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U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D. C. 20555

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

2) NRC Letter to Detroit Edison, "Technical Specification Change Request - Emergency Diesel Generator Allowed Outage Time Extension (TAC No. M94171)," dated March 22, 1996

3) Detroit Edison Letter to NRC, "Proposed Technical Specification Change (License Amendment) - Emergency Diesel Generator Action Statements, Surveillance Requirements and Reports," NRC-95-0124, dated November 22, 1995

4) Detroit Edison Letter to NRC, "Response to NRC Letter on Emergency Diesel Generator Allowed Outage Time Extension (TAC No. M94171)," NRC-96-0041, dated April 19, 1996

5) Detroit Edison Letter to NRC, "Response to Questions on Proposed Emergency Diesel Generator Technical Specification Change," NRC-96-0008, dated February 19, 1996

Subject: Response to Probabilistic Safety Assessment Questions Related to Request for Increasing Emergency Diesel Generator Allowed Out of Service Time (TAC No. M94171)

This letter provides Detroit Edison's response to the questions asked in Enclosure 1 of Reference 2. The questions pertain to Detroit Edison's request to increase the allowed out-of-service time for one onsite AC electrical power division (Reference 3).

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Per Reference 2, the responses to the questions in Enclosure 1 were to be discussed during an upcoming onsite working level meeting on the probabilistic safety assessment (PSA) evaluation used to support the proposed Technical Specification Change and then a response would follow. However, Mr. Tim Colburn, NRC Project Manager, recently requested submittal of the responses. The responses to the questions in Enclosure 2 of Reference 2 were provided in Reference 4.

No new commitments are being made in this letter. Detroit Edison sincerely hopes the responses in the enclosure to this letter will facilitate prompt completion of the NRC review of the proposed Technical Specification changes. Detroit Edison representatives would like to meet with NRC reviewers to address any remaining questions. If there are any additional questions, please contact Lynne Goodman at (313) 586-4097 promptly, so they can be expeditiously answered. Detroit Edison understands the NRC review could not be completed by March 31, 1996 as originally requested; however, completion by May 31, 1996 would be greatly appreciated.

Sincerely,

Enclosure

cc: T. G. Colburn
M. J. Jordan
H. J. Miller
A. Vegel

Response to Risk-Based Request for Additional Information on the Fermi 2 Application for Technical Specifications Change on Emergency Diesel Generator Allowed Outage Time Extension

(A) Tier 1 Questions

(a) Probabilistic Safety Assessment (PSA, or PRA)

NRC Question

The staff is concerned that the extensions of emergency diesel generator (EDG) allowed outage times (AOTs) may increase the mean Core Damage Frequency (CDF) for the station blackout (SBO) events and impact resolution of the SBO issue. Provide the calculated CDF for SBO sequences without the proposed AOT extension and CDF for SBO sequences with the proposed AOT extension. Also provide the overall reliability and unavailability of the EDGs used in the PRA to calculate the CDFs for the SBO sequences requested.

Detroit Edison Response

Two different PSA models were used to evaluate the extended AOTs, as discussed in Reference 3. One model (BASE92B) is the model used for the Independent Plant Evaluation (IPE) of Fermi 2. The other model (IPE95) is an improved representation of the risk associated with at power operation of Fermi 2. The development of IPE95 started with the BASE92B model. Changes were made to BASE92B so that upgraded capabilities made in the software version of RISKMAN, the risk management code used for risk analysis at Fermi 2, could be utilized. System models were changed from the original Boolean equation representation used in BASE92B to the system fault trees used by IPE95. In addition, modifications made to the plant since refueling outage 2 through refueling outage 4 have been incorporated into IPE95.

The BASE92B model was cloned and the cloned model was modified to represent the risk associated with the extended AOT requested for the Fermi 2 EDGs. This modified model is called EDG_AOT. Likewise, the model DIESEL is a clone of IPE95. DIESEL was also modified to represent the risk associated with the extended AOT for the EDGs.

There is more than one way to categorize a SBO event. For this response, SBOs are categorized as they were for the IPE submittal. That is, events are binned into a SBO endstate if off-site power is lost, all four EDGs fail, off-site power is not recovered

within 7 hours and the combustion turbine generator (CTG 11-1) fails. For the current Fermi 2 PSA model this results in a SBO contribution of 2.7 percent to the total core damage frequency. A sensitivity case was run where the SBO contribution pertains to all core damage events involving off-site power failure and failure of the four EDGs. Off-site power may be successfully recovered and CTG 11-1 may be successful in this case. The contribution for this classification of SBO is 3.6 percent of the total core damage frequency.

A summary of the SBO contributions to the total core damage frequency (CDF) for the four models follows:

SBO Contribution to CDF

Model	without AOT extension	with AOT extension
BASE92B	1.26e-07	N/A
EDG-AOT	N/A	1.39e-07
IPE95	1.33e-07	N/A
DIESEL	N/A	1.55e-07

For consistency, numerical risk values presented in this letter are excerpted from the evaluation performed in October 1995 for the Reference 3 submittal. Exceptions to this exists where new information needed to be generated to answer the NRC questions. The new information was generated from updated versions of the IPE95 model. The model has changed slightly since October 1995, mainly as a result of the review mentioned in Reference 3. The changes in CDF between IPE95 and EDG_AOT are very similar, so the conclusions remain valid.

Unavailability and reliability are modeled and evaluated in the system analysis section of RISKMAN. Output from the system analysis, called split fractions, are used in the event tree analysis. Split fractions represents the combined reliability and unavailability of a system and are conditional on the availability of support equipment and other system successes or failures which may be precursors of common cause failures. For example, using model BASE92B, the failure rate of EDG #14 given all support is available and no other EDG failures is 5.8e-02 per demand. If all support is available and EDGs #11, #12 and #13 have failed, the failure rate for EDG #14 jumps to 3.1e-01 per demand due to the potential of a common cause failure. Selected EDG #14 split fractions values for the models used to evaluate the EDG extended AOT are given below:

All Support Available Split Fraction Values

Model	No Other EDG failures	1 other EDG Fails	2 Other EDGs Fail
BASE92B	5.8e-02	7.8e-02	9.1e-02
EDG_AOT	8.0e-02	8.0e-02	9.1e-02
IPE95	5.7e-02	7.5e-02	1.2e-01
DIESEL	7.2e-02	8.0e-02	1.2e-01

NRC Question

Is Fermi 2 capable of cross-connecting the Division 1 engineered safety feature (ESF) buses with the Division 2 ESF buses? If yes, explain how. Is it modeled in the Fermi 2 PRA? How long does it take to establish the cross-tie? How much credit is taken?

Detroit Edison Response

There is a maintenance tie breaker (64T) that can be used to connect Division 1 Balance of Plant (BOP) power to either of the two 4160 volt Division 2 ESF buses 65E and 65F. System Operating Procedure 23.321 "Engineered Safety Features Auxiliary Electrical Distribution System" provides instructions and cautions for performing the cross-tie. A second maintenance tie breaker (65T) also can be used to tie Division 2 BOP power to either of the Division 1 4160V buses. As discussed in Reference 4, there are limitations to the operation of the maintenance cross-tie breakers and a detailed engineering evaluation has not been performed on the use of the cross-tie breakers during an accident.

There is also transfer capability between the two corresponding 480 volt ESF buses on each division. For example, the Division 1 loads from bus 72EA can be transferred to bus 72EB and visa versa. Also, Division 1 loads can be transferred from bus 72B to 72C and vice versa. System Operating Procedure 23.321 provides instructions for the 480 volt transfer on both divisions.

Each of the electrical cross-tie capabilities discussed above are modeled in the Fermi 2 PSA. A human action evaluation of the 480 volt cross-tie, which requires similar operator actions as the 4160 volt cross-tie, established 20 minutes for the time necessary to accomplish the cross-tie.

The following credit is taken in the PSA model for the cross-ties. For ATWS events where the Standby Liquid Control system fails or one of the recirculation pumps fail to trip, or for events involving a failed bus, the cross-tie is guaranteed to fail. For events where the cross-tie is not guaranteed to fail and if low pressure injection is available, the operator has six to eight hours to cross-tie the loads from one 480 volt bus in a division to the other bus in that division and establish decay heat removal capability. The mean failure rate for this operator action is 2.0e-02 per event. If injection is not available then only one hour is available for establishing the cross-tie and the failure rate used in the PSA model is 2.0e-01 per event. The PSA failure rate for the 4160 volt cross-tie is 1.0e-01 per event.

NRC Question

Please explain how Fermi 2 maintains combustion turbine generator 11-1's (CTG 11's) high level of reliability and availability. Is the CTG hardened against severe weather? How much credit has been taken with respect to CTG 11-1's ability to decrease the conditional CDF?

Detroit Edison Response

Detroit Edison periodically performs testing, preventive maintenance and monitoring of CTG 11-1. According to Design Calculation DC-4986, the combustion turbine generator units are outdoor units designed to withstand most likely weather related events. The outdoor metal clad output switchgear is also designed to be weather resistant. Electrical power cables between the generator and switchgear, between the switchgear and transformer CTG-11 and between switchgear bus 1-2B and transformer 64 are underground. Cables between transformer CTG-11 and switchgear bus 1-2B are overhead but inside a protective housing. Between transformer 64 and the plant buses, power cables are mostly underground except for a section running up the side of the reactor building which is inside a housing and designed for outdoor use.

The Fermi 2 PSA does not employ an unrealistically high reliability or availability for CTG 11-1. Given a total loss of off-site power, the failure rate used in the PSA model for CTG 11-1 is 8.8e-02 per demand. For loss of Division 1 off-site power, the failure rate for CTG 11-1 is 3.3e-1 per demand. The difference between the two failure rates reflects an operating philosophy that focuses on available equipment for mitigating a transient rather than attempting to restore failed equipment.

As reported in the Fermi 2 IPE Report, a sensitivity run was made to evaluate the importance of CTG 11-1 with respect to preventing core damage events. Quantification of the full PSA model with CTG 11-1 guaranteed failed resulted in a 37 percent increase in the base CDF.

NRC Question

What are the success criteria for the SBO condition at Fermi 2? Can any one EDG mitigate SBO? Is this modeled in the PRA? Please explain.

Detroit Edison Response

The PSA success criteria for a SBO is the same as for any other transient. Briefly, a means of controlling reactivity, an injection source and a method for removing decay heat are required for mitigating an event. Section 3.1.6, pages 3-38 through 3-73 of

the Fermi 2 IPE Report, Revision 1, provides a more detailed discussion of the success criteria used in the PSA model. Using the cross-tie capability of the ESF buses, one EDG could conceivably mitigate a SBO. As mentioned above, the PSA does model the cross-tie of the ESF buses. Given a total loss of off-site power, CTG 11-1 fails and off-site power is not recovered within 7 hours, the following conditional core damage frequencies (CCDF) were computed for Fermi 2 given the success of one EDG and failure of the other three:

	CCDF per event
EDG #11 successful and EDG #12, 13 and 14 fail	3.2e-02
EDG #12 successful and EDG #11, 13 and 14 fail	3.0e-02
EDG #13 successful and EDG #11, 12 and 14 fail	3.0e-02
EDG #14 successful and EDG #11, 12 and 13 fail	5.3e-03

The difference in risk significance for each EDG is addressed in response to the first Tier 2 question.

NRC Question

What review of the PRA has been made to ensure that the PRA represents the as-built, as-operated plant, and contains the fine structure (resolution) necessary to evaluate the proposed TS requirements? Were any changes made to the PRA due to such reviews.

Detroit Edison Response

As discussed in the Fermi 2 IPE Report, pages 5-6 through 5-15 numerous reviews and refinements of the PSA have been performed to ensure the integrity of the PSA model. Some of the resolutions made to the PSA model as a result of these reviews are also discussed in Section 5.0 of the Fermi 2 IPE submittal. Additional reviews have been performed since the IPE was submitted. ERIN Engineering converted the Boolean system equations to linked fault trees for a REBECA model. These fault trees were converted to system fault trees for RISKMAN by Detroit Edison and reviewed by PLG, Inc. The model has also been modified to reflect changes made to the plant during and prior to the last refueling outage.

NRC Question

Your current PRA is said to be different from your individual plant examination (Rev. 1 submitted on September 22, 1993). Explain any major differences. Among those differences, is there anything related to SBO sequences?

Detroit Edison Response

A major difference is the way systems are modeled. Boolean equations were employed in the model used for the IPE while fault trees are the current mechanism used to represent system unavailability and reliability. Those familiar with the technology know the added flexibility that fault trees provide. While fault trees are a representation of Boolean equations, they give engineers a better representation of the system modeled, showing explicitly what is and what is not included in that model. Upgrading the RISKMAN code from version 2 to version 7 has also improved the modeling capability of the Fermi 2 PSA. Each and every maintenance or test alignment can be explicitly identified with version 7 of RISKMAN with the CDF contribution of each easily quantified.

Several plant modifications have been incorporated into the PSA model since submittal of the IPE. The PSA model has been modified to reflect differences between modeling assumptions and the as-installed hard pipe vent and has incorporated a related pre-existing divisional cross-tie capability within the Noninterruptible Air System.

A redundant ATWS trip signal has been installed since the model for the IPE was developed. The added trip logic and trip coil improves the reliability of the recirculation pump trip for ATWS events. This change was also added to the PSA model.

A new MOV has been added to the Reactor Water Cleanup system. This valve serves as the outboard containment isolation valve. Control logic was added so that the new valve would close on an isolation signal, one of the isolation signals being Standby Liquid Control System (SLC) initiation. The valve and logic was added to the PSA modeling of SLC.

Given the right circumstances, all of the modifications discussed above could impact the mitigation of a SBO. So in the broadest sense, all modifications made to the model will impact how a transient, including a SBO, will be mitigated. However, none stand out as having a significant impact on SBO sequences.

NRC Question

Please provide the truncation cutoff used to quantify the plant CDF changes. In particular, indicate what efforts were made to avoid underestimation when the impact calculated was negligible or nonexistent.

Detroit Edison Response

Table 3.3-11, page 3-221 of the Fermi 2 IPE Report contains the cutoffs used for each initiating event for the BASE92B and EDG_AOT models. These cutoffs result in over 30,000 sequences being evaluated. A frequency of less than 3.7e-07 is unaccounted for in both models. If all of the unaccounted frequency were to go to core damage it would add less than seven percent to the total CDF.

The IPE95 and DIESEL models used a cutoff of 5.0e-12 for all initiating events. This cutoff resulted in over 20,000 sequences being evaluated. A frequency of less than 1.8e-06 is unaccounted for in these models.

The number of sequences evaluated and the small unaccounted frequency gives Detroit Edison confidence that no significant sequences were overlooked.

NRC Question

Provide a discussion of the loss-of-offsite power events at your facility.

Detroit Edison Response

Appendix A of the Fermi 2 IPE Report, "Calculation of Loss of Offsite Power Initiator Frequencies and Recoveries for the Fermi 2 Level 1 PRA", gives a very detailed discussion of the off-site power grid, initiators for the loss of off-site power, and recovery of off-site power for the Fermi 2 site.

NRC Question

Please describe the peer reviews performed on your PRA. Indicate which reviews were performed in-house versus those performed by outside consultants. Summarize their overall conclusions.

Detroit Edison Response

This information can be found in Section 5.0 of the Fermi 2 IPE Report. The review of a complex PSA such as the RISKMAN model used for Fermi 2 is an ongoing process. Comments pertaining to the PSA are reviewed and dispositioned in an effort to maintain a valid and accurate representation of the risk associated with the operation of Fermi 2. As discussed earlier, the conversion to system fault trees was performed by Detroit Edison and reviewed by PLG, Inc.

(b) Quantitative results

NRC Question

Please provide the following calculations and quantitative PRA results due to the AOT extension:

(1) Change in average CDF ($\Delta m(CDF)$):

m(CDF)	=	average CDF (per year)
m_2(CDF)	=	The conditional m(CDF) with the proposed 7-day AOT in place
m_1(CDF)	=	The original m(CDF) with the current 3-day AOT in place

Therefore, $\Delta m(CDF) = m_2(CDF) - m_1(CDF)$

(2) Change in instantaneous CDF (ΔCDF_i):

$CDF_i(2)$	=	The conditional CDF when the plant is in the AOT
$CDF_i(1)$	=	The CDF when the plant is not in the AOT
i	=	a particular AOT configuration

Therefore, $\Delta CDF_i = CDF_i(2) - CDF_i(1)$

(3) Change in conditional core damage probability (ΔCCDP):

CCDP(2)	=	The CCDP while the plant is in the AOT
CCDP(1)	=	The CCDP while the plant is not in the AOT

Therefore, $\Delta CCDP = CCDP(2) - CCDP(1)$

(4) Change in large early release frequency (ΔLERF)

LERF(2)	=	LERF with proposed AOT in place
LERF(1)	=	LERF with current AOT in place

Therefore, $\Delta LERF = LERF(2) - LERF(1)$

Detroit Edison Response

(1)

		Core Damage Events per Year	
		IPE/DIESEL	BASE92B/EDG_AOT
$\Delta m(CDF))$	=	1.0e-07	1.0e-07
$m_1(CDF)$	=	6.46e-06	5.67e-06
$m_2(CDF)$	=	6.56e-06	5.77e-06

(2) The instantaneous CDF was not explicitly calculated for this analysis. However, the instantaneous risk for one diesel out-of-service has been previously calculated. This calculation is conservative in that the failure rates for the three EDGs that are not in maintenance still include unavailability terms representing maintenance. The following results are from an assessment of risk when removing the EDGs from service:

		Core Damage Events per Year			
		EDG #11	EDG #12	EDG #13	EDG #14
$\Delta(CDF)$	=	2.44e-06	3.04e-06	2.09e-06	4.30e-06
$CDF_i(1)$	=	6.70e-06	6.70e-06	6.70e-06	6.70e-06
$CDF_i(2)$	=	9.14e-06	9.74e-06	8.79e-06	1.10e-05

The instantaneous CDF given both EDGs in one division are out for maintenance was calculated explicitly. This calculation was performed for Division 1 (EDG #11 and #12) and Division 2 (EDG #13 and #14). For the calculations it was assumed that if both EDGs in one division are in maintenance and a diesel in the other division became inoperable then the plant would be required to shut down. Therefore, except for the possibility of maintenance on a spare fuel oil transfer pump, the availability of the EDGs in the unaffected division for $CDF_i(2)$ was 100 percent. Likewise, for $CDF_i(1)$ (RISKMAN case EDG), it was assumed that all four diesels are available during the period of interest. In other words, for this calculation, the failure rate for the available EDGs was based solely on reliability and not on the AOT.

	Core Damage Events per Year		
	$CDF_i(1)$	$CDF_i(2)$	$\Delta(CDF)$
EDG #11 and EDG #12 in maintenance	6.43e-06	3.17e-05	2.53e-05
EDG #13 and EDG #14 in maintenance	6.43e-06	2.90e-05	2.26e-05

(3) Using the instantaneous CDFs provided above for the individual EDG outages and a current AOT of three days and an extended AOT of seven days, the following conditional core damage probabilities were computed.

Total CCDP for 1 year (3 day AOT)	=	6.80e-06
Total CCDP for 1 year (7 day AOT)	=	6.92e-06
CCDP(1) 353 days	=	6.48e-06
CCDP(1) 48 weeks	=	6.18e-06
CCDP(2) 3 days for each EDG	=	7.53e-08 + 8.03e-08 + 7.24e-08 + 9.07e-08
CCDP(2) 7 days for each EDG	=	1.76e-07 + 1.87e-07 + 1.69e-07 + 2.12e-07

Therefore, ΔCCDP = 1.2e-07

(4) A level 2 PSA model that reflects the as-built configuration of Fermi 2 has not been maintained. Therefore, the large early release frequency was not explicitly calculated for this analysis. A fair approximation of various releases can be obtained by mapping each core damage endstate to an appropriate release endstate. Since the core damage endstates are not categorized as LOCA and non-LOCA events, all injection failures will be classified as a LOCA event for the following release calculation. This method will overestimate the large release since 74 percent of all LOCA induced core damage events lead to a large early release while only 3 percent of all core damage events due to injection failures with the vessel at high pressure result in a large early release. The following data was obtained by mapping the core damage endstate data to a large early release endstate. Table 4.6-5 from the Fermi 2 IPE Report was used for the endstate mapping logic.

		Large/Early Release per Year	
		IPE95/DIESEL	BASE92B/EDG_AOT
ΔLERF	=	3.0e-08	3.0e-08
LERF(1)	=	2.82e-06	1.87e-06
LERF(2)	=	2.85e-06	1.90e-06

NRC Question

What are the projected average corrective maintenance and preventive maintenance downtimes for EDGs used in your calculations? Explain how they are obtained. Have you performed any sensitivity analyses on your corrective maintenance and preventive maintenance downtimes that affect the risk results in the previous questions? If so, please discuss insights gleaned from the study.

Detroit Edison Response

For the current AOT the PSA projects a 0.5 percent total maintenance downtime for each EDG or about 44 hours per year, using a generic maintenance assumption. An

additional 0.0025 percent of the time or less than 15 minutes per year, both Division 1 EDGs are projected to be simultaneously out-of-service. Likewise, 0.0025 percent of the time both EDGs in Division 2 are projected to be out-of-service.

To assess the extended AOT, 1.9 percent or about 170 hours per year was used as a projected total maintenance time for each EDG. This value was obtained by assuming that once every fuel cycle (16 months of reactor operation) each EDG will undergo one additional seven day maintenance outage. Therefore, a 5.25 day outage for each reactor year of operation was projected for each EDG in addition to the current 44 hours projected in the current PSA. A 0.0058 percent projection was also used for both EDGs in Division 1 being out-of-service and another 0.0058 percent projection for both EDGs in Division 2 being out-of service at the same time.

A sensitivity case was run where it was projected that one additional seven day corrective maintenance (CM) would occur once a fuel cycle. It was also projected that the additional corrective maintenance would occur simultaneously with the preventive maintenance (PM) on the other EDG in the affected division. Note that a PM on an EDG in one division and a CM on a diesel in the other division would not be allowed by the current or proposed revised Technical Specifications. The annual mean CDF for the extended AOT plus the one concurrent PM and CM is 7.5e-06 per year. This is a small increase from the 6.6e-06 per year for the DIESEL model. However, it shows the greater sensitivity to core damage when both EDGs in one division are out-of-service as opposed to removing one EDG at a time from service. One week with both EDGs in a division out-of-service carries an additional risk that is greater than the additional risk associated with four weeks of operation with only one EDG out-of-service.

NRC Question

Have you performed any sensitivity analysis for this requested AOT change? If so, discuss how your results ensure the PRA results in your application are robust and away from a "cliff" or sudden increase in the risk profile.

Detroit Edison Response

Risk Achievement Worth (RAW) calculations have shown the relative low worth of a single EDG. RAW values for the EDGs range from 1.5 to 1.9. The PSA analysis performed for the AOT extension confirms that an insignificant risk is associated with operating for periods of up to five weeks per year with one EDG out-of-service. Outage times used in the analysis are also conservative in that each additional EDG outage is anticipated to take less than four days to complete, not the seven days used in the analysis. In this respect the analysis bounds the anticipated operation of Fermi 2 with the extended EDG AOT. The nature of risk of core damage as a function of

allowed outage time precludes a time dependent "cliff" due to the AOT change alone since risk is linear with the outage time. Risk determination that could involve a "cliff" due to another system out of service together with a diesel out of service is already developed through the risk matrix discussed in the response to the next question. Also, the response to the previous question provides a discussion of the sensitivity analysis performed for the requested change.

(B) Tier 2 Questions

NRC Question

Given the AOT plant configuration, what does your PRA indicate are the other risk-significant systems? Is the significance the same for each EDG, or EDG combination? Please explain the results.

Detroit Edison Response

A risk matrix has been developed that identifies the risk associated with scheduled on-line maintenance. This matrix identifies those systems that are more risk significant during a particular EDG outage. In general these systems are the Essential DC and AC equipment in addition to systems devoted to decay heat removal (DHR). The DHR systems are identified because the dominant core damage sequences at Fermi 2 are due to the loss of DHR.

The absolute risk for each EDG outage and EDG/system outage combination depends on the EDG. This dependence is based on the loads that would be fed by the diesel during a loss of off-site power event. For example, EDG #12 and EDG #14 are more risk significant than the other two diesels because MCC 72C-F is dependent on EDG #12 or EDG #14. EDG #14 is more risk significant than EDG #12 because long term Division 2 DC power requires bus 65F for AC power to the battery chargers while long term Division 1 DC power requires bus 64B for AC power to the battery chargers. EDG #11 provides emergency power to bus 64B while EDG #14 provides emergency power to bus 65F.

NRC Question

For the systems you identified in the previous question, how would you ensure that no risk-significant plant equipment outage configurations would occur while the plant is subject to the LCO proposed for modification? Are the bases for this assurance reflected in your procedures or TS?

Detroit Edison Response

As discussed in Reference 5, the normal conduct of business at Fermi 2 is to determine what other equipment is inoperable prior to removing an EDG from service. Per the Daily Scheduling Program Guidelines, the effect of adding additional work to the schedule during a system outage that would remove additional major equipment from service is evaluated from a Technical Specification and risk standpoint prior to that equipment being removed from service.

NRC Question

Have you thoroughly reviewed your TS to see if there are needs for any other changes to your TS or TS bases (in addition to the TS amendment items you are currently requesting) because of your request of EDG extension from 3 to 7 days? Please identify any TS changes made to ensure that the plant will not enter any risk-significant plant configuration while in the AOT.

Detroit Edison Response

No additional TS changes will be needed. Reference 3 requested changes to Action Statements 3.8.1.1.b and 3.8.1.1.d, Surveillance Requirements 4.8.1.1.2.a, 4.8.1.1.3 and 4.8.1.2, Table 4.8.1.1.2-1 and Bases 3/4 8.1, 3/4 8.2 and 3/4 8.3. While the changes to the EDG Action Statements were, in part, based on the risk assessment, none of the other changes were risk based.

C) Tier 3 Questions

NRC Question

Are you capable of performing a "real-time" assessment of the overall impact on safety functions of related TS activities before conducting maintenance activities including removal of any equipment from service? Please explain how this tool, or other processes, will be used to ensure that risk-significant plant configurations will not be entered during the AOT?

Detroit Edison Response

As discussed earlier, a risk matrix has been developed that identifies the risk associated with scheduled on-line maintenance. The matrix identifies those systems that are more risk significant during a particular scheduled on-line maintenance activity. This matrix is normally used to assess risk significance prior to removing additional systems from service during a scheduled system outage, such as a

scheduled EDG outage. Higher levels of approval are needed for higher risk rankings, with entry into the highest risk ranking configuration prohibited.

NRC Question

Explain how you are going to address the issue of configuration and control, consistent with the maintenance rule, i.e., evaluate the impact of maintenance activities on plant configurations.

Detroit Edison Response

As discussed in Reference 4, factors such as reliability, Technical Specification requirements, and risk are normally evaluated when determining whether to remove key safety systems from service. The matrix described earlier is the main tool used to address risk of potential plant system configurations. Advance preparations are made to minimize the time out of service during on-line maintenance activities. Detroit Edison currently uses this scheduling philosophy and these tools to implement a means of evaluating the impact of maintenance activities on plant configurations consistent with the Maintenance Rule.