Anna and Surry do not declare the offsite power system nonfunctional/inoperable for an analysis that determines the offsite power inadequate, contingent upon loss of another generating facility or transmission device. However, North Anna and Surry would enter the abnormal procedure for grid instability upon notification of a transmission system grid instability issue. Postulated contingencies on the transmission grid are not used as basis for operability/functional determination since: • such events are only postulated and have not actually happened, • the offsite power circuits remain capable of effecting a safe shutdown and mitigating the effects of an accident, and • the GDC 17 criterion in the Generic Letter is still met, i.e., loss of power from the transmission network would not occur as a result of loss of power generated by the NPP.
3(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 a delayed LOOP event) as defined in NRC GL 2006-02 is not part of North Anna and Surry's licensing basis. The design basis accident analysis discussed in the UFSAR considers a loss of coolant accident (LOCA) to occur coincident with a loss of offsite power (LOOP). As a result of NRC Information Notice 85-91, Load Sequencers for Emergency Diesel Generators, and Information Notice 93-17, Safety Systems Response to Loss of Coolant and Loss of Offsite Power, Dominion evaluated this situation with respect to emergency diesel generator loading even though the North Anna and Surry licensing basis consider the LOOP to occur coincident with the LOCA. The evaluation identified that a LOOP subsequent to a LOCA would not result in overloading of the emergency diesel generators.
3(c) Describe your evaluation of onsite safety-related equipment to determine whether it will operate as designed during the condition	Double sequencing is not part of North Anna and Surry licensing/design basis. As a result of NRC Information Notice 85-91, Load Sequencers for Emergency Diesel

described in question 3(b).	Generators, and Information Notice 93-17, Safety Systems Response to Loss of Coolant and Loss of Offsite Power, Dominion evaluated this situation with respect to emergency diesel generator loading even though the North Anna and Surry licensing basis consider the LOOP to occur coincident with the LOCA. The evaluation identified that a LOOP subsequent to a LOCA would not result in overloading of the emergency diesel generators.
3(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.*	Same as 3(a) above. The Abnormal Procedures would establish the conditions for declaring offsite power inoperable. North Anna and Surry declare offsite power inoperable when the predicted voltage following a plant 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/functionality 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 is 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.
3(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.	Double sequencing is not part of North Anna and Surry licensing/design basis. If offsite power supply becomes degraded to the point of not meeting GDC-17 requirements, the operations staff would declare the offsite power supply inoperable and the appropriate action statement from TS would be entered. These actions are directed in accordance with Abnormal Procedures. Postulated contingencies on the transmission grid are not used as a basis for functionality 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 is 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.

3(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).	The North Anna and Surry operating crews are trained, in initial licensee classes and on a continuing basis for on-shift operating crews, on assessing grid conditions based on TSO notifications as per abnormal procedures. The abnormal procedures provide specific guidance on declaring offsite power inoperable and verifying safety related components operable. TS entry conditions are trained and tested during re-qualification exam activities.

4. Use of criteria and methodologies to assess whether the offsite power system will remain operable following a trip of your NPP.	
Question	**Response**
4(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. Procedural guidance is available to North Anna and Surry operators on voltage regulator failures and routine adjustments, as well as, transformer operations including tap changer operation for transformers with adjustable tap changers. Technical Specification guidance addresses the basis for offsite power operability and prescribes required actions when operability is not met. Training is provided on voltage regulator failures, grid instability, and loss of electrical busses on a periodic basis in the simulator and classroom as part of continuing training. On the job training exists for transformer tap changer and transformer operations activities.
4(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.	Not Applicable. Procedural and TS guidance is provided for operators to address situations affecting plant equipment that impacts the operability of offsite power systems.

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

The Maintenance Rule (10 CFR 50.65(a)(4)) requires that licensees assess and manage the increase in risk that may result from proposed maintenance activities before performing them.

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

Question	Response
5(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. This process, however, does not perform a specific check at the time of equipment tagout because the grid is continuously monitored for potential (a)(4) impact before and during all maintenance evolutions. If the TO observes off-normal conditions, they notify the station control room by procedure. Similarly, if the regional operator observes signs of instability, they notify the local operator who, in turn, notifies the station. Finally, the control staff themselves may observe grid instability conditions. In any of these three cases, the plant staff will enter the applicable procedure, which includes a requirement for updating the (a)(4) analysis of the plant configuration while they are in effect. This requirement is also addressed in the (a)(4) guidance documents. Therefore an appropriate process is in place for continuous monitoring of the grid conditions by three independent parties, with procedural requirements to update the (a)(4) assessment during off-normal conditions. The (a)(4) revision can be initiated either qualitatively (observation) or quantitatively (annunciator setpoints). These observations are performed prior to grid-risk-sensitive maintenance and at all other times as well.
5(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 continually monitored. Any significant changes will be communicated in accordance with the agreements. If significant grid or plant changes occur during grid-risk-sensitive maintenance then the risk assessment will be updated with the current conditions per station procedures. Appropriate compensatory measures will be taken to minimize overall station risk in accordance with the PRA program.
5(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?*	Stress on the grid is manifested in a number of ways. Stress can mean the loading levels on individual facilities, overall demand levels, the degree of facilities out of service for maintenance, occurrence of severe weather, etc. Each aspect creates a level of stress on the grid and challenges for the system operators. Regarding the seasonal variability of the stress causers, each has a seasonal component. For example, peak load levels occur at the peak seasons of the summer

If the answer to either question is yes, discuss the time of year when the variations occur and their magnitude.	and winter seasons. While the specific days cannot be predicted, it is known roughly when they will occur. Consequently, maintenance during these times of the year is minimized. From a transmission system operations perspective, it is the simultaneous combination of stress causers that results in the most difficult operational challenges. For example, experiencing very hot (or cold) weather when we are in the maintenance seasons with a lot of equipment out of service can cause the most severe challenges. Grid stress can be caused by several factors, therefore, as discussed in 5(d) below, all of the dominant contributors to time-dependent LOOP frequency are continually monitored to ensure that the risk analyses are updated and any required risk management actions are performed.
5(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?*	The known, time-related variations in LOOP probability are explicitly accounted for in the (a)(4) process for North Anna and Surry. These time-dependent factors are dominated by grid instability, severe weather and switchyard maintenance. When either of these first two conditions exists, the Operations staff enters procedures that include an update of the 10 CFR 50.65(a)(4) risk analysis. The (a)(4) program directs risk management actions when any regulatory risk threshold is crossed. In the case of switchyard maintenance, this activity is monitored by careful communication between the (a)(4) staff and the system operator; all switchyard maintenance is likewise accounted for in the (a)(4) configuration analyses. Therefore, all of the dominant contributors to time-dependent LOOP frequency are specifically monitored to ensure that the risk analyses are updated and any required risk management actions are performed. These risk management actions are designed to protect and restore the affected key safety functions. In this case, the applicable function is electrical power, which is supported by its power supplies, buses and breakers. Risk management actions can include delays in scheduled maintenance or the early recovery of necessary support equipment. As a result, there is no need for a "summer" LOOP penalty. The summer LOOP risk increase is dominated by potential grid instability and severe weather, both of which are already accounted for in the station procedures.
5(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. Both PJM and Dominion TO use Real-Time Contingency Analysis (RTCA) that is conducted prior to and continuously during outages. Contact/Communications concerning the long range planning of maintenance activities are conducted and coordinated as described by Nuclear-Electric Transmission Interface Agreement, Addendum 1 (Switchyard Control).

	Contact with the Dominion TO is via the Switchyard Coordinator who is responsible for coordinating all switchyard work with the station. All Switchyard work will be coordinated with plant work, unit conditions, and testing activities such that an unnecessary risk to the station is not created. Specifically, activities will be coordinated between the station and system to minimize risks from loss of on-site and off-site power. Contact/Communications with the system operators just prior to and during outages are between the Dominion TO and the Shift Manager as described in Nuclear-Electric Transmission Interface Agreement, Addendum 2 and the North Anna Power Station Switchyard Working Level Agreement. Plant maintenance activities are controlled to reduce overall plant risk. Although there is no specific contact for each plant maintenance activity, as discussed in the response to question 1(b), the TO/TSO communicate transmission system concerns with North Anna and Surry.
5(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.	As per the Nuclear-Electric Transmission Interface agreement, the TSO/TO will notify the SM for grid issues as noted in the response to 1(b). The notification occurs whether or not plant maintenance is ongoing. The appropriate actions will then be taken by the Shift Manager to restore important safety systems.
5(g) Do you contact your TSO periodically for the duration of the grid-risk-sensitive maintenance activities?	No specific periodic contacts are specified in our agreements. As discussed in 5(b), any changes or challenges would be communicated in accordance with the agreement. However, communication occurs between the operations maintenance advisor and the onsite transmission maintenance coordinator. On site maintenance activities and grid transmission line and NPP switchyard maintenance activities are coordinated between the two individuals and any changes to key safety systems or grid conditions will result in communication between the SM and the TSO per the Nuclear-Electric Transmission Interface Agreement.
5(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.	Initial training on Interface Agreement was required, as well as, training on associated operating and abnormal procedures for the operations staff. Maintenance personnel are not trained on the TSO agreement since they do not perform maintenance in the switchyard. Grid-risk-sensitive maintenance activities are screened by Operations and the STA for 10 CFR 50.65 (a)(4) and Safety Monitor

	assessment prior to any plant maintenance starting.
5(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).	Risk is re-assessed either when the TO/TSO notifies the station staff of grid stability concerns, or when the control room staff sees indications of off-normal grid condition. In both cases, they will enter the applicable procedure and require an update of the (a)(4) evaluation.
5(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 re-assessed when the TSO notifies the station staff of grid stability concerns. This requirement is written into the station procedures.
5(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.	There is no need for an alternative method. The current method procedurally ensures that off-normal conditions are identified and the (a)(4) assessment is updated.

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).	
Question	**Response**
6(a) Does the TSO coordinate transmission system maintenance activities that can have an impact on the NPP operation with the NPP operator?	Yes. Planned transmission outages are coordinated. The process requires advanced notice and subsequent PJM approval for all outages to ensure grid reliability. On the outage start day, the system is analyzed one last time by PJM before permitting the equipment to be switched out of service. PJM notifies the NPP through Dominion's control center, as discussed in response 1(b). Dominion also analyzes planned outages in advance with studies becoming more detailed as the outage time approaches. Starting 8 days ahead of the planned outage date, detailed studies are performed daily. Coordination of switchyard activities occurs between the System Operator and North Anna and Surry. Once the equipment is switched out of service, grid status is continually evaluated by the Dominion and PJM Security Analysis applications.
6(b) Do you coordinate NPP maintenance activities that can have an impact on the transmission system with the TSO?	Yes. Maintenance at the station, other than inducing a trip of the main generators, is not permitted to make a significant change to the status of the grid in the vicinity of the plant or the grid at-large. The scheduling of maintenance activities for equipment that the station is responsible for is controlled by applicable station administrative procedures. The Station is responsible for the maintenance, modification or replacement of the following: • The isophase bus ducts from the main generators to the low side of the step up transformers. • The low voltage equipment internal to the plant. This includes the station service and reserve station service transformers feeding station loads and low voltage equipment (<69 kV) servicing station loads. The scheduling of maintenance activities for equipment that the transmission system is responsible for is coordinated with the station as described in the Nuclear-Electric Transmission Interface Agreement, Addendum 1 (Switchyard Control). Electric Transmission is responsible for the maintenance, modification or replacement of the following: • Generator Step Up Transformers from the low side bushings toward the Electric Transmission System. • All equipment with a voltage rating at or above 69 kV.

	The Switchyard Working Level Agreement outlines North Anna and Surry's Planning and Scheduling department's role with regard to the coordination of switchyard maintenance activities. Communication between the Work Week Managers (WWMs) and Manager Electric Transmission Substation Operations (METSO) ensure that the planned and emergent activities are analyzed in the Safety Monitor [10 CFR 50.65(a)(4)].
6(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 - For grid-risk-sensitive equipment that the station is responsible for, work will be rescheduled in accordance with applicable station administrative procedures as emergent conditions arise. The impact of these emergent failures and/or changing plant conditions on previously performed risk assessments will be re-evaluated as these conditions arise. Emergent issues with the grid are managed to maintain a high level of plant safety. Specifically, station administrative procedures directs the following: • During the conduct of pre-maintenance activities (or due to completely independent circumstances), plant conditions, personnel/material resources, or work scope may have changed such that Operations cannot approve the work to begin as scheduled then the maintenance activity will be rescheduled. • If an off-site power source becomes inoperable or degraded, or the risk of loss of off-site power is significantly increased due to plant or environmental activity, those systems used to mitigate a loss of off-site power transient (e.g., diesel generators, station batteries, battery chargers) will be maintained operable or be returned to an available status as soon as practical. • Work activities that add significant risk of causing unplanned reactor trip or plant transient should not be scheduled when there are known grid instability issues, or the need for unit capacity is high.
6(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. PRA is used to manage risk. If the risk assessment indicates an elevated risk due to grid instability issues, then contingency actions will be taken to lower the risk as identified in 6(c). These actions will be specifically tailored to the actual plant and switchyard conditions. These could include additional equipment protection measures, rescheduled maintenance, and other measures. Management will further evaluate grid sensitive maintenance using the Operational Decision Making process should grid reliability conditions occur. This process is independent of the risk management process.

6(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 requires a proceduralized process; no individual action results from each risk assessment. The assessments may lead to actions such as compensatory plans or barriers that are put in place to support a specific activity. For example, North Anna and Surry may use barriers or flagging to identify protected components when other systems are out-of-service. Approved station procedures and agreements govern the actions in questions 6(a) through 6d. Procedures associated with the Maintenance Rule are in VPAP-0815, Maintenance Rule Program. Paragraph (a)(4) of the Maintenance Rule, which became effective on November 28, 2000, specifically addresses risk assessment and management due to maintenance activities. It is implemented in accordance with DNAP-2000, Dominion Work Management Process, PLAP-2000, Supplemental Work Management Process, OPAP-0006, Shift Operating Practices, and SEAP-0002, Shift Technical Advisor, for power operation. Shutdown risk is assessed in accordance with VPAP-2805, Shutdown Risk Program. Training and procedure verbatim compliance ensures these procedures are effective and consistently applied. The outage coordination process is documented in the PJM Manuals and agreed to by PJM and the members. In addition, PJM has computerized tools to track the process throughout its evolution so that both PJM and the members are clear what the status is and what the expectations are.
6(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).	Operations, Maintenance, Engineering, Planning, PRA and STAs all perform work associated with 6(e). For operators, the abnormal procedure is used as a basis for training and testing. The formal agreement was a part of required reading for all operators. The Shift Technical Advisors (STA) provide the station risk assessments and are trained in initial STA class to use the Safety Monitor. The Maintenance, Planning and Engineering personnel are trained on the programs and procedures mentioned above.
6(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. There is effective and carefully prescribed coordination between North Anna and Surry operations and planning individuals and the TSO regarding transmission system maintenance and North Anna and Surry maintenance activities.
6(h) If you do not consider and effectively implement appropriate risk management actions during the conditions described above, explain	Not Applicable. North Anna and Surry adequately use risk assessment results, including the results of grid reliability evaluations, in managing maintenance risk, as required by 10 CFR 50.65(a)(4).

why you believe you effectively addressed the relevant provisions of the associated NRC-endorsed industry guidance.	
6(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. North Anna and Surry adequately use risk assessment results, including the results of grid reliability evaluations, in managing maintenance risk, as required by 10 CFR 50.65(a)(4).

Offsite power restoration procedures in accordance with 10 CFR 50.63 as developed in Section 2 of RG 1.155.

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 recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches for complying with 10 CFR 50.63.

7. Procedures for identifying local power sources[1] that could be made available to resupply your plant following a LOOP event.
Note: Section 2, "Offsite Power," of RG 1.155 (ADAMS Accession No. ML003740034) states:
Procedures should include the actions necessary to restore offsite power and use nearby power sources when offsite power is unavailable. As a minimum, the following potential causes for loss of offsite power should be considered:
- Grid 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

Question	Response
7(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.	An agreement is in place to restore power to the NPP as soon as possible. In addition, a grid operations procedure provides detailed instructions for prompt NPP offsite power restoration. The procedure specifies various means of accomplishing the required power restoration. Grid Operators train on this procedure annually per NERC training requirements. Dominion's System Restoration Plan lists potential power sources for the re-supply of offsite power to the NPP. The PJM restoration process allows for the fact that the blacked out area may or may not be separated from the remainder of the system. Regardless of the scenario, there is a clear recognition of the importance of restoring an NPP offsite power source. In support of the restoration objectives outlined in the PJM Restoration Manual, there are generating units designated as critical black-start units electrically close to each of the NPPs. These black-start units are required to provide black-start capability whenever necessary. The adequacy of black-start resources to support system restoration is managed to ensure the continuous availability of black-start units to support the restoration needs of the NPPs even when a designated black-start unit is on a planned outage.

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

7(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.	No. The TSO re-supplies power to the switchyard. The operating crews are trained and evaluated on assessing and responding to loss of onsite and offsite power conditions, and taking actions for restoration of these power sources.
7(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 (See response to 7(a) above). Details would be 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 basis.

Losses of offsite power caused by grid failures at a frequency of equal to or greater than once in 20 site-years in accordance with Table 4 of Regulatory Guide 1.155 for complying with 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 recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches for complying with 10 CFR 50.63.**	
8. Maintaining SBO coping capabilities in accordance with 10 CFR 50.63.	
Question	**Response**
8(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?	North Anna and Surry have not experienced a total LOOP caused by grid failure since that time.
8(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. See 8(a) above
8(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. See 8(a) above
8(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. See 8(a) above

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