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Perry Nuclear Power Plant
Docket No. 50-440
License Amendment Request: Extension of the Emergency Diesel Generator Completion Time and performance of the 24-hour Surveillance Requirement in Modes 1 and 2

Ladies and Gentlemen:

Pursuant to 10 CFR 50.90, Nuclear Regulatory Commission review and approval of a license amendment for the Perry Nuclear Power Plant is requested. Based on safety and design reviews that have been performed, the proposed amendment would permit an Emergency Diesel Generator (EDG) Technical Specification (TS) Action Completion Time of up to 14 days for a Division 1 or 2 EDG and allow performance of the EDG 24-hour TS Surveillance Requirement test in Modes 1 and 2. This proposed change will reduce the complexity of activities being performed during refuel outages and potentially reduce the duration of refuel outages as well as reduce human performance errors while not adversely impacting the margin of safety.

Attachment 1 provides a Summary and description of the proposed change, a Safety Analysis, and an Environmental Consideration. Attachment 2 provides the Significant Hazards Consideration. Attachment 3 provides the annotated TS pages reflecting the proposed change. Attachment 4 provides the annotated TS Bases pages reflecting the proposed change. Attachment 4 is for information only, since the Bases is not a formal part of the Technical Specifications.

If you have questions or require additional information, please contact Mr. Henry L. Hegrat, Manager - Regulatory Affairs, at (440) 280-5606.

Very truly yours,

Lew W. Myers

Attachment

cc: NRC Project Manager
NRC Resident Inspector
NRC Region III
State of Ohio

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P PDR

I, Lew W. Myers, being duly sworn state that (1) I am Vice President - Nuclear, of the Centerior Service Company, (2) I am duly authorized to execute and file this certification on behalf of The Cleveland Electric Illuminating Company and Toledo Edison Company, and as the duly authorized agent for Duquesne Light Company, Ohio Edison Company, and Pennsylvania Power Company, and (3) the statements set forth herein are true and correct to the best of my knowledge, information and belief.

Lew W. Myers

Sworn to and subscribed before me, the 3rd day of September, 1998.

Lori J. Strauss

LORI J. STRAUSS
Notary Public, State of Ohio
My Commission Expires 3/24/2003

SUMMARY

This submittal proposes to change the Technical Specifications (TS) to:

1. Extend the existing TS Completion Time for one inoperable Division 1 or 2 Emergency Diesel Generator (EDG) from 72 hours to 14 days.

2. Allow the EDG 24-hour load surveillance run to be completed on-line, i.e., all Modes including Modes 1 and 2.

The Perry Nuclear Power Plant (PNPP) is equipped with three (3) Seismic Category I, Class 1E, diesel driven generators which supply an independent source of AC power to the 4.16 kV vital AC buses. Each division is provided with an EDG. In addition to the safety classification of the diesels, each diesel generator set is electrically and physically isolated from the other and is located in a Seismic Category I structure.

At PNPP, Division 1 supports the Low Pressure Core Spray System and the Low Pressure Core Injection "A" train of the Residual Heat Removal System. Division 2 supports the Low Pressure Core Injection "B" and "C" trains of the Residual Heat Removal System, and Division 3 supports the High Pressure Core Spray System (HPCS). Division 3 is capable of being manually cross-tied to Division 2 during a Station Blackout to provide power to selected Division 2 loads.

Each diesel generator is automatically started upon receipt of a Loss of Coolant Accident (LOCA) signal, an undervoltage signal or a degraded voltage signal at the associated division bus. For Division 1 and Division 2, each EDG is designed to start automatically so that within 10 seconds following receipt of an initiation signal, it is operating at rated speed and ready to begin load sequencing. For Division 3, the EDG is designed to start automatically so that within 13 seconds following receipt of an initiation signal, it is operating at rated speed and ready to begin load sequencing.

The EDGs are described in Section 8.3.1 of the Perry Unit 1 Updated Safety Analysis Report (USAR).

The first part of this change request proposes to revise the TS Completion Times for an inoperable Division 1 or 2 EDG. The PNPP TS 3.8.1, Required Action B.4, requires that if an EDG is declared inoperable for any reason, the EDG must be restored to operable status within 72 hours and 6 days from discovery of failure to meet the Limiting Condition for Operation (LCO) or place the plant in Hot Standby within 12 hours and Cold Shutdown within 36 hours. The proposed change (1) continues to require a 72 hour Completion Time for an inoperable Division 3 EDG, and (2) makes provisions for a 14 day Completion Time for a single Division 1 or 2 inoperable EDG. The proposed TS change allows up to 17 days (72 hours + 14 days) from discovery of failure to meet the LCO consistent with the proposed 14 day EDG Completion Time for Required Action A.2 and B.4.

The proposed change also adds a Configuration Risk Management Program (CRMP) in Section 5.5 to provide a risk-informed assessment associated with the EDG Completion Time, i.e., limiting the Completion Time based upon frequency or purpose of entry into the associated condition.

A deterministic engineering evaluation in addition to a probabilistic risk assessment was completed to evaluate the acceptability of extending the Division 1 and 2 EDG Completion Time to 14 days. The results of these analyses showed that the increase in risk was insignificant and within the limits of the NRC guidance (References 1-3).

The second part of this change request proposes to allow the EDG 24-hour load surveillance run to be completed on-line. The proposed change modifies Note 2 to TS Surveillance Requirement (SR) 3.8.1.14 to delete the current restriction on performing the SR in Mode 1or 2. This allows the 24-hour load run (completed to satisfy TS SR 3.8.1.14) to be performed in all modes of plant operation including Modes 1 and 2.

An evaluation of the impact to the worst-case design basis events was completed to establish the acceptability of completing the 24-hour surveillance run on-line. This evaluation showed that the EDGs will adequately respond within the time necessary to mitigate anticipated operational occurrences or postulated Design Basis Accidents.

DESCRIPTION OF PROPOSED TECHNICAL SPECIFICATION CHANGE

Technical Specification Section 3.8.1, "AC Sources-Operating", Actions, Page 3.8-2, Action A.2, Completion Time, change "6 days from discovery of failure to meet LCO" to "17 days from discovery of failure to meet LCO".

Technical Specification Section 3.8.1, "AC Sources-Operating", Actions, Page 3.8-3, Action B.4, Completion Time, change "72 hours" to "72 hours from discovery of an inoperable Division 3 DG", add a Completion Time of "14 days" and change "6 days from discovery of failure to meet LCO" to "17 days from discovery of failure to meet LCO".

Technical Specification Section 3.8.1, "AC Sources-Operating", Surveillance Requirements, Page 3.8-11, Surveillance (SR) 3.8.1.14, Note 2, change "This Surveillance shall not be performed in Mode 1 or 2. However, credit may be taken for unplanned events that satisfy this SR " to "Credit may be taken for unplanned events that satisfy this SR."

Technical Specification Section 5.5, "Programs and Manuals", add Page 5.0-15b, which outlines a Configuration Risk Management Program (CRMP).

SAFETY ANALYSIS

Implementation of the proposed Technical Specification change will:

- Permit scheduling of EDG overhauls of up to 14 days on-line.
- Permit performance of 24-hour surveillance runs on line.
- Allow increased flexibility in the scheduling and performance of preventative maintenance.

- Reduce the number of individual entries into LCO action statements by providing sufficient time to perform related maintenance tasks with a single entry.
- Allow better control of resource allocation. During outage maintenance windows, plant personnel and resources are spread across a large number and wide variety of maintenance tasks. Allowing on-line preventative maintenance (including overhauls) and on-line 24-hour runs gives the flexibility to focus more quality resources on any required or elected EDG maintenance.
- Avert unplanned plant shutdowns and minimize the potential for requests for Notice of Enforcement Discretion (NOEDs). Risks incurred by unexpected plant shutdowns can be comparable to and often exceed those associated with continued power operation.
- Improve EDG availability during shutdown modes.

BACKGROUND

The Class 1E AC electrical power distribution systems consists of offsite and onsite sources of electrical power designed to meet the requirements of 10 CFR 50, Appendix A, General Design Criteria (GDC) 17. Two qualified circuits between the offsite transmission network and the onsite Class 1E Distribution System, and three separate and independent EDGs (Division 1, 2, and 3), ensure availability of the required power to shut down the reactor and maintain it in a safe shut down condition after an anticipated operational occurrence or a postulated Design Basis Accident.

Offsite power is supplied to the 345 kV transmission station (switchyard) from 345 kV transmission circuits. The interface between the switchyard and the Class 1E power system consists of 345 kV transmission circuits, disconnect switches, startup transformers, interbus transformers, and 5 and 15 kV switchgear.

One offsite circuit consists of the Unit 1 startup transformer through the Unit 1 interbus transformer, to the Class 1E 4.16 kV ESF buses (EH buses) through source feeder breakers for each division. The second offsite circuit consists of the Unit 2 startup transformer through the Unit 2 interbus transformer to the EH buses through source feeder breakers for each division.

Several additional paths from the transmission system to the Class 1E system are available as alternate offsite power sources if loss of a startup transformer occurs. The basic layout of the offsite transmission system is illustrated on USAR Figure 8.2-3.

The onsite Class 1E system is designed with three independent divisions having radial supplied loads operating at voltages of 4.16 kV and below. Complete electrical separation is maintained to ensure maximum integrity. Engineered Safety Feature (ESF) system loads are assigned to the three independent divisions designated as Divisions 1, 2 and 3. Divisions 1 and 2 are redundant while Division 3 supplies power for the HPCS. Each division consists of 4.16 kV switchgear, diesel generator standby power supply, 480 Volt unit substations and motor control centers, 120 Volt AC and 125 Volt DC distribution panels, battery chargers, and interconnecting cables. ESF loads are assigned to divisions in such a manner that a loss of a single division from any cause does not affect redundant equipment. The onsite Class 1E power system is illustrated on USAR Figures 8.3-1 and 8.3-2.

There are at least two separate paths, with sufficient capacity provided from the transmission network to the standby power distribution system. The two paths are available in sufficient time, to ensure availability of the required power to shut down the reactor and maintain it in a safe shut down condition in accordance with GDC-17. The design of the electrical power distribution systems provide independence and redundancy to ensure an available source of power to the ESF systems. The AC electric power system, the associated structures and interconnections between the switchgear and the system, are designed to withstand the loading conditions for climatic conditions prevalent in the area in regard to wind, temperature, lightning, flood and ice.

PERMIT PERFORMANCE OF 24 HOUR SURVEILLANCE RUNS ON LINE

The proposed change allows performance of TS SR 3.8.1.14 while in Modes 1 or 2. This SR requires that the diesel generator being tested operate in parallel with the offsite power system for a 24-hour period. The electrical lineup for performing this SR will be the same as the lineup necessary for performance of TS SR 3.8.1.3, which is routinely performed at least once per month for each diesel generator. The difference between these two SRs is in the duration of the Surveillances. SR 3.8.1.3 requires that the diesel generator being tested in parallel with offsite power for ≥ 60 minutes, whereas SR 3.8.1.14 requires the parallel operation for 24-hours.

The diesel generator for each division is automatically started upon receipt of three auto start signals: a Loss of Coolant Accident (LOCA), an undervoltage signal, and a degraded voltage signal at the associated division bus.

The response to postulated events associated with the EDG start signals will be discussed in relation to the proposed change to the EDG 24-hour Surveillance. The events to be discussed are: 1) a Loss of Coolant Accident (LOCA), 2) a Loss of Offsite Power (LOOP), and 3) a LOCA coincident with a LOOP.

1. <u>Response to a LOCA Signal</u>

   Receipt of a LOCA signal with the EDG operating in parallel with the offsite supply results in the immediate automatic isolation of the EDG from the EH bus and the offsite supply. The EDG will continue to run in the standby mode with an output voltage approximately equal to the EH bus offsite supply voltage. The EDG test voltage limit will insure the EDG output voltage is sufficient to support the LOCA response if a subsequent LOOP occurs. The LOCA response load sequencing will be initiated and safety related loads connected to the offsite supply. Safety related loads, which were operating prior to the LOCA, will continue to run and automatically shift to the LOCA response mode of operation. The redundant divisions of safety related equipment will respond in a similar manner with their EDGs starting upon receipt of the LOCA signal but remaining disconnected from the EH bus. Operation of a single EDG in parallel with the offsite supply will not affect the LOCA response. LOCA load sequence timers are reset by a loss of EH bus voltage or reset of the LOCA initiation signal. Although EH bus voltage is maintained in this scenario, the transition of the LOCA initiation logic from reset to initiate status will result in proper LOCA load sequencing.

The only viable contingency that can be applied to this scenario is the failure of the output breaker of the EDG under test to open and isolate the EDG from the EH bus and the offsite supply. Such a failure would not affect LOCA load sequencing. LOCA response loads will be connected to the EH bus and the total load distributed between the EDG and the offsite supply. This may result in a minor overload condition on the EDG. Based on close monitoring of EDG parameters during testing, such an overload condition will be quickly identified. If the EDG cannot be manually isolated from the EH bus, EDG load adjustments can be manually initiated to correct the overload condition.

2. Response to a Loss of Offsite Power

Each EH bus has its own independent LOOP instrumentation and associated trip logic. The voltage on the Division 1, 2 and 3 buses is monitored at two levels, providing two separate undervoltage response functions: loss of voltage and degraded voltage. Reference TS Table 3.3.8.1-1 for Loss of Power Instrumentation setpoint and surveillance requirements.

Actuation of the LOOP instrumentation initiates the following actions simultaneously: automatic isolation of the EH buses from the offsite power supply; starting of the associated EDGs; and EH bus load shedding.
After the EH bus is isolated from the offsite supply, by tripping the offsite supply isolation breaker, the EDG voltage regulator automatically shifts to the isochronous (ISOCH) mode providing a tighter regulation tolerance on EDG output voltage. The EDG governor also shifts to the ISOCH mode (Div 1 and 2) providing a +/- 1% tolerance on speed (frequency) regulation.

The Div 3 EDG governor is maintained at a constant DROOP setting tolerance on speed regulation for both parallel operation and when providing the only source of power to the EH buses. After EDG output voltage and frequency permissives are satisfied, the EDG is automatically connected to the EH bus by closing the EDG output breaker. EH bus LOOP load sequencing is initiated upon restoration of voltage to the bus from the EDG supply.

If a EDG is operating in parallel with the offsite supply when a LOOP is detected the response will be as described above with the following exceptions:

a. The LOOP logic will isolate the EH bus from the offsite supply by tripping the offsite supply isolation breakers but the EDG will remain connected to the bus.

b. If the offsite supply isolation breaker fails to open in response to a loss of voltage condition on the offsite supply, the EDG under test will be the only source of power to safety and non safety auxiliary system loads. The EDG is incapable of maintaining bus voltage above the degraded voltage relay dropout setpoint under this loading condition and no detectable delay will be observed in the LOOP response of redundant divisions of safety related equipment.

Therefore, the failure of the offsite supply isolation breaker to remove non-safety loads from the EDG under test will not impact the LOOP response capability of redundant divisions.

c. The EDG voltage regulator and governor will be operating in the DROOP mode while the EDG is connected to the offsite supply. The larger output voltage and frequency regulation band (+/- 5%) of the DROOP mode provides for more stable EDG response to auxiliary system load fluctuations during parallel operation (the Div 3 EDG frequency regulation band is maintained at a maximum of +/- 2% for all modes of operation). After tripping the offsite supply isolation breakers and establishing the EDG as the only source of power to the EH bus, the voltage regulator and governor automatically shift to the ISOCH mode. The ISOCH mode provides tighter regulation of EDG output voltage and frequency (+/- 1% Div 1 and 2, +/- 2% Div 3) to meet LOOP response load requirements.

d. LOOP load sequencing is controlled by LOOP logic initiation, which must be manually reset following restoration of EH bus voltage. Some loads if operating prior to LOOP initiation will continue to run after LOOP logic initiation if bus voltage is not interrupted, as would be the case if the EDG is operating in parallel with the offsite supply. The resulting EDG maximum LOOP demand load is bounded by analysis.

3. <u>Response to a LOCA Coincident with a Loss of Offsite Power</u>

If the EDG is operating in parallel with the offsite supply when a coincident LOCA - LOOP initiation occurs, the EDG will be immediately isolated from the EH bus upon receipt of the LOCA signal. The EDG will continue to run disconnected from the bus until the offsite supply breakers are opened in response to the LOOP signal. The EDG will then reconnect to the EH bus and Emergency Core Cooling System (ECCS) load sequencing will start.

The actions described above will occur in rapid succession and ECCS response will be as described in Item # 1, "Response to a LOCA Signal". The EDG will be the only source of power to the EH buses with the voltage regulator and governor operating in the ISOCH mode as described in Item #2, "Response to a Loss of Offsite Power".

The impact of single failures on the division under test such as the failure of the offsite supply isolation breakers to open or the failure of the EDG output breaker to open or reclose will not effect the proper response of redundant divisions. Details of the response to these single failure events are as discussed in Items #1 and 2.

Therefore, when performing TS SR 3.8.1.14 for a 24-hour period, the EDGs will adequately respond within the time necessary to mitigate anticipated operational occurrences or postulated Design Basis Accidents in accordance with GDC-17.

There are provisions/limitations that will be taken to appropriately manage the performance of the EDG 24-hour test during Modes 1 and 2. These provisions/limitations are:

1. Only one EDG will be tested at a time in parallel to the offsite grid in accordance with SR 3.8.1.14.

2. Appropriate precautions/limitations will be provided that cautions against conducting the 24-hour test during periods of inclement weather, unstable offsite grid conditions, or maintenance and test conditions that have an adverse effect on the test.

3. No additional maintenance or testing will be performed on required safety systems, subsystems, trains, components and devices that depend on the remaining EDGs as sources of emergency power.

The three provisions/limitations mentioned above will be included in the appropriate plant instructions following the staff's approval of this Technical Specification change and prior to performing the 24-hour test in either Modes 1 or 2.

PERMIT SCHEDULING OF EDG OUTAGES OF UP TO 14 DAYS

An increased Completion Time (CT) for TS LCO 3.8.1, Required Actions A2 and B.4, will provide flexibility in scheduling preventative maintenance consistent with ensuring the reliability of the EDGs.

Generally, an increased CompletionTime will reduce the need to perform such maintenance during times of shutdown risk. Performance of EDG preventative maintenance with the station on-line will not have a significant adverse effect on station safety.

The increase in Completion Time will provide for additional time in troubleshooting and repairing an inoperable EDG should this occur while the station is on-line. An extended Completion Time will also reduce the likelihood of forcing the plant through a shutdown transient with only one EDG available.

In accordance with accepted guidance regarding risk assessment of licensing changes (References 1-3), a deterministic engineering evaluation in addition to a probabilistic risk assessment was completed to evaluate the acceptance of extending the EDG Completion Time to 14 days. The probabilistic technical evaluation was completed in a two step process. Conservatively, the first step was to analyze the risk for a 14 day EDG Completion Time at a one year frequency, i.e., reactor year. Next, the 14 day Completion Time was analyzed for a 2 year frequency. The following information outlines the completed evaluations for the proposed Completion Time extension.

Deterministic Engineering Evaluation

A deterministic evaluation was conducted by applying a two part approach and by following the guidance as specified in References 1-3, which provide an acceptable approach to risk-informed decision making.

An assessment was made of the effect of the USAR acceptance criteria as discussed in the draft regulatory guidance pertaining to risk-informed criteria (Reference 1). This assessment assumed the plant is in the Completion Time (i.e., the subject equipment is inoperable), and there are no additional failures. This is understood to mean that single active failure is not applicable.

The deterministic evaluation showed that for a one year cycle, the Completion Time of up to 14 days per diesel, the defense-in-depth principle in accordance the current design and licensing basis is maintained. Under this evaluation, one division of injection and heat removal capability (minimum ESF requirement) will be satisfied and capable of supporting the mitigation of the previously analyzed accident(s). The deterministic evaluation for the proposed supplemental 14 day Completion Time proved the ECCS systems available will continue to satisfy 10CFR50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light-Water-Cooled Nuclear Power Reactors," as previously analyzed.

Probabilistic Engineering Evaluation

To further assess the overall effect on plant safety, the impact of the proposed 14 day Completion Time was evaluated on PNPP's Probabilistic Safety Assessment (PSA) model. This evaluation considers both the short-term increase in the plant risk during the period of the EDG unavailability and the long-term increase in the EDG average unavailability.

The original Probabilistic Safety (Risk) Assessment (PSA) model was developed pursuant to Generic Letter 88-20, including Supplements 1 through 3. The Perry Nuclear Power Plant's Individual Plant Examination (IPE) Level 2 PSA assessment was forwarded to the NRC for review via letter dated July 15, 1992, PY-CEI/NRR-1517L.

Since the original submittal, two revisions to the PSA model have been conducted. Revision 1 to the model incorporated various design changes that affected components in the model in addition to procedural changes to Emergency Operating Procedures. Revision 2 to the model involved efforts of explicitly modeling the AC and DC electrical power distribution systems, including the switchyard, and incorporating comments generated as a result of the Perry Nuclear Power Plant's (PNPP) PSA Peer Review Certification conducted in May 1997. The PNPP PSA model has essentially been a "living" model since the development in 1992.

To determine the affect of a 14 day Completion Time, basic events were added to the fault trees, which contained unavailability due to maintenance terms for the Division 1 and Division 2 EDGs. To model these proposed planned maintenance activities, the affected fault trees were revised to include a planned maintenance term added to the previously evaluated maintenance unavailability terms.

For conservatism, the 14 day term was modeled for a one year cycle of as well as for a two year cycle.

Following the guidance setforth in the draft regulatory guides (Reference 1), the following methodology was used:

For determination in the increase in probability:

The change in Core Damage Frequency (CDF) was calculated as:

$\Delta CDF = CDF_{CT} - CDF_{baseline}$, CT=Completion Time

The change in the Incremental Conditional Core Damage Probability (ICCDP) was calculated as:

ICCDP = [(conditional CDF with the subject equipment out of service) – (baseline CDF with nominal expected equipment unavailability's)] x (duration of single Completion Time under consideration)

= (ΔCDF) x (duration of single Completion Time under consideration (per year))

The change in the Incremental Large Early Release Probability (ILERP) was calculated as:

ICLERP = [($LERF_{CT}$ - $LERF_{baseline}$) x (duration of single CT under consideration (per year))]

The values calculated from the previously referenced formulas are tabulated in the following tables.

NOTE: *The 14 day CT per 1 year cycle = 365 days*
The 14 day CT per 2 year cycle = 730 days
CT = Completion Time
N/A = *Parameter is Not Applicable*

Table 1
Division 1 Diesel Generator Completion Time
Conditional Risk Contribution (CDF)

Parameter	**Freq** *(days)*	**W/O Flooding** *(CT per 1 year cycle*	**With Flooding** *(CT per 1 year cycle)*	**W/O Flooding** *(CT per 2 year cycle)*	**With Flooding** *(CT per 2 year cycle)*
IPE Core Damage Frequency, per reactor year (Submittal)	3	1.2×10^{-5}	1.3×10^{-5}	N/A	N/A
Previous Core Damage Frequency, per reactor year	3	1.4×10^{-5}	1.6×10^{-5}	N/A	N/A
Revised Core Damage Frequency, per reactor year ($CDF_{baseline}$)	3	1.7×10^{-5}	1.8×10^{-5}	N/A	N/A
Proposed Core Damage Frequency, per reactor year (CDF_{CT})	14	3.9×10^{-5}	N/A	N/A	N/A
Δ Core Damage Frequency CT	14	2.2×10^{-5}	N/A	N/A	N/A
Incremental Conditional Core Damage Probability	14	8.4×10^{-7}	N/A	4.2×10^{-7}	N/A
Overall Proposed Mean Core Damage Frequency, per reactor year (assuming both diesels)	14	2.0×10^{-5}	2.1×10^{-5}	N/A	N/A
Percent increase in Core Damage Frequency	17.7%	N/A	N/A	N/A	N/A

Table 2
Division 1 Diesel Generator Completion Time
Conditional Risk Contribution (LERF)

Parameter	**Freq** *(days)*	**With Flooding** *(CT per 1 year cycle)*	**With Flooding** *(CT per 2 year cycle)*
Revised Large Early Release Frequency, per reactor year ($LERF_{baseline}$)	3	$1.3x10^{-6}$	N/A
Proposed Large Early Release Frequency, per reactor year ($LERF_{CT}$)	14	$1.9x10^{-6}$	N/A
Δ Large Early Release Frequency CT	14	$6.4x10^{-7}$	$6.4x10^{-7}$
Incremental Large Early Release Probability	14	$2.4x10^{-8}$	N/A
Overall Proposed Mean Large Early Release Frequency per reactor year, (assuming both diesels)	14	$1.4x10^{-6}$	N/A
Percent Increase in Large Early Release Frequency	0.7%	N/A	N/A

Table 3
Division 2 Diesel Generator Completion Time

Conditional Risk Contribution (CDF)

Parameter	**Freq** *(days)*	**W/O Flooding** *(CT per 1 year cycle)*	**With Flooding** *(CT per 1 year cycle)*	**W/O Flooding** *(CT per 2 year cycle)*	**With Flooding** *(CT per 2 year cycle)*
IPE Core Damage Frequency, per reactor year (Submittal)	3	$1.2x10^{-5}$	$1.3x10^{-5}$	N/A	N/A
Previous Core Damage Frequency, per reactor year	3	$1.4x10^{-5}$	$1.6x10^{-5}$	N/A	N/A
Revised Core Damage Frequency, per reactor year ($CDF_{baseline}$)	3	$1.7x10^{-5}$	$1.8x10^{-5}$	N/A	N/A
Proposed Core Damage Frequency, per reactor year (CDF_{CT})	14	$3.2x10^{-5}$	N/A	N/A	N/A

Parameter	Freq *(days)*	W/O Flooding *(CT per 1 year cycle)*	With Flooding *(CT per 1 year cycle)*	W/O Flooding *(CT per 2 year cycle)*	With Flooding *(CT per 2 year cycle)*
Δ Core Damage Frequency CT	14	1.5×10^{-5}	N/A	N/A	N/A
Incremental Conditional Core Damage Probability	14	5.4×10^{-7}	N/A	2.9×10^{-7}	N/A
Overall Proposed Mean Core Damage Frequency, per reactor year (assuming both diesels)	14	2.0×10^{-5}	2.1×10^{-5}	N/A	N/A
Percent increase in Core Damage Frequency	17.7%	N/A	N/A	N/A	N/A

Table 4
Division 2 Diesel Generator Completion Time
Conditional Risk Contribution (LERF)

Parameter	Freq *(days)*	With Flooding *(14 day CT per 1 year cycle)*	With Flooding *(14 day CT per 2 year cycle)*
Revised Large Early Release Frequency, per reactor year ($LERF_{baseline}$)	3	1.3×10^{-6}	N/A
Proposed Large Early Release Frequency, per reactor year ($LERF_{CT}$)	14	1.8×10^{-6}	N/A
Δ Large Early Release Frequency CT	14	5.4×10^{-7}	5.4×10^{-7}
Incremental Large Early Release Probability	14	2.1×10^{-8}	1.0×10^{-8}
Overall Proposed Mean Large Early Release Frequency per reactor year, (assuming both diesels)	14	1.4×10^{-6}	N/A
Percent Increase in Large Early Release Frequency	0.7%	N/A	N/A

The results of Tables 1-4 show that the proposed 14 day increase in EDG Completion Time at a 2 year frequency is within the acceptance guidance criteria outlined in Draft Regulatory Guide (RG) DG-1065, Reference 1. Within Draft RG 1065, an ICCDP and ICLERP that is less than 5.0×10^{-7} and 5.0×10^{-8} respectively is considered "very small".

The probabilistic analysis completed reflects the high reliability of the PNPP AC power system. This high reliability is due to the excellent performance of the EDGs and the robustness of the offsite power supply.

EDG performance criteria has been developed as part of implementation of the PNPP Maintenance Rule program in compliance with 10CFR50.65. As such, the overall long term average unavailability of each EDG is monitored and trended. PNPP is committed to a 0.95 target reliability for the EDGs. The reliability performance of PNPP's EDGs is within the industry upper quartile over the last 11 years, with only 1 failure to start in 493 demands and 1 failure to run during a total of 1260 hours of loaded operation. The increase in EDG planned unavailability as a result of the proposed TS change and the PNPP reliability performance are planned to result in Maintenance Rule performance criteria changes to the following: no more than 0.027 unavailability per fuel cycle per diesel, and no more than 3 total diesel generator functional failures per 2 fuel cycles.

Scheduling of EDG maintenance will be in accordance with plant administrative processes to control work on equipment important to plant risk, and configurations will be strictly controlled to assure the requirements of TS are met and decrease the likelihood of a transient, thereby mitigating the impact on plant safety. PNPP on-line scheduling process controls the combinations of risk significant systems that may be scheduled for on-line maintenance. Combinations of risk significant systems that exceed established guidelines require further management review to determine if the resultant risk is acceptable. Work on risk significant systems are minimized in both frequency and duration by prudent scheduling methods.

In performing EDG planned maintenance at power, material and parts will be pre-staged on order to minimize the likelihood of delays during the performance of maintenance. PNPP administrative processes require that on-line maintenance be performed on a continuous work basis (around the clock) in order to minimize the outage time. Flexibility in scheduling EDG maintenance will assist in avoiding simultaneous outages of risk significant components. In addition, performing planned maintenance on-line, as opposed to during an outage will allow PNPP to better select and schedule the maintenance personnel and focus on the successful completion of the EDG outage. It is anticipated that conducting preventative maintenance evolutions at power rather than during shutdown conditions will reduce shutdown risk.

Administratively, risk levels have been procedurally structured to provide indication of risk significance associated with the various on-line maintenance activities. Pre-evaluation of the on-line activities, in addition to discussion and communication of the involved risk is involved. The proposed EDG Completion Time extension will fall under this process, in addition to being strictly controlled via a Configuration Risk Management Program that will be instituted concurrently with the acceptance of this submittal.

An EDG is declared inoperable if it fails to pass its TS surveillance periodic tests. The Completion Time is entered and troubleshooting, repairs, and/or replacements are performed in order to restore the EDG to operability. At PNPP, these activities are performed around the clock in order to restore the inoperable EDG as soon as possible.

An increased Completion Time will have a positive effect by providing additional time to perform these activities, if required, and reducing the likelihood of forcing the station through a shutdown transient with only one EDG available.

Configuration Risk Management Program

To ensure plant safety is maintained and monitored, PNPP will implement a Configuration Risk Management Program (CRMP). The purpose of the Configuration Risk Management Program (CRMP) is to ensure that a proceduralized Probabilistic Risk Assessment informed process is in place that assesses the overall impact of plant maintenance on plant risk. The intent of the program is to implement an extension of the Maintenance Rule (10CFR50.65) with respect to on-line maintenance for risk-informed Technical Specifications.

Implementation of the CRMP will enable appropriate actions to be taken or decisions to be made to minimize and control risk when performing on-line maintenance for systems, structures and components with a risk-informed Completion Time. TS Section 5.5.13 regarding the CRMP is proposed to be added and will be applicable to TS 3.8.1 because the Completion Times for TS 3.8.1 are "risk-informed Completion Times". Guidance for implementing CRMP will be provided in plant administrative procedures.

In addition to the CRMP, there are provisions that will be required to be taken to appropriately manage the risk associated with removing an EDG for a planned extended outage (3-14 days). These provisions are:

1. The required systems, subsystems, trains, components and devices that depend on the applicable EDG as a source of emergency power will be verified to be operable before removing the associated EDG for a planned extended outage.

2. Positive measures will be taken to preclude subsequent testing or maintenance activities on those systems, subsystems, trains, components and devices that depend on the remaining operable EDG as a source of emergency power.

3. The preferred alternate AC power sources will be verified to be functional and capable of being connected to the safety bus associated with the inoperable EDG and this will be verified every shift thereafter.

4. Based on the current PSA model, a CDF will be calculated and verified acceptable in accordance with a Station Blackout (SBO) scenario, as defined in the current design and licensing basis.

5. Scheduling of EDG outages will be in accordance with the overall EDG unavailability, which will be tracked and controlled via the Maintenance Rule program pursuant to 10CFR50.65 requirements.

6. Appropriate precautions/limitations will be provided that cautions against conducting any EDG outage during periods of inclement weather, unstable offsite grid conditions, or maintenance and test conditions that have an adverse effect on the outage.

REFERENCES

1. Draft Regulatory Guide DG-1065, "An Approach for Plant Specific, Risk Informed Decisionmaking: Technical Specifications", dated June 1997.

2. Regulatory Guide 1.174, "An Approach for using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Current Licensing Basis", dated June 1997.

3. Standard Review Plan, (Draft for Comment), "Risk-Informed Decision Making: Technical Specifications", Draft SRP Chapter 16.1, Revision 13, dated March 13, 1997.

4. EPRI TR-105396, Project 3200-12, Final Report "PSA Applications Guide", dated August 1995.

COMMITMENTS WITHIN THIS LETTER

The following list identifies those actions which are considered to be regulatory commitments. Any other actions discussed in this document represent intended or planned actions, are described for the NRC's information, and are not regulatory commitments. Please notify the Manager - Regulatory Affairs at the Perry Nuclear Power Plant of any questions regarding this document or any associated regulatory commitments.

Commitments

The precautions listed below will be included in the appropriate plant procedures following the staff's approval of this Technical specification change and prior to performing the 24-hour test (TS SR 3.8.1.14) in either Mode 1 or 2.

1. Only one EDG will be tested at a time in parallel to the offsite grid in accordance with TS SR 3.8.1.14

2. Appropriate precautions/limitations will be provided that cautions against conducting the 24-hour test during periods of inclement weather, unstable offsite grid conditions, or maintenance and test conditions that have an adverse effect on the test.

3. No additional maintenance or testing will be performed on required safety systems, subsystems, trains, components and devices that depend on the remaining EDGs as sources of emergency power.

Commitments

The precautions listed below will be included in the appropriate plant procedures following the staff's approval of this Technical Specification change and prior to performing an extended EDG outage (3-14 days) in accordance with the Configuration Risk Management Program.

1. The required systems, subsystems, trains, components and devices that depend on the operating EDG as a source of emergency power will be verified to be operable before removing the associated EDG for a planned extended outage.

2. Positive measures will be taken to preclude subsequent testing or maintenance activities on those systems, subsystems, trains, components and devices that depend on the operable EDG as a source of emergency power.

3. The alternate AC power sources will be verified to be functional and capable of being connected to the safety bus associated with the inoperable EDG and this will be verified every shift thereafter.

4. Based on the current PSA model, a CDF will be calculated and verified acceptable.

5. Scheduling of EDG outages will be in accordance with the overall EDG unavailability, which will be tracked and controlled via the Maintenance Rule program pursuant to 10CFR50.65 requirements.

6. Appropriate precautions/limitations will be provided that cautions against conducting any EDG outage during periods of inclement weather, unstable offsite grid conditions, or maintenance and test conditions that have an adverse effect on the outage.

ENVIRONMENTAL CONSIDERATIONS

The proposed Technical Specification change request was evaluated against the criteria of 10 CFR 51.22 for environmental considerations. The proposed change does not significantly increase individual or cumulative occupational radiation exposures, does not significantly change the types or significantly increase the amounts of effluents that may be released off-site and, as discussed in Attachment 2, does not involve a significant hazards consideration. Based on the foregoing, it has been concluded that the proposed Technical Specification change meets the criteria given in 10 CFR 51.22(c)(9) for categorical exclusion from the requirement for an Environmental Impact Statement.

SIGNIFICANT HAZARDS CONSIDERATION

The standards used to arrive at a determination that a request for amendment involves no significant hazards considerations are included in the Commission's Regulations, 10 CFR 50.92, which state that the operation of the facility in accordance with the proposed amendment would not (1) involve a significant increase in the probability or consequences of an accident previously evaluated, (2) create the possibility of a new or different kind of accident from any previously evaluated, or (3) involve a significant reduction in a margin of safety.

The proposed amendment has been reviewed with respect to these three factors and it has been determined that the proposed change does not involve a significant hazard because:

1. The proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

   The proposed Technical Specification changes do not significantly increase the probability of occurrence of a previously evaluated accident because the standby Emergency Diesel Generators (EDGs), including the High Pressure Core Spray diesel generator, are not initiators of previously evaluated accidents. The EDGs mitigate the consequences of previously evaluated accidents involving a loss of offsite power. The proposed changes to the Technical Specification Action Completion Times do not affect any of the assumptions used in the deterministic or Probabilistic Safety Analysis (PSA).

   The proposed Technical Specification changes will continue to ensure the EDGs perform their function when called upon. Extending the Technical Specification Completion Times to 14 days and allowing the performance of the EDG 24-hour run test in either Modes 1 or 2 does not affect the design of the EDGs, the operational characteristics of the EDGs, the interfaces between the EDGs and other plant systems, the function, or the reliability of the EDGs. Thus, the EDGs will be capable of performing their accident mitigation function and there is no impact to the radiological consequences of any accident analysis.

   To fully evaluate the effect of the EDG Completion Time extension, PSA methods and deterministic analysis were utilized. The results of this analysis show no significant increase in the Core Damage Frequency. The proposed changes remain bounded by the Core Damage Frequency identified in the Individual Plant Examination.

   The Configuration Risk Management Program (CRMP) is an administrative program that assesses risk based on plant status. Adding the requirement to implement the CRMP for Technical Specification 3.8.1 requires the consideration of other measures to mitigate consequences of an accident occurring while an EDG is inoperable.

The proposed change will not alter the operation of any plant equipment assumed to function in response to an analyzed event or otherwise increase its failure probability. Therefore, this change does not involve a significant increase in the probability or consequences of any accident previously evaluated.

2. The proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

   This proposed change does not change the design, configuration, or method of operation of the plant. The proposed activity involves a change to the allowed plant mode for the performance of specific Technical Specification surveillance requirements. No physical or operational changes to the EDGs or supporting systems are made by this activity. Since the proposed changes do not involve a change to the plant design or operation, no new system interactions are created by this change. The proposed Technical Specification changes do not produce any parameters or conditions that could contribute to the initiation of accidents different from those already evaluated in the Updated Safety Analysis Report.

   The proposed changes only address the methods used to ensure EDG reliability. Thus, the proposed Technical Specification change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. The proposed change does not involve a significant reduction in a margin of safety.

   The proposed changes do not affect the Limiting Conditions for Operation or their Bases that are used in the deterministic analysis to establish any margin of safety. PSA evaluations were used to evaluate these changes, and these evaluations determined that the changes are either risk neutral or risk beneficial. The proposed activity involves changes to certain Completion Times and to the allowed plant mode for the performance of specific Technical Specification Surveillance Requirements. The proposed change remains bounded by the existing Surveillance Requirement Completion Times and therefore has no impact to the margins of safety.

   The proposed change does not involve a change to the plant design or operation, and thus does not affect the design of the EDGs, the operational characteristics of the EDGs, the interfaces between the EDGs and other plant systems, or the function or reliability of the EDGs. Because EDG performance and reliability will continue to be ensured by the proposed Technical Specification changes, the proposed changes do not result in a reduction in the margin of safety.

On the basis of the above, it has been determined that the license amendment request does not involve a significant hazards consideration. As this license amendment request concerns a proposed change to the Technical Specifications that must be reviewed by the Nuclear Regulatory Commission, this license amendment request does not constitute an unreviewed safety question.