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DTE Energy

10 CFR 50.54(f)

April 3, 2006
NRC-06-0013

U. S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington D C 20555-0001

References: 1) Fermi 2
NRC Docket No. 50-341
NRC License No. NPF-43

2) NRC Generic Letter 2006-02, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power

Subject: Detroit Edison's 60-Day Response to Generic Letter 2006-02, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power

The purpose of this letter is to provide the information requested in NRC Generic Letter (GL) 2006-02. On February 1, 2006, the NRC issued GL 2006-02 (Reference 2) requesting licensees to provide information, within 60 days of the date of the GL, to enable the NRC staff to determine whether compliance is being maintained with the regulatory requirements governing electric power sources and associated personnel training for the plant. Information was requested 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). (The TSO, ISO, or RC/RA is responsible for preserving the reliability of the local transmission system. In this GL the term TSO is used to denote these entities);

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

(3) offsite power restoration procedures in accordance with Section 2 of 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.

Enclosure 1 provides a general overview of the interfaces between the Fermi 2 Nuclear Power Plant and various offsite entities that monitor, control and operate the transmission system that otherwise might not be evident in reviewing the responses to individual specific questions in Generic Letter 2006-02.

Enclosure 2 provides the Fermi 2 responses to the specific questions asked in Generic Letter 2006-02.

Some of the questions in Generic Letter 2006-02 seek information about analyses, procedures, and activities concerning grid reliability which Fermi 2 does not have first hand knowledge and which are beyond the control of Fermi 2. In providing information to such questions, Fermi 2 makes no representation as to its accuracy and completeness.

No commitments are being made as a result of this letter

Should you have any questions or require additional information, please contact Mr. Ronald W. Gaston of my staff at (734) 586-5197.

Sincerely,

Donald K. Cobb

Enclosures

cc: D. H. Jaffe
T. J. Kozak
NRC Resident Office
Regional Administrator, Region III
Supervisor, Electric Operators,
Michigan Public Service Commission

I, DONALD K. COBB, do hereby affirm that the foregoing statements are based on facts and circumstances which are true and accurate to the best of my knowledge and belief.

DONALD K. COBB
Assistant Vice President, Nuclear Generation

On this 3rd day of April, 2006 before me personally appeared Donald K. Cobb, being first duly sworn and says that he executed the foregoing as his free act and deed.

NORMAN K. PETERSON
NOTARY PUBLIC MONROE CO., MI
MY COMMISSION EXPIRES Jul 24, 2006

Notary Public

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ENCLOSURE 1
to NRC-06-0013

FERMI 2 NUCLEAR POWER PLANT

GENERAL OVERVIEW OF INTERFACES

This enclosure provides general overview of the interfaces between the Fermi 2 Nuclear Power Plant and various offsite entities that monitor, control and operate the transmission system that otherwise might not be evident in reviewing the responses to individual specific questions in Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power."

BACKGROUND INFORMATION

The interfaces between the Fermi 2 Nuclear Power Plant (EF2 NPP) and "the grid" are through a number of different offsite entities:

- The Midwest Independent Transmission System Operator, Inc. (Midwest ISO) provides open access transmission service to customers in the Michigan Electric Coordinated Systems (MECS) Balancing Authority Area, including the EF2 NPP, and acts as the Reliability Coordinator/Assessor (RC/RA) over its footprint. Midwest ISO acts as the "ISO" and "RC/RA" as described in the Generic Letter.
- The MECS Balancing Authority is a jointly operated Control Area of the International Transmission Company (ITC) and the Michigan Electric Transmission Company (METC).
- The ITC owns and operates an independent electric transmission system that serves the EF2 NPP and is the "TSO" as described in the NRC Generic Letter.
- The Detroit Edison System Operations Center (DE SOC) is the Distribution Provider and Operating Authority for the Detroit Edison Electrical System which includes onsite electrical distribution equipment (>4160VAC) at the EF2 NPP between the ITC and the EF2 NPP.

Interfaces between EF2 NPP and the above offsite organizations are currently controlled though a number of formal and informal agreements.

The EF2 NPP interfaces with the DE SOC through internal corporate directives and procedures. Interfaces from the EF2 NPP to other transmission entities are coordinated through the DE SOC. In addition, formal agreements for design, material and maintenance control of switchyard activities between the EF2 NPP and other Detroit Edison entities are included in Augmented Quality Program, *AQP-0001, 120 kV and 345 kV Switchyard, Transformers, and Peaker CTG 11-1 Configuration.*

The interface between the EF2 NPP, DE SOC and the ITC is governed by the *Generator Interconnection and Operating Agreement* (GIA) executed between the International Transmission Company and the Detroit Edison Company. In particular, Exhibit C of this formal agreement (*Fermi 2 Nuclear power Plant Requirements for Offsite Power Supply Operability and Switchyard Interfaces*) outlines the operating requirements, safe shutdown and design basis load and voltage requirements, Maintenance Rule performance requirements, communications, required annual system studies, blackout

restoration priority and criteria, design and material control, maintenance activity control as well as records. Notable formal agreements for design, material and maintenance control of switchyard activities between the EF2 NPP and ITC are detailed in Augmented Quality Program *AQP-0002, ITC-Fermi 2 Interface – 120 kV and 345 kV Switchyards.*

The interface between the ITC and Midwest ISO is governed by the *Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator*, of which Appendix E requires the Midwest ISO to enter into written agreements which define scheduling protocols, limitations, and restrictions necessary to ensure the safety and reliability of nuclear facilities and to define planned transmission and generation unit maintenance scheduling criteria, limitations and restrictions to ensure the safety and reliability of nuclear facilities. Representatives of Midwest ISO, ITC, DE SOC and the EF2 NPP are members of the Midwest ISO Nuclear Power Plant Working Group (NPWG), which has developed an informal agreement and communications protocol in *RTO-OP-03, Midwest ISO Real Time Operations Communication and Mitigation Protocols for Nuclear Plant/Electric System Interfaces* [the Operations Protocol]. The Operations Protocol RTO-OP-03 coordinates communications regarding transmission system and Nuclear Power plant operating criteria to ensure reliable offsite power to facilities by which the Midwest ISO has Control Authority through the Midwest ISO Transmission Owners Agreement and/or NERC Standards as Reliability Authority. The Operations Protocol RTO-OP-03 has been adopted by Midwest ISO, ITC, and Detroit Edison. Midwest ISO, ITC, and Detroit Edison are developing a formal *Nuclear Plant Operating Agreement* (NPOA), which will include as Exhibit A, the *Fermi 2 Nuclear Power Plant Operating Guide.* The NPOA will formalize and define coordination of communications between Midwest ISO, ITC, and Detroit Edison (including the DE SOC and the EF2 NPP) with respect to scheduling protocols, emergency procedures, operating and maintenance limitations and other restrictions applicable to the EF2 NPP.

All of the offsite entities (Midwest ISO, MECS, ITC and DE SOC) that interface the transmission system to the EF2 NPP have an Energy Management System (EMS) that includes a Supervisory Control and Data Acquisition (SCADA) system and State Estimator (SE) that serve a Real Time Contingency Analysis (RTCA) program. The scope of each SCADA, SE and RTCA is progressively larger as the footprint of the control area increases, with the largest scope being that of Midwest ISO. The Midwest ISO SE model includes not only its footprint, but portions of Tennessee Valley Authority (TVA) and the adjacent Regional Transmission Operators (RTOs) of PJM Interconnection (PJM), Southwest Power Pool (SPP) and Independent Electricity System Operator (IESO).

Some data on each of the previously mentioned EMS's follows:

Entity	SE Update Frequency	RTCA Update Frequency	Number of Analyzed Contingencies
Midwest ISO	90 Seconds	5 minutes	>7000
MECS*	Old - 5 Minutes New - 60 Seconds	Old - 5 Minutes New - 5 Minutes	Old - ~400 New - ~1000
ITC	60 Seconds	10 Minutes	>970
DE SOC	60 Seconds	10 Minutes	>960

*The MECS has two EMS's, the older one is primary with the new one running in parallel as a development system to become primary in the near future.

Each of the above RTCA programs analyzes *at least* the following Contingencies:

- Trip of the EF2 NPP
- Trip of each (separately) nearby generating plant
- Loss of transmission lines critical to the EF2 NPP
- Loss of large loads

Each of the above EMS systems have alarms to detect pre and post contingency conditions where offsite power voltages are insufficient to meet the needs of the EF2 NPP and have protocols, procedures or practices in place to communicate the presence of these alarms.

In addition to the above four EMS systems monitoring the EF2 NPP offsite power supply voltages for pre and post contingency operations, Fermi 2 UFSAR 8.2.2.5.4 requires reviews of the transmission grid system stability and voltage levels to ensure that grid configuration changes do not adversely affect previous analyses. On a yearly basis, 5-year load and generation forecasts are made and based on these forecasts, base grid systems for a 5-year period are established. These base grid systems are tested via computer simulations to meet voltage and stability criteria. From the results of these tests, any grid configuration modification or operating restrictions required to maintain required grid operation are initiated. The ITC performs these annual grid systems studies as required by the GIA, Exhibit C.

Lastly, as corporate policy for Detroit Edison, interface communications for transmission system operations are between the EF2 NPP and the DE SOC (the Operating Authority for the Detroit Edison electrical system), and then from the DE SOC to the ITC. The Operations Protocol RTO-OP-03 governs communications between Midwest ISO, ITC and the EF2 NPP for pre and post contingency conditions where EF2 NPP offsite power requirements are challenged or unknown, and for these communications, the ITC or Midwest ISO are to contact the EF2 NPP directly. However, EF2 NPP procedures are written to contact the DE SOC (typically the Central System Supervisor (CSS) for

abnormal conditions, and then the DE SOC is to contact the ITC. For the responses to this Generic Letter, it must be understood that any discussion of "communications to/from/with the TSO" will assume that the TSO is the ITC, and that protocol driven communications *to* the ITC that are *through* the DE SOC satisfy the intent of "to the TSO".

Because the individual Generic Letter question answers provided in Enclosure 2 are mostly from the perspective of the ITC as TSO, additional discussion on the role of the Midwest ISO is also warranted.

The Midwest ISO has provided the following generic information to the EF2 NPP and the other 12 NPPs in its footprint for use in their response to this Generic Letter (Reference *Midwest ISO memorandum from Roger C. Harzey to Nuclear Plant and Transmission Operators dated 3/10/2006*)

Background

The Midwest Independent Transmission System Operator (Midwest ISO) was formed in 1998 through an agreement with transmission owning entities spanning an area from Ohio to North Dakota. In December 2001 the Federal Energy Regulatory Commission (FERC) approved Midwest ISO as a Regional Transmission Organization (RTO) to provide transmission and interconnection services for entities within its footprint. In December 2001 Midwest ISO became a North American Electric Reliability Council (NERC) qualified Reliability Coordinator providing reliability services for member entities within its footprint and for others under contract in the former Mid-Continent Area Power Pool (MAPP) Reliability Region.

In April 2005, Midwest ISO began operating a security-constrained economic dispatch energy market. Market Participants submit bids and offers for their load and generation resources. The Midwest Market commits and dispatches generation to meet the load within its footprint. The Market also dispatches generation to alleviate constraints that are affected by the market operation.

Transmission Owners Agreement

Midwest ISO is required under the Transmission Owners Agreement to maintain the reliability of the transmission system, while adhering to the operating criteria and guidelines of the Transmission Owners. Midwest ISO is required to meet the requirements of the North American Electric Reliability Council, applicable regional reliability councils, or any successor organizations, and applicable federal regulatory authorities, including the Nuclear Regulatory Commission.

The Midwest ISO (i) shall take no action that would impair the safety and reliability of nuclear facilities; and (ii) shall take actions consistent with nuclear license conditions or requirements or as otherwise required by the Nuclear Regulatory Commission (NRC). 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.

In March 2005 the Midwest ISO established a communication protocol [The Operations Protocol RTO-OP-03] with the Nuclear Power Plants (13) within its reliability footprint and their interconnected transmission owners. This protocol delineates the responsibilities and ensures the necessary communication about transmission system conditions to the nuclear power plants.

Outage Scheduling

Planned transmission and generation outages are coordinated in accordance with *Midwest ISO Business Practices Manual for Outage Operations*. The Midwest ISO is responsible for approving requested maintenance on all transmission facilities making up the Midwest ISO Transmission System and coordinating with generation owners the scheduling of maintenance on generation facilities within the Midwest ISO. The Midwest ISO also coordinates transmission and generation maintenance schedules with entities outside of the Midwest ISO transmission system (i.e. PJM). The requested outages are analyzed to ensure the Transmission System can be operated within required criteria and guidelines.

State Estimation

Midwest ISO's state estimator model not only covers the generation and Transmission System within its reliability footprint, but also covers portions of Tennessee Valley Authority (TVA) and the adjacent Regional Transmission Operators (RTOs) of PJM Interconnection (PJM), Southwest Power Pool (SPP) and Independent Electricity System Operator (IESO). The Midwest ISO members provide real-time load, generation, line flow and voltage values every 30 seconds. From this data, Midwest ISO runs its State Estimator (SE) function every 90 seconds. The SE performs an estimation of the electric system, filling in missing and bad data. Many other programs, such as Real-time Contingency Analysis (RTCA), Market Dispatch programs, etc, then use the SE solution.

Real-time Contingency Analysis

Midwest ISO's real-time contingency analysis runs every 5 minutes using the most recent SE output. RTCA simulates 7000+ different contingencies, including the loss of transmission lines and generators. RTCA checks transmission lines and transformers for overloaded conditions and out of range voltage. RTCA output is reviewed by the Midwest ISO Reliability Coordinator/Assessor (RC/RA), who initiates communication with the affected local transmission operators. The Midwest ISO RC/RA verifies the criteria and solution results with the local transmission operator. Once the solution is validated the Midwest ISO RC/RA initiates the necessary actions to alleviate the conditions.

Constraint Management

Known constrained portions of the transmission system have pre-established operating guides for the Midwest ISO RC/RA and the local transmission operator to follow for expeditious relief of the constraint. These operating guides have the established operating criteria and action plan to return to a state within the criteria. The action plan may include re-configuring the transmission system, activating voltage control devices or redispatching generation. The goal of the Midwest ISO is to alleviate constraints within 30 minutes of their occurrence. The Midwest ISO has experienced conditions that required the redispatch of the market generation to protect the offsite power requirement of a NPP within its system.

ENCLOSURE 2
to NRC-06-0013

FERMI 2 NUCLEAR POWER PLANT

SPECIFIC RESPONSES TO GENERIC LETTER 2006-02 QUESTIONS

This enclosure provides the Fermi 2 responses to the specific questions asked in Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power."

Throughout Enclosure 2 the Midwest ISO has provided "generic" responses to some Generic Letter questions which complement similar responses provided by the ITC. Where these "generic" responses are provided, Fermi 2 personnel have added clarifying text in brackets [ ] to make the "generic" responses Fermi 2 specific. Information requested by the NRC in Generic Letter 2006-02 is underlined with the Fermi 2 response immediately following.

REQUESTED INFORMATION

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

GDC 17, 10 CFR Part 50, Appendix A, requires that licensees minimize the probability of the loss of power from the transmission network given a loss of the power generated by the nuclear power unit(s).

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

(1a) <u>Do you have a formal agreement or protocol with your TSO?</u>

Response: Yes.

A formal agreement with the TSO, the International Transmission Company (ITC), is documented in Exhibit C, *Fermi 2 Nuclear Power Plant Requirements for Offsite Power Supply Operability and Switchyard Interfaces* of the *Generator Interconnection and Operating Agreement (GIA)* executed between the International Transmission Company and the Detroit Edison Company. Exhibit C of the GIA outlines operating requirements, safe shutdown and design basis load and voltage requirements, Maintenance Rule performance requirements, communications, required annual system studies, blackout restoration priority and criteria, design and material control, maintenance activity control as well as records.

The TSO (ITC) and Detroit Edison are also members of the Midwest Independent Transmission System Operator, Inc. (Midwest ISO). In Appendix E, Section C of

the *Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator*, it 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." Midwest ISO, ITC and Detroit Edison are currently in the final stages of developing a plant specific operating agreement, but the *Nuclear Plant Operating Agreement for Fermi 2 Nuclear Power Plant* (NPOA) has not been finalized.

Until the NPOA is in place, as members of the Midwest ISO, Detroit Edison and ITC operate pursuant to the *Midwest ISO Real-Time Operations Communication and Mitigation Protocol for Nuclear Plant/Electric System Interfaces, RTO-OP-03* (The Operations Protocol). The Operations Protocol RTO-OP-03 establishes, on an informal level, "a communication protocol between Midwest ISO, Transmission Operators and Nuclear Plant Operators to ensure reliable offsite power from facilities that the Midwest ISO has control authority through the Midwest ISO Transmission Owners Agreement and/or NERC standards as a Reliability Authority."

(1b) Describe any grid conditions that would trigger a notification from the TSO to the NPP licensee and if there is a time period required for the notification.

Response:

The Operations Protocol, RTO-OP-03, referenced in subpart (1a) above, provides for the following:

- That the Transmission Operator is responsible for communicating operating criteria and any changes to the operating criteria to the Midwest ISO and the Nuclear Plant, and for communicating to the Nuclear Plant and Midwest ISO when the transmission system is outside of the operating criteria related to offsite power requirements for the Nuclear Plant for pre and post contingent conditions.

- That Midwest ISO will monitor the appropriate system conditions and notify the Nuclear Plant's operating personnel via the Transmission Operator when operating conditions are outside of established limits, as well as, when they are restored to within acceptable criteria.

- That if the Midwest ISO or Transmission Operator observes violations to operating criteria or anticipates violations to operating criteria (pre or post contingency) at any Nuclear Plant, Midwest ISO and the Transmission Operator will verify study results and the Transmission

Operator will notify the operations personnel at the Nuclear Plant. Midwest ISO and the Transmission Operator will clearly differentiate the transmission system's ability to serve offsite power to the Nuclear Plant from other grid operating conditions.

- That the Midwest ISO will notify the Nuclear Plant Operator through the Transmission Operator with the actual conditions that impact the Nuclear Plant's offsite power, the pre and post contingency condition that impact the Nuclear Plant's offsite power, the limiting contingency causing the violation and the estimated time to resolve the operating criteria violations (pre and post contingent).

- That 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, and that 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 who will immediately initiate communication with the Nuclear Plant and the Midwest ISO if the Transmission Operator verifies an actual violation to the operating criteria affecting the Nuclear Plant. The Transmission Operator and the Midwest ISO will immediately initiate steps to mitigate the actual violation.

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

- That should the Transmission Operator lose its ability to monitor or predict the operation of the transmission system affecting offsite 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.

The GIA, referenced in subpart (1a) above, provides for the following:

- That Transmission System operating procedures and programs shall be in place to ensure that various system operating conditions (generating unit outages, line outages, system loads, spinning reserve, etc.), including multiple contingency events, are evaluated and understood, such that impaired or potentially degraded grid conditions are recognized, assessed and immediately communicated to the Fermi 2 operating Staff for Operability Assessments of plant equipment.

- That Fermi 2 is connected to two 345 kV transmission lines and three 120 kV transmission lines. Any long term increase or decrease in the physical number of these lines requires the prior notification, review and approval by the Fermi 2 operating staff. None of these five lines may be removed from service without prior notification of the Fermi 2 Operating Staff, except in an emergency.

- That if any planned switchyard activities would invalidate the Maintenance Rule compliance assumptions by affecting equipment in the Fermi 2 345 kV and 120 kV switchyards or associated relaying, the Fermi 2 Operating Staff must be informed and compensatory measures or corrective actions must be taken.

- That records of the most recent system study results shall be maintained by the Transmission Owner. These records are subject to Detroit Edison and NRC review. Study results, including revisions and updates, shall be transmitted via letter to Detroit Edison. Study results and calculations shall be assessed at least annually and updated by the Transmission Owner if needed based on changing grid conditions. This assessment shall be provided to the Fermi 2 Engineering Staff at least annually.

- That bulk power transmission system reliability as described in the Updated Final Safety Analysis Report (UFSAR) Section 8.2 Offsite Power System (or successor document) shall be maintained. Changes to planning criteria or operating practices that have the potential to adversely impact grid reliability and availability as described in the UFSAR require prior notification and evaluation by the Fermi 2 Operating Staff.

- That any equipment upgrades, circuit re-designs, setpoint changes, or control logic additions, deletions or revisions, on the Transmission System that may affect the operational requirements of the Fermi 2

offsite power supply shall be communicated to the Fermi 2 operating staff by the Transmission Owner. The information shall be in sufficient detail to permit the Fermi 2 Operating Staff to accurately revise Chapter 8, "Electric Power" of the UFSAR.

- That (four) Combustion Turbine Generators (CTG) 11 and the alternate AC source in the 120 kV switchyard and the transmission path from CTGs 11 and the alternate AC Source to Fermi 2 have been defined as being important to Nuclear Safety. Any design changes, or maintenance, that affects CTG-11 and the alternate AC source and the associated Transmission path, must have the concurrence of the Fermi 2 Operating Staff. Any operational events that affect CTG-11 and the alternate AC Source and the associated transmission path must be immediately communicated to the Fermi 2 Operating Staff.

- That any environmental releases or reports to other agencies that are made regarding either Fermi switchyard must be immediately reported to the Fermi Operating Staff. These may be reportable under NRC regulations.

(1c) Describe any grid conditions that would cause the NPP licensee to contact the TSO. Describe the procedures associated with such a communication. If you do not have procedures, describe how you assess grid conditions that may cause the NPP licensee to contact the TSO.

Response: Grid conditions and status are the primary responsibility of the TSO (ITC) and Reliability Coordinator (Midwest ISO). The Grid parameters observable to Fermi 2 Operators include only real and reactive voltage, frequency, breaker status, line status, line current and various switchyard alarms.

Regardless, communications protocols and procedures do require contact with the TSO (ITC), typically through the Detroit Edison Central System Supervisor (CSS) at the Detroit Edison System Operations Center (DE SOC).

The GIA requires the Fermi 2 Operating Staff to monitor Switchyard voltage and notify the Transmission Owner if voltage falls below a predefined screening value for the 345 kV or the 120 kV Switchyard.

MOP01013, *Control Room Status Checklist* is performed shiftly by Control Room Operators. Included in this checklist are 120 kV and 345 kV breaker status and bus voltage, 4160 VAC and 480 VAC bus voltages and CTG status. Surveillance Procedure 24.000.02, *Shiftly, Daily, and Weekly Required*

Surveillances is also used to monitor voltmeters in the 345 kV or the 120 kV Switchyard. If the 120 kV or 345 kV bus voltage is < 116 VAC (meter volts) the Fermi 2 Shift Manager must be notified. [Note: 100% of system voltage is represented by 120 VAC (meter volts), thus on the 345 kV system 116 VAC (meter volts) represents 333.5 kV, and on the 120 kV system 116 VAC (meter volts) represents 116 kV.] Conduct Manual MOP05, *Control of Equipment* requires an immediate communication to the CSS if this condition exists.

UFSAR Section 8.2.2.5.2 describes Identification of Degraded Grid Conditions and includes monitoring of voltmeters and alarm sensors.

Each of the Fermi 2 offsite sources is monitored by indicating voltmeters. In addition to the offsite source voltmeters, a low voltage alarm sensor and an indicating voltmeter are provided for monitoring the Division 1 4160 VAC buses 64B, 64C, 11EA, and 12EB, since they are all at a common bus voltage. Another indicating voltmeter and a low voltage alarm sensor are provided for monitoring the Division 2 4160 VAC buses 65E, 65F, 13EC, and 14ED. In both cases, the low voltage alarm sensor will initiate alarms in the control room through the annunciator system if the voltage on the buses drops below normal. These alarms would consist of both audio and visual indication to attract operator attention. Supplementing the indicating voltmeters are recording voltmeters for each of the reactor building safety-related 4160 VAC buses. These also could be used to evaluate voltage at the corresponding bus in the residual heat removal complex since the voltage is essentially the same. Safety-related 480 VAC buses use one indicating voltmeter per division. The voltmeter may be switched to read the desired bus voltage.

The Fermi 2 UFSAR establishes the values from which the licensed limits for operability are derived. The UFSAR limits, per section 8.2.2.5, Operation With Degraded Grid, are as follows:

- 120 kV Offsite Source Minimum Voltage – 112 kV (112 meter volts)
- 120 kV Offsite Source Maximum Voltage – 126 kV (126 meter volts)
- 345 kV Offsite Source Minimum Voltage – 328 kV (114 meter volts)
- 345 kV Offsite Source Maximum Voltage – 362 kV (126 meter volts)
- 120 kV and 345 kV Offsite Source Minimum Frequency – 59.5 Hz
- 120 kV and 345 kV Offsite Source Maximum Frequency – 60.5 Hz

Deviating from these values would be outside of the analyzed conditions in the UFSAR, therefore requiring the affected offsite source to be declared inoperable. Part of the resolution of this nonconforming condition would be to contact the CSS to determine the time for resolution.

Alarm Response Procedures (ARP) are procedures used to address off normal conditions that would result in a control room annunciator alarm. The following ARPs respond to Low Voltage and High/Low Frequency alarms and their initiating values:

- ARP 9D22, *Div 1 Bus Voltage Low* – The annunciator alarms when bus voltage on the secondary side of Transformer 64 decreases to 117.6 meter volts after a 30 second time delay. Direction is given for Fermi 2 to coordinate with the Central System Supervisor to start and load the Combustion Turbine Generators (CTG's) if Bus 101 and/or Bus 102 voltages decrease to less than 118 meter volts.

- ARP 10D43, *Div 2 Bus Voltage Low* – Alarms when Bus Voltage on the secondary side of Transformer 65 decreases to 114 meter volts. The ARP then directs Fermi 2 to coordinate corrective actions with the Central System Supervisor.

- ARP 4D132, *Generator Frequency High/Low* – If generator frequency decreases to < 59.5 Hz but > 59.4 Hz Fermi 2 shall coordinate corrective actions with the Central System Supervisor. If frequency is between 59.4 and 58.6 Hz Fermi 2 shall coordinate corrective actions with the Central System Supervisor and if this condition occurs for > 30 minutes Fermi 2 shall shut down the reactor and trip the main turbine generator. Below 58.6 Hz Fermi 2 will shut down. If generator frequency increases to > 60.5 Hz but < 60.6 Hz Fermi 2 shall coordinate corrective actions with the Central System Supervisor. If frequency is between 60.6 and 61.4 Hz Fermi 2 shall coordinate corrective actions with the Central System Supervisor and if this condition occurs for > 30 minutes Fermi 2 shall shut down the reactor and trip the main turbine generator. Above 61.4 Hz Fermi 2 will shut down. This ARP also is an entry condition for Abnormal Operating Procedure 20.300.345kV, *Loss of 345kV* and Abnormal Operating Procedure 20.300.120kV, *Loss of 120kV*.

Various annunciators are also present in the Fermi 2 Control Room that alarm when an abnormal condition exists on the 120 kV switchyard, 345 kV switchyard and on the offsite lines. Examples of these alarms are breaker status and offsite line relaying abnormalities. The ARPs for these alarms require a notification to the CSS to inform them of the abnormal condition and take any necessary actions, as directed by the CSS. These Alarm Response Procedures include the following:

- ARP 4D121, *345kV Bkr Pos Open*
- ARP 4D123, *345kV Bkr Pos CM Open*

- ARP 11D1, *345kV Bkr Pos CT Open*
- ARP 11D9, *345kV Bkr Pos DM Open*
- ARP 11D13, *345kV Bkr Pos DF Open*
- ARP 11D17, *Brownstown 2 Line Relaying System Failure*
- ARP 11D18, *Brownstown 2 Line Relaying Transfer Trip Ch Failure*
- ARP 11D19, *Brownstown 3 Line Relaying System Failure*
- ARP 11D20, *Brownstown 3 Line Relaying Transfer Trip Ch Failure*
- ARP 11D23, *Line Relaying Channel Failure*
- ARP 11D27, *120kV Breaker Trip*
- ARP 11D57, *120kV Undervoltage Scheme Abnormal*

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

Response: Operators are trained and evaluated (tested) as follows:

(i) Lesson Plan LP-OP-202-054A4, *Electrical Topics/Grid Stability* was last presented in Licensed Operator Requalification Training Program in the fall of 2005. Topics included:

- Technical Specification Bases for offsite power.
- UFSAR voltage limits for offsite power and bases for the limits.
- INPO SOER 99-01, *Loss of Grid* concerns and the growing concern by the NRC because of grid related events.
- General Design Criteria 17 and upcoming changes to Technical Specifications bases for offsite electrical supply sources.
- Current plant monitoring capabilities for degrading offsite power.
- Actions required by plant procedures for power degrading as indicated by Division 1 and 2 low voltage alarms or Generator frequency low.
- Differences between divisional voltage setpoints for Emergency Diesel Generator (EDG) start and bases.
- Relationships between DE SOC, Midwest ISO, ITC, and Fermi 2 Control Room personnel.
- Purpose and function of State Estimators and RTCAs and procedure requirements if voltages are determined to be out of specification or if notified analysis cannot be performed for declaring offsite circuits inoperable.
- Simulator exercise on loss of power events including degraded voltage on Division 1 power sources.

(ii) The above lesson was immediately incorporated into the Initial Licensed Operator Training program using Lesson Plan LP-OP-802-2002, *Integrated Electrical Events.* In addition to the above topics, the following related information is presented in this lesson.

- Review of INPO SOER, 99-01 *Loss of Grid* and addendum
- Review of station procedures for loss of offsite power and station blackout.
- Review of equipment which will be returned to service after a SBO.
- Review of sequence of power restoration.

(iii) Simulator Scenario SS-OP-802-2001, *Emergency and Abnormal Event Scenarios* allows operators to practice the station procedures for restoring power during station blackout using the alternate power sources (Combustion Turbine Generators) located at the Fermi 2 site.

(iv) Simulator Scenario SS-OP-904-0182, *Evaluation Scenario 95%/ MSIV Closure/ Freq low/ Turbine Trip/ Total Scram Failure/ Steam Leak in Cont* was used to evaluate crews abilities to implement station procedures for low generator frequency condition due to grid instabilities during a recent cycle of requalification training. It was also included in a scenario set during the NRC licensed operator annual exam.

(v) Operations Required Reading 06-03-05, *Monitoring and Assessment of Offsite Sources* was presented in March of 2006. Topics included:

- A new section in Conduct Manual MOP05, *Control of Equipment* that provided a single source for information and actions required relating to offsite power, including:
    - Background information concerning plant equipment and monitoring devices which could impair the reliability of the offsite power sources.
    - Requirements for periodic communications during normal operations between the plant and the CSS.
    - Specific time requirements for communications to be made to and from the plant and the CSS if grid conditions degrade or equipment which may affect reliability is impacted, including a list of this equipment.
    - Requirements to initiate risk assessments based on grid conditions.

- A new attachment to Operations Department Expectation (ODE)-12, *LCOs* to be used during shiftly communications with the CSS to verify the status of offsite lines.
- UFSAR voltage limits and their inclusion in ODE-12, *LCOs*.

Information presented by Operations Required Reading 06-03-05, *Monitoring and Assessment of Offsite Sources* in March of 2006 was immediately incorporated into objectives in the operator qualification cards in QC-OP-725-0200/OS-OP-725-0000, *Licensed SRO Qualification Program* and QC-OP-725-0100/OS-OP-725-0000, *Licensed RO Qualification Program.* Also, lesson material for LP-OP-802-2002, *Integrated Electrical Events* was modified to include these new procedure sections.

Operators are evaluated on the use of the procedures, assessing grid conditions during on the job training task evaluations included in Qualification Card QC-OP-725-0200/OS-OP-725-0000, *Licensed SRO Qualification Program* and Qualification Card QC-OP-725-0100/OS-OP-725-0000, *Licensed RO Qualification Program.*

(1e) <u>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.</u>

Response: Fermi 2 has a formal agreement with the TSO (ITC) and an informal protocol with the Reliability Coordinator/Assessor (RC/RA) Midwest ISO, therefore, the requested information is not applicable. However, GDC 17 does not specifically require formal agreements with the TSO nor does it mention communications with the TSO. Compliance with GDC-17, as documented in the Fermi 2 license basis and plant Technical Specifications, is not predicated on such an agreement.

(1f) <u>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).</u>

Response: As previously detailed in the response to question (1b), Fermi 2 does have both formal and informal agreements with the TSO (ITC) and

informal agreements with the RC/RA (Midwest ISO). Prompt notification regarding pre-trip analysis of predicted post trip voltage that results in operation outside acceptance limits is required by both the Operations Protocol RTO-OP-03 and the GIA.

(1g) <u>Describe the low switchyard voltage conditions that would initiate operation of plant degraded voltage protection.</u>

Response: Fermi 2 does not use direct switchyard voltage to activate the degraded voltage relay protection. At Fermi 2, the degraded voltage is sensed at the Essential 4160 VAC buses.

The Division 1 electrical distribution system is supplied from the 120 kV switchyard through one of two 120 kV to 13.2 kV transformers to either one of two 13.2 kV buses. From either of these 13.2 kV buses, underground cabling is routed to Station Service transformer #64. Station Service transformer #64 is a 13.2 kV to 4.16 kV transformer with a non-safety related Automatic Load Tap Changer (ALTC) installed. Station Service transformer #64 has a fixed tap of - 5% and the ALTC is capable of a +10%/-20% voltage regulation. The secondary side of Station Service transformer #64 is connected to buses 64A, 64B and 64C. Bus 64A is a BOP bus while buses 64B and 64C are Essential 4160 VAC buses.

The Division 2 electrical distribution system is a different design configuration. It is supplied from the 345 kV switchyard via a ring bus configuration to Station Service transformer #65. Station Service transformer #65 is a three winding 345 kV to 4.16 kV transformer with a -2.5% fixed tap. One of the secondary connections supplies bus 65G which is the feed to both Reactor Recirculation Pump Motor Generator sets and is non-safety related. The other secondary winding supplies buses 65D, 65E and 65F. Bus 65D is a non-safety related bus while buses 65E and 65F are Essential 4160 VAC buses. Unlike the Division 1 electrical distribution system there is no voltage regulation at the 4160 VAC level, however there are safety related voltage regulators on the Division 2 Essential 480 VAC buses.

At Fermi 2, the degraded voltage protection is based upon the voltage sensed at the Essential 4160 VAC Switchgear. Per Technical Specification 3.3.8.1 the Division 1 degraded voltage setpoints are: voltage between 3873 and 4031 VAC with a time delay between 41.8 and 46.2 seconds. For Division 2, the degraded voltage setpoints are: voltage between 3628 and 3776 VAC with a time delay between 20.33 and 22.47 seconds. Since the degraded voltage is sensed at the Essential 4160 VAC buses, the voltage at the Essential 4160 VAC buses is the switchyard voltage minus the voltage drop between the

switchyard and the Essential 4160 VAC buses. This voltage drop is influenced by the amount of current and the intervening transformers' tap settings and impedances and therefore the voltage drop is dependent upon the amount of power being transferred.

When the secondary undervoltage relays are activated, they cause a Class 1E bus isolation, load shedding to prevent overloading of the associated EDG, transfers, and automatic starting of the associated EDG and load sequencer.

Fermi 2 uses an Electrical Transient Analysis Program (ETAP) computer modeling program to perform load flow studies. For the Essential 4160 buses, the most severe voltage drop is experienced in the Normal Operation - Summer loading category. This loading category results in an analyzed loading of approximately 68 MW for plant loads. Actual operating experience has shown that this loading remains below 50 MW, therefore the analyzed voltage drop is over-conservative. The highest analyzed continuous switchyard voltage that will activate the degraded voltage protection for Division 1 is slightly less than 101.4 kV. The highest analyzed continuous switchyard voltage that will activate the degraded voltage protection for Division 2 is slightly less than 327 kV. Degraded voltage alarms would have come in at slightly less than 102.3 kV and 340 kV respectively. The ESF equipment remains operable to 98.3 kV and 315.5 kV in the respective switchyards.

The following table demonstrates:

(1) The analyzed switchyard voltages which will activate the essential 4160 VAC bus degraded voltage alarm.

(2) The analyzed switchyard voltages which will activate the degraded voltage relay schemes for the essential 4160 VAC buses, at the highest allowed setpoint per TS 3.3.8.1 and cause the bus(es) to separate from the preferred power supply.

(3) The analyzed switchyard voltages which will activate the degraded voltage relay schemes for the essential 4160 VAC buses, at the lowest allowed setpoint per TS 3.3.8.1, which is the basis for ESF equipment operability for voltage limitations.

(4) The lower limits for switchyard voltage as described in the UFSAR and contained within the energy management systems of the offsite entities which monitor the Fermi 2 switchyards.

Summary Table

	Degraded Voltage Alarm (1)	Earliest Separation (2)	ESF Equipment Operability Limit (3)	UFSAR Limit and Transmission Provider Limits (4)
Division 1	102.264 kV	101.364 kV	98.256 kV	112 kV
Division 2	339.825 kV	326.612 kV	315.463 kV	328 kV

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

(2a) Does your NPP's TSO use any analysis tools, an online analytical transmission system studies program, or other equivalent predictive methods to determine the grid conditions that would make the NPP offsite power system inoperable during various contingencies? If available to you, please provide a brief description of the analysis tool that is used by the TSO.

Response: Yes.

ITC uses the real-time contingency analysis provided with the ABB Network Manager System. In this analysis, the results of the State Estimator, for the current network condition, are used as the base case. Up to 974 different contingencies are analyzed, including the loss of the Fermi 2 NPP.

The Midwest ISO Energy Management System (EMS) includes a State Estimator (SE) that currently runs every 90 seconds and Real-Time Contingency Analysis (RTCA) programs that analyze over 7000 contingencies based on the transmission owner's criteria. One of the contingencies analyzed by the Midwest ISO EMS is the trip of the [Fermi 2] NPP. The analysis provides results with respect to thermal, voltage, and voltage drop limit violations.

(2b) Does your NPP's TSO use an analysis tool as the basis for notifying the NPP licensee when such a condition is identified? If not, how does the TSO determine if conditions on the grid warrant NPP licensee notification?

Response: Yes.

ITC uses the above analysis tools, in conjunction with a visual alarm list and procedures, as the basis for determining when conditions warrant Fermi 2 NPP notification in accordance with communication protocols in the GIA and the Operations Protocol RTO-OP-03.

The results of the Midwest ISO RTCA program application contain the specific contingency of the nuclear power plant tripping as the contingent element. Operation outside of the voltage limits for a unit trip contingency would result in notification to the [Fermi 2] NPP per Midwest ISO Operations Protocol RTO-OP-03. If Midwest ISO determines the transmission system is outside of operating criteria, the Midwest ISO will notify the local transmission operator [ITC, who will notify Fermi 2].

(2c) If your TSO uses an analysis tool, would the analysis tool identify a condition in which a trip of the NPP would result in switchyard voltages (immediate and/or long-term) falling below TS nominal trip setpoint value requirements (including NPP licensees using allowable value in its TSs) and consequent actuation of plant degraded voltage protection? If not, discuss how such a condition would be identified on the grid.

Response: Yes.

Procedures and monitoring / predictive analysis tools are in place for this purpose. The ITC analysis tool, in conjunction with Fermi 2 plant analysis, identifies conditions which could actuate the Fermi 2 degraded voltage protection logic and initiate separation from an offsite power source upon a Fermi 2 trip so that Fermi 2 can be informed.

The Midwest ISO RTCA program simulates the loss of [the Fermi 2] NPP and analyzes the post trip condition against the criteria provide by the transmission owner [ITC]. If the conditions are exceeded, the Midwest ISO RC/RA would notify the local transmission operator [ITC] per Midwest ISO [Operations Protocol] RTO-OP-03 [which also requires Fermi 2 to be informed by ITC].

Transient voltage response is not modeled by state estimators and RTCA programs, therefore, it is possible that undervoltage settings or degraded voltage settings may be reached, even though contingency scenarios do not predict it. The annual grid study does model the short term transients associated with postulated contingencies. Various contingencies will result in short term transients achieving the setpoints on the primary under voltage relays, however the length of such transients is less than 1/2 second and then the voltage recovers to a value near to or greater than the initial value which is sufficient to reset the primary under voltage relays before the time delay of 2 seconds is reached. Since the voltage recovers to a value near to or greater than the initial value the secondary undervoltage relays will also reset due to their time delays being much greater than 2 seconds. Therefore Fermi 2 has confidence that any short term transients will not activate the plant undervoltage protection.

(2d) If your TSO uses an analysis tool, how frequently does the analysis tool program update?

Response: Real-time contingency analysis is triggered off State Estimator results. The ITC State Estimator calculates once every minute. Real-time contingency analysis is automatically triggered every 10th run of the State Estimator and can also be triggered on demand.

The Midwest ISO State Estimator runs every 90 seconds and [its] Real-Time Contingency Analysis program runs every 5 minutes or by Midwest ISO Reliability Coordinator action.

(2e) Provide details of analysis tool-identified contingency conditions that would trigger an NPP licensee notification from the TSO.

Response: The Fermi 2 notification from the ITC is based upon State Estimator and RTCA grid conditions. Examples include:

- Pre contingency or post contingency overloading of Fermi-Swan Creek, Fermi-Radka, or Fermi-Shoal 120 kV circuits
- A contingency loss of either Brownstown-Fermi 345 kV circuit
- A contingency loss of any of the three circuits at the Fermi 120 kV switchyard (Fermi-Swan Creek, Fermi-Radka, or Fermi-Shoal)
- Any pre contingency or post contingency voltage violation at the Fermi 345 kV or 120 kV switchyards, such as loss of another generator, loss of a significant transmission line, loss of a large load or loss of the Fermi 2 Plant

If Midwest ISO observes that the transmission system real-time or post contingent analysis data indicates the system to be outside of operating criteria, the Midwest ISO will notify the local transmission operator [ITC, who will notify Fermi 2]. The Midwest ISO criterion for contingency analysis is to monitor all generators greater than100 MW, all non-radial lines above 100 kV, and all transformers with two windings greater than 100 kV. This contingency list is validated with the local transmission operator [ITC] to ensure inclusion of all critical contingencies, and may include lower voltage facilities and smaller generators if deemed critical.

(2f) <u>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?</u>

Response: Yes.

The Operations Protocol RTO-OP-03 requires that Fermi 2 be notified when the ITC RTCA is unavailable. In these circumstances, there are functionally equivalent RTCA systems at the Midwest ISO, MECS and at the DE SOC that could be consulted for grid contingency analyses. In the event that all of these RTCAs were unavailable, Fermi 2 Conduct Manual MOP05, *Control of Equipment* states that Fermi 2 would evaluate the annual grid reliability study conducted by ITC in accordance with UFSAR 8.2.2.5.4 in conjunction with verification from the Midwest ISO, ITC and DE SOC that current grid conditions were not outside the bounds of that study. This arrangement is consistent with the original licensing basis of the Fermi 2 Plant which existed before grid operators had access to RTCA type monitoring programs. Conduct Manual MOP05, *Control of Equipment* also requires a risk assessment in accordance with MMR12, *Equipment out of Service Risk Management* in the unlikely event of the loss of RTCA capability.

The Operations Protocol RTO-OP-03, referenced in subpart (1a) above, provides for the following:

- That should the Transmission Operator lose its ability to monitor or predict the operation of the transmission system affecting offsite 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.

Lastly, the Midwest ISO has developed Abnormal Operating Procedures (AOPs) to guide its transmission system operation for failures of different components of analytical and communication tools. For loss of the Midwest ISO RTCA, Midwest ISO will consider the results of the local transmission operator's [ITC] analytical tools [Note: MECS and DE SOC RTCAs can also be used]. For loss of both sets of tools, the Midwest ISO Operating Engineer

will attempt to use off-line power flow tools to replicate operating conditions and predict contingent operation.

(2g) <u>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?</u>

Response: No.

ITC currently does not have a written procedure that requires post event analysis, but ITC has the capability to perform such analyses. Degraded voltage has not been a problem following any EF2 NPP trip with ITC as the TSO. Had problems been evident, ITC could have compared historical data from PI Historian data before and after the Fermi 2 trip against what the contingency analysis would have predicted for the loss of the EF2 NPP.

There is no formal process for comparing the actual post trip voltages to the post trip contingency voltage results calculated by the Midwest ISO RTCA program. Because many of the Midwest ISO transmission owning member companies have similar RTCA programs, there are many opportunities to compare the results. This results in a high confidence that the RTCA results are accurate. However, if the [post trip] resultant voltages are outside of the criteria, when they are predicted to be within, Midwest ISO would initiate an investigation.

(2h) <u>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?</u>

Response: Not applicable to Fermi 2, since analysis tools are presently in use at ITC and Midwest ISO.

(2i) <u>If an analysis tool is not available, does your TSO perform periodic studies to verify that adequate offsite power capability, including adequate NPP post trip switchyard voltages (immediate and/or long-term), will be available to the NPP licensee over the projected timeframe of the study?</u>

Response: ITC and Midwest ISO analysis tools are presently in use and are rarely unavailable. As discussed in the response to question (2f) above, several other RTCAs are available to monitor real time grid conditions that would be consulted in the event of an ITC RTCA outage. In the event that all of these RTCAs were unavailable, Fermi 2 would rely on the annual grid reliability study conducted by ITC in accordance with UFSAR 8.2.2.5.4 in conjunction with verification with the DE SOC, ITC and Midwest ISO that

current grid conditions were not outside the bounds of that study. This arrangement is consistent with the original licensing basis of the Fermi 2 Plant which existed before grid operators had access to RTCA type monitoring programs.

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

Response: Key assumptions and parameters are not translated into ITC procedural guidance. The response to question (2f) above discusses how RTCA outages would be addressed.

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

Response: The response to question (2f) above discusses how RTCA outages would be addressed. This includes verification with the DE SOC, ITC and Midwest ISO that current grid conditions were not outside the bounds of that study.

(2j) If your TSO does not use, or you do not have access to the results of an analysis tool, or your TSO does not perform and make available to you periodic studies that determine the adequacy of offsite power capability, please describe why you believe you comply with the provisions of GDC 17 as stated above, or describe what compensatory actions you intend to take to ensure that the offsite power system will be sufficiently reliable and remain operable with high probability following a trip of your NPP.

Response: Not applicable to Fermi 2, since the ITC utilizes analysis tools and communicates the applicable results to the plant. As discussed above, several additional RTCA systems are available to monitor grid conditions in the event of an outage of the ITC RTCA system. Annual grid studies are also available and would be used to determine operability of the offsite circuits in the event of a loss of all of the available RTCA systems.

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.

(3a) If the TSO notifies the NPP operator that a trip of the NPP, or the loss of the most critical transmission line or the largest supply to the grid would result in switchyard voltages (immediate and/or long-term) below TS nominal trip

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

Response: At Fermi 2, degraded voltage protection for ESF buses is sensed at the 4160 VAC ESF buses, and not at the 120 kV or 345 kV switchyards. TSO notifications to Fermi 2 occur when pre or post contingent 120 kV or 345 kV switchyard voltages are outside of UFSAR values, and these values are conservative to those that would result in actuation of degraded voltage protection as described in the response to question (1g).

Upon notification by the TSO that 120 kV or 345 kV switchyard voltages are below UFSAR values for pre or post contingent operation, the affected offsite circuit(s) will be considered inoperable if loss of the Fermi 2 generator is the N-1 Contingency that would cause the degraded switchyard voltage condition to occur. The bases for Technical Specification 3.8.1 are consistent with this action. They state that GDC-17 requires that provisions be included to minimize the probability of losing electric power from any of the remaining supplies (i.e. offsite circuit(s)) as a result of or coincident with the loss of power generated by the nuclear power unit.

If the degraded voltage is from an N-1 contingency other than the loss of the Fermi 2 generator, then this postulated contingency on the transmission grid would not be used as a basis for Technical Specification operability determinations since:

- Such events are only postulated and have not actually occurred,
- The offsite power circuits remain capable of effecting a safe shutdown and mitigating the effects of an accident, and
- The GDC 17 criterion discussed in the Generic Letter is still met, i.e., loss of power from the transmission network would not occur as a result of loss of power generated by Fermi 2.

If the N-1 Contingency is from a grid component other than the Fermi 2 generator then risk mitigating actions would be directed in accordance with MMR12, *Equipment Out Of Service Risk Management.*

(3b) If onsite safety-related equipment (e.g., emergency diesel generators or safety-related motors) is lost when subjected to a Double Sequencing (Loss of Coolant Accident (LOCA) with delayed Loss of Offsite Power (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

<u>actuation signal during this condition, is the equipment considered inoperable? If not, why not?</u>

Response: If onsite safety-related equipment was lost when subjected to a Double Sequencing (LOCA with delayed LOOP event) and was incapable of performing its safety functions as a result of its response to multiple emergency actuation signals, the equipment would be declared inoperable.

Double Sequencing is not in the Fermi 2 licensing basis and Fermi 2 is not designed or analyzed for Double Sequencing scenarios, so equipment will not be declared inoperable in anticipation of such a response. Therefore, GDC 17 and Technical Specifications do not apply.

While onsite safety related equipment is not declared inoperable as a result of postulated Double Sequencing scenarios, offsite circuits would be declared inoperable if they were incapable of maintaining required voltage as a result of the trip of the Fermi 2 NPP due to a LOCA (or any other trip initiator) as described in (3a) above.

In conclusion, Double Sequencing is outside of the design and licensing bases of the plant. However, offsite circuits are declared inoperable per Technical Specifications Limiting Condition for Operation (LCO) 3.8.1 when projected switchyard voltages are insufficient to ensure the proper operation of required safety systems as a result of a trip of the Fermi 2 nuclear power plant. This limits the time that the plant can be subjected to conditions where degraded voltage could lead to Double Sequencing in the event of a LOCA. Therefore, no other specific compensatory measures are planned to address Double Sequencing that will not already be taken in the event of a degraded voltage situation alone.

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

Response: Fermi 2 has not performed an evaluation of onsite safety-related equipment to determine whether it will operate as designed following a Double Sequencing event because Double Sequencing is not in the Fermi 2 licensing basis and Fermi 2 is not designed or analyzed for Double Sequencing scenarios. Therefore, GDC 17 and Technical Specifications do not apply.

EPRI has performed generic studies on the impact of equipment from Double Sequencing scenarios. EPRI Reports 1007966, *Double Sequencing Analysis*

for BWRs: The Probability and Consequences of Double Sequencing Nuclear Power Plant Safety Loads, Considerations Specific to Boiling Water Plants, and 1009110, *The Probability and Consequences of Double Sequencing Nuclear Power Plant Safety Loads*, conclude that "Critical electrical components are not likely to be damaged or made unavailable as a result of Double Sequencing."

Therefore no other specific compensatory measures will be implemented to address Double Sequencing that will not already be taken in the event of a degraded voltage situation alone. However, evaluation of Double Sequencing has been added to the Fermi 2 corrective action system for further consideration, if warranted.

(3d) <u>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.</u>

Response: No.

Offsite sources are considered operable unless either their voltage and/or frequency is outside of the UFSAR values or would be as a result of the trip of the Fermi 2 Generator. Guidance for Offsite Circuit operability is located in Technical Specification 3.8.1, UFSAR 8.2.2.5 and in Fermi 2 Conduct Manual MOP05, *Control of Equipment*. However, as discussed in the response to question (3a), receipt of a N-1 contingency notification would require 10 CFR 50.65(a)(4) risk mitigating actions in accordance with procedure MMR12, *Equipment Out Of Service Risk Management*.

Postulated contingencies on the transmission grid are not used as a basis for Technical Specifications operability determinations since:

- Such events are only postulated and have not actually occurred,
- The offsite power circuits remain capable of effecting a safe shutdown and mitigating the effects of an accident, and
- The GDC 17 criterion discussed in the Generic Letter is still met, i.e., loss of power from the transmission network would not occur as a result of loss of power generated by Fermi 2.

(3e) <u>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</u>

that the offsite power system and safety-related components will remain operable when switchyard voltages are inadequate.

Response: The response to this question is answered in the responses to questions (3a), (3b), (3c), and (3d) above.

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

Response: As discussed in the responses (3b) and (3c), there are no compensatory actions performed related to double sequencing which is outsde of the Fermi 2 design and licensing basis. Therefore there are no compensatory measures on which to be trained or evaluated. For the risk mitigation compensatory actions described in responses (3a) and (3d), operators are trained and evaluated (tested) as follows:

Operations – Lesson Plan LP-OP-802-1004, *PSA Fundamentals and Introduction to Auto EOOS* – is presented to operations personnel. This includes information on risk assessment fundamentals and use of computer software to assess risk during maintenance planning and equipment malfunctions during normal plant operations. Senior Reactor Operators receive the software training.

Lesson Plan LP-OP-802-2001, *Integrated Electrical Events* includes discussion of compensatory actions and the bases for these actions using station procedures.

Qualification Card QC-OP-725-0200/OS-OP-725-0000, *Licensed SRO Qualification Program* includes training and evaluation implementing Technical Specification requirements for determining and acting if offsite voltages are outside predetermined values or if the station is notified by Midwest ISO, ITC, or DE SOC that post trip voltages would be outside required limits.

Operations Required Reading 06-03-05, *Monitoring and Assessment of Offsite Sources* was presented in March of 2006. Topics included:

- A new section in Conduct Manual MOP05, *Control of Equipment* that provides a single source for information and actions required relating to offsite power, including:
  - o Background information concerning plant equipment and monitoring devices which could impair the reliability of the offsite power sources.

  - o Requirements for periodic communications during normal operations between the plant and the CSS.
  - o Specific time requirements for communications to be made to and from the plant and the CSS if grid conditions degrade or equipment which may affect reliability is impacted, including a list of this equipment.
  - o Requirements to initiate risk assessments based on grid conditions.
- A new attachment to Operations Department Expectation ODE-12, *LCOs* to be used during shiftly communications with the CSS to verify the status of offsite lines.
- UFSAR voltage limits and their inclusion in ODE-12, *LCOs*.

Information presented by Operations Required Reading 06-03-05, *Monitoring and Assessment of Offsite Sources* in March of 2006 was immediately incorporated into objectives in the operator qualification cards in QC-OP-725-0200/OS-OP-725-0000, *Licensed SRO Qualification Program* and QC-OP-725-0100/OS-OP-725-0000, *Licensed RO Qualification Program.* Also, lesson material for LP-OP-802-2002, *Integrated Electrical Events* was modified to include these new procedure sections.

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

(4a) Do the NPP operators have any guidance or procedures in plant TS bases sections, the final safety analysis report, or plant procedures regarding situations in which the condition of plant-controlled or -monitored equipment (e.g., voltage regulators, auto tap changing transformers, capacitors, static VAR compensators, main generator voltage regulators) can adversely affect the operability of the NPP offsite power system? If so, describe how the operators are trained and tested on the guidance and procedures.

Response: Yes.

The main generator automatic voltage regulator (AVR), 480 VAC voltage regulators and load tap changing transformers are the only devices referenced in (4a) applicable to Fermi 2. Neither Technical Specifications, UFSAR, nor System Operating Procedures (SOP) currently prohibit manual control of the main generator AVR, 480 VAC Voltage Regulator or tap changers. Fermi 2 System Operating Procedure SOP 23.118, *Main Generator and Generator Excitation* requires Operations to contact the CSS if the AVR is placed in Manual. Alarm Response Procedure (ARP) 4D61, *AVR on Manual Control*, references the same action. Regarding auto tap changing transformers, guidance is provided in ARP 9D22, *Div 1 Bus Voltage Low*, to dispatch an operator and verify proper tap changer operation. Conduct Manual MOP05,

Control of Equipment requires contacting the CSS if any of the above listed voltage regulating devices are not in the normal automatic mode. Conduct Manual MOP05, *Control of Equipment* also states that automatic tap changers, 480 VAC voltage regulators and main generator automatic voltage regulator functionality is required to maintain ESF Bus voltage to ensure all electrical components can function as required over the full range of offsite circuit voltages specified in the UFSAR.

The Load Tap Changer (LTC) on Station Service Transformer (SS)64 is discussed in UFSAR Sections 8.2.1.3, 8.2.2.5.1, and 8.3.1.1.3. The 480VAC bus voltage regulators are discussed in UFSAR Section 8.3.1.1.3 and Table 3.10-1. UFSAR Figure 8.3-01 shows the SS64 LTC and 480VAC Bus voltage regulators, Figure 8.3-02 shows the SS64 LTC, Figure 8.3-03 shows the voltage regulators on 480VAC buses 72E and 72F and Figure 8.3-04 shows the voltage regulators on 480VAC buses 72EC and 72ED. The UFSAR figures include the amount of regulation provided.

Operators are trained and evaluated (tested) as follows:

Lesson Plan LP-OP-802-2001, *Integrated Electrical Events* include discussion of compensatory actions and the bases for these actions implemented such as those described in Conduct Manual MOP05, *Control of Equipment.* USFAR limits, Technical Specifications bases and the relation to plant procedures are discussed.

Qualification Card QC-OP-725-0200/OS-OP-725-0000, *Licensed SRO Qualification Program* includes training and evaluation implementing Technical Specification requirements for determining and acting if offsite voltages are outside predetermined values or if the station is notified by Midwest ISO, ITC, or DE SOC that post trip voltages would be outside required limits. Also included is training and evaluation for required communications to be conducted with the grid operator during times when components affecting the stability of the grid are not operating properly, normal shiftly updates on system status or upcoming maintenance in accordance with Conduct Manual MOP05, *Control of Equipment.*

Qualification Card QC-OP-725-0100/OS-OP-725-0000, *Licensed RO Qualification Program* includes training and evaluation for required communications to be conducted with the grid operator during times when components affecting the stability of the grid are not operating properly such as those described in Conduct Manual MOP05, *Control of Equipment.*

Lesson Plan LP-OP-202-06R1, *Scenario 2* was presented in the first cycle of training for 2006. It allows the operators to walkthrough a new procedure section of the General Operating Procedure 22.000.04, *Plant Shutdown From 25% Power* for conducting a plant shutdown when tripping the turbine will cause a loss of offsite power.

Operations Required Reading 06-03-05, *Monitoring and Assessment of Offsite Sources* was presented in March of 2006. Topics included:

- A new section in Conduct Manual MOP05, *Control of Equipment* that provided a single source for information and actions required relating to offsite power, including:
  - o Background information concerning plant equipment and monitoring devices which could impair the reliability of the offsite power sources.
  - o Requirements for periodic communications during normal operations between the plant and the CSS.
  - o Specific time requirements for communications to be made to and from the plant and the CSS if grid conditions degrade or equipment which may affect reliability is impacted, including a list of this equipment.
  - o Requirements to initiate risk assessments based on grid conditions.
- A new attachment to ODE-12, *LCOs* to be used during shiftly communications with the CSS to verify the status of offsite lines.
- UFSAR voltage limits and their inclusion in ODE-12, *LCOs*.

Information presented by Operations Required Reading 06-03-05, *Monitoring and Assessment of Offsite Sources* in March of 2006 was immediately incorporated into objectives in the operator qualification cards in QC-OP-725-0200/OS-OP-725-0000, *Licensed SRO Qualification Program* and QC-OP-725-0100/OS-OP-725-0000, *Licensed RO Qualification Program*. Also, lesson material for LP-OP-802-2002,*Integrated Electrical Events* was modified to include these new procedure sections.

(4b) <u>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.</u>

Response: Not Applicable, as the UFSAR and plant procedures do 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 to deliver adequate ESF Bus voltage over the full range of offsite circuit voltages as described in the UFSAR.

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

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

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

(5a) Is a quantitative or qualitative grid reliability evaluation performed at your NPP as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4) before performing grid-risk-sensitive maintenance activities? This includes surveillances, post-maintenance testing, and preventive and corrective maintenance that could increase the probability of a plant trip or LOOP or impact LOOP or SBO coping capability, for example, before taking a risk-significant piece of equipment (such as an EDG, a battery, a steam-driven pump, an alternate AC power source) out-of-service?

Response: Yes.

A blended (qualitative and quantitative) grid reliability evaluation is performed at Fermi prior to removing any risk significant equipment from service for maintenance in accordance with Fermi Conduct Manual MMR12, *Equipment Out of Service Risk Management*. This is accomplished through the utilization of electronic evaluation of all scheduled activities, including surveillances, post-maintenance testing, preventive and corrective maintenance, by the Equipment Out Of Service (EOOS) / Computer Aided Fault Tree Analysis (CAFTA) computer program suite. This includes all scheduled activities that may impact the availability of the incoming offsite power lines. From a qualitative standpoint, the operating crew communicates with the TSO (through the DE SOC) via shiftly phone calls to ensure that the offsite power supply remains available and there are no upcoming events that are known that will adversely affect their availability. Adjustments to the availability of the offsite power supplies or offsite power related initiating event frequencies would be considered and implemented by the operating shift in accordance with Conduct Manual MMR12, *Equipment out of Service Risk Management*.

(5b) Is grid status monitored by some means for the duration of the grid-risk-sensitive maintenance to confirm the continued validity of the risk assessment and is risk reassessed when warranted? If not, how is the risk assessed during grid-risk-sensitive maintenance?

Response: Yes.

The grid status is monitored through voltage and frequency alarms located in the Control Room, as well as individual voltage meters and alarms that will indicate potential problems with any of the incoming lines or breakers as described in the response to question (1c).

As the plant configuration changes during the performance of maintenance on grid-risk-sensitive equipment, it is reassessed in accordance with Conduct Manual MMR12, *Equipment out of Service Risk Management* through the utilization of the Auto EOOS program. As equipment is logged out of service or mitigating event frequencies are adjusted, the Core Damage Frequency and Large Early Release Frequency are recalculated and actions taken as appropriate. From a qualitative standpoint, the operating crew communicates with the TSO (through the DE SOC) via shiftly phone calls (refer to the response to (5g)) to ensure that the offsite power supply remains available and there are no upcoming events that are known that will adversely affect their availability. Adjustments to the availability of the offsite power supplies or initiating event frequencies would be considered and implemented by the operating shift in accordance with MMR12, *Equipment out of Service Risk Management*.

(5c) Is there a significant variation in the stress on the grid in the vicinity of your NPP site caused by seasonal loads or maintenance activities associated with critical transmission elements? Is there a seasonal variation (or the potential for a seasonal variation) in the LOOP frequency in the local transmission region? If the answer to either question is yes, discuss the time of year when the variations occur and their magnitude.

Response: No.

There is no significant seasonal variation on stress on the ITC grid because the ITC grid is managed so that NERC Energy Emergency Alerts are infrequent occurrences. In regards to inadequate generation, ITC would order the shedding of firm load to alleviate operating emergencies if necessary. Transmission paths are the responsibility of both Midwest ISO and ITC and scheduled outages are studied to determine the effects on the grid before they are allowed to proceed. For unscheduled outages, remedial actions are taken

based on the contingencies presented and reliability directives from the Transmission Operator could include the shedding of firm load if necessary to restore reliability of the grid.

After a [Midwest ISO] review of Energy Emergency Alerts within the Midwest ISO Reliability Footprint, [it has been concluded that] there is no correlation between grid stress and seasonal load or maintenance activities.

There is no known significant seasonal variation in the LOOP frequency in the local transmission region. The recently completed update of the Fermi total LOOP frequency (completed in conjunction with ABS Consulting) confirmed that there is no significant seasonal variation in the LOOP frequency in the local transmission region.

(5d) <u>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?</u>

Response: No.

As part of Fermi's configuration risk management program, time related variations (e.g., grid instability, severe weather) are not considered a configuration change. They are only explicitly evaluated when the conditions are present or could potentially occur.

Severe weather, switchyard maintenance and test activities, and other events (not only grid specific) are routinely considered within our Configuration Risk Management (CRM) model.

Fermi's CRM program procedures (Conduct Manual MMR12, *Equipment out of Service Risk Management* and MMR Appendix H, *On-line Maintenance Risk Matrix*) require increased controls on maintenance during the described conditions. Risk is usually not calculated solely due to changes in grid reliability (i.e., it is assessed in conjunction with plant equipment being out of service).

(5e) <u>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?</u>

Response: Yes.

Fermi 2 has contact with the TSO (through the DE SOC) on a shiftly periodicity. It is at this time that any current or anticipated grid conditions that may warrant consideration in performing grid-risk-sensitive maintenance are requested to be identified so that risk mitigation actions can be considered. In addition, the TSO is contractually required to notify Fermi 2 when grid conditions degrade to the point where adequate voltage (less than the Safe Shutdown requirement) either does not exist or cannot be assured in the event of a grid disturbance (Fermi plant trip or other single grid component failure). The coordination of work activities with the TSO is further discussed in the response to questions (6a) and (6b).

(5f) <u>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.</u>

Response: As discussed in the response to question (1b), a formal agreement and informal protocol exist such that Fermi 2 personnel are promptly alerted to a worsening grid condition *regardless* of whether a maintenance activity is in progress or not.

(5g) <u>Do you contact your TSO periodically for the duration of the grid-risk-sensitive maintenance activities?</u>

Response: Yes.

Fermi Conduct Manual MOP05, *Control of Equipment* directs that communications between Fermi 2 Operators and the CSS shall be performed shiftly to ensure vital information regarding offsite line status and Fermi 2 generation and equipment capability is conveyed. The communication between Operations and the CSS is to enable Operations to obtain up-to-date information on existing and projected transmission system reliability for use in ensuring offsite circuit operability, maintaining a current and valid maintenance risk assessment, and in managing potential changing risk. The information that Fermi 2 provides the CSS regarding generation capabilities and status of equipment affecting the transmission system is used to update the State Estimator and RTCA. The following are examples of procedurally driven communications / actions:

- Determination of which offsite lines are energized and available as an offsite feed.
- Determination if any activity is scheduled in the next 12 hours that would deenergize or degrade the reliability of the offsite line to being a single failure away from deenergization.

- If a line is determined NOT to be a reliable offsite feed an Emergent Risk Evaluation shall be performed in accordance with 10 CFR 50.65(a)(4).
- Determination of the status of the State Estimator and RTCA.
- If no State Estimator or RTCA is available a Risk Evaluation shall be performed IAW 10 CFR 50.65(a)(4).
- Fermi 2 Operations shall contact the CSS of any abnormal plant conditions that could reasonably result in a plant shutdown. Notification shall be made as soon as possible.
- Fermi 2 Operations shall contact the CSS of any scheduled downpowers and plant shutdowns, including time, length and magnitude of derates.
- Fermi 2 Operations shall contact the CSS of any changes to derates previously communicated to the DE SOC.
- Fermi 2 Operations shall notify the CSS of the status of components that affect the transmission system. Items included are:
  - Main generator AVR in Manual.
  - SST 64 Load Tap Changer not in AUTO.
  - Generator Real or Reactive Load limitations.
  - Combustion Turbine Generator unavailability.
  - Emergency switching operations.
  - 72E, 72F, 72EC or 72ED 480 Voltage Regulators not in AUTO.
  - Offsite voltage limitations due to a failed voltage regulator or load tap changer.

Fermi 2 Conduct Manual MOP04, *Shift Operations* gives procedural guidance regarding Detroit Edison and ITC Shutdown Requests and Switching Operations. Included in the procedure is:

- Operations Engineer review of Requests for Shutdown
- Directions for performing risk assessment in accordance with 10 CFR 50.65(a)(4).
- Work Control scheduling.
- Ensuring adequate coordination between ITC and Detroit Edison.

(5h) <u>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.</u>

Response: Operators are trained and evaluated (tested) as follows:

Operations – Lesson Plan LP-OP-202-054A4, *Electrical Topics/Grid Stability* lesson was presented in Licensed Operator Requalification Training Program in the fall of 2005 which included relationships between DE SOC, Midwest ISO, ITC, and Control Room personnel, the purpose and function of State

Estimators and RTCAs, procedure requirements if voltages are determined to be out of specification, actions when notified analysis cannot be performed, and when to declare offsite circuits inoperable.

Operations Required Reading 06-03-05, *Monitoring and Assessment of Offsite Sources* was presented in March of 2006. Topics included:

- A new section in Conduct Manual MOP05, *Control of Equipment* that provided a single source for information and actions required relating to offsite power, including:
  - Background information concerning plant equipment and monitoring devices which could impair the reliability of the offsite power sources.
  - Requirements for periodic communications during normal operations between the plant and the CSS.
  - Specific time requirements for communications to be made to and from the plant and the CSS if grid conditions degrade or equipment which may affect reliability is impacted, including a list of this equipment.
  - Requirements to initiate risk assessments based on grid conditions.
- A new attachment to ODE-12, *LCOs* to be used during shiftly communications with the CSS to verify the status of offsite lines.
- UFSAR voltage limits and their inclusion in ODE-12, *LCOs*.

Information presented by Operations Required Reading 06-03-05, *Monitoring and Assessment of Offsite Sources* in March of 2006 was immediately incorporated into objectives in the operator qualification cards in QC-OP-725-0200/OS-OP-725-0000, *Licensed SRO Qualification Program* and QC-OP-725-0100/OS-OP-725-0000, *Licensed RO Qualification Program*. Also, lesson material for LP-OP-802-2002, *Integrated Electrical Events* was modified to include these new procedure sections.

Operators are not evaluated on the formal protocol. The information in the protocol which operators are required to use or comply has been incorporated into station procedures MOP05, *Control of Equipment* and ODE-12, *LCOs*. Operators are evaluated on the use of the procedures during on the job training task evaluations included in Qualification Card QC-OP-725-0200/OS-OP-725-0000, *Licensed SRO Qualification Program* and Qualification Card QC-OP-725-0100/OS-OP-725-0000, *Licensed RO Qualification Program*.

Maintenance – Currently no Fermi maintenance personnel are trained on the relationships between the TSO and the NPP. The Fermi switchyards are primarily maintained by ITC which qualifies its own people. During activities where ITC is performing maintenance, Fermi 2 Operations department personnel control tagging of the equipment and a Maintenance Supervisor

liaison from Fermi monitors the activities. The ITC personnel performing activities on the Fermi Switchyards are required to complete Lesson Plan LP-EM-763-0001, *Edison Switchyard Foreign Labor* which informs them of nuclear requirements and procedures to be followed.

(5i) If your grid reliability evaluation, performed as part of the maintenance risk assessment required by 10 CFR 50.65(a)(4), does not consider or rely on some arrangement for communication with the TSO, explain why you believe you comply with 10 CFR 50.65(a)(4).

Response: The grid reliability evaluation does include shiftly phone calls made to the TSO through the DE SOC, as well as the requirement for the TSO to notify Fermi when conditions are discovered that may affect grid reliability.

(5j) If risk is not assessed (when warranted) based on continuing communication with the TSO throughout the duration of grid-risk-sensitive maintenance activities, explain why you believe you have effectively implemented the relevant provisions of the endorsed industry guidance associated with the Maintenance Rule.

Response: Risk is assessed as any emergent conditions are identified, including grid reliability issues identified by Fermi 2 personnel or by communications from the TSO.

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

Response: Not applicable, as procedures, formal and informal agreements and informal protocols are in place to trigger condition assessments.

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).

(6a) Does the TSO coordinate transmission system maintenance activities that can have an impact on the NPP operation with the NPP operator?

Response: Yes.

The TSO in Detroit Edison Company's service area is the International Transmission Company (ITC). The Detroit Edison electrical system operating authority is referred to as the Central System Supervisor (CSS) located at the

Detroit Edison System Operations Center (DE SOC). The TSO operating authority communicates and coordinates with the CSS on scheduled and emergent maintenance activities. Detroit Edison's Real-Time Contingency Analysis (RTCA) program runs in parallel with the ITC's and Midwest ISO's RTCA programs and discrepancies are discussed and resolved on a continuous basis. This information is discussed with the NPP operator as described in the responses to question (1b) so operability and Maintenance Rule risk evaluations can promptly be made.

Pre-planned [transmission system] maintenance activities are studied and approved by the Midwest Independent Transmission System Operator, Inc. (Midwest ISO) in accordance with the *Midwest ISO Outage Coordination Business Practice Manual.*

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

The [Midwest ISO] 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.

Pre-planned maintenance activities are also governed by Exhibit C of the GIA between Detroit Edison and ITC. Exhibit C of the GIA invokes Augmented Quality Program AQP-0001, *120 kV and 345 kV Switchyard, Transformers, and Peaker CTG 11-1 Configuration* and/or Augmented Quality Program AQP-0002, *ITC-Fermi 2 Interface – 120 kV and 345 kV Switchyards*, depending on whether the affected equipment is under the jurisdiction of the DE SOC or the ITC. The ITC communicates information regarding pre-planned maintenance activities directly to the DE SOC via formal memorandum, and the DE SOC then communicates this information to the EF2 NPP. Fermi 2 personnel initiate a Condition Assessment Resolution Document (CARD) that describes the proposed maintenance at the level needed to produce a work request. Operations Conduct Manual *MOP04, Shift Operations*, proceduralizes the requirement to submit a CARD. The intent of

the CARD is to schedule the activity, coordinate the activity between Detroit Edison and ITC and to trigger a risk assessment review as required by 10 CFR 50.65(a)(4). These scheduled maintenance activities are discussed among ITC, DE SOC and the EF2 NPP as necessary before any transmission outage is allowed to proceed, and contingency analysis applications are modeled and run multiple times, starting several weeks in advance, continuing up to and including the day prior to the start of any transmission outage.

(6b) Do you coordinate NPP maintenance activities that can have an impact on the transmission system with the TSO?

Response: Yes.

Fermi 2 Conduct Manual MOP05, *Control of Equipment* requires that CSS be notified whenever equipment that affects the transmission system is degraded. Components referred to under this procedure are the main generator AVR, SST 64 load tap changer, 480 VAC voltage regulators, offsite voltage limitations due to a failed voltage regulator or load tap changer, main generator real or reactive load limitations, CTG's and following any emergency switching operations.

Fermi 2 Operations would be expected to immediately work to resolve degraded conditions with the Detroit Edison Central System Supervisor (CSS) at the DE SOC. The CSS would work with the TSO (ITC) to determine the best way to resolve the issue. Augmented Quality Program documents AQP-0001 and AQP-0002 (referenced in the response to question (6a)) are formal protocols between Fermi 2 and the DE SOC and ITC (respectively) which require these offsite entities to work with plant personnel in the timely development and implementation of corrective actions for deficiencies that could lead to the inability to meet established performance criteria.

(6c) Do you consider and implement, if warranted, the rescheduling of grid-risk-sensitive maintenance activities (activities that could (i) increase the likelihood of a plant trip, (ii) increase LOOP probability, or (iii) reduce LOOP or SBO coping capability) under existing, imminent, or worsening degraded grid reliability conditions?

Response: Yes.

For degraded grid reliability conditions, maintenance on grid-risk-sensitive equipment or on equipment that mitigates a loss of offsite power would not be started (consistent with the guidelines provided in Fermi Conduct Manual MMR Appendix H, *On-line Maintenance Risk Matrix*).

(6d) <u>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.)</u>

Response: Yes.

For existing degraded grid conditions, grid-risk-sensitive maintenance would be evaluated utilizing the existing process outlined in Conduct Manual MMR12, *Equipment out of Service Risk Management* and also in MMR Appendix H, *On-line Maintenance Risk Matrix.* Guidelines are included that recommend not starting maintenance on grid-risk-sensitive equipment, including Standby Feedwater (SBFW), High Pressure Coolant Injection (HPCI), Reactor Core Isolation Cooling (RCIC), Emergency Diesel Generators (EDGs) and Combustion Turbine Generator (CTG 11-1), when there is an increased probability of the loss of 120 kV or 345 kV power. If maintenance has already started, equipment would be restored to service in as short a time frame as possible. Fermi Conduct Manual MWC07, *Online Scheduling Process*, contains provisions to evaluate the work on the daily scheduling plan in the event that a major course correction is required, which includes assessing the risk of the required changes. For all planned System Outages, Conduct Manual MOP05, *Control of Equipment* describes the Protected Systems program, which protects other equipment based on its importance to plant production and core damage risk.

(6e) <u>Describe the actions associated with questions (6a) through (6d) 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.</u>

Response: Actions taken and procedures that govern them are individually identified and discussed in the responses to questions (6a) through (6d).

Interfaces with the TSO (ITC) or DE SOC for coordinating maintenance on equipment under their jurisdiction are well described in formal protocols, and have been incorporated in Fermi 2 procedures. While there is new and increased emphasis on TSO / DE SOC coordination for some equipment identified in the response to question (6b), the process for such communications and coordination has not substantially changed. The Fermi 2 Risk Management Program is also well developed, recognizes grid related risk

impacts, is proceduralized, and has been in place as procedures in the plant Conduct Manuals for about four years. As a result, the described actions in responses to questions (6a) through (6d) have been consistently and effectively accomplished at Fermi 2, ITC and DE SOC for some time, and expectations are that this will continue to be so in the future.

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

Response: Operators are trained and evaluated (tested) as follows:

Operations – Lesson Plan LP-OP-802-1004, *PSA Fundamentals and Introduction to Auto EOOS* – is presented to Operations personnel. This lesson includes information on risk assessment fundamentals and use of computer software to assess risk during maintenance planning and equipment malfunctions during normal plant operations. Senior Reactor Operators receive the software training.

Operations Senior Reactor Operators who assume roles as work control supervisors complete *QP-OP-915-0014, Field Support Supervisor Operations Guide.* Topics covered in this guide include: Work Control procedure guidelines, reviewing work activities for risk using the protected systems program in Conduct Manual MOP05, *Control of Equipment,* providing protection for outside organizations such as the TSO, and quantifying risk for preplanned work activities involving the grid using the Auto EOOS software in accordance with MMR12, *Equipment out of Service Risk Management.* This qualification guide includes evaluation from a qualified operator to ensure the trainee can complete required actions.

Operations Required Reading 06-03-05, *Monitoring and Assessment of Offsite Sources* was presented in March of 2006. Topics included:

- A new section in Conduct Manual MOP05, *Control of Equipment* that provided a single source for information and actions required relating to offsite power, including:
  - Background information concerning plant equipment and monitoring devices which could impair the reliability of the offsite power sources.
  - Requirements for periodic communications during normal operations between the plant and the CSS.
  - Specific time requirements for communications to be made to and from the plant and the CSS if grid conditions degrade or equipment which may affect reliability is impacted, including a list of this equipment.

  - o Requirements to initiate risk assessments based on grid conditions.
- A new attachment to ODE-12, *LCOs* to be used during shiftly communications with the CSS to verify the status of offsite lines.
- UFSAR voltage limits and their inclusion in ODE-12, *LCOs*.

Information presented by Operations Required Reading 06-03-05, *Monitoring and Assessment of Offsite Sources* in March of 2006 was immediately incorporated into objectives in the operator qualification cards in QC-OP-725-0200/OS-OP-725-0000, *Licensed SRO Qualification Program* and QC-OP-725-0100/OS-OP-725-0000, *Licensed RO Qualification Program.* Also, lesson material for LP-OP-802-2002, *Integrated Electrical Events* was modified to include these new procedure sections.

Maintenance – Currently no Fermi maintenance personnel are trained on the relationships between the TSO and the NPP. The Fermi switchyards are primarily maintained by ITC which qualifies its own people. During activities where ITC is performing maintenance, Fermi 2 Operations department personnel control tagging of the equipment and a Maintenance Supervisor liaison from Fermi monitors the activities. The ITC personnel performing activities on the Fermi Switchyards are required to complete Lesson Plan LP-EM-763-0001, *Edison Switchyard Foreign Labor* which informs them of nuclear requirements and procedures to be followed.

(6g) <u>If there is no effective coordination between the NPP operator and the TSO regarding transmission system maintenance or NPP maintenance activities, please explain why you believe you comply with the provisions of 10 CFR 50.65(a)(4).</u>

Response: Not applicable, as procedures, formal agreements and informal protocols are in place to trigger 10 CFR 50.65(a)(4) assessments.

(6h) <u>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.</u>

Response: Not Applicable, as Fermi 2 personnel effectively implement appropriate risk management actions.

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

Response: Not applicable, as Fermi 2 personnel effectively implement risk management actions and no additional actions are planned at this time.

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

Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate be able to withstand an SBO for a specified duration and recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches for complying with 10 CFR 50.63.

7. Procedures for identifying local power sources that could be made available to resupply your plant following a LOOP event. (Local power sources include items such as nearby or onsite gas turbine generators, portable generators, hydro generators, and black-start fossil power plants.)

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

> Procedures should include the actions necessary to restore offsite power and use nearby power sources when offsite power is unavailable. As a minimum, the following potential causes for loss of offsite power should be considered:
>
> - Grid undervoltage and collapse
> - Weather-induced power loss
> - Preferred power distribution system faults that could result in the loss of normal power to Essential switchgear buses

(7a) <u>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.</u>

Response: On site CTG's are started to supply plant loads when directed by AOP 20.300.Offsite, *Loss of Offsite Power*, 20.300.120kV, *Loss of 120kV*, and 20.300.SBO, *Station Blackout*. These actions are performed without the need for prior permission from the CSS or ITC.

The Midwest ISO restoration process coordinates the development of individual Transmission Owner Restoration Plans. Midwest ISO conducts

reviews, workshops and drills to ensure the effectiveness of the restoration plan.

The Midwest ISO restoration process will provide updates to the TSO [ITC] and NPP [Fermi 2] on transmission system status during emergency restoration, and will give the highest priority to restoring power to essential affected nuclear facilities, per NERC standard EOP-005-0.

However, due to the myriad of possible restoration scenarios, no specific power sources to resupply NPPs [Fermi 2] are identified. 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 units or cranking paths from non-blacked out areas. Regardless of the scenario, there is a clear recognition of the importance of expeditious restoration of an NPP [Fermi 2] offsite power source.

The need for priority restoration of power to the EF2 NPP is recognized and acknowledged in the GIA, as referenced in subpart (1a) above, and provides for the following:

- That in the event of a loss of the Fermi offsite power supply, transmission lines terminating at the Fermi power plant will be returned to service based upon the following criteria:

  Note: With regard to station blackout, Fermi 2 is an alternate AC plant. Federal law requires that Fermi 2 be able to withstand a loss of all AC power for 4 hours without sustaining damage to the reactor core.

  - Highest priority for blackout restoration shall be given to restoring power to the Fermi 2 120 kV switchyard from offsite power.
  - Should incoming lines to the Fermi 2 power plant be damaged, highest priority will be given to restoring one 120 kV line to the Fermi 2 power plant. In the event of significant delay in the restoration of the 120 kV system, then restoration of one 345 kV line to the Fermi power plant shall be expedited.
  - Repair crews engaging in power restoration activities for Fermi shall be given the highest priority for manpower, equipment and materials.
  - Blackout restoration procedures will address transmission lines capable of transferring power to restart those units which are in turn capable of supplying offsite power to the Fermi power plant.

(7b) Are your NPP operators trained and tested on identifying and using local power sources to resupply your plant following a LOOP event? If so, describe how.

Response: Operators are trained and evaluated (tested) as follows:

Lesson Plan LP-OP-802-2001, *Integrated Electrical Events* provides a walkthrough of station procedures necessary to restore power using local power sources (CTG 11-1 thru 4) in the event of a loss of power using station procedures 20.300.120kv *Loss of 120kv,* 20.300.Offsite, *Loss of Offsite Power,* and 20.300.SBO, *Station Blackout.*

Simulator Scenario SS-OP-802-2001, *Emergency and Abnormal Event Scenarios* allows the operators to practice performing power restoration using local power sources (CTG 11-1 thru 4) using station procedures on the simulator.

Qualification Card QC-OP-725-0100, *Licensed Reactor Operator Qualification Card* evaluates (tests) that each licensed operator can start and load the CTG units from the main control room.

Qualification Card QC-OP-714-0100, *Non Licensed Operator Outside Rounds Qualification Card* evaluates (tests) that each non licensed operator can start the local power sources (CTG's) under station blackout conditions.

(7c) If you have not established an agreement with your plant's TSO to identify local power sources that could be made available to resupply power to your plant following a LOOP event, explain why you believe you comply with the provisions of 10 CFR 50.63, or describe what actions you intend to take to establish compliance.

Response: Not applicable, as CTG's are procedurally started and aligned to supply plant loads without the need for prior permission from the CSS or ITC. In addition, formal agreements and informal protocols are in place with the TSO and RC/RA to expedite restoration of offsite power.

Losses of offsite power caused by grid failures at a frequency of equal to or greater than once in 20 site-years in accordance with Table 4 of Regulatory Guide 1.155 for complying with 10 CFR 50.63

Pursuant to 10 CFR 50.63, the NRC requires that each NPP licensed to operate be able to withstand an SBO for a specified duration and recover from the SBO. NRC RG 1.155 gives licensees guidance on developing their approaches for complying with 10 CFR 50.63.

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

(8a) Has your NPP experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63?

Response: Yes.

There has been one instance where a total LOOP was experienced at Fermi. On August 14, 2003, the Northeast US and Canadian regional power loss resulted in a total LOOP at Fermi.

(8b) If so, have you reevaluated the NPP using the guidance in Table 4 of RG 1.155 to determine if your NPP should be assigned to the P3 offsite power design characteristic group?

Response: No.

While the P2 classification of Fermi 2 has been re-evaluated, it has not been done using the guidance in Table 4 of RG 1.155, which applied to initial responses to the SBO rule.

(8c) If so, what were the results of this reevaluation, and did the initially determined coping duration for the NPP need to be adjusted?

Response: Not applicable.

While the P2 classification of Fermi 2 has been re-evaluated, it has not been done using the using the guidance in Table 4 of RG 1.155, which applied to initial responses to the SBO rule.

(8d) If your NPP has experienced a total LOOP caused by grid failure since the plant's coping duration was initially determined under 10 CFR 50.63 and has not been reevaluated using the guidance in Table 4 of RG 1.155, explain why you believe you comply with the provisions of 10 CFR 50.63 as stated above.

or describe what actions you intend to take to ensure that the NPP maintains its SBO coping capabilities in accordance with 10 CFR 50.63.

Response: Of the various factors utilized to determine a plant's offsite power design characteristic category, the impact of the August 14, 2003 total LOOP would only influence Fermi's total LOOP (as opposed to divisional LOOP) frequency. As a result of efforts to comply with upcoming NRC Mitigating System Performance Indicators requirements, the total LOOP frequency was recently reviewed with data analysts from ABS Consulting Services for the purposes of updating Fermi's PSA model (the August 14, 2003 total LOOP was taken into account). The results of this analysis determined Fermi's updated total LOOP frequency is 1.09E-02 events/yr. This frequency would result in Fermi remaining in the P2 AC Power Design Characteristic Group.

Actions to ensure compliance

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

Response: Fermi 2 fully complies with NRC regulatory requirements, including Technical Specifications, GDC 17, 10 CFR 50.65(a)(4), 10 CFR 50.63, 10 CFR 55.59 or 10 CFR 50.120, as described in this Enclosure 2.

The Midwest ISO, ITC, and Detroit Edison are currently in the final stages of developing a more formal *Nuclear Plant Operating Agreement* (the NPOA), which will include an Exhibit A, the *Fermi 2 Nuclear Power Plant Operating Guide.* The NPOA will formalize and coordinate communications between Midwest ISO, ITC, and Detroit Edison (includes the DE SOC and the Fermi 2 plant) with respect to scheduling protocols, emergency procedures, operating and maintenance limitations and other restrictions applicable to the EF2 NPP.