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U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
One White Flint North
11555 Rockville Pike
Rockville, Maryland 20852

Beaver Valley Power Station, Units 1 and 2
Docket Nos. 50-334 and 50-412

Davis-Besse Nuclear Power Station, Unit 1
Docket No. 50-346

Perry Nuclear Power Plant, Unit 1
Docket No. 50-440

Subject: Response to NRC Generic Letter 2006-02

Ladies and Gentlemen:

On February 2, 2006, the NRC issued Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power." The NRC issued the letter to determine if compliance is being maintained with regulatory requirements and to obtain information in the following four areas:

> (1) use of protocols between the nuclear power plant (NPP) and the transmission system operator (TSO), independent system operator (ISO), or reliability coordinator/authority (RC/RA) and the use of transmission load flow analysis tools (analysis tools) by TSOs to assist NPPs in monitoring grid conditions to determine the operability of offsite power systems under plant technical specifications (TSs).
>
> (2) use of NPP/TSO protocols and analysis tools by TSOs to assist NPPs in monitoring grid conditions for consideration in maintenance risk assessments

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(3) offsite power restoration procedures in accordance with Section 2 of NRC Regulatory Guide (RG) 1.155, "Station Blackout;" and

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

The FirstEnergy Nuclear Operating Company (FENOC) is submitting the attached response to address the Generic Letter for the Beaver Valley Power Station, Units 1 and 2, the Davis-Besse Nuclear Power Station, Unit 1, and the Perry Nuclear Power Plant, Unit 1.

Some of the questions in Generic Letter 2006-02 seek information about analyses, procedures, and activities concerning grid reliability, about which FENOC does not have first-hand knowledge and which are beyond the control of FENOC. For these questions, FENOC relied on input that was provided by third parties.

The attached response is based on currently approved procedures and agreements. These procedures and agreements may be revised in the future based on lessons learned during the preparation of the response to this Generic Letter, including during benchmarking.

There are no commitments included in the enclosure.

If there are any questions or additional information is required, please contact Mr. Gregory A. Dunn, Manager – Fleet Licensing, at (330) 315-7243.

I declare under penalty of perjury that the foregoing is true and correct. Executed on April 3, 2006.

Gary R Leidich

Enclosure:

1. Response to Generic Letter 2006-02, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power.

Attachment:

1. Regulatory Commitments.

cc: NRC Project Manager - Beaver Valley Power Station (without Enclosures)
NRC Project Manager - Davis Besse Nuclear Power Station (without Enclosures)
NRC Project Manager - Perry Nuclear Power Plant (without Enclosures)
NRC Resident Inspector - Beaver Valley Power Station (without Enclosures)
NRC Resident Inspector - Davis Besse Nuclear Power Station (without Enclosures)
NRC Resident Inspector - Perry Nuclear Power Plant (without Enclosures)
NRC Regional Administrator - Region I
NRC Regional Administrator - Region III

Regulatory Commitments

The following list identifies those actions committed to by FirstEnergy Nuclear Operating Company (FENOC) for Beaver Valley, Davis Besse, and Perry. Any other actions discussed in the submittal represent intended or planned actions by FENOC. They are described only as information and are not regulatory commitments. Please notify Mr. Gregory A. Dunn, Manager - Fleet Licensing at (330) 315-7243 of any questions regarding this document or associated regulatory commitments.

	Commitment	Due Date
1.	None	

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

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

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

Yes. The Beaver Valley, Davis-Besse, and Perry plants have formal agreements with their respective TSO.

Beaver Valley is located in the service territory of PJM Interconnection, L.L.C. (PJM). The Transmission Owner (TO) providing interconnection services to Beaver Valley is the Duquesne Light Company (DLCO). The Transmission Owner is a member of PJM.

The following agreement for Beaver Valley is applicable: "Interconnection Service Agreement." This Interconnection Service Agreement ("ISA"), dated as of 12/30/04, including its Specifications, Schedules and Appendices, is entered into by and between PJM Interconnection, L.L.C., the Regional Transmission Organization for the PJM Region (hereinafter "Transmission Provider"), FirstEnergy Nuclear Operating Company ("FENOC" or "Interconnection Customer") and Duquesne Light Company ("DLCO") and American Transmission Systems, Inc. ("ATSI") (for purposes of this ISA and all terms and conditions thereof, DLCO and ATSI are jointly referred to as "Interconnected Transmission Owner").

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 PJM Manuals contain the specific operational requirements that each member is required to follow and indicate the requirements of PJM to the members.

The PJM Operating Agreement requires PJM to "Incorporate the grid reliability requirements applicable to nuclear generating units in the PJM Region planning and operating principles and practices."

PJM Manual M-1, "Control Center Requirements", Attachment B, entitled "Nuclear Plant Communication Protocol" provides the roles and

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responsibilities of nuclear stations, Transmission Owners, and PJM with regard to communications both in normal and emergency circumstances.

The nuclear plant notification requirements are contained in PJM Manual M-3, Transmission Operations, Section 3.

Davis-Besse and Perry are located in the service territory of Midwest Independent Transmission System Operator, Inc. (Midwest ISO). The Transmission Owner (TO) providing interconnection services to Davis-Besse and Perry is American Transmission Systems, Incorporated (ATSI). Davis-Besse and Perry are party to several formal agreements or protocols with the Midwest ISO and American Transmission Systems, Incorporated (ATSI).

The following agreement is applicable for Davis-Besse: "Large Generator Interconnection Agreement." This large generator interconnection agreement (the "Agreement") is made and entered into this 10th day of March, 2006, by and between FirstEnergy Nuclear Operating Company ("FENOC"), existing under the laws of the State of Ohio ("Interconnection Customer" with a Large Generation Facility), American Transmission Systems, Incorporated, organized and existing under the laws of the State of Ohio, sometimes hereinafter referred to as "ATSI" or "Transmission Owner" and the Midwest Independent Transmission System Operator, Inc., a non-profit, non-stock corporation organized and existing under the laws of the State of Delaware, ("Transmission Provider").

The following agreement is applicable for Perry: "Second Revised and Restated Generator Interconnection and Operating Agreement." This revised and restated generator interconnection and operating agreement (the "Agreement") is made and entered into this 24th day of March, 2006, by and among the Midwest Independent Transmission System Operator, Inc. ("Transmission Provider"), a non-profit, non-stock corporation organized and existing under the laws of the State of Delaware, FirstEnergy Nuclear Operating Company ("FENOC"), existing under the laws of the State of Ohio, sometimes hereinafter referred to as "Interconnection Customer", and the American Transmission Systems, Incorporated, organized and existing under the laws of the State of Ohio, sometimes hereinafter referred to as "ATSI" or "Transmission Owner."

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The following agreement is also applicable to Davis-Besse and Perry: "Service Level Agreement Engineering, Construction, Operations & Maintenance." This Service Level Agreement ("Service Level Agreement") dated as of July 26, 2005, is entered into, by, and between FirstEnergy Nuclear Operation Company ("FENOC") an Ohio corporation, FirstEnergy Service Company, an Ohio corporation ("Service Company"), Ohio Edison Company, an Ohio corporation ("OE"),. Pennsylvania Power Company, a Pennsylvania corporation ("Penn Power"), The Cleveland Electric Illuminating Company, an Ohio corporation ("CEI"), and The Toledo Edison Company, an Ohio corporation ("TE") (Service Company, OE, Penn Power, CEI, and TE are sometimes referred to herein individually as a "Contractor" and collectively as "Contractors").

Midwest ISO, Davis-Besse, Perry, and their associate Transmission Owners (TOs) have developed a generic communication protocol, "Midwest ISO Real-Time Operations Communication and Mitigation Protocols for Nuclear Plant/Electric System Interfaces" to address roles and responsibilities in grid monitoring and communication.

The TOs are signatories to the Midwest ISO Transmission Owners Agreement. In Appendix E, Section C, the agreement states "For Members and Users who are operators of nuclear generating facilities, the Midwest ISO shall enter into written agreements, which define scheduling protocols, limitations, and restrictions necessary to ensure the safety and reliability of such facilities."

FENOC and Midwest ISO are currently developing plant specific operating agreements for the Davis-Besse and Perry.

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(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.

Beaver Valley, Davis-Besse, and Perry have agreements for the TSO to notify them whenever the TSO recognizes an impaired or potentially degraded grid condition.

For Beaver Valley, PJM Manual, M-3, "Transmission Operations" requires PJM to initiate notification through DLCO if PJM identifies a Beaver Valley switchyard voltage violation. PJM manual M-3 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, PJM Manual, M-13, "Emergency Operations" identifies a series of alerts, warnings, and actions that PJM issues to PJM members depending on the identified grid condition. The PJM generation dispatcher communicates this message to Beaver Valley. Notifications include Minimum Generation Emergency, Maximum Emergency Generation, and Manual Load Dump Warning.

The following sections of the "Interconnection Service Agreement" described in the response to question 1(a) apply to this response:

DLCO and ATSI jointly represent and warrant that DLCO presently has, and for the duration of the term of this ISA, shall have, full authority to act on behalf of both itself and ATSI, with respect to the Beaver Valley Switchyard in order to fulfill all obligations of a PJM Transmission Owner regarding:

- operation and maintenance of such facilities;
- Transmission Provider's Regional Transmission Expansion Planning Protocol (Schedule 6 of the Operating Agreement); and

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- any other applicable obligations of a PJM Transmission Owner under the Tariff or Operating Agreement.

Operating voltage of the Beaver Valley switchyard will be maintained to values (Normal Low = 343 kV, Post Contingency Emergency Low = 341 kV, and Normal High = 355 kV) presented by FENOC to the Transmission Provider's Manager of Transmission consistent with the PJM Manuals and applicable operating policies. FENOC will inform Transmission Provider of any changes in operating values in order to assure that such values are current in the Transmission Provider's computer models.

The parties recognize that transmission voltages at the Beaver Valley Switchyard, a resource on the Midwest Independent Transmission System Operator, Inc. ("MISO") - PJM seam, are dependent upon reactive resources within PJM and Midwest ISO. Transmission Provider will notify DLCO and Transmission Provider will take action, consistent with Good Utility Practice, to coordinate with Midwest ISO to improve voltage levels when the Beaver Valley switchyard voltage falls outside the operating values as described in this schedule. DLCO will notify FENOC Operations at Beaver Valley of the alarm condition and identify what actions are being taken by Transmission Provider and when restoration within the operating values can be expected.

Transmission Provider will notify DLCO that grid voltage may not be within the required range at the occurrence of the next contingency (e.g. loss of a Beaver Valley generating unit, other generating unit, etc.), through the use of a state estimator and contingency analysis. DLCO will notify FENOC Operations at Beaver Valley of the alarm condition and Transmission Provider will take action, consistent with Good Utility Practice, to coordinate with Midwest ISO to identify what actions are to be taken and when restoration within the operating values can be expected. The contingency analysis shall be completed automatically and frequently consistent with North American Electric Reliability Council (NERC) requirements.

For Davis-Besse, the following sections from the "Large Generator Interconnection Agreement" described in the response to question 1(a) apply:

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> Operating voltage of the Davis-Besse transmission yard is to be between 98.3% and 103.3% of the 345 kV nominal value. These operating values are current at the time of signing this Agreement. The values are subject to change based on modifications to the facility's nuclear design bases.
>
> Transmission Provider or Transmission Owner will notify Davis-Besse and take action, consistent with Good Utility Practice, to improve voltage levels when the Davis-Besse transmission yard voltage falls outside the operating values identified in this Appendix C, Section A, Item o. Transmission Provider, Transmission Owner or Interconnection Customer will identify what actions are being taken and when restoration within the operating values can be expected.
>
> Transmission Provider or Transmission Owner will notify Davis-Besse that grid voltage may not be within the required range at the occurrence of the next N-1 contingency (e.g., loss of the Davis-Besse generating unit), and what steps are being taken to alleviate the condition. The contingency analysis shall be completed automatically consistent with NERC requirements.

For Perry, the following sections from the "Second Revised and Restated Generator Interconnection and Operating Agreement" described in the response to question 1(a) apply:

> Operating voltage of the Perry transmission yard at Perry to be between 96% and 102% of the 345 kV nominal value. These operating values are current at the time of signing this Agreement. The values are subject to change based on modifications to the facility's nuclear design bases.
>
> Transmission Owner and/or Transmission Provider will take action, consistent with Good Utility Practice, to improve voltage levels when the Perry transmission yard voltage falls outside the operating values identified in this Appendix C, Section A, Item o. Interconnection Customer, Transmission Provider or Transmission Owner will identify what actions are being taken and when restoration within the operating values can be expected.

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> Transmission Provider or Transmission Owner will notify Perry that grid voltage may not be within the required range at the occurrence of the next N-1 contingency (e.g., loss of Perry generating unit), and what steps are being taken to alleviate the condition. The contingency analysis shall be completed automatically consistent with NERC requirements.

The following sections are from the "Midwest ISO Real-Time Operations Communication and Mitigation Protocols for Nuclear Plant/Electric System Interfaces" as described in the response to question 1(a) and apply to Davis-Besse and Perry:

> The Midwest ISO and Transmission Operator will model and analyze the impact of events within their system on the reliability of the electric system within their area of responsibility.
>
> The Midwest ISO will model and analyze the impact of events in adjacent systems and across the Midwest ISO system. The Midwest ISO will coordinate and communicate these impacts to the Transmission Operator.
>
> Transmission Operator will immediately initiate communication with the nuclear plant and the Midwest ISO if the Transmission Operator identifies actual violations to the operating criteria affecting the nuclear plant. The Transmission Operator and the Midwest ISO will immediately initiate steps to mitigate the actual violation.
>
> The Midwest ISO or the Transmission Operator will immediately initiate communication with each other to verify study results that indicate a pre and post-contingent violation of operating criteria. The Transmission Operator and the Midwest ISO will immediately initiate steps to mitigate the pre and post-contingent operating criteria violation. If the violation is not mitigated within 15 minutes of the verification of the study results, the Transmission Operator shall immediately notify the nuclear plant.

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(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.

Grid conditions and status are the primary responsibility of the TSO and Reliability Coordinator (RC). The grid parameters observable to a nuclear power plant operator include voltage and frequency, generator reactive output, breaker status, line status, and certain switchyard alarm points. Relative to this question, "grid conditions" is assumed to refer to changes at the nuclear power plant that impact the TSO analysis of the grid interface.

In accordance with the Fleet-wide business practice NOBP-OP-0011, "Fleet Reporting and Updates," each FENOC nuclear power plant participates in a daily phone call where each site reports current power and activities with potential grid risk impact. For Davis-Besse and Perry, the asset utilization representative communicates this risk information to the grid reliability coordinator.

Changes that occur throughout the day that have impact on the grid are communicated to the TSO, including problems encountered in meeting voltage schedules for power production to support the grid. Each FENOC nuclear power plant would contact their respective TSO if a grid perturbation (e.g., a swing in megawatts or megavars) was observed.

Instructions for when and how to contact the TSO are found in the following procedures:

- Beaver Valley, 53C.4A.35-1, "Degraded Grid"
- Davis-Besse, DB-OP-01300, "Switchyard Management"
- Perry, PAP-0102, "Interface With the Transmission System Operator"

Each FENOC plant would be in close communication with their respective TSO throughout restoration on partial or complete loss of power and would coordinate the black restart plan and site procedures.

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

The following procedures contain information that licensed operators would use at Beaver Valley, Davis-Besse, and Perry to assess grid conditions.

- Beaver Valley, 53C.4A.35-1, "Degraded Grid"
- Davis-Besse, DB-OP-01300, "Switchyard Management"
- Perry, ONI-S11, "Unstable Grid"

Licensed operators are required to have an initial and a continuing training program. This training is developed in accordance with the Systematic Approach to Training (SAT) and covers administrative programs, technical knowledge of systems, practical performance during simulator exercises, and job performance measures. As part of operators' initial and continuing training program, operators are trained on Technical Specifications and operating procedures, as well as abnormal operating procedures. The procedures listed above are part of that process. Operators are trained in the use of these procedures and would be expected to demonstrate their appropriate use of them when presented with a degraded grid scenario on the simulator.

(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. FENOC maintains a formal agreement and protocol with the TSO for Beaver Valley, Davis-Besse, and Perry.

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(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)

Beaver Valley, Davis-Besse, and Perry have formal agreements with the TSO. Prompt notification regarding pre-trip analysis of predicted post-trip voltage that results in below acceptance limits is included. "Prompt" is defined in the protocols.

For Beaver Valley, PJM Manual, M-3, "Transmission Operations" requires PJM to initiate notification to an NPP through its respective transmission owner's control center if PJM identifies a NPP switchyard voltage violation. PJM manual M-3 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." The trip of Beaver Valley is one of the contingencies analyzed by PJM. PJM analyzes the Beaver Valley switchyard contingency voltages to the voltage limits provided by the NPP. The voltage limits provided by Beaver Valley are based on the plant's design basis analysis.

The following sections of the "Interconnection Service Agreement" described in the response to question 1(a) apply to this response:

> DLCO and ATSI jointly represent and warrant that DLCO presently has, and for the duration of the term of this ISA, shall have, full authority to act on behalf of both itself and ATSI, with respect to the Beaver Valley Switchyard in order to fulfill all obligations of a PJM Transmission Owner regarding
>
> - operation and maintenance of such facilities;
> - Transmission Provider's Regional Transmission Expansion Planning Protocol (Schedule 6 of the Operating Agreement); and

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- any other applicable obligations of a PJM Transmission Owner under the Tariff or Operating Agreement.

Operating voltage of the Beaver Valley Switchyard will be maintained to values (Normal Low = 343 kV, Post Contingency Emergency Low = 341 kV, and Normal High = 355 kV) presented by FENOC to the Transmission Provider's Manager of Transmission consistent with the PJM Manuals and applicable operating policies. FENOC will inform Transmission Provider of any changes in operating values in order to assure that such values are current in the Transmission Provider's computer models.

The parties recognize that Transmission voltages at the Beaver Valley Switchyard, a resource on the Midwest Independent Transmission System Operator, Inc. ("MISO") - PJM seam, are dependent upon reactive resources within PJM and Midwest ISO. Transmission Provider will notify DLCO and Transmission Provider will take action, consistent with Good Utility Practice, to coordinate with Midwest ISO to improve voltage levels when the Beaver Valley switchyard voltage falls outside the operating values as described in this schedule. DLCO will notify FENOC Operations of the alarm condition and identify what actions are being taken by Transmission Provider and when restoration within the operating values can be expected.

Transmission Provider will notify DLCO that grid voltage may not be within the required range at the occurrence of the next contingency (e.g. loss of a Beaver Valley generating unit, other generating unit, etc.), through the use of a state estimator and contingency analysis. DLCO will notify FENOC Operations at Beaver Valley of the alarm condition and Transmission Provider will take action, consistent with Good Utility Practice, to coordinate with Midwest ISO to identify what actions are to be taken and when restoration within the operating values can be expected. The contingency analysis shall be completed automatically and frequently consistent with NERC requirements.

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The following sections are from the "Large Generator Interconnection Agreement" as described in the response to question 1(a) and apply to Davis-Besse:

> Operating voltage of the Davis-Besse transmission yard to be between 98.3% and 103.3% of the 345kV nominal value. These operating values are current at the time of signing this Agreement. The values are subject to change based on modifications to the facility's nuclear design bases.
>
> Transmission Provider or Transmission Owner will notify Davis-Besse and take action, consistent with Good Utility Practice, to improve voltage levels when the Davis-Besse transmission yard voltage falls outside the operating values identified in this Appendix C, Section A, Item o. Transmission Provider, Transmission Owner or Interconnection Customer will identify what actions are being taken and when restoration within the operating values can be expected.
>
> Transmission Provider or Transmission Owner will notify Davis-Besse that grid voltage may not be within the required range at the occurrence of the next N-1 contingency (e.g., loss of the Davis-Besse generating unit), and what steps are being taken to alleviate the condition. The contingency analysis shall be completed automatically consistent with NERC requirements.

The following sections are from the "Second Revised and Restated Generator Interconnection and Operating Agreement" as described in the response to question 1(a) and apply to Perry:

> Operating voltage of the Perry transmission yard at Perry to be between 96% and 102% of the 345 kV nominal value. These operating values are current at the time of signing this Agreement. The values are subject to change based on modifications to the facility's nuclear design bases.
>
> Transmission Owner and/or Transmission Provider will take action, consistent with Good Utility Practice, to improve voltage levels when the Perry transmission yard voltage falls outside the

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operating values identified in this Appendix G, Item o. Interconnection Customer, Transmission Provider or Transmission Owner will identify what actions are being taken and when restoration within the operating values can be expected.

Transmission Provider or Transmission Owner will notify Perry that grid voltage may not be within the required range at the occurrence of the next N-1 contingency (e.g., loss of Perry generating unit), and what steps are being taken to alleviate the condition. The contingency analysis shall be completed automatically consistent with NERC requirements.

The following sections are from the "Midwest ISO Real-Time Operations Communication and Mitigation Protocols for Nuclear Plant/Electric System Interfaces" as described in the response to question 1(a) and apply to Davis-Besse and Perry:

The Midwest ISO and Transmission Operator will model and analyze the impact of events within their system on the reliability of the electric system within their area of responsibility.

The Midwest ISO will model and analyze the impact of events in adjacent systems and across the Midwest ISO system. The Midwest ISO will coordinate and communicate these impacts to the Transmission Operator.

Transmission Operator will immediately initiate communication with the Nuclear Plant and the Midwest ISO if the Transmission Operator identifies actual violations to the operating criteria affecting the nuclear plant. The Transmission Operator and the Midwest ISO will immediately initiate steps to mitigate the actual violation.

The Midwest ISO or the Transmission Operator will immediately initiate communication with each other to verify study results that indicate a pre and post-contingent violation of operating criteria. The Transmission Operator and the Midwest ISO will immediately initiate steps to mitigate the pre and post-contingent operating criteria violation. If the violation is not mitigated within 15 minutes

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of the verification of the study results, the Transmission Operator shall immediately notify the Nuclear Plant.

In addition, ATSI provides procedural instruction for dispatchers and nuclear plant Control Room operators to communicate appropriately during a grid emergency.

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

At Beaver Valley Unit 1, the 4KV Class 1E bus Degraded Voltage Protection Relays (DVPR) have a nominal dropout setting of 93.7% of 4160 Volts and at Beaver Valley Unit 2, the Class 1E 4kV bus DVPRs have a nominal drop out setting of 93.4% of 4160 volts. The Beaver Valley Unit 1 Class 1E 480V bus DVPRs have a nominal drop out setting of 93.7% of 480 volts and the Beaver Valley Unit 2 Class 1E 480V bus DVRs have a nominal dropout setting of 93.4% of 480 volts. During normal alignment, the 4kV bus voltage will be adjusted by changing the main generator voltage (VAR output) to meet the voltage schedule.

Beaver Valley Unit 1 and Beaver Valley Unit 2 System Station Service Transformers (SSSTs) have automatic load tap changers (LTCs) to regulate voltage when supplied from the 138 kV switchyard. The minimum settings for the LTC voltage regulator relays is 103.48% for Unit 1 and 103.49% for Unit 2.

The Beaver Valley substation grid operating voltage range is from 343 kV to 355 kV. This operating voltage range is established between Beaver Valley, FirstEnergy Planning, and PJM to assure availability of adequate voltages at the emergency busses. The station load flow analyses for Beaver Valley Unit 1 and Beaver Valley Unit 2 performed for operating scenarios for Unit Station Service Transformers (USSTs) used grid voltage range of 339.8 kV (98.5%) to 355.35 kV (103%).

If grid voltage drops below 343 kV, the plant loads will be manually transferred to the 138 kV offsite power source through the SSSTs, which have automatic LTCs to regulate the plant bus voltages. The station load flow analyses for Beaver Valley Unit 1 and Beaver Valley Unit 2 were performed using grid voltage range from 135.93 kV (98.5%) to 142.7

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(103.4%). The automatic LTCs maintain the 4kV bus voltage following the occurrence of a LOCA and turbine/generator trip.

The most likely low switchyard voltage conditions that would initiate operation of plant degraded voltage protection would be a more rapid degradation of the grid that would lower voltages to the degraded voltage protection relay settings, such as extreme fault conditions or loss of multiple generating stations or transmission lines.

The grid at BVPS is normally stable. It would not be expected that the degraded voltage protection would be initiated if the grid conditions changed slowly. If the Beaver Valley units were powered through the SSSTs, both units have availability of the voltage regulation for the offsite power source. Generally, the grid voltage changes would be accommodated by the LTCs maintaining the emergency bus voltages. If the Beaver Valley units were powered through the USSTs, voltage would be maintained through adjustment of the main generator output until its limits were reached. In the event of grid degradation to a point where the LTC or main generator would not be able to raise the voltage sufficiently to maintain the emergency bus voltage above the degraded grid relay dropout setting, the emergency bus loads would be transferred to the emergency diesel generator supply.

At Davis-Besse, the degraded voltage protection relays are connected to 4160 Volt essential busses C1 and D1. During normal plant operation, these buses are not aligned directly to the switchyard but are supplied from the main generator output through the Auxiliary and Bus-Tie transformers. As a result, the voltage at busses C1 and D1 is more directly governed by main generator terminal voltage during normal operation.

The nominal dropout setpoint for the degraded voltage relays was determined to be 3744 Volts. This was established based on the voltage requirements for safety-related loads supplied by busses C1 and D1 during a design basis event. To preclude premature separation from the switchyard, and startup of the Emergency Diesel Generators following main generator trip, a reset setpoint of 3753 Volts has also been established.

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No specific analysis has been completed to determine how low the switchyard voltage would have to be, with the main generator operating, to dropout the degraded voltage relays. An analysis was completed with the switchyard at 100% nominal and the main generator at 95% terminal voltage. In this case, the voltage at bus C1 was calculated to be above the nominal dropout setpoint of the degraded voltage relays.

Following a design basis event, with a main generator trip, busses C1 and D1 will initially be supplied from the switchyard through the Startup and Bus-Tie transformers. This alignment will persist as long as the degraded voltage relays have either not dropped out or have dropped out and then reset within the required time delay. Current analysis indicates that the switchyard voltage must be ≥ 98.3% of nominal to reset the degraded voltage relays.

As a result, low switchyard voltage (< 98.3%) following a design basis event and main generator trip could result in a second sequencing of safety-related loads when they load onto the Emergency Diesel Generators. To compensate for this, online grid monitoring by the TSO using the State Estimator technology has been implemented.

At Perry, the design of the Degraded Voltage Protection Scheme is consistent with the requirements of Branch Technical Position PSB-1 "Adequacy of Station Electrical distribution System Voltages" (PSB-1). PSB-1 requires that the Degraded Voltage Relays (DVR) be physically located at and electrically connected to the Class 1E switchgear. Meeting this requirement necessitated that the DVRs be electrically connected to the 4kV Class 1E buses (EH11, EH 12 and EH13). Since no voltage regulation capability is provided between the grid and the EH buses, it was necessary to adjust the transformer taps on the interbus transformers to ensure adequate voltage is available to support a Design Basis Accident Event (LOCA). Since the EH buses are lightly loaded during normal plant operations and will only be heavily loaded following a LOCA event, the voltage on the EH buses is normally at a high level (approximately 4200 Volts with a grid voltage of 345kV). The DVRs have a nominal dropout setting of 3800 Volts that would equate to a grid voltage of approximately 312.1kV (90%) under normal plant operating conditions. The DVRs cannot be expected to detect or respond to a degraded grid condition that occurs prior to a Design Basis Accident unless the measured grid voltage

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falls below 312.1kV (90%). The minimum grid voltage required to support a Design Basis Accident is 331.2kV (96%). If grid voltage falls below 331.2kV (96%), following the occurrence of a LOCA and turbine/generator trip, double sequencing is likely to occur since the DVRs will not detect the degraded grid condition until after LOCA load sequencing has commenced. The DVR protection scheme would not identify a degraded grid condition (Grid Voltage ≤ 96%) during normal plant operations when the EH buses are lightly loaded. To compensate for this deficiency in the DVR protection scheme, on-line grid monitoring by the TSO using State Estimator technology has been implemented.

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

(a) Does your NPP's TSO use any analysis tools, an online analytical transmission system studies program, or other equivalent predictive methods to determine the grid conditions that would make the NPP offsite power system inoperable during various contingencies? If available to you, please provide a brief description of the analysis tool that is used by the TSO.

Yes. The appropriate TSO makes use of analysis tools to predict grid conditions that would make the Beaver Valley, Davis-Besse, or Perry offsite power system non-functional.

For Beaver Valley, the PJM Energy Management System (EMS) includes a Security Analysis application, which runs approximately every 1 minute and analyzes approximately 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 Beaver Valley.

For Davis-Besse and Perry, the Midwest ISO EMS includes a Security Analysis application that runs approximately every 90 seconds and analyzes approximately 4,000 contingencies on the Midwest ISO system. The analysis provides results with respect to thermal, voltage, and voltage drop limit violations. Two of the contingencies analyzed by the Midwest ISO EMS are the trips of Davis-Besse or Perry.

In addition, for Davis-Besse and Perry, ATSI includes a State Estimator (SE) and Real-Time Contingency Analysis (RTCA) that analyzes over 300 contingencies based on its criteria. This system also analyzes the trip of either Davis-Besse or Perry and provides results with respect to thermal, voltage and voltage drop limit violations.

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

Yes. The TSO uses the analysis tools discussed in response to question 2(a), in conjunction with procedures, as the basis for determining when conditions warrant NPP notification.

At Beaver Valley, the results of the PJM Security Analysis application contain the specific contingency of the nuclear power plant tripping as the contingent element. Violation of the unit trip contingency voltage limit would result in notification to Beaver Valley through Duquesne Light Company (DLCO) the Interconnected Transmission Owner.

At Davis-Besse and Perry, the results of the Midwest ISO Security Analysis application contain the specific contingency of the nuclear power plant tripping as the contingent element. Violation of the unit trip contingency voltage limit would result in notification to ATSI, which is relayed to Perry or Davis-Besse.

In addition, for Davis-Besse and Perry, ATSI performs this Security Analysis function and provides the first line communications for notification to the plant.

Refer to the responses to question 1(b) and 1(f) for a discussion of the conditions on the grid that warrant notification of Beaver Valley, Davis-Besse, or Perry.

(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 longterm) 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 TSOs for Beaver Valley, Davis-Besse, and Perry use analysis tools that can identify a condition in which a trip of the nuclear power plant would result in switchyard voltages (immediate and/or long-term) falling

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below Technical Specification nominal trip setpoint value requirements and consequent actuation of plant degraded voltage protection.

The trip of Beaver Valley is one of the contingencies analyzed by the PJM Security Analysis application. PJM analyzes Beaver Valley switchyard contingency voltages to the voltage limits provided by Beaver Valley. The voltage limits provided by Beaver Valley are based on the plant's design basis analysis.

The trip of Perry or Davis-Besse is one of the contingencies analyzed by the Midwest ISO Security Analysis application. Midwest ISO analyzes the Perry and Davis-Besse switchyard contingency voltages to the voltage limits provided by Perry and Davis-Besse. The voltage limits provided by Perry and Davis-Besse are based on the plant's design basis analysis.

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

For Beaver Valley, the PJM EMS includes a Security Analysis application that currently updates approximately every 1 minute.

For Davis-Besse and Perry, the Midwest ISO EMS includes a Security Analysis application that currently updates approximately every 90 seconds and the and the real time contingency analysis program currently runs automatically every 5 minutes.

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

Notification from each TSO is based upon the predicted post-trip switchyard voltage given actual RTCAs grid conditions.

The analyzed contingencies that are evaluated against the nuclear power plant voltage requirements include:

- loss of another generator,
- loss of a significant transmission line, or
- loss of the nuclear power plant itself.

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If the nuclear power plant voltage requirement cannot be met under any of the contingencies considered, the licensee will be notified. The same minimum required switchyard voltage limit bases that are used in the grid operating procedures are also used in the predictive analysis computer programs.

PJM notifies Beaver Valley through the DLCO control center whenever actual or post-contingency voltages are determined to be below the Beaver Valley switchyard voltage limits provided by Beaver Valley. This requirement applies to all contingencies involving the tripping of Beaver Valley 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.

Midwest ISO notifies Davis-Besse or Perry through the ATSI control center whenever actual or post-contingency voltages are determined to be below the Davis-Besse or Perry switchyard voltage limits provided by Davis-Besse and Perry. This requirement applies to all contingencies involving the tripping of Davis-Besse or Perry or any transmission facility as the contingent element.

ATSI notifies Davis-Besse or Perry directly after conferring with Midwest ISO when receiving voltage limit alarms.

(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 agreements specifically require the applicable TSO to notify Beaver Valley, Davis-Besse, or Perry, as appropriate, for periods when the TSO is unable to determine if offsite power voltage and capacity could be inadequate.

Beaver Valley unit trip contingency voltage calculations are performed by the PJM EMS and Security Analysis application. The PJM EMS consists of a primary and backup system. Beaver Valley is notified if the real time contingency analysis capability is lost.

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PJM and DLCO could provide an assessment of the current condition of the grid based on the remaining tools that PJM and the DLCO have available.

As a member of Midwest ISO, Perry and Davis-Besse comply with Real Time Operations Communication and Mitigation Protocols for Nuclear Plant/Electric System Interfaces. This document contains the following requirements:

> Should the Transmission Operator lose its ability to monitor or predict the operation of the transmission system affecting off-site power to the nuclear plant, the Transmission Operator shall notify the Midwest ISO, validate Midwest ISO's ability to monitor and predict the operation of the transmission system and then communicate to the nuclear plant. Transmission Operator will communicate to the nuclear plant and Midwest ISO when this capability is restored. This communication should be as soon as practicable or per established agreements with the Transmission Operator.
>
> Should Midwest ISO lose its ability to monitor or predict the operation of the transmission system affecting off-site power to the nuclear plant, Midwest ISO shall notify the Transmission Operator.

In addition, the ATSI Network Analysis Execution Guideline requires that Davis-Besse or Perry be notified whenever the real-time case solution cannot be determined.

Beaver Valley, Davis-Besse, and Perry follow Technical Specification requirements when notified by the TSO that grid conditions are indeterminate. Beaver Valley, Davis-Besse, and Perry operate within the bounds of the long-term analyses, ensuring that the design and Technical Specification requirements are met.

The Real Time Contingency Analysis software provides an input to the decision to declare the offsite power sources inoperable. The fact that the tool is not available does not mean that the offsite power sources are inoperable.

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When notified that the TSO is unable to determine if offsite power voltage and capacity could be inadequate, nuclear plant operators would rely on indication and alarming conditions as well as notification by the TSO of grid indication encroaching or exceeding specified limits, if capable.

When the state estimator fails, the TSO has protocols in place to use historical data to manually provide grid reliability stability assessments to the site. In the interim, direct observation is available to determine if grid stability or reliability has changed. Without an observed changing grid status or notification by the TSO of a unit or line loss, the plant would continue operation with off-site sources operable to maintain grid reliability and stability. In the situation where unit or line loss occurs, discussion and close coordination with the TSO and visual observation of grid condition would drive conservative action.

(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?

For Davis-Besse, the following is from the recently revised interconnection agreement:

> Transmission Provider or Transmission Owner shall have a process for verifying that measured bus voltages provided by the Transmission Owner after an inadvertent trip of Davis-Besse fall within the bounds set by the Transmission Owner and Transmission Provider and predicted by the real-time analysis tools.

There is no other formal process at PJM, DLCO, Midwest ISO, or ATSI for comparing the actual post-trip voltages to the post-trip contingency voltage results calculated by the Security Analysis applications.

However, ATSI has an informal process for periodically verifying state estimator analysis tool accuracy. As an example, simulated event output data is compared with actual event data and benchmarked with other similar analysis tools. Adjustments are then made, as needed, to improve the model and simulation accuracy.

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(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. Analysis tools are available through PJM, Midwest ISO and ATSI for Beaver Valley, Davis-Besse, and Perry.

(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 longterm), 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. Analysis tools are available through PJM, Midwest ISO and ATSI for Beaver Valley, Davis-Besse, and Perry.

(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. Analysis tools are available through PJM, Midwest ISO and ATSI for Beaver Valley, Davis-Besse, and Perry.

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

(a) If the TSO notifies the NPP operator that

- **a trip of the NPP, or**
- **the loss of the most critical transmission line or**
- **the largest supply to the grid**

would result in switchyard voltages (immediate and/or longterm) below TS nominal trip setpoint value requirements (including NPP licensees using allowable value in its TSs) and would actuate plant degraded voltage protection, is the NPP offsite power system declared inoperable under the plant TSs? If not, why not?

As discussed in response to question 2(e), the TSO notifies Beaver Valley, Davis-Besse, or Perry whenever actual or post-contingency voltages are determined to be below the switchyard voltage limits provided by the site. This requirement applies to all N-1 contingencies involving the tripping of the nuclear power plant or any transmission facility as the contingent element.

Beaver Valley procedure 1/2OM-53.C.4A.35.1, "Degraded Grid," lists notification from DLCO System Operations Control Center of possible grid instability as an entry condition. The DLCO System Operations Control Center would make that notification on the three N-1 contingency scenarios. The procedure instructs operations to check with the appropriate system operations control center for reasonable assurance that voltage and frequency can be maintained within Technical Specification operability limits during the degraded grid condition. Absent obtaining reasonable assurance, the procedure directs Operations to declare both sources of offsite power inoperable.

Davis-Besse procedure DB-OP-01300, "Switchyard Management," defines Degraded Grid as an actual or predicted grid condition that does not support either continued operation or the safe shutdown of the Davis-Besse Nuclear Power Station. This condition will typically be indicated by degraded voltage or frequency conditions. The Grid should be considered

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degraded when grid conditions do not support operable off-site lines (i.e. voltage on the essential buses is not within the Surveillance Requirement acceptance criteria). The grid should also be considered degraded when a grid stability condition exists (i.e. fluctuating voltages or frequencies). The procedure requires the Shift Manager and the System Dispatcher to communicate to determine any actions or compensatory measures that may be necessary. The procedure states that the System Dispatcher notifies the Shift Manager of potential or developing degraded grid conditions. ATSI would make that notification on the three N-1 contingency scenarios. The procedure requires the Shift Manager to declare the off-site AC source lines inoperable if informed by the System Dispatcher that projected voltages would be below the Technical Specification minimum if Davis-Besse tripped or had to shutdown. No specific direction is given for the other N-1 contingencies.

Perry procedure ONI-S11, "Unstable Grid," lists a degraded grid as an entry condition and defines it as either a grid condition where a single failure will result in a low voltage condition approaching the analysis limit of 96% (331kV) of the nominal grid voltage of 345kV or as a measured grid low voltage condition. The Subsequent Action section directs operations to declare both sources of off-site power inoperable.

Although not explicitly stated in the operating procedures for all three plants, current operations management philosophy at Beaver Valley, Davis-Besse, and Perry would result in declaring the off-site sources inoperable in the three examples given above.

Fleet Operations is currently conducting benchmarking and will formalize a consistent approach taking into consideration this Generic Letter, responses to this Generic Letter from other licensees, and input from the Owners Groups and NEI.

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(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?

Yes. If onsite safety-related equipment is deemed incapable of performing its safety function (as governed by plant Technical Specifications), then the equipment is declared inoperable.

The current licensing basis for Beaver Valley, Davis-Besse, and Perry is a simultaneous LOOP/LOCA. Double sequencing is not in the licensing basis for Beaver Valley, Davis-Besse, or Perry and they are not designed or analyzed for double sequencing scenarios. Therefore, onsite safety-related equipment would not be declared inoperable due to a postulated double-sequencing event.

In response to NRC Information Notice 93-17, Revisions 0 and 1, "Safety Systems Response to Loss of Coolant and Loss of Offsite Power," Beaver Valley, Davis-Besse, and Perry reviewed double-sequencing events and concluded that there would be no anticipated loss of function of the engineered safety feature electrical equipment.

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

One of the scenarios reviewed by Beaver Valley, Davis-Besse, and Perry as a result of NRC Information Notice 93-17, Revisions 0 and 1, "Safety Systems Response to Loss of Coolant and Loss of Offsite Power," was a LOCA with a delayed LOOP.

During the review, Beaver Valley did not identify any concerns with the ability of Unit 2 to respond to a LOCA with a delayed LOOP. One potential scenario of concern was identified for Unit 1. This potential scenario includes a reactor trip and subsequent generator trip, along with other unspecified system degradation that causes a reduction in the switchyard voltage. The scenario proposes that the electrical load

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decreases due to the post-LOCA protection equipment starting and causes the safety bus voltage to fall below the degraded voltage setpoint. Further, after the loads have started there may be insufficient reserve for the bus voltage to recover to clear the low voltage trip before the end of the 90-second time delay. If this were to occur, then the LOCA response would be interrupted while the required loads restarted on the diesel. The review concluded that in this scenario the required safety systems would be expected to fulfill their design function.

During the review, Davis-Besse did not identify any concerns with the ability of the electrical equipment to respond to a LOCA with a delayed LOOP. On the loss of offsite power, the energized safety-related loads previously required by the LOCA would be denergized as the undervoltage relays isolate the 4160 volt buses. When the emergency diesel generator reaches rated voltage, the diesel breaker would close, and energize the 4160 volt bus. The engineered safety features loads would then be automatically sequenced on to the diesel.

During the review at Perry, attempts were made to evaluate the worst-case double sequencing scenario; however, the timing between the LOCA and LOOP events can result in different electrical loading scenarios (i.e. simultaneous motor starts that were not considered in the original plant design). The impact of undefined system lineups resulting from the interruption and re-initiation of the response sequence is also based on the timing of the LOCA and LOOP events. The review was limited to the identification of electrical conditions adverse to equipment reliability resulting from a double sequencing event. No condition was identified that would adversely affect the electrical power systems including the diesel generators and the connected loads. The diesel generators were determined to be capable of supporting a double sequencing event resulting in the successful restart of all required Emergency Core Cooling System loads.

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(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.

Current procedures do not specify notifications by the TSO (other than those addressed in question 3(a)) that would result in off-site source inoperability. If notified of grid conditions that may impair the capability or availability of off-site power, following discussion with TSO, operators would utilize conservative decision-making and operational decision-making to assess the situation and take appropriate action, which may include a declaration of off-site source inoperability and entry into a Technical Specification Action Statement.

(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.

Not applicable. As previously stated in 3(a), 3(b), and 3(d), based on specific situations the off-site sources will be declared inoperable.

(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 following procedures contain actions that licensed operators would take at Beaver Valley, Davis-Besse, and Perry in response to notification from the TSO that switchyard voltages are inadequate.

- Beaver Valley, 53C.4A.35-1, "Degraded Grid"
- Davis-Besse, DB-OP-01300, "Switchyard Management"
- Perry, ONI-S11, "Unstable Grid"

Licensed operators are required to have an initial and continuing training program. This training is developed in accordance with SAT and covers administrative programs, technical knowledge of systems, practical

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performance during simulator exercises and job performance measures. As part of operators' initial and continuing training program, operators are trained on Technical Specifications and operating procedures, as well as abnormal operating procedures. The procedures listed above are part of that process. Operators are trained in the use of these procedures and would be expected to demonstrate their appropriate use when presented with a degraded grid scenario on the simulator.

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

(a) Do the NPP operators have any guidance or procedures in plant TS bases sections, the final safety analysis report, or plant procedures regarding situations in which the condition of plant-controlled or - monitored equipment (e.g., voltage regulators, auto tap changing transformers, capacitors, static VAR compensators, main generator voltage regulators) can adversely affect the operability of the NPP offsite power system? If so, describe how the operators are trained and tested on the guidance and procedures.

Yes. Procedural guidance is available to operators at Beaver Valley, Davis-Besse, and Perry. Additional information is available in the Final or Updated Safety Analysis Reports.

The following procedures contain guidance that governs control of the main turbine generator voltage and response to over-excitation and other conditions that may result in a generator trip that has the potential to have impact on off-site source voltage:

- Beaver Valley, 53C.4A.35-1, "Degraded Grid"
- Davis-Besse, DB-OP-06301, "Generator and Exciter Operating Procedure"
- Davis-Besse, DB-OP-06313, "Station Transformer Auxiliaries System Procedure"
- Perry, PAP-0102, "Interface With the Transmission System Operator"
- Perry, SOI-S11, "Power Transformers"

Beaver Valley has automatic load tap changers on the SSSTs to adjust automatically the onsite bus voltages for changes in the grid voltage in the event of a bus transfer. Guidance on the operation of the tap changers is available to the operators in 1OST-36.7, "Offsite to Onsite Power Distribution System Breaker Alignment Verification." Davis-Besse and Perry do not have automatic tap changers.

Plant control and monitored equipment may adversely affect the nuclear power plant off-site power system through a switching error or vehicle

incident in the switchyard. Switching activities, including tag-outs, are strictly controlled utilizing both FENOC and TSO tagging programs. The FENOC tagging program is described in NOP-OP-1001, "Clearance/ Tagging Program." Additionally, strict controls have been put in place to control access and vehicular movement within the switchyards. These controls are located in the following procedures:

- Beaver Valley, NPDAP-3.15, "Beaver Valley Substation Access and Vehicle Controls"
- Davis-Besse, DB-OP-01300, "Switchyard Management"
- Perry, PAP-0102, "Interface With the Transmission System Operator"

Licensed operators are trained during initial and continuing systems training regarding operation of main generator, voltage regulation, and the power grid. This training provides the operation personnel with and understanding of potential impact of voltage control on the power grid. Unless notified by the TSO that the plant is in a specific degraded condition (e.g., N-1 contingency) loss of a unit is not expected to impact the operability of off-site sources.

(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 regarding situations in which the condition of plant-controlled or monitored equipment can adversely affect the operability of the NPP offsite power system.

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5. Performance of grid reliability evaluations as part of the maintenance risk assessments required by 10 CFR50.65(a)(4).

(a) Is a quantitative or qualitative grid reliability evaluation performed at your NPP as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4) before performing grid-risk-sensitive maintenance activities? This includes surveillances, post-maintenance testing, and preventive and corrective maintenance that could increase the probability of a plant trip or LOOP or impact LOOP or SBO coping capability, for example, before taking a risk-significant piece of equipment (such as an EDG, a battery, a steam-driven pump, an alternate AC power source) out-of-service?

Yes. 10CFR 50.65(a)(4) requires performance of a risk assessment prior to performing maintenance activities. Maintenance is defined broadly and includes surveillances, post-maintenance testing, and preventive and corrective maintenance. Relative to increasing the initiating event frequency, such as the frequency of a plant trip, the industry guidance, NUMARC 93-01 (endorsed without exception by NRC Regulatory Guide 1.182), states that the following should be considered:

- The likelihood of an initiating event or accident that would require the performance of the affected safety function.
- The likelihood that the maintenance activity will significantly increase the frequency of a risk-significant initiating event (e.g., by an order of magnitude or more as determined by each licensee, consistent with its obligation to manage maintenance-related risk).

The first bullet above is generally met by using the Probabilistic Risk Assessment (PRA) and associated configuration risk management tools, which explicitly consider initiating event frequencies for transients and accidents. LOOP sequences are important elements of PRAs, and are thoroughly modeled and assessed during plant peer reviews. Risk management personnel are sensitized to the importance of these sequences.

The second bullet clarifies that if a maintenance activity is expected to increase initiating event likelihood by an order of magnitude, then it should be considered in the assessment. Otherwise, the baseline initiating event

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frequencies may be used. These frequencies are based on generic data updated with plant specific data and take into account the plant specific LOOP and trip frequencies.

Beaver Valley, Davis-Besse, and Perry utilize a risk tool called Safety Monitor within the work management process to manage risk. Strict controls have been put in place to control access and vehicular movement within the switchyards. Within the process, maintenance activities that involve 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 are reviewed for impact. In addition, work in the switchyard is reviewed for impact and is specifically designated to receive heightened awareness for potential impact of emergent work or switchyard issues.

(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?

For Beaver Valley, grid status is evaluated by PJM using the Security Analysis application. PJM notifies Beaver Valley through DLCO of emergent grid conditions as discussed in the response to question 1(b). Based on these notifications, Beaver Valley personnel perform a risk review to reassess scheduled work and work in progress for stop work or expediting completion as warranted.

For Davis-Besse and Perry, grid status is continually evaluated by Midwest ISO using the Security Analysis application. Midwest ISO notifies Perry or Davis-Besse through ATSI of emergent grid conditions as discussed in the response to question 1(b). In addition, ATSI is performing similar monitoring and evaluation. Based on these notifications, Davis-Besse and Perry personnel perform a risk review to reassess scheduled work and work in progress for stop work or expedited completion as warranted.

The following guidance is included in NUMARC 93-01:

> Emergent conditions may result in the need for action prior to conduct of the assessment, or could change the conditions of a

previously performed assessment. Examples include plant configuration or mode changes, additional Structures, Systems, and Components (SSCs) out of service due to failures, or significant changes in external conditions (weather, offsite power availability). The following guidance applies to this situation:

- The safety assessment should be performed (or re-evaluated) to address the changed plant conditions on a reasonable schedule commensurate with the safety significance of the condition. Based on the results of the assessment, ongoing or planned maintenance activities may need to be suspended or rescheduled, and SSCs may need to be returned to service.

- Performance (or re-evaluation) of the assessment should not interfere with, or delay, the operator and/or maintenance crew from taking timely actions to restore the equipment to service or take compensatory actions.

- If the plant configuration is restored prior to conducting or re-evaluating the assessment, the assessment need not be conducted, or re-evaluated if already performed.

These principles are discussed in site-specific risk assessment guidelines at Beaver Valley, Davis-Besse, and Perry.

(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.

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

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of facilities out of service for maintenance, occurrence of severe weather, etc. Each aspect creates a level of stress on the grid.

Peak load levels occur at the peak seasons of the summer and winter seasons. While the specific days cannot be predicted, it is known approximately when they will occur.

Since maintenance activities can also be a contributor to stress on the grid, attempts are made to limit maintenance activities during summer and winter peaks. Maintenance activities are influenced by the opportunities to perform maintenance during off-peak seasons.

From PJM's perspective, stress on the grid is caused by a simultaneous combination of stress causers that result 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. Therefore, efforts are made to balance the stress causers to reduce the peaks related to seasonal variation.

(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?

Yes, as part of the risk management program, Beaver Valley, Davis-Besse, and Perry are programmatically driven to consider the potential risk impacts of grid instability and severe weather. In addition, the configuration risk management program considers a wide variety of other inputs, including the potential for maintenance activities to affect the grid. Re-evaluations are conducted when emergent conditions dictate.

(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. Station procedures provide operations personnel with TSO contact information for acquiring information concerning current and anticipated grid conditions.

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Planned maintenance outages for each of the FENOC nuclear plants are planned in advance with significant input from all stakeholders.

All planned work conducted in the nuclear plant switchyards is planned in advance with review by the site work management organizations and assigned Work Control Senior Reactor Operator as part of the pre-planned schedule assessing plant activities and switchyard activities.

Each morning the FENOC Fleet Support organization conducts a morning call where plant status and activities, including risk to generation activities are discussed. A representative from Asset Utilization is a participant on the call. High risk activities and LCO time durations are discussed. For Davis-Besse and Perry, these activities are reported by Asset Utilization to the local System Operator's Grid Reliability Coordinator; a parallel call is conducted to discuss operating megawatt and VAR capabilities. Additionally, the control room operators contact the system operator for emergent issues where capability is impacted or a LCO time clock may be challenged.

(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.

Notification occurs whether or not maintenance is on-going.

Beaver Valley, Davis-Besse, and Perry are contacted by their respective TSO via established communication protocols. These protocols require the TSO to communicate to the local transmission owner whenever they determine that the pre and post-contingent voltage is outside of the acceptable voltage range.

In addition, there is a protocol established with ATSI to notify Davis-Besse or Perry promptly when a transmission line feeding the switchyard has been opened and is no longer considered a contributor to offsite power.

Also, the following is from the Davis-Besse recently revised interconnection agreement:

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"Transmission Provider and/or Transmission Owner will promptly notify Davis-Besse to a worsening grid condition that may emerge during a grid maintenance activity. All communications will adhere to Transmission Provider and/or Transmission Owner's communication and mitigation protocols for nuclear plants, and FERC's Interpretive Order Relating to the Standards of Conduct (Issued February 16, 2006)."

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

As discussed in response to question 5(e), daily communications and notification of emerging issues are communicated to the TSO.

(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.

Licensed operators and maintenance personnel are not trained and tested specifically on the formal agreement with the TSO. Responsibilities from the agreements are included in plant procedures. Work groups within the organization (e.g., maintenance, operations, work management) are trained on their procedures and their responsibilities to carry out specific portions of the agreement or guiding documents associated with the agreement. This training is typically on-the-job training for basic roles and responsibilities, classroom training, and simulator training, as appropriate.

(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. Communication with the TSO is a consideration for the maintenance risk assessment.

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(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 warranted, based on communication with the TSO.

The point of risk assessment under 10CFR50.65(a)(4) is to highlight the condition of the plant and ensure the plant staff is aware of the safety implications of maintenance work so that the proper risk management actions can be taken. Once the implications of the work are known, risk management practices are identified and implemented, including deferral of the work to another time.

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

Not applicable. No alternative actions are required.

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

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

Yes.

For Beaver Valley, planned transmission outages are coordinated in accordance with a process detailed in PJM Manual M-3, Transmission Operations, Section 4. 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.

Once the equipment is switched out of service, grid status is continually evaluated by the PJM Security Analysis application. PJM notifies Beaver Valley through DLCO, as discussed in the response to question 1(b).

For Davis-Besse and Perry, Midwest ISO is responsible for approving maintenance schedule of transmission facilities and coordinating the scheduling of generation facilities. The decision to approve transmission and generation facility maintenance schedules is based on the ability of Midwest ISO to operate the transmission system within the criteria set forth by the transmission owner and NERC and the applicable regional reliability organization.

The outage scheduling process analyzes the outages under expected operating conditions. On the day prior, and on the outage start day, the system is analyzed by Midwest ISO before permitting the equipment to be switched out of service.

Once the equipment is switched out of service, grid status is automatically captured by the Midwest ISO State Estimator and continually evaluated by the Midwest ISO RTCA program.

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ATSI provides a procedure that acknowledges outage coordination with transmission facility maintenance and testing activities to prevent inadvertent reduction in nuclear plant defense-in-depth.

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

Planned maintenance outages for each of the FENOC nuclear plants are planned in advance with significant input from all stakeholders.

As discussed in the response to question 5(e), all planned work conducted in the nuclear plant switchyards is planned in advance with review by the site work management organizations and assigned Work Control Senior Reactor Operator as part of the pre-planned schedule assessing plant activities and switchyard activities.

Each morning the FENOC Fleet Support organization conducts a morning call where plant status and activities, including risk to generation activities are discussed. A representative from Asset Utilization is a participant on the call. High risk activities and LCO time durations are discussed. For Davis-Besse and Perry, these activities are reported by Asset Utilization to the local System Operator's Grid Reliability Coordinator; a parallel call is conducted to discuss operating megawatt and VAR capabilities. Additionally, the control room operators contact the system operator for emergent issues where capability is impacted or a LCO time clock may be challenged.

(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. FENOC utilizes color coordination for escalating grid risk, from a green low risk through yellow, orange, and red. For yellow grid conditions and above, grid risk activities are reviewed when notified. For orange or red, work is precluded or completed expeditiously to minimize risk as appropriate.

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Each morning the FENOC Fleet Support organization conducts a morning call where plant status and activities, including risk to generation activities are discussed. A representative from Asset Utilization is a participant on the call and communicates predicted grid risk for the day. During elevated grid risk scheduled in-progress work is reviewed for postponement or expedited completion as appropriate. High-risk activities and LCO time durations are discussed. Additionally, when the control room operators are notified of escalating grid risk conditions, work in progress is reviewed for postponement or escalated completion.

(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. FENOC utilizes standard industry practices for protecting trains of equipment when critical or risk significant systems are worked on. Additionally, all work is screened for risk, and medium and high-risk activities receive additional reviews. Heightened supervisory and senior management oversight is engaged to assure proper use of human performance and error reduction methods are used, as well as ensuring a proactive management presence to assist the workforce in problem resolution or conflict management as needed to ensure a safe and timely conclusion to the task.

(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 actions discussed in the responses to questions 6(a) through 6(d) that are taken by plant staff are included in site procedures and are part of the risk management and work management programs.

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For Beaver Valley, planned transmission outages are coordinated in accordance with a process detailed in PJM Manual M-3 Transmission Operations, Section 4.

In addition, for Beaver Valley, NPDAP-3.15, "Beaver Valley Substation Access and Vehicle Controls," specifies that Duquesne Light Company System Operators are responsible to provide notification to on-duty Shift Manager of activities requested by the System Operator with the potential to effect system reliability and system integrity.

For Perry and Davis-Besse, the transmission operations procedure NOP43, "Outage Coordination with Nuclear Plant Facilities," specifies that plant safety system maintenance and testing activities that could affect electrical supply diversity must be coordinated with transmission facility maintenance and testing activities to prevent inadvertent reduction in nuclear plant defense-in-depth.

The actions described in the responses to question 6(b) through 6(d) include planning and scheduling equipment and system outages, removing equipment from service, risk management and communicating plant status. The following Beaver Valley, Davis-Besse, procedures govern on-line risk management and work management:

- Beaver Valley, 1/2-ADM-2033, "Risk Management Program"
- Beaver Valley, 1/2-ADM-0804, "On-Line Risk Assessment and Management"
- Beaver Valley, 1/2-ADM-0805, "Production/Generation Risk Determination"
- Beaver Valley, BVBP-WMI-006, "Emergency Load Conservation Guidelines"
- Davis-Besse, DB-OP-1300, "Switchyard Management"
- Davis-Besse, NG-DB-00001, "On-Line Risk Management"
- Davis-Besse, DBBP-OPS-0003, "On-Line Risk Management Process"
- Perry, PAP-0102, "Interface with the Transmission System Operator"
- Perry, PAP-1924, "Risk-Informed Safety Assessment and Risk Management"

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- Perry, PYBP-DES-0001, "On-Line Risk Assessment and Risk Management"

These site-specific procedures implement the requirements of 10CFR50.65(a)(4). Additionally, there is a FENOC-wide procedure governing the morning phone call discussed in response to questions 5(b) and 5(c). Fleet Operations is currently conducting benchmarking and will formalize a consistent fleet approach.

The risk management procedures are based on industry and NRC regulatory guidance, including NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants", and NRC Regulatory Guide 1.182, "Assessing and Managing the Risk Before Maintenance Activities at Nuclear Power Plants." The work management process is based on Institute of Nuclear Power Operations (INPO) guidelines.

The actions described in the responses to questions 6(a) through 6(d) that are taken by site personnel are expected to be effective because many of them are based on internal and external operating experience and current guidance provided to the industry by the Nuclear Energy Institute, Electric Power Research Institute, NRC, and INPO. The actions are expected to be consistently accomplished because they are included in the site-specific on-line risk management procedure.

(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).

As part of general employee training all employees are trained on signs and requirements for protected train equipment. Operator training and maintenance training, as well as specific human performance training, have been conducted on human performance and error reduction techniques. Operators are trained on the procedure for risk, and supervisors are trained in observation and coaching techniques. Additionally, these actions are reviewed in pre-job briefs.

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(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 CFR50.65(a)(4).

Not Applicable. There is effective coordination between FENOC and the TSO regarding transmission system maintenance or nuclear power plant maintenance activities.

(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. As discussed in questions 6(a)—6(d), FENOC effectively implements appropriate risk management actions.

(i) You may, as an alternative to questions 6(g) and 6(h) describe what actions you intend to take to ensure that the increase in risk that may result from grid-risk-sensitive maintenance activities is managed in accordance with 10CFR50.65(a)(4).

Not Applicable. No alternative actions are intended.

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

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

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

- **Grid under-voltage and collapse**
- **Weather-induced power loss**
- **Preferred power distribution system faults that could result in the loss of normal power to essential switchgear buses**

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

Agreements, including black start plans, are in place to restore power to Beaver Valley, Davis-Besse, and Perry as soon as possible. In addition, grid operation procedures provide detailed instructions for prompt restoration of offsite power to Beaver Valley, Davis-Besse, and Perry. These procedures specify various means of accomplishing the required power restoration. Grid operators train on these procedures annually per NERC training requirements.

At Beaver Valley, the PJM Restoration Manual details the process to be followed during a system restoration. The process reiterates the following specific offsite power requirements:

> "Offsite power should be restored as soon as possible to nuclear units, both units that had been operating and those that were already offline prior to the system disturbance, without regard to using these units for restoring customer load."

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Potential restoration scenarios are included in the site-specific black start plans. 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 a nuclear power plant offsite power source.

PJM Manual M-36 also contains the following provisions:

> "Transmission Owners and Nuclear Power Plants must effectively communicate to keep the Nuclear Power Plant apprised of the anticipated restoration time for offsite power."
>
> For PJM Restoration Drills the objectives should include "Ensure that all nuclear units have been provided with one offsite source within 4 hours" and that the PJM Nuclear Generation Owner/Operator Users Group should be debriefed on the drill results. The adequacy of black-start resources to support system restoration is managed through a process contained in PJM Manual M-11, Pre-Scheduling Operations, Section 2.

In addition, the interconnection agreement described in response to question 1(a) provides the following requirement:

> "DLCO shall restore power to the Customer Facility in accordance with its Black Start Plan in a controlled expeditious manner as described in Section 50.18 of the Tariff."

The Midwest ISO restoration process coordinates the development of individual Transmission Owner Restoration Plans. Midwest ISO conducts reviews, workshops and drills to ensure the effectiveness of the restoration plan.

The Midwest ISO restoration process provides updates to the transmission owner and the associated FENOC plant on transmission system status during emergency restoration, and gives the highest priority to restoring power to essential affected nuclear facilities, per NERC standard EOP-005-0.

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Potential restoration scenarios are included in the site-specific black start plans. The Midwest ISO restoration process allows for the fact that the blacked out area may or may not be separated from the remainder of the system. The Midwest ISO restoration process allows the use of black start unit or cranking path from non-blacked out areas. Regardless of the scenario, there is a clear recognition of the importance of expeditious restoration of a nuclear power plant offsite power source.

The interconnection agreement for Perry described in 1(a) requires the Transmission Provider and/or Transmission Owner to restore power to Perry in accordance with its Black Start Plan in a controlled expeditious manner.

For Davis-Besse, the Transmission Provider and/or Transmission Owner shall restore power to Davis-Besse on a priority basis in accordance with its Black Start Plan in a controlled expeditious manner. Transmission Provider and/or Transmission Owner shall provide Davis-Besse with details of the black start plan that pertain specifically to Davis-Besse's likely sources of off-site power (i.e. gas turbines, black start fossil plants, etc.).

In addition, for Davis-Besse and Perry, ATSI provides a procedure whose purpose is to establish the requirements to ensure plans, procedures and resources are available to restore the electric system to a normal condition in the event of partial or total shut down of the system. In this document, the ATSI gives high priority to restoration of off-site power to nuclear stations.

(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. Beaver Valley, Davis-Besse, and Perry operators are not trained and tested on identifying and using local power sources to resupply the plant following a LOOP. However, nuclear power plant control room operators participate in an initial and continuing training program. This training covers administrative programs, technical knowledge of systems, practical performance during simulator exercises and job performance measures.

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As part of operators' initial and continuing training program, operators are trained on abnormal operating procedures in accordance with SAT, which includes the procedures and processes required for restoration of power, once offsite power is available. Additionally, loss of offsite power simulator scenarios are reviewed and performed in license re-qualification. Training consists of both classroom and simulator training.

(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 with PJM and DLCO that allows for the restoration of offsite power to Beaver Valley. An existing agreement exists with Midwest ISO and ATSI that allows for the restoration of offsite power to Davis-Besse and Perry.

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

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

Beaver Valley has not experienced a total LOOP caused by grid failure since its coping duration was initially determined under 10 CFR 50.63.

Davis-Besse and Perry experienced a total LOOP caused by grid failure on August 14, 2003.

(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?

As described in the response to question 8(a) there have been no grid related LOOP events at Beaver Valley, but the original basis for the Station Blackout coping duration was revisited.

Davis-Besse and Perry were reviewed to determine whether they should be assigned to the P3 offsite power design characteristic group.

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

The review at Beaver Valley determined that the updated LOOP frequencies would be one per 31.6 years for Beaver Valley Unit 1 and one per 43.3 years for Beaver Valley Unit 2. Therefore, the Beaver Valley units should not be assigned to the P3 Offsite Power Design Characteristic Group.

The review at Davis-Besse determined that Davis-Besse should not be assigned to the P3 Offsite Power Design Characteristic Group. The decision that Davis-Besse should remain in the P1 Offsite Power Design Characteristic Group is based on the independence of the plant offsite power system characteristics, the expected frequency of grid-related LOOPS of less than one per 20 years, the estimated frequency of LOOPs due to Extremely Severe Weather (ESW) that places the plant in ESW

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Group "2", and the estimated frequency of LOOPs due to Severe Weather (SW) that places the plant in SW Group "2".

Review of grid history at Davis-Besse for the last 28 years indicates that the August 14, 2003, event was the only grid related loss of offsite power so the expected frequency of grid-related LOOPS of less than one per 20 years is still appropriate.

Davis-Besse also had loss of off-site power events on June 24, 1998, due to a tornado, and on April 22, 2000, due to a human error during testing of the off-site AC sources bus transfer scheme. These events are not grid-related LOOP events per guidance in NUMARC 87-00:

> "Grid-related loss of off-site power events are defined as LOOPs that are strictly related with the loss of the transmission and distribution system due to insufficient generating capacity, excessive loads or dynamic instability. Although grid failure may also be caused by other factors such as severe weather conditions or brushfires, these events are not considered grid-related since they were caused by external events."

The review at Perry determined that Perry should not be assigned to the P3 Offsite Power Design Characteristic Group. The assignment of Perry to the P1 Offsite Power Design Characteristic Group was reviewed based on the LOOP event of August 14, 2003, and the requirements of Regulatory Guide 1.155. The August 14, 2003, event was the first LOOP event to occur at the plant in the last 23 years. The previous plant-centered LOOP event occurred in 1983 when the plant was under construction prior to fuel load. It was concluded with a grid failure rate of once in 23-years, based on the guidance provided by Regulatory Guide 1.155, Table 4 (P3 sites are those expected to have grid failure frequencies equal to or greater than once in 20-years), that Perry should remain in the P1 Group.

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(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. Beaver Valley, Davis-Besse, and Perry have been reviewed using the guidance in Table 4 of RG 1.155.

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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.

Not applicable. FENOC has determined that Beaver Valley, Davis-Besse, and Perry are in compliance with NRC regulatory requirements, including Technical Specifications, GDC 17, 10CFR50.65(a)(4), 10CFR50.63, 10CFR55.59, and 10CFR50.120.