August 1, 2007

Mr. Jack M. Davis
Senior Vice President and Chief Nuclear Officer
Detroit Edison Company
Fermi 2 - 210 NOC
6400 North Dixie Highway
Newport, MI 48166

SUBJECT: FERMI, UNIT 2 - ISSUANCE OF AMENDMENT RE: EXTEND THE COMPLETION TIME FOR TECHNICAL SPECIFICATION 3.8.1 FOR AN INOPERABLE DIESEL GENERATOR (TAC NO. MD2618)

Dear Mr. Davis:

The Commission has issued the enclosed Amendment No. 175 to Facility Operating License No. NPF-43 for the Fermi 2 facility. The amendment consists of changes to the Technical Specifications (TS) in response to your application dated July 12, 2006, as supplemented by letters dated April 25, May 23, June 15, June 20, and June 29, 2007.

The amendment modifies Conditions, Required Actions and Completion Times in TS 3.8.1, "AC Sources - Operating," when one or more emergency diesel generators are declared inoperable.

A copy of our safety evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

/RA/

Adrian Muñiz, Project Manager
Plant Licensing Branch III-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-341

Enclosures:
1. Amendment No. 175 to NPF-43
2. Safety Evaluation

cc w/encls: See next page

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OFFICE	NRR/LPL3-1/PM	NRR/LPL3-1/LA	EEEB/BC	APLA/BC
NAM	AMuñiz	THarris	GWilson*	MRubin*
DATE	07/31/07	07/18/07	6 / 27/07	6/ 20 /07

OFFICE	ITSB/BC	OGC	NRR/LPL3-1/(A)BC
NAM	TKobetz	APHodgdon (NLO w/comments)	TTate
DATE	07/16/07	07/11/07	08/01/07

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DETROIT EDISON COMPANY

DOCKET NO. 50-341

FERMI 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 175

License No. NPF-43

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by the Detroit Edison Company (the licensee) dated July 12, 2006, as supplemented by letters dated April 25, May 23, June 15, June 20, and June 29, 2007, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment and paragraph 2.C.(2) of Facility Operating License No. NPF-43 is hereby amended to read as follows:

Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 175, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of its date of issuance and shall be implemented within 30 days.

FOR THE NUCLEAR REGULATORY COMMISSION

/RA/

Travis L. Tate, Acting Chief
Plant Licensing Branch III-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment: Changes to the Technical Specifications

Date of Issuance: August 1, 2007

ATTACHMENT TO LICENSE AMENDMENT NO. 175

FACILITY OPERATING LICENSE NO. NPF-43

DOCKET NO. 50-341

Replace the following pages of the Facility Operating License and Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

REMOVE	INSERT
License Page 3	License Page 3
3.8-1	3.8-1
3.8-2	3.8-2
3.8-2a	3.8-2a
3.8-2b	3.8-2b
	3.8-2c

(4) DECo, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use at any time any byproduct, source and special nuclear material such as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(5) DECo, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(6) DECo, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

DECo is authorized to operate the facility at reactor core power levels not in excess of 3430 megawatts thermal (100% power) in accordance with conditions specified herein and in Attachment 1 to this license. The items identified in Attachment 1 to this license shall be completed as specified. Attachment 1 is hereby incorporated into this license.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A as revised through Amendment No. 175 and the Environmental Protection Plan contained in Appendix B, are hereby incorporated into this license. DECo shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Antitrust Conditions

DECo shall abide by the agreements and interpretations between it and the Department of Justice relating to Article I, Paragraph 3 of the Electric Power Pool Agreement between Detroit Edison Company and

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 175 FACILITY OPERATING LICENSE NO. NPF-43

DETROIT EDISON COMPANY

FERMI 2

DOCKET NO. 50-341

1.0 INTRODUCTION

By application dated July 12, 2006, as supplemented by letters dated April 25, May 23, June 15, June 20, and June 29, 2007, the Detroit Edison Company (DECo or the licensee) requested changes to the Technical Specifications (TSs) for Fermi 2. The supplements dated April 25, May 23, June 15, June 20, and June 29, 2007, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the U.S. Nuclear Regulatory Commission (NRC) staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on August 29, 2006, (71 FR 51225). The proposed changes would modify Conditions, Required Actions and Completion Times (CTs) in TS 3.8.1, "AC Sources - Operating," when one or more emergency diesel generators (EDG) are declared inoperable. Specifically, the proposed change would extend the CT associated with TS 3.8.1, Condition A from 7 to 14 days for a single inoperable EDG. It would also create a new Condition in TS 3.8.1 with a CT of 72 hours for both EDGs inoperable in one division of onsite electrical power distribution and remove the second CT for one inoperable EDG and one inoperable offsite circuit. Additionally, the licensee requested changes that are administrative in nature.

2.0 REGULATORY EVALUATION

Title 10 of the *Code of Federal Regulations* (10 CFR) Section 50.36, "Technical specifications," provides the regulatory requirements for the content required in a licensee's TSs. As stated in 10 CFR 50.36, the TSs will include Surveillance Requirements to assure that the limiting conditions for operation (LCO) will be met.

Section 50.63 of 10 CFR, "Loss of all alternating current power," requires that light-water-cooled nuclear power plants licensed to operate be able to withstand for a specified duration and recover from a station blackout.

Section 50.65 of 10 CFR, “Requirements for monitoring the effectiveness of maintenance at nuclear power plants,” requires that preventive maintenance activities must not reduce the overall availability of the systems, structures and components. It also requires that before performing maintenance activities, the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities.

General Design Criterion (GDC) 17, “Electric power systems,” of Appendix A, “General Design Criteria for Nuclear Power Plants,” to 10 CFR Part 50 states, in part, that nuclear power plants have onsite and offsite electric power systems to permit the functioning of structures, systems, and components (SSC) that are important to safety. The onsite system is required to have sufficient independence, redundancy, and testability to perform its safety function, assuming a single failure. The offsite power system is required to be supplied by two physically independent circuits that are designed and located so as to minimize, to the extent practical, the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions.

GDC-18, “Inspection and testing of electric power systems,” states that electric power systems that are important to safety must be designed to permit appropriate periodic inspection and testing of important areas and features, such as insulation and connections to assess the continuity of the systems and the condition of their components.

Regulatory Guide (RG) 1.93, “Availability of Electric Power Sources,” provides guidance with respect to operating restrictions (i.e., CTs) if the number of available alternate current (AC) sources is less than that required by the TS LCO. In particular, this guide prescribes a maximum CT of 72 hours for an inoperable onsite or offsite AC source.

RG 1.155, "Station Blackout," describes a method acceptable to the NRC staff for complying with the Commission regulation that requires nuclear power plants to be capable of coping with a station blackout (SBO) event for a specified duration.

RG 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants," provides guidance on methods acceptable to the NRC for assessing and managing the increase in risk that may result from maintenance activities and for implementing the optional reduction in scope of SSCs considered in the assessments.

RG 1.174, “An Approach for Using Probabilistic Risk Assessment [PRA] in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis,” describes a risk-informed approach, acceptable to the NRC, for assessing the nature and impact of proposed licensing basis changes by considering engineering issues and applying risk insights. This RG also provides risk acceptance guidelines for evaluating the results of such assessments.

RG 1.177 identifies an acceptable risk-informed approach including additional guidance specifically geared toward the assessment of proposed TS CT changes. Specifically, RG 1.177 identifies a three-tiered approach for the evaluation of the risk associated with a proposed CT TS change as identified below.

1. Tier 1 is an evaluation of the plant-specific plant operational risk associated with the proposed TS change, as shown by the change in core damage frequency (ΔCDF) and change in large early release frequency (ΔLERF). The change in risk is compared to the acceptance guidelines of RG 1.174. Tier 1 also evaluates the plant risk increase during the time equipment is removed from service as measured by the incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP). The incremental risk is compared to the acceptance guidelines of RG 1.177. Tier 1 also addresses PRA quality, including the technical adequacy of the licensee’s plant-specific PRA for the subject application.

2. Tier 2 identifies and evaluates any potential risk-significant plant equipment outage configurations that could result if other equipment with that associated with the proposed license amendment is removed from service simultaneously or if other risk-significant operational factors, such as concurrent system or equipment testing, are also involved. The purpose of this evaluation is to ensure that there are appropriate restrictions in place such that risk-significant plant equipment outage configurations will not occur when equipment associated with the proposed CT is out-of-service.

3. Tier 3 addresses the licensee's overall configuration risk management program (CRMP) to ensure that adequate programs and procedures are in place for identifying risk-significant plant configurations resulting from maintenance or other operational activities and appropriate compensatory measures to avoid such configurations are taken that may not have been considered when the Tier 2 guidance was developed. Compared with Tier 2, Tier 3 provides additional coverage to ensure risk-significant plant equipment outage configurations are identified in a timely manner and that the risk impact of out-of-service equipment is appropriately evaluated prior to performing any maintenance activity over extended periods of plant operation. Tier 3 guidance can be satisfied by the Maintenance Rule (10 CFR 50.65(a)(4)), which requires a licensee to assess and manage the increase in risk that may result from activities such as surveillance, testing, and corrective and preventive maintenance, subject to the guidance provided in RG 1.177 Section 2.3.7.1 and the adequacy of the licensee's program and PRA model for this application. The CRMP is to ensure that equipment removed from service prior to or during the proposed extended CT will be appropriately assessed from a risk perspective.

Generic Letter (GL) 88-20, Supplement 5, "Individual Plant Examination of External Events for Severe Accident Vulnerabilities," notified addressees of modifications in the recommended scope of seismic reviews that are performed as part of individual plant examinations of external events (IPEEEs) for the focused-scope and full-scope plants and provide guidance to licensees who wish to voluntarily modify their previously committed seismic IPEEE programs.

General guidance for NRC staff review of proposed risk-informed changes is provided in Chapter 19.0, "Use of Probabilistic Risk Assessment in Plant-Specific, Risk-Informed Decisionmaking: General Guidance," of the NRC Standard Review Plan (SRP), NUREG-0800. More specific guidance related to risk-informed TS changes is provided in SRP Section 16.1, "Risk-Informed Decisionmaking: Technical Specifications," which includes CT changes as part of risk-informed decisionmaking.

3.0 TECHNICAL EVALUATION

3.1 Description of the Fermi 2 Electrical Power System

Fermi 2 TS 3.8.1 requires two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system. Offsite power for Fermi 2 is comprised of two physically independent circuits supplied at two different voltage levels, 345 kilovolt (kV) and 120 kV. The 120 kV switchyard is an arrangement of buses, breakers, disconnects, transformers, and transmission lines which connect the four Combustion Turbine Generators (CTGs) located at Fermi 1 and the Fermi 2 Division 1 essential safeguard features (ESF) and balance of plant loads (BOP) with the electrical system. Only one of the above redundant 120 kV lines is required to comply with the Fermi 2 TS in supplying one of the required independent offsite circuits. Two transmission lines provide 345 kV power from the electrical system to the 345 kV switchyard located at the Fermi 2 site. The 345 kV switchyard is an arrangement of buses, breakers, disconnects, transformers, and transmission lines which connect the Fermi 2 main turbine generator and the Fermi 2 Division 2 ESF and BOP loads with the electrical system. Only one of the 345 kV lines is required to comply with the Fermi 2 TS in supplying one of the two required physically independent offsite circuits. In the event of a unit trip, the offsite supply to the ESF buses would not be interrupted. The design of the 345 kV switchyard utilizes a "breaker-and-one-half" design such that a unit trip does not isolate auxiliary power from the ESF buses.

The Fermi 2 Class 1E distribution system consists of two physically and electrically independent and redundant power trains, Division 1 and Division 2, that supply power to safety-related equipment. The ESF buses are divided into two divisions, with different offsite power sources to each division. Each of the two ESF divisions, Division 1 and Division 2, consist of two separate buses. The loads on each ESF division are split between two EDGs. Either Division 1 or Division 2 EDG has the capability and the capacity to supply the ESF power loads required for safe shutdown.

Manually operated tie breakers are provided to cross-tie the Division 1 and Division 2 ESF buses. These tie breakers are normally maintained in the open and disconnected position. Administrative controls limit the operation of these breakers.

Four EDGs, each connected to its respective ESF bus, provide an emergency source of power upon loss of the offsite power sources. In the scenario of a loss-of-offsite power (LOOP) event, each EDG will receive an automatic start signal. Load shedding and bus isolation will occur automatically. Following load shedding and bus isolation, each EDG output breaker will automatically close, energizing the associated ESF Buses. Essential loads will then be automatically connected to their respective ESF buses sequentially. Each EDG will receive a start signal on the following signals:

a. Loss of voltage

b. Degraded voltage

c. ESF actuation signal (High Drywell Pressure or Level 1-Low Reactor Water Level)

d. Manual start

Four CTGs can be used to supply power to the Division 1 ESF buses during an SBO event. Plant procedures provide for operation of the CTGs and the electrical system under SBO conditions. CTG 11-1 is the normal alternate AC (AAC) source with black start (i.e., independent capability to start itself) capability integrated within the unit. Additionally, a dedicated diesel generator can be manually aligned to provide power for starting CTG 11-2, 11-3, or 11-4, providing a backup AAC source.

3.2 Deterministic Evaluation

3.2.1 LCO 3.8.1 Change 1:

Current TS 3.8.1, Condition A applies with one or both EDGs in one division declared inoperable, and requires that the EDG(s) be restored to operable status within 7 days, provided CTG 11-1 is operable. The licensee proposed to revise Condition A to apply when one EDG is declared inoperable. The licensee also proposed to change the CT to 14 days for the condition of one EDG declared inoperable. The proposed change would permit an additional 7 days beyond the current TS allowed CT and help avoid TS required plant shutdown due to EDG maintenance. The licensee also proposed to remove the second Completion Time for Required Actions A.6 and C.3.

AAC Source

The Fermi 2 electrical design complies with 10 CFR 50.63(c)(2) by using CTG 11-1 as the normal AAC source with black start capability integrated within the unit. Additionally, a dedicated diesel generator can be manually aligned to provide power for starting CTG 11-2, 11-3, or 11-4, providing a backup AAC source. CTG11-1 is located near the 120 kV switchyard and meets the guidance of NUMARC 87-00, Appendix B,"Guidelines for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," and RG 1.155,"Station Blackout," as an AAC power source. The nominal rating of the CTG11-1 is 18 megawatts. The CTG 11-1 can be manually connected to the Division 1 safety buses within approximately 29 minutes and Division 2 safety buses (thru the cross-tie) within 35 minutes in the event of a loss of power to the safety buses or during an SBO event. Therefore, the CTG 11-1 source is capable of supplying power to equipment that would be energized by the Division 1 and Division 2 EDGs in the event of an SBO or LOOP. The CTG 11-1 is load tested every 31 days as required by the Fermi 2 Technical Requirements Manual. In addition, with one EDG declared inoperable, TS 3.8.1, Required Action A.3 requires the verification of the status of CTG 11-1 once per 8 hours. In addition to the TS Required Action, the licensee stated that as part of the work planning processes, this status would also be verified operable prior to taking an EDG out-of-service for an extended period.

Based on the above considerations and the capability of CTG 11-1 to power the inoperable EDG bus loads in the event of an SBO or LOOP, the NRC staff concludes that the licensee's request to extend the CT specified in TS 3.8.1 to restore an inoperable EDG to operable status from the current 7 days to 14 days is acceptable from a deterministic standpoint.

In addition to the above, the licensee proposed to delete the second CT of 10 days from discovery of failure to meet the LCO in TS 3.8.1 Required Actions A.6 and C.3.

In the Fermi 2 TS, consistent with the Improved Standard Technical Specifications (NUREGs 1430 through 1434) (ISTS), a second CT was included for certain Required Actions to establish a limit on the maximum time allowed for any combination of Conditions that result in a single continuous failure to meet the LCO. These CTs are joined by an "AND" logical connector to the Condition-specific CT and state "10 days from discovery of failure to meet the LCO". The intent of the second CT was to preclude entry into and out of the Actions for an indefinite period of time without meeting the LCO by providing a limit on the amount of time that the LCO could not be met for various combinations of Conditions.

The adoption of a second CT in the ISTS was based on an NRC concern that a plant could continue to operate indefinitely with an LCO governing safety significant systems never being met by alternately meeting the requirements of separate Conditions. In 1991, the NRC could not identify any regulatory requirement or program which could prevent this misuse of the TS. However, that is no longer the case. There are now two programs which would provide a strong disincentive to continued operation with concurrent multiple inoperabilities of the type the second CTs were designed to prevent.

The Maintenance Rule: 10 CFR 50.65 (a)(1), the Maintenance Rule, requires each licensee to monitor the performance or condition of SSCs against licensee-established goals to ensure that the SSCs are capable of fulfilling their intended functions. If the performance or condition of an SSC does not meet established goals, appropriate corrective action is required to be taken. The NRC Resident Inspectors monitor the licensee's Corrective Action process and could take action if the licensee's maintenance program allowed the systems required by a single LCO to become concurrently inoperable multiple times. The performance and condition monitoring activities required by 10 CFR 50.65 (a)(1) and (a)(2) would identify if poor maintenance practices resulted in multiple entries into the ACTIONS of the TS and unacceptable unavailability of these SSCs. The effectiveness of these performance monitoring activities, and associated corrective actions, is evaluated at least every refueling cycle, not to exceed 24 months per 10 CFR 50.65 (a)(3).

Under the TS the CT for one system is not affected by other inoperable equipment. The second CTs were an attempt to influence the Completion Time for one system based on the condition of another system, if the two systems were required by the same LCO. However 10 CFR 50.65 (a)(4) is a much better mechanism to apply this influence as the Maintenance Rule considers all inoperable risk-significant equipment, not just the one or two systems governed by the same LCO.

Under 10 CFR 50.65(a)(4), the risk impact of all inoperable risk-significant equipment is assessed and managed when performing preventative or corrective maintenance. The risk assessments are conducted using the procedures and guidance endorsed by RG 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." RG 1.182 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed maintenance is acceptable. This comprehensive program provides much greater assurance of safe plant operation than the second CTs in the TS.

The Reactor Oversight Process: NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," describes the tracking and reporting of performance indicators to support the NRC's Reactor Oversight Process (ROP). The NEI document is endorsed by RIS 2001-11, "Voluntary Submission Of Performance Indicator Data." NEI 99-02, Section 2.2, describes the Mitigating Systems Cornerstone. NEI 99-02 specifically addresses emergency AC Sources (which encompasses the AC Sources and Distribution System LCOs), and the Auxiliary feedwater system. Extended unavailability of these systems due to multiple entries into the ACTIONS would affect the NRC's evaluation of the licensee's performance under the ROP.

In addition to these programs, a requirement is added to Section 1.3 of the TS to require licenses to have administrative controls to limit the maximum time allowed for any combination of Conditions that result in a single contiguous occurrence of failing to meet the LCO. These administrative controls should consider plant risk and shall limit the maximum contiguous time of failing to meet the LCO. This TS requirement, when considered with the regulatory processes discussed above, provide an equivalent or superior level of plant safety without the unnecessary complication of the TS by second CTs on some Specifications.

AC Sources - Operating

Fermi current TS 3.8.1, AC Sources - Operating, has a 7 day CT for one or both EDGs in one division inoperable (Condition A) and a 72 hour CT for one offsite circuit inoperable (Condition C). Both Condition A and Condition C have a second CT of "10 days from discovery of failure to meet the LCO." The second CT limits plant operation when Condition A or C is entered, and before the inoperable system is restored, the other Condition is entered, and then the first inoperable system is restored, and before the remaining inoperable system is restored, the other Condition is entered again. This highly improbable scenario is further limited by current Condition E which applies when an offsite circuit and one or both EDGs in one division are inoperable. It limits plant operation in this Condition to 12 hours.

As stated above, the ROP monitors the availability of mitigating systems, including the emergency AC sources DG unavailability). Such frequent, repeated failures of the AC sources would be reported to the NRC and this represents a strong disincentive to such operation.

The NRC staff finds that the proposed change to the second CT for Required Actions A.6 and C.3 are consistent with TSTF 439, Revision 2 and, therefore, acceptable.

3.2.2 LCO 3.8.1 Change 2:

The licensee proposed to add a new Condition B with a 72 hours CT when both EDGs in one division of onsite electrical power are inoperable. Current Required Action A.6 allows 7 days to restore both EDGs to operable status. Current TS also requires that CTG 11-1 is available within 72 hours. This was eliminated since the EDGs are now required to be restored to operable status within 72 hours. The NRC staff finds the proposed addition of Condition B to be conservative because current Required Action A.6 allows 7 days to restore both EDGs. Based on the above, the NRC staff finds the proposed change acceptable.

3.2.3 LCO 3.8.1 Change 3:

The licensee has proposed to delete the footnote at the bottom of TS page 3.8-2 and the asterisk (*) in the CT column of Required Action A.6. The footnote reads as follows:

> "The 7 day allowed outage time of Technical Specification 3.8.1 Condition "A" Required Action A.6 which was entered on January 30, 2006, at 0200 hours, may be extended one time by an additional 7 days to complete repair and testing of EDG 12."

The NRC staff finds the proposed change acceptable because the one-time use of this footnote has expired and the footnote is no longer required.

3.2.4 LCO 3.8.1 Change 4:

With the addition of new Condition B, Conditions B thru F are renumbered. The NRC staff finds the proposed change to be administrative in nature and, therefore, acceptable.

3.2.5 Summary

Based on the considerations discussed above, the NRC staff concludes that the licensee's proposed changes are justified from a deterministic standpoint. Further, the NRC staff believes that the regulatory commitments to implement other restrictions and compensatory measures will ensure the availability of the remaining sources of AC power during the extended EDG CT. The NRC staff also concludes that the proposed changes do not affect Fermi 2's conformance with the requirements of GDCs 17 and 18.

3.3 Implementation and Monitoring Program

RG 1.174 states that an implementation and monitoring plan should be developed to ensure that the impact of the proposed change continues to reflect the actual reliability and availability of the EDGs evaluated to support the proposed extended CT. Monitoring performed in conformance with the Maintenance Rule of 10 CFR 50.65 can be used when such monitoring is sufficient for the structures, systems and components affected by the risk-informed application. Therefore, to ensure that the proposed extended CT does not degrade operational safety over time, should equipment not meet its performance criteria, an evaluation is required as part of the Maintenance Rule, 10 CFR 50.65.

EDG reliability and availability are monitored and evaluated per the Maintenance Rule. If pre-established reliability or availability performance criteria are not achieved for the EDGs, they are considered for 10 CFR 50.65(a)(1) actions, including increased management attention and goal setting to restore EDG performance. According to the licensee, EDG Maintenance Rule system health has been classified as 10 CFR 50.65(a)(2) since November 29, 2005. Between April 8, 1997, and November 29, 2005, system health was classified as 10 CFR 50.65(a)(1).

Additionally, Fermi 2 has an EDG reliability program based on RG 1.55, "Station Blackout" and consistent with NUMARC 87-00, "Guidelines for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors." The EDG reliability program requires a root cause evaluation and corrective actions when established "trigger values" are exceeded. As of May 2006, the licensee recorded no failures in the last 100 EDG demands. The licensee states that the EDG reliability program will not be negatively impacted by the proposed CT extension, because EDG testing frequencies will not be affected.

3.4 Risk Evaluation

In accordance with SRP Chapter 19 and Section 16.1, the NRC staff reviewed the licensee's submittal using the three-tiered approach and five key principles of risk-informed decision making presented in RG 1.177. Only the CT extension was presented by the licensee as a risk-informed change and evaluated using the guidelines in RGs 1.174 and 1.177.

For the quantitative evaluation of risk impacts of extending the CT for one EDG inoperable from 7 days to 14 days, the licensee used the Fermi V7 revision of its Level 1 and Level 2 PRA. Fire risk was qualitatively evaluated using the Fermi 2 IPEEE fire study, based on the Electric Power Research Institute (EPRI) Fire-Induced Vulnerability Evaluation (FIVE) methodology and the Fire PRA Implementation Guide. Seismic risk was also qualitatively evaluated using the Fermi 2 IPEEE, based on the EPRI Seismic Margins Assessment methodology. The licensee's submittal stated that the proposed changes have negligible effect on the risk profile from high winds, floods, and other external events (HFO) as characterized qualitatively in the IPEEE.

The risk evaluation assumed that the preventive maintenance (PM) term would increase as a result of performing four additional EDG major overhauls online each operating cycle. Specifically, the full 14-day extended CT would be used once per EDG per cycle.

3.4.1 *Tier 1: PRA Capability and Insights*

The first tier evaluates the impact of the proposed CT extension on plant operational risk based on the Fermi 2 PRA model. The Tier 1 NRC staff review involves two aspects: (1) evaluation of the validity of the PRA and its application to the proposed CT extension, and (2) evaluation of the PRA results and insights stemming from its application.

3.4.1.1 *PRA Capability*

To determine whether the PRA used in support of the proposed CT extension is of sufficient quality, scope, and detail, the NRC staff evaluated the relevant information provided by the licensee in its submittal, as supplemented, and considered the findings of recent PRA peer reviews and evaluations. The NRC staff's review of the licensee's submittal focused on the capability of the licensee's PRA model to analyze the risks resulting from the proposed EDG CT extension and did not involve an in-depth review of the licensee's PRA.

The Fermi 2 PRA model is an upgrade to the IPE developed in response to GL 88-20 and submitted to the NRC staff by letter dated September 1, 1992, revised by letter dated September 22, 1993. The NRC staff issued its staff evaluation for the Fermi 2 IPE by letter dated November 16, 1994, concluding that the IPE met the intent of GL 88-20 (Reference 4).

The current Fermi 2 PRA model addresses internal events (including internal flooding) at full power conditions, and includes level one (core damage) and level two (containment release). The current model includes updates relevant to the proposed change, including proper characterization of initiating events involving LOOP, treatment of time-dependent offsite power recovery, and treatment of operator actions to implement bus ties and other Emergency Operating Procedures, equipment success criteria calculations, data analysis of key parameters (such as EDG failure rates), maintenance unavailabilities, and common cause failure probabilities.

The Fermi 2 internal events level one and level two PRA model received a formal industry peer review in 1997. The peer review team included PRA and system analysts in both PRA development and application. The team used a set of checklists as a framework to evaluate the scope, comprehensiveness, completeness, and fidelity of the PRA. As a result of the peer review, 5 level "A" and 60 level "B" Fact and Observation (F&O) findings were identified. The majority of F&Os, including all level "A" F&Os, have been dispositioned as part of PRA model updates completed between 1999 and 2006.

Improvements to the Fermi 2 PRA model as a result of the peer review included:

1. re-analysis of the Fermi Human Reliability Analysis (HRA) using the HRA Calculator software package,
2. internal review of the Level 1 model top logic,
3. re-evaluation and documentation of thermal-hydraulic (TH) and electrical success criteria for implementation of the Mitigating System Performance Index (MSPI),
4. development of an improved fault-tree-based Level 2 model,
5. analysis of revised industry data to determine Fermi-specific LOOP frequencies,
6. revision of basic event probabilities and initiating event frequencies to reflect revised plant and industry data,
7. incorporation of plant modifications,
8. modifications to reflect revised plant operating procedures, and
9. improvement of risk monitoring capabilities for performance of Maintenance Rule (a)(4) assessments.

The licensee stated that a formal peer review was not performed after new methodologies were introduced for HRA and TH. However, the HRA methodology change was performed by an acknowledged HRA expert with over 26 years of PRA experience and reviewed by a staff technical expert with over 25 years of PRA experience. The TH success criteria calculations were prepared by a consultant with 12 years of specialized TH modeling experience and reviewed by two staff engineers who specialize in TH. A comprehensive comparison of initiating event contributions, end states, cutsets, system importance, and HRA event importance was reviewed and compared against the previous major model revision. Also, implementation of the MSPI required that Fermi PRA model results be subjected to an industry cross-comparison to determine if the PRA model was an outlier in the MSPI-monitored areas. The Fermi PRA model was determined as not an outlier for the EDGs or any other monitored system.

Additionally, the model has been revised to credit the dedicated diesel generator that enables operators to start CTGs 11-2, 11-3, and 11-4 during an SBO, in addition to the black start capability of CTG 11-1. This modification was made as a result of Amendment No. 171 (Reference 2), issued on February 6, 2006, which allowed a one-time extension of the CT for EDG 12 from 7 to 14 days. The licensee stated that the dedicated blackstart diesel generator and CTGs 11-2, 11-3, and 11-4 are in the scope of the plant's implementation of the Maintenance Rule, and that performance criteria exist to monitor the reliability and availability of the components.

In a letter dated March 29, 1996, the licensee submitted its IPEEE. The NRC staff issued its evaluation for the Fermi 2 IPEEE by letter dated July 5, 2000 (Reference 5). On the basis of its review, the NRC staff concluded that the aspects of seismic, fires, and high winds, floods, transportation and other external events were adequately addressed. The licensee's submittal addressed shutdown risk by stating that performance of EDG maintenance at power will maximize EDG availability during refueling outages and minimize the overall risk due to the synergistic effects on shutdown risk due to EDG unavailability occurring concurrently with other activities and equipment outages during a refueling outage. Shutdown risk was not specifically evaluated for the EDG CT extension request since the CT extension request is only applicable in modes 1, 2, and 3.

Based on review of the above information, the NRC staff finds that the licensee has satisfied the intent of RG 1.174 (Sections 2.2.3 and 2.5), RG 1.177 (Sections 2.3.1, 2.3.2, and 2.3.3), and SRP Chapter 19.1, and that the quality of the Fermi 2 PRA is sufficient to support the risk evaluation provided by the licensee in support of the proposed license amendment.

3.4.1.2 *PRA Insights*

Using the Fermi 2 PRA model, version V7, the licensee calculated values for ΔCDF, ICCDP, ΔLERF, and ICLERP for the proposed 14-day EDG CT assuming internal events and internal flooding. The baseline values for CDF and LERF are 1.05E-5 per year (/yr) and 3.01E-7/yr, respectively. A qualitative evaluation of internal fires and other external events was then provided. The evaluation was performed assuming that an extended 14-day CT would be applied to each EDG once per fuel cycle, which is currently 18 months. Based on a sensitivity study that showed EDG 14 to be most risk significant, the evaluation reflects EDG 14 being out of service for the duration of the CT.

The licensee's methodology, including the qualitative treatment of internal fires and external events, is consistent with the guidance of RG 1.177, Sections 2.3.4 and 2.4 and is, therefore, acceptable to the NRC staff.

The licensee's submittal identified five key assumptions:

1. The model represents normal plant operation at full power and includes nominal maintenance and failure terms for all systems, as well as nominal initiating event frequencies.
2. A single EDG is taken out of service and assumed to be returned to service 14 days from the initial LCO entry.
3. All calculations were performed with a 1E-9 truncation limit.
4. The model includes credit for the blackstart diesel generator, which allows CTG 11-2, 11-3, and 11-4 to be used as a source of electrical power in the event of a LOOP. CTG 11-1 is also explicitly included in the model but was not identified by the licensee as a key assumption.
5. No credit is taken for improved EDG availability due to the ability to schedule a single outage during a fuel cycle versus two shorter duration outages.

The licensee assumed that only preventive maintenance (PM – planned maintenance, not the direct result of equipment failure) was in progress for the 14-day CT, based on unavailability history where the majority of unavailability is due to planned maintenance. Table 1 shows these PM results for the most risk-significant EDG.

Table 1: 14-DAY PREVENTIVE MAINTENANCE EDG CT (EDG 14)		
Risk Metric	**Acceptance Guideline***	**Licensee's Results**
ΔCDF	< 1.0E-6/yr	4.5E-7/yr
ICCDP	< 5.0E-7	1.6E-7
ΔLERF	< 1.0E-7/yr	2.7E-8/yr
ICLERP	< 5.0E-8	9.5E-9

**Acceptance guidelines in this and subsequent tables are for very small changes, for which RG 1.174 states that the change will be considered regardless of whether there is a calculation of total CDF. Acceptance guidelines for small changes are an order of magnitude higher and require the licensee to reasonably show that the total CDF is less than 1E-4 per reactor year (RY).*

The licensee provided additional risk evaluations for corrective maintenance (CM) situations. The licensee stated that, following plant procedures and risk management practices, it is reasonable to assume that within 2 days other risk-significant non-EDG work activities would be completed or rescheduled. Therefore, the "with maintenance" model was used for the first 2 days and the "no maintenance" model was used for the remaining 14 days. The total ICCDP and ICLERP for this situation were calculated as 1.69E-7 and 1.61E-9, respectively. These values are slightly higher than the PM value and within the RG 1.177 acceptance guidelines.

The licensee also evaluated situations in which one EDG is out of service for PM when the other EDG in the same division is inoperable and requires CM for restoration. The proposed TS includes a 3-day CT before one of the EDGs must be returned to service, a decrease from the current CT of 7 days. Table 2 shows the calculated ICCDP and ICLERP values for the most limiting combination of intradivision failures, both of which are within the RG 1.177 acceptance guidelines. The licensee provided a similar calculation for the current TS requirement, in which both EDGs in a division can be out of service for 7 days, indicating that approximately a 50 percent risk reduction was achieved by limiting the time that the second EDG could be out of service.

Table 2: 14-DAY PM OF EDG 14 CONCURRENT WITH 3-DAY CM OF EDG 13		
Risk Metric	**Acceptance Guideline**	**Licensee's Results**
ICCDP	< 5.0E-7	4.33E-7
ICLERP	< 5.0E-8	3.84E-9

TS 3.8.1, Action B.3.1 requires that the licensee determine within 24 hours that the operable DGs are not declared inoperable due to common cause is not specifically incorporated into the licensee's risk results. This requirement is not changed and would therefore prevent entry into an extended CT should an EDG become inoperable due to common cause. In addition, LCO 3.8.1 Condition C requires restoration of one DG to operable status within 2 hours when one or

both EDGs in both divisions are inoperable. Therefore, the impact of not including the common cause CT into the risk evaluation for the proposed extended CT is not considered significant.

The licensee provided a discussion of the effects of the proposed CT extension on dominant accident sequences. Only two core damage sequences contributed more than 5 percent to the total CDF in the baseline model, and these sequences continued to be the only dominant contributors for the extended CT case. Additionally, the LERF sequences that contributed more than 5 percent to the total risk involved interfacing system loss of coolant accidents and breaks outside containment. This result did not change for the extended CT case. The licensee concluded that the proposed CT extension does not create or exacerbate risk outliers.

<u>Sensitivity Studies</u>

To address uncertainties in the PRA model, the licensee performed multiple sensitivity studies. Several of these studies are summarized below.

Extended Maintenance Unavailability

The licensee performed a sensitivity study to determine the number of days that EDG 14 (the most risk-significant EDG) could be out of service before one of the four risk metrics (ΔCDF, ΔCDF, ICCDP, or ICLERP) reached the acceptance guidelines in RG 1.174 and RG 1.177. The licensee concluded that EDG 14 could be out of service for 30 days per year, more than twice the requested CT, before ΔCDF would reach the 1.0E-6 acceptance guideline. The other three risk metrics would remain below their respective acceptance guidelines for more than 30 days. Because the calculation was performed using the values for the most risk-significant EDG, the estimate is bounding.

Additionally, the licensee performed a sensitivity study to reflect the effect of an additional 14 days of planned maintenance per cycle. In the baseline PRA model, the maintenance unavailability is conservatively assumed to be 18.2 days per 18-month refueling cycle. This value is higher than the highest MSPI result of 15.7 days per cycle. When the licensee performed an assessment using a planned unavailability of 28 days per cycle, the results were within the RG 1.174 and RG 1.177 acceptance guidelines, as shown in Table 4.

Table 4: 14-DAY OUTAGE OF EDG 14 WITH 28 DAYS/CYCLE UNAVAILABILITY		
Risk Metric	**Acceptance Guideline**	**Licensee's Results**
ΔCDF	< 1.0E-6/RY	5.6E-7/RY
ICCDP	< 5.0E-7	2.0E-7
ΔLERF	< 1.0E-7/RY	4.0E-8/RY
ICLERP	< 5.0E-8	1.4E-8

Unavailability of CTGs 11-2, 11-3 and 11-4

Sensitivity cases were analyzed for outages of the blackstart diesel (for CTG 11-2, 11-3, or 11-4) and EDG 14 simultaneously and of CTG 11-2 and EDG 14 simultaneously, as shown in Tables 5 and 6. In both of these cases, using the “no maintenance” model, the ICCDP and ICLERP values are within the RG 1.177 acceptance guidelines. The same is true for the “with maintenance” model except for the ICLERP value for the concurrent outage of the blackstart diesel and EDG 14. The licensee states that the “with maintenance” case does not represent the plant configuration during diesel outages, when risk management and scheduling concerns would preclude elective maintenance on risk-significant systems. If an elevated risk category were attained during an EDG outage, the risk management procedure would require compensatory measures and appropriate work approvals.

Table 5: CONCURRENT 14-DAY OUTAGE OF EDG 14 AND BLACKSTART DIESEL

Risk Metric	Acceptance Guideline	Licensee’s Results	
		No Maintenance	With Maintenance
ICCDP	< 5.0E-7	8.9E-8	2.8E-7
ICLERP	< 5.0E-8	7.0E-9	6.7E-8

Table 6: CONCURRENT 14-DAY OUTAGE OF EDG 14 AND CTG 11-2

Risk Metric	Acceptance Guideline	Licensee’s Results	
		No Maintenance	With Maintenance
ICCDP	< 5.0E-7	6.5E-8	1.7E-7
ICLERP	< 5.0E-8	3.0E-10	1.3E-8

LOOP Initiating Event Frequency

Sensitivity cases were analyzed for an EDG outage concurrent with an increase in the LOOP frequency by both a factor of two and a factor of ten. As shown in Tables 7 and 8, The ICCDP and ICLERP values are within the RG 1.177 acceptance guidelines for every case except the ten-fold increase using the “with maintenance” model. Again, the licensee states that the “with maintenance” case does not represent the plant configuration during diesel outages, when risk management and scheduling concerns would preclude elective maintenance on risk-significant systems. If an elevated risk category were attained during an EDG outage, the risk management procedure would require compensatory measures and appropriate work approvals.

Table 7: 14-DAY OUTAGE OF EDG 14 WITH LOOP FREQUENCY x2

Risk Metric	Acceptance Guideline	Licensee's Results	
		No Maintenance	With Maintenance
ICCDP	< 5.0E-7	8.4E-8	2.4E-7
ICLERP	< 5.0E-8	1.1E-9	2.7E-8

Table 8: 14-DAY OUTAGE OF EDG 14 WITH LOOP FREQUENCY x10			
Risk Metric	**Acceptance Guideline**	**Licensee's Results**	
		No Maintenance	**With Maintenance**
ICCDP	< 5.0E-7	2.7E-7	1.0E-6
ICLERP	< 5.0E-8	1.4E-8	2.3E-7

Truncation Limit

In its submittal, the licensee used a 1E-9 truncation limit. In this sensitivity case, using the "with maintenance" model for a 14-day outage of EDG 14 and a truncation limit of 1E-10, the ΔCDF, ΔLERF, ICCDP, and ICLERP values are within the guidelines of RG 1.174 and 1.177.

Table 9: 14-DAY OUTAGE OF EDG 14 WITH 1.0E-10 TRUNCATION LIMIT		
Risk Metric	**Acceptance Guideline**	**Licensee's Results**
ΔCDF	< 1.0E-6/RY	6.2E-7/RY
ICCDP	< 5.0E-7	2.2E-7
ΔLERF	< 1.0E-7/RY	6.8E-8/RY
ICLERP	< 5.0E-8	2.4E-8

"Combined Sensitivity" Case

Finally, a "combined sensitivity" case was analyzed in which:

1. both the dedicated diesel that is used to blackstart CTG 11-2, 11-3, or 11-4 and EDG 14 are out of service for 14 days,
2. the LOOP initiating event frequency is increased by a factor of two, and
3. the truncation limit is decreased to 1E-10.

Using the "no maintenance" model, the ICCDP and ICLERP values are still below the RG 1.177 acceptance guidelines (1.7E-7 and 2.9E-8, respectively). The licensee states that this result is significant, since the likelihood of the dedicated blackstart diesel being out of service concurrently with a condition that requires the elevation of the LOOP frequency by a factor of two for the entire duration of the EDG outage is extremely small. The high margins to the

RG 1.177 guidelines in this case accommodate uncertainties associated with the analysis. Again, according to the licensee, the “with maintenance” case (for which the guidelines are exceeded in this case by about a factor of 1.3 for ICCDP and 4.4 for ICLERP) does not appropriately reflect the plant configuration during diesel outages, when risk management and scheduling concerns would preclude elective maintenance on risk-significant systems. If an elevated risk category were attained during an EDG outage, the risk management procedure would require compensatory measures and appropriate work approvals.

The results of the sensitivity studies performed by the licensee provide confidence that changes in the key assumptions identified in the submittal (listed at the beginning of this section) do not significantly affect the risk assessment. Based on the licensee’s evaluation of the internal events contribution to risk and the sensitivity studies provided, the NRC staff finds that the licensee has satisfied the intent of RG 1.174 (Section 2.2.4 and 2.2.5), RG 1.177 (Section 2.4), and SRP Chapter 19.1.

Fire Risk

The Technical Evaluation Report on the Fermi 2 IPEEE fire risk assessment, included in the staff evaluation of the IPEEE (Reference 5) discusses fire screening in detail. Phase I of the FIVE assessment eliminates zones that do not include safety equipment and do not result in a reactor shutdown. Because cable routing for the reactor protection system could not be easily determined, fire in any fire zone was assumed to result in a reactor scram.

Additionally, no fire compartments were screened during the Fire Compartment Interaction Analysis. As a result, no fire zones were qualitatively screened out in Phase I.

In Phase II, no fire zones were screened out based on a fire frequency of less than 1E-6/RY. Therefore, the Fermi 2 IPEEE calculated the CCDP for every fire zone, and 30 fire zones were eliminated based on a fire CDF of less than 1E-6/RY. The licensee determined that there are seven compartments with fire CDFs exceeding the screening criterion of 1E-6/RY. The largest fire CDF of the seven compartments is 7.4E-6/RY due to a control room fire. The total CDF from fires in the seven compartments was about 2.1E-5/RY. The total CDF from all fire-induced scenarios was about 3.2E-5/RY.

The licensee’s Appendix R safe-shutdown analyses included safe-shutdown capability evaluations and associated circuits of concern (for example, common power supply, common enclosure, spurious operation, and high-low pressure interfaces). For fires in most zones, safe shutdown is performed from the main control room using one of the divisions of safe shutdown equipment. For fires occurring in one of the dedicated shutdown areas, safe shutdown is accomplished using the alternative shutdown system outside the main control room as described in updated final safety analysis report Section 7.5.2.5 (Reference 1). The alternative shutdown system uses CTG 11-1 for AC power, not the EDGs.

The configuration of two EDGs in each division, with either division capable of supplying safe shutdown loads, combined with four CTGs capable of supplying power to Division 1 in a station blackout, reduces the impact of a single EDG outage on plant fire risk.

The following are additional statements relevant to the potential fire risk increase as a result of the extended EDG CT:

1. The extension of the TS completion time for the EDGs does not have any significant impact on the likelihood of the occurrence of fires.

2. The safety function of the EDGs is to start and run to provide onsite power to ESF equipment in the event that offsite power becomes unavailable.

3. Appendix R analyses are conservative since they assume a concurrent LOOP with the fire initiating event.

4. Even if one of the fires of concern occurs during the small fraction of the year in which an EDG is assumed to be unavailable for maintenance, the additional capability of non-fire-affected AC sources would remain available.

5. Fermi 2 has three CTG units in addition to CTG 11-1. These additional CTGs support mitigation of fire scenarios, but are not credited in the Appendix R and IPEEE analyses. If they were credited, they would reduce the risk significance of the extended CT.

The licensee provided a qualitative assessment of the impact of the extended CT on fire risk in the unscreened compartments identified in the IPEEE and Appendix R analyses. Of the seven unscreened compartments, only one results in a “small” challenge with EDG 14 (the most risk-significant EDG) out of service. Given a fire in the Division 1 switchgear room, Division 2 offsite power and EDG 13 would still be available to support safe shutdown.

The licensee provided additional information on the numerical basis of this “small” challenge. The licensee stated that the most applicable condition is a Transformer 64 fire, which results in a non-recoverable loss of Division 1 power and the loss of the CTGs. The licensee performed a sensitivity study for the scenario in which EDG 14 is out of service for 14 days, and the frequency of a Transformer 64 fire is increased by a factor of 10 (demonstrating margin). For this scenario, the ICCDP calculated by the licensee is 2.2E-7, which is below the RG 1.177 guideline of 5.0E-7. If the result is added to the 1.6E-7 ICCDP result from the submittal, the value is still within the RG 1.177 guideline.

Six compartments result in a “negligible” challenge with an EDG out of service:

1. Two compartments for which two divisions of offsite power are available and the EDGs are not required;

2. Three compartments for which the most risk-significant scenarios depend on CTG 11-1 for AC power rather than the EDGs; and

3. One compartment (the Division 2 switchgear room) in which a fire fails Division 2 equipment, with success depending on Division 1 safe shutdown equipment, supported by Division 1 EDGs and CTG 11-1.

Based on this review of unscreened compartments, the licensee asserted that the internal fire risk due to the EDG CT extension is considered small.
The licensee reviewed scenarios that were screened out based on a fire CDF less than 1E-6. Of the zones that screened out, there are six zones in which a fire could cause a total loss of

offsite power. Fires in these zones were also assumed to result in damage affecting equipment needed for safe shutdown. However, the licensee stated that sufficient equipment is maintained free of fire damage to maintain safe shutdown capability assuming a single EDG is out of service.

In two of these zones (02AB and 08AB), there are no credible ignition sources other than those from hot work or transient combustibles, both of which are controlled by procedure. The combination of the lack of significant fixed ignition sources and the fire detection and automatic fire suppression in these areas were considered adequate to preclude a credible fire event from damaging cables in these compartments in the IPEEE.

Fire zone 02AB contains cables supporting both divisions of safe shutdown equipment. For the design basis (Appendix R) fire in the 02AB fire zone, one division of safe shutdown equipment is maintained free of fire damage, and that division and its EDGs are credited for the safe shutdown analysis. However, due to the lack of ignition sources combined with fire detection and automatic suppression in this area, fire damage affecting safe shutdown capability is not considered credible. In addition, the licensee stated that a best estimate analysis shows that safe shutdown can be achieved with a single EDG should equipment supported by the other division of EDGs be unavailable. For a fire in zone 08AB, safe shutdown is achieved using provisions relying on CTG 11-1. EDGs are not credited for safe shutdown for a fire in this zone.

In the other four zones, the standby feedwater system is assumed not to be functional, but the mitigating equipment (for example, residual heat removal (RHR), RHR service water, high-pressure coolant injection (HPCI), and reactor core isolation cooling (RCIC)) and electrical support necessary to achieve safe shutdown is available, as well the three EDGs that are not impacted by the extended CT.

Based on this information, the NRC staff concludes that the proposed CT extension will not significantly impact the analysis of screened fire compartments.

<u>Seismic Risk</u>

Since Fermi 2 is a 0.3g focused-scope plant as defined in Supplement 5 to GL 88-20, the licensee did not perform CDF estimates of seismic scenarios. The licensee’s IPEEE submittal included a Seismic Margins Assessment, which concluded that the plant possesses sufficient seismic margin. The licensee provided representative calculations of the high confidence low probability of failure (HCLPF) capacities of some important components and showed that the HCLPF capacity of Fermi 2 was at least 0.3g, which is the review level earthquake.

During a design-basis safe shutdown earthquake, the plant switchyard is assumed to fail, causing a LOOP. The probability of a safe-shutdown earthquake (SSE) occurring during the 14-day period that an EDG may be inoperable due to maintenance is very low. With all other EDGs remaining operable and with the intra-division crosstie capability between 4.16 kV buses, the licensee concluded that the proposed change has a negligible effect on the Fermi 2 seismic risk profile.

<u>Risk from Other External Events</u>

With respect to HFO, the licensee's IPEEE submittal did not provide any CDF estimates. The licensee estimated that aircraft accident occurrence frequency using the current air traffic data is about 1.7E-7/yr. Even if the CCDP for an aircraft accident were 1.0, the resulting CDF would be about 1.6 percent of the total internal events CDF (1.05E-5/yr, as provided by the licensee). Therefore, a quantitative estimate of CDF resulting from aircraft accidents was not provided. The licensee performed walkdowns on other HFO events and screened out the HFO events in accordance with the guidance in NUREG-1407. The licensee's submittal stated that the proposed change to the EDG CT has negligible effect on the risk profile from these other external events.

Considering the information provided in the licensee's submittal, the NRC staff has reasonable confidence that the risks associated with external events will not impact the NRC staff's conclusion regarding the acceptability of the proposed CT extension to 14 days. Based on the risk analysis results demonstrating margin to the RG 1.177 guidelines, the NRC staff finds that the licensee has satisfied the intent of RG 1.174 (Section 2.2.3), RG 1.177 (Section 2.3.2), and SRP Chapter 19.1.

3.4.2 *Tier 2: Avoidance of Risk-Significant Plant Configurations*

The second tier requires licensees to provide reasonable assurance that risk-significant plant equipment outage configurations will not occur when specific plant equipment is out-of-service in accordance with the proposed TS change. Tier 2 identifies and evaluates any potential risk-significant plant equipment outage configurations that could result if other equipment with that associated with the proposed license amendment is removed from service simultaneously or if other risk-significant operational factors, such as concurrent system or equipment testing, are also involved. Therefore, Tier 2 helps ensure that appropriate restrictions are placed on dominant risk-significant configurations relevant to the proposed TS change.

The licensee's Tier 2 evaluation identified the following Tier 2 conditions as a result of the proposed EDG CT extension:

1. Work performed on safety significant systems and their applicable support systems will be reviewed and rescheduled as necessary based on routine and emergent Maintenance Rule 10 CFR 50.65(a)(4) evaluations performed per MMR12 (the site risk management procedure).

2. No work will be performed that could potentially jeopardize the availability of the opposite division EDGs. This is ensured by restricting and/or controlling access to this equipment via controls provided in existing plant procedure MOP05, "Control of Equipment."

3. For two EDGs in the same division, the CT will revert to the original (pre-Amendment 119) TS CT of 3 days.

The licensee stated that during an EDG outage, there is restricted access to the opposite division EDGs (e.g., EDGs 11 and 12 during an EDG 14 outage), controlled access to the 120 kV and 345 kV switchyards, and controlled access to CTG 11-1. These systems are listed in MMR Appendix H. During times of increased probability of loss of divisional (or all) offsite power, consideration is given to not beginning maintenance on an EDG or completing maintenance on an EDG in as short a time as possible.

Based on the above, the NRC staff finds the licensee's Tier 2 assessment is adequate to ensure that risk-significant equipment outage configurations will not occur during an extended EDG outage, consistent with the guidance of Chapter 16.1 of the SRP and RG 1.177, and thus is acceptable.

3.4.3 *Tier 3: Risk-Informed Configuration Risk Management*

The third tier requires licensees to develop programs to ensure that the risk impact of out-of-service equipment is properly evaluated prior to performing any maintenance activity. This program ensures that while an EDG is unavailable, additional activities will not be performed that could further degrade the capability of the plant to respond to a condition the inoperable EDG was designed to mitigate, and as a result, increase plant risk beyond that assumed by the risk-informed licensing action. Tier 3 programs: (1) ensure that additional maintenance does not increase the likelihood of an initiating event intended to be mitigated by the out-of-service equipment, (2) evaluate the effects of additional equipment out-of-service during EDG maintenance activities that would adversely impact EDG CT risk such as from redundant or associated systems or components, and (3) evaluate the impact of maintenance on equipment or systems assumed to remain operable by the EDG CT analysis.

Accordingly, a licensee should develop a CRMP to ensure that it appropriately evaluates the risk impact of out-of-service equipment before performing a maintenance activity. Licensees can utilize the overall CRMP (as referenced in RG 1.177) through the Maintenance Rule. Specifically, the rule requires that, before performing any maintenance activity, the licensee must assess and manage the potential risk increase that may result from a proposed maintenance activity. The licensee agreed to implement a CRMP as part of Amendment No. 119 (Reference 3), which originally increased the CT from 3 days to 7 days for one or both EDGs in a division inoperable. The intent of the original CRMP was to implement 10 CFR 50.65(a)(3) with respect to on-line maintenance for risk-informed TS. A description of the program was added to the Administrative Controls section of the TSs. When Fermi 2 converted its TSs to improved standard TSs (Amendment No. 134), the CRMP was relocated to the Technical Requirements Manual (TRM). Changes to the TRM are controlled by the requirements of 10 CFR 50.59.

The licensee stated that overall plant risk will be managed by the existing 10 CFR 50.65(a)(4) program. This program evaluates increases in risk posed by potential combinations of equipment out-of-service and potential increases in initiating event frequency. Risk recommendations must be implemented as appropriate for a given plant configuration. The licensee stated that the Maintenance Rule implementation is fully compliant with Chapter 11 of NUMARC 93-01 and is monitored by various internal and external oversight groups. The original CRMP addressed only EDGs and has been superceded by the more detailed Maintenance Rule program information in site procedure MMR12, "Equipment Out of Service Risk Management."

Based on the above, the NRC staff finds the licensee's Tier 3 program for complying with paragraph (a)(4) of 10 CFR 50.65 is consistent with the guidance of Chapter 16.1 of the SRP and RG 1.177 and thus is acceptable.

3.4.4 Comparison Against Regulatory Guidelines

The risk evaluation of the proposed extended EDG CT, including the qualitative consideration of fires and external events, is consistent with the acceptance guidance of RG 1.174 and RG 1.177 and the guidance outlined in SRP Chapters 19.0 and 16.1.

3.4.5 Summary

The Tier 1 risk impacts for ΔCDF, ΔLERF, ICCDP, and ICLERP, as estimated by the licensee for internal events and qualitatively evaluated for fires and external events, was found to be consistent with the acceptance guidelines in RG 1.174 and RG 1.177 for the proposed CT extension from 7 days to 14 days. The licensee's Tier 2 analysis was found to provide reasonable assurance that risk-significant plant equipment outage configurations will not occur when an EDG is taken out of service in accordance with the proposed TS change. The licensee's Tier 3 CRMP was found to be consistent with the RG 1.177 CRMP guidelines. The proposed change to extend the CT for one inoperable EDG satisfies the fourth key principle of risk-informed decisionmaking identified in RG 1.174 and RG 1.177 and is therefore acceptable.

The NRC staff does not have any objections to the proposed changes to the TS Bases.

3.5 Regulatory Commitments

1. No elective maintenance or testing that affects the reliability of the train associated with the EDGs in the other division will be scheduled during the extended Completion Time. If any such testing and maintenance activities must be performed while the extended Completion Time is in effect, a 10 CFR 50.65(a)(4) evaluation will be performed.

2. The EDG extended Completion Time will not be entered for preplanned maintenance if severe weather conditions are expected.

3. The EDG extended Completion Time will not be entered for preplanned maintenance if grid stress conditions are expected to be high, resulting in a significant potential for the grid to become unstable or unable to supply post trip offsite power minimum voltages.

4. The system load dispatcher will be contacted at least once per day to ensure no significant grid perturbations are expected during the extended Completion Time. The system operator will inform the plant operator if conditions change during the extended Completion Time (e.g., unacceptable voltages could result due to a trip of the nuclear unit).

5. Electric testing or maintenance of safety systems and important non-safety equipment including offsite power systems (i.e., station service transformer) that significantly increases the likelihood of a plant transient or loss of offsite power will not be scheduled concurrently with planned EDG outages utilizing the extended Completion Time. In addition, no discretionary switchyard maintenance will be allowed. If any such testing or maintenance activities must be performed while the extended Completion Time is in effect, a 10 CFR 50.65(a)(4) evaluation will be performed.

6. Steam-driven HPCI and RCIC systems will be controlled as “protected equipment,” and will not be taken out of service for planned maintenance while an EDG is out of service for planned maintenance utilizing the extended Completion Time.

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Michigan State official was notified of the proposed issuance of the amendment. The State official had no comments.

5.0 ENVIRONMENTAL CONSIDERATION

The amendment changes a requirement with respect to the installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20. The staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration and there has been no public comment on such finding (71 FR 51225). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

6.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

7.0 REFERENCES

1. Fermi 2 Updated Final Safety Analysis Report, Revision 14, November 6, 2006.

2. Letter from D.H. Jaffe, U.S. Nuclear Regulatory Commission, to D.K. Cobb, Detroit Edison Company, “Fermi 2 - Issuance of Amendment Re: Allowed Outage Time Extension for Emergency Diesel Generator 12 for One Specific Incident (TAC No. MC9728),” February 6, 2006.

3. Letter from A.J. Kugler, U.S. Nuclear Regulatory Commission, to D.R. Gipson, Detroit Edison Company, “Fermi 2 - Issuance of Amendment Re: Extension of Emergency Diesel Generator Allowed Outage Times for Fermi 2 (TAC No. M94171),” June 2, 1998.

4. Letter from T.G. Colburn, U.S. Nuclear Regulatory Commission, to D.R. Gipson, Detroit Edison Company, “Fermi 2 - Generic Letter (GL) 88-20, Individual Plant Examination (IPE) Submittal - Internal Events - Completion of Staff Review,” November 16, 1994.

5. Letter from A.J. Kugler, U.S. Nuclear Regulatory Commission, to W.T. O'Connor, Detroit Edison Company, "Fermi 2 - Completion of Licensing Action for Generic Letter (GL) 88-20, Supplement 4, 'Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities,' Dated June 28, 1991 (TAC No. M83621)," July 5, 2000.

6. Fermi 2 Individual Plant Examination (External Events), March 1996.

7. NUREG-1488, "Revised Livermore Seismic Hazard Estimates for Sixty-Nine Nuclear Power Plant Sites East of the Rocky Mountains," April 1994.

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Fermi 2

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