Florida Power & Light Company, 6501 South Ocean Drive, Jensen Beach, FL 34957

FPL

January 17, 2001

L-2001-005
10 CFR 50.90
10 CFR 50.4

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

Re: St. Lucie Unit 1
Docket No. 50-335
Proposed License Amendment
Performance of EDG 24-Hour Surveillance
Requirement in Modes 1 and 2 and Conforming Amendments

Pursuant to 10 CFR 50.90, Florida Power & Light Company (FPL) requests to amend Facility Operating License DPR-67 for St. Lucie Unit 1. The proposed amendment revises Technical Specification (TS) Section 4.8.1.1.2.e by relocating the restriction to only perform the 18-month surveillance tests during shutdown to the individual surveillance requirements under 4.8.1.1.2.e. In addition, the proposed amendment revises TS 4.8.1.1.2.e.6 to remove the restriction to perform the emergency diesel generator (EDG) 24-hour run surveillance test during shutdown. Approval of this license amendment request is expected to reduce the complexity of activities performed during refueling outages, therefore, reducing the likelihood of human performance errors and the duration of refueling outages.

The electrical lineup for performing surveillance TS 4.8.1.1.2.e.6 is the same as the lineup used during performance of monthly surveillance TS 4.8.1.1.2.a.5. The basic difference between the two surveillance technical specifications is the test duration. TS 4.8.1.1.2.a.5 requires that the EDG be operated in a loaded condition parallel with off-site power for at least 60 minutes, whereas TS 4.8.1.1.2.e.6 requires parallel operation for at least 24 hours. The automatic response of the electrical distribution system to electrical disturbances and/or accidents, including EDG performance, is the same regardless of the test duration.

FPL recognizes the historical concerns related to performing the 24-hour EDG load test paralleled to the off-site power while in Modes 1 and 2. Specifically, if a fault or power disturbance was to occur while an EDG is paralleled with the off-site power system, the availability of the EDG for subsequent emergency operation could be adversely affected. This historical concern was based on the potential for common-mode vulnerability of the off-site and on-site sources during testing. This led to restricting the performance of the test to periods when the reactor was shutdown (i.e., Mode 3, 4, 5, or 6).

The calculated total change in core damage frequency (CDF), including the conservatively estimated fire risk contribution, is less than 1E-06 per reactor year and the calculated total change in the large early release frequency (LERF), including the conservatively estimated fire risk contribution, is less than 1E-07 per reactor year. The change in CDF and LERF is, therefore, within Region III of Regulatory Guide (RG) 1.174 Figures 3 and 4, and is considered very small. When the full scope of plant risk and compensatory measures are considered, the

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risks incurred by performing the EDG 24-hour surveillance test during power operation will be substantially offset by plant benefits associated with reducing risks during shutdown operations.

The NRC has approved several licensee requests (e.g., Southern California Edison, First Energy, Pennsylvania Power & Light, Niagara Mohawk Power, Tennessee Valley Authority, Entergy, and Public Service Electric and Gas Company) to eliminate the shutdown requirement for the 24-hour endurance run. These approvals were granted considering the existence of unique EDG design features and/or special provisions that ensured that paralleled operation of the EDG with off-site sources would not prevent the EDG from performing its safety functions. The St. Lucie design when considered with the special provision commitments will ensure that paralleled operation of the EDG with off-site sources would not prevent the EDG from performing its assumed safety functions.

Attachment 1 is a Safety Analysis in support of the proposed amendment. Attachment 2 is the Determination of No Significant Hazards Consideration. Attachment 3 is marked up copies of the proposed Technical Specification changes.

The St. Lucie Facility Review Group and the Florida Power & Light Company Nuclear Review Board have reviewed the proposed amendment. In accordance with 10 CFR 50.91 (b)(1), a copy of the proposed amendment is being forwarded to the State Designee for the State of Florida.

This risk-informed cost beneficial licensing action has a potential for significant savings in outage critical path time and outage cost. Approval is requested by April 15, 2001 to support the spring 2001 Unit 1 refueling outage (SL1-17). Please issue the amendment to be effective on date of issuance and to be implemented within 60 days of receipt by FPL. Contact us if there are any questions about this submittal.

Very truly yours,

Rajiv S. Kundalkar

Rajiv S. Kundalkar
Vice President
St. Lucie Plant

RSK/GRM

Attachments

cc: Regional Administrator, Region II, USNRC
Senior Resident Inspector, USNRC, St. Lucie Plant
Mr. William A. Passetti, Florida Department of Health

STATE OF FLORIDA)
) ss.
COUNTY OF ST. LUCIE)

Rajiv S. Kundalkar being first duly sworn, deposes and says:

That he is Vice President, St. Lucie Plant, for the Nuclear Division of Florida Power & Light Company, the Licensee herein;

That he has executed the foregoing document; that the statements made in this document are true and correct to the best of his knowledge, information and belief, and that he is authorized to execute the document on behalf of said Licensee.

Rajiv S. Kundalkar

Rajiv S. Kundalkar

STATE OF FLORIDA

COUNTY OF ST. LUCIE

Sworn to and subscribed before me

this 17 day of January, 2001
by Rajiv S. Kundalkar, who is personally known to me.

Leslie J. Whitwell

Name of Notary Public - State of Florida

Leslie J. Whitwell
MY COMMISSION # CC646183 EXPIRES
May 12, 2001
BONDED THRU TROY FAIN INSURANCE, INC.

(Print, type or stamp Commissioned Name of Notary Public)

ATTACHMENT 1

SAFETY ANALYSIS

Introduction

The proposed amendment revises Technical Specification (TS) Section 4.8.1.1.2.e by relocating the restriction to perform all the 18-month emergency diesel generator (EDG) surveillance tests in that section during shutdown to the individual surveillance requirements under 4.8.1.1.2.e. In addition, the proposed amendment revises Unit 1 TS 4.8.1.1.2.e.6 to remove the restriction to perform the EDG 24-hour run surveillance test during shutdown.

Discussion

The following paragraphs provide a brief description of the St. Lucie electrical power systems, their interaction with the emergency diesel generators (EDG), and specific design features that assure the separation and independence of the off-site and on-site power systems:

Off-site Power System

There are three separate 240 kV transmission circuits connecting the St. Lucie switchyard to the system transmission grid at Midway substation. These circuits are on three separate transmission lines and are located parallel to each other. Each transmission circuit connecting the St. Lucie switchyard and the Midway substation is rated at approximately 1000 MVA and is capable of handling the total plant output of either St. Lucie Unit 1 or Unit 2. A four bay 240 kV (nominal) switchyard provides switching capability for main generator output, each of the two startup transformers per unit, and the three outgoing transmission lines. The main generator supplies electrical power at 22 kV through an isolated phase bus to the two main transformers and two auxiliary transformers. The main transformer steps up the voltage to 240 kV for transmission to Bay 1 in the switchyard. Each auxiliary transformer steps down the voltage and feeds a unit 6.9 kV bus and 4.16 kV bus.

There are two startup transformers, 1A and 1B, which supply Unit 1 with power when the main generator is not operating. 1A and 1B startup transformers step down the switchyard 240 kV to 6.9 kV and 4.16 kV.

The function of the plant auxiliary power distribution system is to distribute electrical power to plant components. The system receives power from off-site through the switchyard, from the unit main generator, or from the on-site diesel generators. Plant auxiliary power is utilized for plant operation through the system network of busses, transformers, switches, and related equipment. The off-site transmission system is designed to provide reliable facilities to accept the electrical output of the plant and to provide off-site power for supplying the plant auxiliary power system for station startup, shutdown, or any time that auxiliary power is unavailable from the unit auxiliary transformers.

On-site Power System

The on-site auxiliary power system is designed to supply the functional requirements of all auxiliary loads required for all modes of plant operation. Plant auxiliary power is distributed throughout the unit by the two 6.9 kV busses and five 4.16 kV busses. Each of the 6.9 kV busses supplies two reactor coolant pump motors and one feedwater pump motor. The 4.16 kV distribution system consists of two normal operation power busses 1A2 and 1B2 that receive power from the auxiliary or startup transformers, and three emergency busses 1A3, 1B3 and 1AB. Depending on plant conditions, the three emergency busses receive power from either the normal 4.16 kV busses or the two standby emergency diesel generators.

Section 8.3.1.1.7 of the UFSAR states the requirements for the standby power system. This system consists of two redundant diesel generators, their attendant air starting and fuel supply systems, and automatic control circuitry. The EDGs supply power to those electrical loads which are needed to achieve safe shutdown of the plant or to mitigate the consequences of a loss of coolant accident (LOCA) in the event of a coincident loss of normal AC power supply.

Each diesel engine is supplied fuel from an independent subsystem consisting of a diesel oil storage tank, a diesel oil transfer pump, two day tanks, and associated piping, valves, and controls. Two oil storage tanks are provided with a combined usable capacity of 38,350 gallons, which is sufficient for eight days of post-LOCA load profile operation of one diesel generator set. Each diesel generator has two diesel oil day tanks, each of which has a usable capacity of 159 gallons. This is sufficient to allow 1.25 hours of full post-accident load operation of the associated diesel generator. Two diesel oil transfer pumps are provided to replenish the day tanks from the oil storage tanks.

The diesel generators start upon a manual start signal, loss of voltage on their associated 4.16 kV or 480V AC busses or actuation of the safety injection actuation signal (SIAS).

Redundancy of the emergency auxiliary power system has been provided for the operation of redundant safety-related electrical load groups. This redundancy extends from the emergency power sources, through 4.16 kV buses, station service transformers, 480 Volt buses, motor control centers (MCC), distribution cables, switchgear, and protective devices.

Each of the redundant on-site emergency power sources and associated load groups can independently provide for safe shutdown of the plant and/or mitigate the consequences of a design accident.

In the event a loss of off-site power (LOOP) occurs, electrical loads on the 4.16 kV buses are shed and each diesel generator set is automatically started. After each EDG has attained nominal rated frequency and voltage, its output breaker closes to restore power to the bus. With bus voltage established, some loads are immediately loaded onto the bus either directly or indirectly via the station service transformers. Subsequent loading of required 4.16 kV AC loads is accomplished via timing relays. The loads that are sequenced onto the bus depend on what emergency signals are present. For a LOOP without any associated ESFAS signals, the loads required for safe shutdown only are loaded. For a LOOP with emergency signals present (SIAS, CIAS, CSAS), the loads required for mitigating the design basis accident are loaded.

Undervoltage protection on the 4.16 kV vital bus is provided in two levels as described below.

First Level Undervoltage Protection

Each Class 1E 4.16 kV bus (1A3 and 1B3) utilizes two undervoltage definite-time delay relays, in a 2 out of 2 coincident logic, for loss of voltage detection. The undervoltage relays are set to trip at no less than 2900 Volts (69.7% of 4160 Volts) with a time delay of 1 +/- 0.5 seconds. The function of these relays is to initiate source disconnection, load shedding, diesel generator starting, and load sequencing on the affected bus (train).

Second Level Undervoltage Protection

Each Class 1E 4.16 kV bus (1A3 and 1B3) utilizes two undervoltage definite time delay relays, in a 2 out of 2 coincident logic, for degraded grid voltage detection. The relays are set to actuate at no less than 3831 Volts (92.1% of 4.16 kV) with a time delay of 18 +/- 2.0 seconds. The function of these relays is the same as described above.

In addition, each Class 1E 480V bus (1A2 and 1B2) utilizes two undervoltage definite time delay relays in a 2 out of 2 coincident logic scheme. These relays are interlocked with an ESFAS to ensure adequate starting voltage during accident conditions. The relays are set to actuate at no less than 415 Volts (86.5 % of 480 Volts) with a time delay of 8 +/- 1 seconds. This setpoint is equivalent to 3850 Volts (92.5% of 4160 kV) on the 4.16 kV busses under accident conditions with all the normal and all the ESFAS initiated loads operating.

For sustained degraded voltage concurrent with or without a safeguard signal, all the above undervoltage schemes will initiate automatic source disconnection, load shedding diesel generator starting and load sequencing. The degraded/undervoltage relays are bypassed 0.2 seconds after diesel generator breaker closure and are automatically reinstated following breaker trip.

Proposed Changes

The existing Surveillance Requirement 4.8.1.1.2.e requires that all the 18-month surveillance tests be performed during shutdown. The shutdown requirement will be relocated to the individual surveillance tests required by TS 4.8.1.1.2.e with the exception of TS 4.8.1.1.2.e.1 and TS 4.8.1.1.2.e.6. The deletion of the shutdown requirement for the EDG inspection program was approved by license amendment 168 on December 7, 2000. This amendment request deletes the TS 4.8.1.1.2.e.6 requirement to perform the EDG 24-hour endurance while shutdown (i.e., Mode 3, 4, 5, or 6).

The bases for Unit 1 TS 4.8.1.1.2.e.6 originates from revision 3 of NRC Regulatory Guide (RG) 1.9[1], paragraph 2.3.2.3. The RG requires demonstration once per 18 months that the EDGs can start and run continuously at full load for an interval of not less than 24 hours. At least 2 hours of which must be at a load equivalent to 110% of the continuous duty rating. The remainder of the time should be at a load equivalent to the continuous duty rating of the EDG. Starting the EDG for this surveillance can be performed either from standby or hot conditions. The load band is provided to avoid routine overloading of the EDG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations to maintain the EDG operable. The 18-month frequency is consistent with the recommendations of NRC RG 1.9, paragraph 2.3.2.3, which takes into consideration unit conditions required to perform the surveillance, and is expected to be consistent with fuel cycle lengths. The historical basis for limiting performance of the 24-hour surveillance run to periods when the reactor is not critical is that performance of this surveillance may cause perturbations to the electrical distribution systems and, as a result, unit safety systems.

NUREG-1432, Revision 1, contains the following reviewer's note for removal of the mode restrictions for certain surveillance requirements:

> *The Mode restrictions may be deleted if it can be demonstrated to the NRC, on a plant specific basis, that performing the surveillance test with the reactor in any of the restricted Modes (Mode 1 or 2) can satisfy the following applicable criteria.*
>
> 1. *Performance of the surveillance will not render any safety system or component inoperable; and*
> 2. *Performance of the surveillance will not cause perturbations to any of the electrical distribution systems that could result in a challenge to steady state operation or plant systems; and*
> 3. *Performance of the surveillance, or failure of the surveillance, will not cause, or result in, an anticipated operational occurrence (AOO) with attendant challenge to plant safety systems.*

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1 NRC Regulatory Guide 1.9, Revision 3, *Selection, Design, Qualification, and Testing of Emergency Diesel Generator Units Used as Class 1E On-site Electric Power Systems at Nuclear Power Plants*, Section 2.2.3, July 1993.

Description of the Changes

1. **Unit 1 TS 4.8.1.1.2.e.**

   Revise the Unit 1 Surveillance Requirement 4.8.1.1.2.e. to delete the words "during shutdown by." The requirement to perform the test during shutdown will be relocated to the individual surveillance tests. TS 4.8.1.1.2.e.1 was relocated to a licensee controlled program by license amendment 168.

2. **Unit 1 TS 4.8.1.1.2.e.2**

   Change "Verifying" to "During shutdown by verifying"

3. **Unit 1 TS 4.8.1.1.2.e.3**

   Change "Simulating" to "During shutdown by simulating"

4. **Unit 1 TS 4.8.1.1.2.e.4**

   Change "Verifying" to "During shutdown by verifying"

5. **Unit 1 TS 4.8.1.1.2.e.5**

   Change "Simulating" to "During shutdown by simulating"

6. **Unit 1 TS 4.8.1.1.2.e. 7**

   Change "Verifying" to "During shutdown by verifying"

7. **Unit 1 TS 4.8.1.1.2.e.8**

   Change "Verifying" to "During shutdown by verifying"

8. **Unit 1 TS 4.8.1.1.2.e.9**

   Change "Verifying" to "During shutdown by verifying"

9. **Unit 1 TS 4.8.1.1.2.e.10**

   Change "Verifying" to "During shutdown by verifying"

10. **Unit 1 TS 4.8.1.1.2.e.11**

Change "Verifying" to "During shutdown by verifying"

Bases of Changes 1 through 10

These changes are administrative in nature in that the requirement to perform the 18-month surveillance tests "during shutdown" is being relocated to each individual surveillance test. No change has been proposed for TS 4.8.1.1.2.e.1. The requirements of the existing TS 4.8.1.1.2.e.1 were relocated to a licensee controlled maintenance program for the EDGs by license amendment 168.

11. **Unit 1 TS 4.8.1.1.2.e.6**

The requirement to perform TS 4.8.1.1.2.e.6 during shutdown is deleted.

Bases of Change 11

FPL recognizes historic prohibitions on performing the 24-hour EDG load test paralleled to the off-site power while in Modes 1 and 2. Specifically, if a fault or power disturbance were to occur while an individual EDG is paralleled with the off-site power system, the availability of that EDG for subsequent emergency operation could be adversely affected. This is based on the potential for common-mode vulnerability of the off-site and on-site sources during testing, and led to restricting the performance of the test to periods when the reactor was shutdown (i.e., Mode 3, 4, 5, or 6).

The NRC has approved several licensee requests (e.g., Southern California Edison, First Energy, Pennsylvania Power & Light, Niagara Mohawk Power, Tennessee Valley Authority, Entergy, and Public Service Electric and Gas Company) to eliminate the shutdown restriction for the EDG 24-hour endurance run. These approvals were granted based on the existence of unique EDG design features and/or special provisions that ensured that paralleled operation of the EDG with off-site sources would not prevent the EDG from performing its assumed safety functions. The St. Lucie design when considered with the special provisions described on page 28 will ensure that paralleled operation of the EDG with off-site sources would not prevent the EDG from performing its assumed safety functions.

Risk Assessment

Probabilistic Safety Assessment (PSA)

The FPL evaluation of the risk associated with performing the St. Lucie Unit 1 24-hour EDG surveillance test in Mode 1 or 2 generally conforms to the three-tiered approach that is identified in USNRC Regulatory Guide 1.177, *An Approach for Plant-Specific, Risk-Informed*

Decision Making: Technical Specifications, August 1998. Tier 1 consists of the PSA capability and insights; Tier 2 identifies risk-significant plant configurations that should be avoided; and Tier 3 describes a risk-informed configuration risk management program.

Tier 1, Analysis of Risk Impact and Calculated Results

Tier 1 is an evaluation of the impact on plant risk of the proposed TS change as expressed by the change in core damage frequency (CDF), the incremental conditional change in core damage probability (ICCDP), the change in large early release frequency (LERF), and the incremental conditional large early release probability (ICLERP).

FPL letter L-99-228 dated November 17, 1999, *St. Lucie Unit 1 and Unit 2 Proposed License Amendments, EDG Risk Informed AOT Extension,* provided justification for an increase in the allowable outage time (AOT) for a single EDG from 3 to 14 days. The above referenced proposed license amendments provided the results of ICCDP and ICLERP calculations for a 14-day AOT. The risk due to performing the 24-hour surveillance test in Mode 1 or 2 is associated with additional EDG unavailability during the testing and does not impact the previous ICCDP and ICLERP calculations. The ICCDP and ICLERP are based on the full AOT duration and not the assumed annual unavailability. The risk assessment below, therefore, addresses the change in CDF and change in LERF and compares the estimated values to acceptance criteria provided in USNRC RG 1.174, *An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant Specific Changes to the Licensing Basis.*

The EDG under test will be declared out-of-service during the duration of the test. For this evaluation, the EDG out-of-service time required to perform the EDG testing in Mode 1 or 2 is assumed to be in addition to the EDG out-of-service time previously assumed for the EDG AOT extension proposed license amendments referenced above. It is estimated that the total EDG out-of-service time associated with the 24-hour surveillance test is less than 30 hours. For this evaluation, however, a conservative out-of-service time of 96 hours per EDG per year is assumed. The total unavailability per year is, therefore, conservatively estimated to be 328 hours per EDG: 232 hours for preventive and corrective maintenance (from the EDG AOT proposed license amendments) plus 96 hours conservatively assumed for testing. This evaluation estimates the change in CDF and LERF based on an unavailability of 328 hours/year/EDG, not just the additional unavailability incurred as a result of performing the 24-hour test in Mode 1 or 2.

Table 1 provides the calculated nonfire-related change in CDF and LERF based on the assumed total annual EDG unavailability (including the 24-hour surveillance test).

TABLE 1

ST. LUCIE UNIT 1
NONFIRE-RELATED CHANGE IN CDF AND LERF
BASED ON PROPOSED EDG DOWNTIME
INCLUDING THE 24-HOUR SURVEILLANCE TEST

CHANGE IN CDF	2E-07	
	USING EARLY CONTAINMENT FAILURE PROBABILITY = 0.01 (1)	USING EARLY CONTAINMENT FAILURE PROBABILITY = 0.1 (2)
CHANGE IN LERF	1E-08	3E-08

(1) Baseline Early Containment Failure Probability
(2) Sensitivity Evaluation (Factor of 10 Increase in Baseline Early Containment Failure Probability)

Impact on Fire Risk

The PSA models used to calculate the above estimated change in CDF and LERF do not include an assessment of the potential risk due to internal fires. The following provides a scoping estimate of the change in CDF and LERF due to fire risk.

The Fire Induced Vulnerability Evaluation (FIVE) method (Revision 1, September 29, 1993) was selected by FPL to analyze the fire risk for the St. Lucie Unit 1 Individual Plant Examination of External Events (IPEEE). FIVE was developed by the Electric Power Research Institute (EPRI) and Professional Loss Control, under the guidance of the Nuclear Management and Resources Council (NUMARC) for use in the IPEEE arena.

Three Unit 1 fire compartments were not screened through application of the FIVE methodology. The compartments that were not screened based on the combined factors of fire frequency, alternate train unavailability, automatic or manual suppression, and fire damage modeling include the following:

Compartment F - Unit 1 Control Room Envelope
Compartment B - Unit 1 Cable Spreading Room
Compartment C - Unit 1 'B' Switchgear Room

Unit 1 Cable Spreading Room and Main Control Room

The following summarizes the engineering information collected and assessments performed to determine the risk associated with postulated fire events in either the Unit 1 cable spreading or main control room.

- Engineering Information to Support the Risk Assessment

  The following information was collected to provide input to the risk assessment of the fires in the Unit 1 cable spreading room and control room.

  1. Cabinets were characterized in the cable spreading room and the main control room. The features characterized were cabinet ventilated or not, open top or not, top penetrations sealed or not, penetrations in conduits or not, and the main function and system associated with the cabinet. These features were identified and recorded in a videotape provided to the NRC in a meeting on October 24, 2000 at the NRC White Flint Offices.

  2. The routing of the cables associated with the essential control of off-site power, EDG A, EDG B, and blackout crosstie.

  3. The relative locations of the cable trays and cabinets.

- Unit 1 Cable Spreading Room and Control Room Risk Assessment Details

  The proposed TS change results in an increase in the time an EDG may be unavailable to support post fire safe shutdown needs. The issue to be addressed is whether the total assumed EDG unavailability (including the 24-hour test) results in an unacceptable fire risk.

  The approach to the assessment relies on the redundancy that is an integral part of the plant design basis. Each of the safety-related electrical distribution buses is provided with an off-site supply and a dedicated on-site EDG. Each of these sources is available to support plant system needs following a postulated fire induced plant trip. Assuming a postulated fire event does not impact any of these power sources, the conditional core damage probability would be dominated by random failures of the mechanical front line systems. Based on this insight, the assessment for the cable spreading room and main control room followed the general steps shown below.

  1. Identify the circuits and equipment located in the two fire areas of interest associated with off-site power and the EDGs.
  2. Develop a 'target' footprint for the circuits and equipment noting train designations.
  3. Perform walkdowns of the fire areas to examine potential fire ignition sources and identify critical pinchpoints.
  4. Develop conservative CDF estimates to bound potential risk increases.

<u>Unit 1 Cable Spreading Room</u>

The St. Lucie Unit 1 cable spreading room is configured such that it is better characterized as a combined auxiliary relay and cable spreading room. A review of the existing IPEEE analysis of this room concluded that the analysis was extremely conservative. This characterization is based on the walkdown that found that the majority of the potential fire ignition sources are completely enclosed and did not present a fire propagation threat. The only fire sources of concern were the two pressurizer heater bus transformers and the regulating group power programmer cabinets.

1. Pressurizer heater transformers – these are 4kV-460V dry type transformers. A postulated fire involving the transformer windings could generate significant heat. This is especially critical since the enclosure is not sealed. However, a transformer internal failure that would cause such a 'fire event' is likely to also cause upstream electrical overcurrent protective devices to operate and 'terminate' the fire event. However, for conservatism, a fire requiring brigade response to suppress the fire was assumed.
2. Power programmer cabinets – these cabinets have a ventilation fan on the upper portion of the rear panel door. The lower portion of the rear panel door has ventilation louvers. Because of these ventilation openings, a credible fire propagation pathway is considered to exist.

The walkdown also noted other cabinets existed with ventilation screens on their tops. However, a screening fire modeling assessment was performed and concluded that the available vertical target spacing precluded target damage. The screening assessments found the critical spacing to be between 5½ feet and 8¾ feet, depending on the estimated heat release rate. Heat rates of 65 British thermal units per second (Btu/s) and 190 Btu/s were considered. The heat rate that is applicable to any particular area is a function of the cabinet size and combustible loading. With the exception of the power programmer cabinets, the walkdown found that the 8¾-foot spacing was satisfied for all other ventilated cabinets. Although trays may be located within the 8¾-foot spacing in some instances, the trays did not contain circuits of concern. In addition, the trays had a solid bottom with a continuous solid cover. While this 'lower' tray was considered to be damaged, it did not represent a fire propagation mechanism. As such, the 8¾-foot required spacing was evaluated on the basis of the next higher tray.

- <u>Transformer Fire</u>

  The evaluation of the pressurizer heater power transformers found a postulated severe fire event could result in damage to overhead cable trays.

  A postulated fire involving the transformer for heater bus 1A3 could result in loss of Train 'A' AC power from off-site sources and the EDG as well as other Train 'A' plant system equipment. The Train 'B' AC power from off-site sources and the associated EDG are not affected. In addition, circuits for other Train 'B' plant system equipment are also unaffected. For this fire scenario, any incremental CDF increase would be due to the CCDP change based on the Train 'B' EDG availability given the AOT extension. The CDF contribution due to this fire scenario is conservatively estimated as follows. The assessment does not credit the automatic Halon system.

$$CDF = 7.90E-03\ x\ \frac{1}{20}\ x\ 0.20\ x\ \frac{328}{8760}\ x\ 0.10\ x\ 1.0E-02\ =\ 2.96E-09/yr.$$

where:

7.90E-03 =	Plant-wide transformer fire frequency – FIVE
20 =	Assume a total of 20 transformers in the plant
0.20 =	Severity factor
328 =	Assumed OOS hours/year/EDG
8760 =	Hours per year
0.10 =	Fire brigade fails to suppress fire before target damage occurs
1.0E-02 =	CCDP assuming Train 'B' equipment only, off-site power available, but no EDG due to AOT

A postulated fire involving the transformer for heater bus 1B3 could result in loss of Train 'B' AC power from the EDG as well as other Train 'B' plant system equipment. Train 'A' AC power from off-site sources and the associated EDG is not affected. In addition, circuits for other Train 'A' equipment are also unaffected. For this fire scenario, any incremental CDF increase would be due to the CCDP change based on the Train 'A' EDG availability. The CDF change due to this fire scenario is conservatively estimated in the same fashion as above and yields the same CDF.

The total CDF contribution for the postulated pressurizer heater transformer fires is estimated to be:

2.96E-09 + 2.96E-09 = 5.92E-09/yr

- Power Programmer Cabinets

The evaluation of the regulating group power programmer cabinets found a postulated severe fire event could result in damage to overhead cable trays. In addition, these cabinets are located directly beneath the main control board section containing the controls for both trains of AC power and both EDGs. This area constitutes a critical pinchpoint.

A postulated severe fire involving these cabinets which propagates to overhead cable trays would require operator action outside of the main control room to restore AC power. This action would involve recovery of the Train 'B' power supply system in accordance with the Appendix R related station procedures. For this fire scenario, any incremental CDF increase would be due to the CCDP change based on the Train 'B'

EDG availability. The Train 'A' EDG AOT has no impact since the fire is postulated to have damaged the circuits, and recovery from outside the area is not available. The CDF contribution due to this fire scenario is conservatively estimated as follows. The assessment does not credit the automatic Halon system.

$$CDF = 3.20E-03 \; x \; \frac{10}{80} \; x \; 0.20 \; x \; \frac{328}{8760} \; x \; 0.10 \; x \; 0.10 \;=\; 3.00E-08/yr.$$

where:

3.20E-03 =	Electrical cabinet fires in cable spreading room – FIVE
10 =	Cabinets of interest assigned a weighting factor of 10
80 =	Cumulative weighting factor for total scope of cabinets in room
0.20 =	Severity factor
328 =	Assumed OOS hours/year/EDG
8760 =	Hours per year
0.10 =	Fire brigade fails to suppress fire before target damage occurs
0.10 =	CCDP assuming Train 'B' equipment only, recovery of off-site power via operator action, and no EDG

The 0.10 CCDP is based on credit for operator actions outside the main control room to restore off-site power. No other actions outside the main control room are credited in this scenario. In this scenario, the main control room remains manned. The CDF contribution for the electrical cabinet fires is thus conservatively estimated to be 3.00E-08/yr

Total CDF for Cable Spreading Room

Based on the conservative assessment presented above, the CDF contribution for a Unit 1 cable spreading room fire is:

5.92E-09 + 3.00E-08 = 3.59E-08/yr

Since a baseline cable spreading room CDF was not calculated, it is conservatively assumed that the CDF estimated above represents the total cable spreading room fire-related change in CDF based on the assumed EDG unavailability (including the 24-hour test). The method used to calculate the CDF contribution for the cable spreading room fire does not allow a

LERF contribution to be readily calculated. Based on the low CDF, and the very small change in LERF calculated for the switchgear rooms (see Table 2), it is judged that the change in LERF for the cable spreading room fire would be on the order of 1E-08 or less.

Unit 1 Main Control Room

A review of the existing IPEEE analysis of the control room also concluded that the analysis was extremely conservative. The revised assessment for the main control room is similar to that presented for the cable spreading room. Fire scenarios were defined for those fire events that affect off-site power and/or the EDGs. A walkdown of the main control board determined that internal barriers exist to separate it into subsections. These internal barriers extend the full height and depth of the control board and extend into the apron area. Given this configuration, a number of fire scenarios are applicable.

1. A non-severe fire in the control board sections containing AC power controls. This fire is assumed to cause localized damage to the extent defined by the internal barriers.
2. A severe fire occurs in any of the cabinets in the main control room. Failure to suppress this fire within a fixed time period is assumed to cause control room abandonment due to habitability and visibility concerns.

The main control room board containing controls associated with AC power was determined to have a linear length-weighting factor of 2. The entire scope of control room boards and cabinets was determined to have a cumulative length-weighting factor of 90.

The internal barriers in the electrical control section of the main control board effectively divided the section into three subsections. One subsection contained the controls for the Train 'A' safety-related portion of the system. Another subsection contained the controls for the Train 'B' safety-related portion of the system. Each of these subsections was assigned a weighting factor of 0.5. The third subsection contained the controls for the nonsafety-related buses and the 'common' bus which forms the connection to the opposite unit for off-site supply. This third subsection was assigned a weighting factor of 1.0.

- Non-Severe Fires

  A postulated non-severe fire involving that portion of the main control board containing controls for the safety-related power system would result in complete loss of control room control for that portion. In the case of the Train 'B' controls, existing Appendix R related design features provides provisions for recovery from outside the main control room.

  If the fire involved the Train 'B' section, post fire response would rely on the Train 'A' power with the potential for operator recovery of the Train 'B' power. The recovery of Train 'B' power would involve operator actions outside the main control room in accordance with existing Appendix R related station procedures. If the fire involved the Train 'A' section, post fire response would rely on the Train 'B' power alone. Actions outside the main control room are not needed in this case. Therefore, the postulated fire involving the Train 'A' section is expected to yield the greater CDF impact. This is because the fire would disable Train 'A' with no available recovery. Train 'B' would rely solely on off-site power based on an assumed EDG AOT event. The CDF contribution due to this fire scenario is conservatively estimated as follows.

$$CDF = 9.50E-03 \; x \; \frac{1}{90} \; x \; 1.0 \; x \; \frac{328}{8760} \; x \; 1.0E-02 \;\; = \;\; 3.95E-08/yr.$$

where:

9.50E-03 =	Electrical cabinet fires in main control room – FIVE
1 =	Sum of weighting factors for two subsections
90 =	Cumulative weighting factor for total scope of cabinets in room
1.0 =	A severity factor of 0.80 would normally be applicable for that fraction of fires assumed to be non-severe. However, a value of 1.0 is used to account for that fraction of fires assumed to be severe, but is suppressed in time to prevent control room abandonment.
328 =	Assumed OOS hours/year/EDG
8760 =	Hours per year
1.0E-02 =	CCDP assuming Train 'B' equipment only, off-site power available, but no EDG

If the fire were assumed to be in the Train 'B' section, the resultant scenario would be similar, but the CCDP would be lower since recovery of the Train 'B' power from outside the main control room can be credited. The CDF calculated above (3.95E-08/yr), however, is conservatively assumed also to apply for a fire affecting the 'B' train.

A postulated non-severe fire involving that portion of the main control board containing the controls for the nonsafety-related buses and the 'AB' bus also needs to be considered. The 'AB' bus forms the connection to the opposite unit (blackout crosstie). In this case, the fire does not disable either safety-related train of AC power. Instead, it disables the power feed from the opposite unit. Each safety-related bus is reduced to having one off-site power supply since the fire disables the blackout crosstie. The CDF contribution due to this fire scenario is conservatively estimated in the same fashion as that shown above except the CCDP is assumed to be 1.0E-03 and a 0.80

severity factor is assumed. This CCDP is based on the assumption that the only fire-induced impacts are a plant trip and loss of the blackout crosstie.

$$CDF\ per\ EDG = 9.50E-03\ x\ \frac{1}{90}\ x\ 0.80\ x\ \frac{328}{8760}\ x\ 1.0E-03\ =\ 3.16E-09/yr.$$

The total CDF contribution for the postulated non-severe main control board fires is conservatively estimated to be:

3.95E-08 + 3.95E-08 + 3.16E-09 + 3.16E-09 = 8.53E-08/yr

- Severe Fires

A postulated severe fire involving any of the main control room control boards or cabinets presents a threat to habitability. A postulated severe control room fire that is not suppressed within a relatively short period of time will require abandonment of the main control room. This abandonment would be forced due to habitability and visibility concerns. Completion of required post fire safe shutdown actions would be performed by the plant operators using controls outside the main control room in accordance with existing Appendix R related station procedures. The probability for failure to manually suppress a severe fire is obtained from NSAC-181 and is based on available time for suppression. The manual suppression failure probability is 1.6E-02 and 3.4E-03 for 10 and 15 minutes, respectively. The CDF contribution due to this fire scenario is conservatively estimated as follows.

$$CDF\ = 9.50E-03\ x\ 0.20\ x\ \frac{328}{8760}\ x\ 7.38E-03\ x\ 2.5E-02\ =\ 1.31E-08/yr.$$

where:

9.50E-03 =	Electrical cabinet fires in main control room – FIVE
0.20 =	Severity factor
328 =	Assumed OOS hours/year/EDG
8760 =	Hours per year
7.38E-03 =	Log based average of 10 and 15 minute suppression failure
2.5E-02 =	Change in CCDP assuming Train 'B' equipment only, recovery of off-site power via operator action, and no EDG. See discussion below.

The calculation presented above differs from that performed for the other scenarios. In this calculation, the CCDP value is the change (increase) given the unavailability of the Train 'B' EDG. The baseline CCDP assuming no EDG is unavailable is some value that is not developed in this evaluation. However, this value would be the sum of the human reliability event (failure probability of operator actions) given the scope of actions outside the main control room plus the random failure probability of the safe shutdown equipment. The EDG being unavailable does not affect the human reliability. However, the random failure probability is expected to increase since the EDG is unavailable. A conservative estimate of the increase is 5.0E-02. Assuming the baseline CCDP is half-human reliability and half random failure events, the net increment in CCDP due to unavailability of the EDG is 2.5E-02.

The analysis for the postulated severe fire event would typically also address a fire that is successfully suppressed. In this case, the resultant scenario has a CCDP that is the same as for the non-severe event. This is because successful suppression is assumed to prevent propagation of the fire to an adjacent panel compartment. However, the analysis for the non-severe fires already incorporated this scenario by using a severity factor of 1.0. Refer to the prior discussion of non-severe fires for further details.

The total CDF contribution (both EDGs) for the postulated severe main control board fires is conservatively estimated to be:

1.31E-08 + 1.31E-08 = 2.62E-08/yr

Total CDF Main Control Room

Based on the conservative assessment presented above, the total fire-related CDF contribution for the main control room is:

8.53E-08 + 2.62E-08 = 1.12E-07/yr

Since a baseline control room CDF was not calculated, it is conservatively assumed that the CDF estimated above represents the total control room fire-related change in CDF based on the assumed EDG unavailability (including the 24-hour test). The method used to calculate the CDF contribution for the control room fire does not allow a LERF contribution to be readily calculated. Based on the low CDF, and the very small change in LERF calculated for the switchgear rooms (see Table 2), it is judged that the change in LERF for the control room fire would be on the order of 1E-08 or less.

- 'B' Switchgear Room

  The 'B' switchgear compartment provides power for 'B' train components. The 'B' switchgear compartment also contains power and control cables for the 'C' (steam driven) auxiliary feedwater pump, unlike the 'A' compartment. This is the primary explanation for 'A' switchgear compartment screening while the 'B' one does not.

The 'B' switchgear room fire-related cutsets generated in support of the IPEEE were used to estimate the risk due to the increased EDG unavailability. The 'B' EDG was failed in the model before the cutsets were generated. For this analysis, the 'A' EDG test and maintenance basic event was set to "true" and a new conditional probability for safe shutdown equipment failure/unavailability was calculated. The change in CDF and LERF based on the assumed EDG unavailability was then estimated (see Table 2).

- Turbine Building Switchgear Rooms

  Off-site power is connected to the safety-related 4kV busses via switchgear located in the turbine building switchgear rooms. Since off-site power could be affected, the impact of a fire in one of these rooms with an EDG out-of-service has been evaluated, even though these rooms screened out in the FIVE analysis. See Table 2 for the estimated change in CDF and LERF.

TABLE 2

ST. LUCIE UNIT 1
'B' SWGR ROOM AND TURBINE SWGR ROOM FIRE-RELATED CHANGE IN CDF AND LERF BASED ON PROPOSED EDG UNAVAILABILITY INCLUDING THE 24-HOUR SURVEILLANCE TEST

	CHANGE IN CDF	CHANGE IN LERF
'B' SWGR ROOM	2E-07	<1E-08
TURBINE BLDG SWITCHGEAR ROOM 'A'	2E-08	<1E-08
TURBINE BLDG SWITCHGEAR ROOM 'B'	2E-07	<1E-08

As can be seen from the results in Table 3, the calculated total change in CDF, including the conservatively estimated fire risk contribution, is less than 1E-06 per reactor year. The calculated total change in the LERF, including the conservatively estimated fire risk contribution, is less than 1E-07 per reactor year. The change in CDF and LERF is, therefore, within Region III of RG 1.174 Figures 3 and 4, and is considered very small.

TABLE 3

**ST. LUCIE UNIT 1
TOTAL CHANGE IN CDF AND LERF
BASED ON PROPOSED EDG UNAVAILABILITY
INCLUDING THE 24-HOUR SURVEILLANCE TEST**

	CHANGE IN CDF	CHANGE IN LERF
NONFIRE-RELATED (FROM TABLE 1)	2E-07	3E-08 (1)
CABLE SPREADING ROOM	3.59E-08	Approx. 1E-08
CONTROL ROOM	1.12E-07	Approx. 1E-08
'B' SWGR ROOM	2E-07	<1E-08
TURBINE BLDG SWITCHGEAR ROOM 'A'	2E-08	<1E-08
TURBINE BLDG SWITCHGEAR ROOM 'B'	2E-07	<1E-08
TOTAL	7.68E-07	<1E-07

(1) Assumes sensitivity study value (factor of 10 increase in baseline early containment failure probability)

Sensitivity/Uncertainty Analysis

FPL letter L-99-228 dated November 17, 1999 documented an analysis, which assessed the sensitivity of the risk impact of an extended EDG AOT to changes in off-site power and select human reliability analysis (HRA) non-recovery probabilities. The events chosen for the sensitivity study were based on review of the St. Lucie IPE safety evaluation report (SER) dated July 21, 1997 in conjunction with engineering judgement to determine which events are associated with recovery of an EDG or the functions impacted due to loss of an EDG. Table 4 provides a summary of the basic event probability changes made to support the sensitivity study. The results of a similar analysis assuming the proposed increase in EDG unavailability due to performing the 24-hour surveillance test in Mode 1 or 2 is provided in Table 5.

TABLE 4

ST. LUCIE UNIT 1
SUMMARY OF NON-RECOVERY PROBABILITY CHANGES USED FOR SENSITIVITY STUDY

BASIC EVENT	DESCRIPTION	BASELINE PROB	PROB USED IN STUDY	FACTOR INCREASE FROM BASELINE
RTOP1ROTC (RTOP2ROTC)	OPERATOR FAILS TO INITIATE ONCE-THROUGH COOLING FOR SGTR	7.5E-03	5E-02	6.7
RTOP1TOTC	OPERATOR FAILS TO INITIATE ONCE-THROUGH COOLING [FOR TRANSIENTS]	7.5E-03	5E-02	6.7
RTOP1S1OTC	OPERATOR FAILS TO INITIATE ONCE-THROUGH COOLING FOR S1 LOCA	7.5E-03	5E-02	6.7
RTOP1S1RCP	OPERATOR FAILS TO SECURE RCPS FOLLOWING LOSS OF SEAL COOLING	3E-04	1E-02	33.33
R#CAFWMAN	OPERATOR FAILS TO MANUALLY START C AFW PP PER EOP-99, APP. G	7.88E-02	0.2	2.5
R#DC-AB	OPERATOR FAILS TO REALIGN 'AB' DC BUS	9.1E-03	0.1	11.0
R#DGFO	OPERATOR FAILS TO RECOVER EDG BY OPENING DG FILL VALVE	3.68E-02	0.1	2.7
R#HFDG	OPERATOR FAILS TO RECOVER IMPROPERLY ALIGNED EDG	0.1	0.5	5.0
R#RESET	OPERATOR FAILS TO DIAGNOSE MAIN GEN. LOCKOUT, RESET AND MANUALLY ENERGIZE S/UP TRANSFORMER	8.77E-02	BASELINE	1.0
R#AFXVLVS	OPER FAILS TO UTILIZE AFW X- CONNECT VLVS	3.68E-02	0.1	2.7
VARIOUS	ALL OFF-SITE POWER RECOVERY	VARIOUS	VARIOUS	2

TABLE 5

ST. LUCIE UNIT 1
CHANGE IN CDF AND LERF FOR RECOVERY ACTION NON-RECOVERY PROBABILITY CHANGE SENSITIVITY STUDY
[EDG UNAVAILABILITY INCLUDES 24-HOUR SURVEILLANCE TEST]

CHANGE IN CDF	9E-07	
	USING EARLY CONTAINMENT FAILURE PROBABILITY = 0.01 (1)	USING EARLY CONTAINMENT FAILURE PROBABILITY = 0.1 (2)
CHANGE IN LERF	2E-08	1E-07

(1) Baseline Early Containment Failure Probability
(2) Sensitivity Evaluation (Factor of 10 Increase in Baseline Early Containment Failure Probability)

The calculated change in CDF assuming the increased EDG unavailability due to performing the 24-hour surveillance test in Mode 1 or 2 and the recovery action non-recovery probability sensitivity study changes is less than 1E-06 per reactor year. The calculated change in LERF assuming the increased EDG unavailability due to performing the 24-hour surveillance test in Mode 1 or 2 and the recovery action non-recovery probability sensitivity study changes is less than 1E-07 per reactor year with the early containment failure probability at the baseline value. The change in LERF is equal to 1E-07 per reactor year with the early containment failure probability a factor of 10 higher than the baseline value. The change in CDF and LERF is, therefore, within Region III of RG 1.174 Figures 3 and 4, and is considered very small. FPL has determined that the appropriate uncertainty issues are addressed by this sensitivity study.

Consideration of Cumulative Impact of Risk-Informed AOTs

The NRC has previously approved a proposed license amendment for a risk-informed AOT extension (from 3 to 7 days) for the low pressure safety injection (LPSI) system (FPL Letter L-99-079, dated June 1, 1999). The NRC is also reviewing a proposed license amendment for a risk-informed AOT extension (from 3 to 14 days) for the St. Lucie emergency diesel generators (EDGs) (FPL letter L-99-228 dated November 17, 1999). Accordingly, the cumulative impact that both of the proposed EDG and LPSI AOT changes (including the recovery action non-recovery probability sensitivity study changes discussed above) could have on the average CDF was evaluated and the results are provided in Table 6.

TABLE 6

ST. LUCIE UNIT 1
CHANGE IN CDF AND LERF FOR RECOVERY ACTION NON-RECOVERY PROBABILITY CHANGE SENSITIVITY STUDY
[INCLUDES LPSI AND EDG UNAVAILABILITY (W/EDG 24-HOUR SURVEILLANCE TEST)]

CHANGE IN CDF	1E-06	
	USING EARLY CONTAINMENT FAILURE PROBABILITY = 0.01 (1)	USING EARLY CONTAINMENT FAILURE PROBABILITY = 0.1 (2)
CHANGE IN LERF	3E-08	1.1E-07

(1) Baseline Early Containment Failure Probability
(2) Sensitivity Evaluation (Factor of 10 Increase in Baseline Early Containment Failure Probability)

The calculated change in CDF assuming the increased EDG unavailability due to performing the 24-hour surveillance test in Mode 1 or 2 and the cumulative affect of the LPSI and EDG AOT extensions (including the recovery action non-recovery probability sensitivity study changes) is equal to 1E-06 per reactor year. Taking into account the conservative EDG out-of-service time and sensitivity study values assumed, the change in CDF is judged to be within Region III of RG 1.174 Figure 3, and is considered very small.

The calculated change in LERF assuming the increased EDG unavailability due to performing the 24-hour surveillance test in Mode 1 or 2 and the cumulative affect of the LPSI and EDG AOT extensions (including the recovery action non-recovery probability sensitivity study changes) is less than 1E-07 per reactor year with the baseline early containment failure probability. The calculated change in LERF is only slightly above 1E-07 per reactor year (1.1E-07) with the early containment failure probability a factor of 10 higher than the baseline value. Taking into account the conservative EDG out-of-service time and sensitivity study values assumed, the change in LERF is judged to be within Region III of RG 1.174 Figure 4, and is considered very small. Even with a change in LERF of 1.1E-07/yr, the change would be considered small (Region II of RG 1.174 Figure 4).

Modeling Adequacy and Completeness Relative to this Application

Two PSA engineers from the FPL Nuclear Engineering Reliability and Risk Assessment Group (a preparer and an independent reviewer) reviewed the results of the evaluations performed in support of this proposed license amendment. Both concluded that the results were appropriate considering the inputs and assumptions used, and based on a review of the dominant cutsets, that the results are reasonable and the models are adequate for this application.

Quality of the St. Lucie PSA

FPL letter L-99-228 dated November 17, 1999 provided a detailed discussion related to PSA quality. That submittal is under review by the NRC staff, and the discussion related to PSA quality therein is considered part of this proposed license amendment by reference.

In summary, the discussion states that applications of the PSA models and associated databases are handled as quality-related. Administrative controls include written procedures, independent review of all model changes, data updates, and risk assessments performed using PSA methods and models. Risk assessments are performed by a PSA engineer, independently reviewed by another PSA engineer, and approved by the department head or designee. The Reliability and Risk Assessment Group (RRAG) is required to follow the FPL Nuclear Engineering Quality Instructions (QI) with written procedures derived from those QIs. Procedures, risk assessment documentation, and associated records are controlled and retained as QA records. FPL has maintained the PSA models consistent with the current plant configuration such that they are considered "living" models.

PSA Software

FPL letter L-99-228 dated November 17, 1999 provided a detailed discussion related to PSA software. That submittal is under review by the NRC staff, and the discussion related to PSA software therein is considered part of this proposed license amendment by reference.

In summary, the discussion stated that all computer programs that process PSA model inputs are verified and validated as needed. The policy on verification and validation of QA controlled/procured software, as well as the verification and validation for software and computers when used for quality-related applications, are described in the Reliability and Risk Assessment Group (RRAG) Standard entitled, *Probability Safety Assessment Software Control Procedure*. This standard provides a list of all the software used by the RRAG and indicates whether the software is QA controlled/procured. The PSA software that is procured with a QA option and is developed under a 10 CFR 50, Appendix B, QA program does not require further software verification by the RRAG. However, the PSA software that is not procured with a QA option can be verified by comparison of results to previously approved software.

Model Changes Since Submittal of the IPE

FPL letter L-99-228 dated November 17, 1999 provided a detailed summary of model changes since the IPE. There have been no significant model changes since submittal of the EDG AOT extension proposed license amendment. That submittal is under review by the NRC staff, and the discussion related to model changes since the IPE therein is considered part of this proposed license amendment by reference.

PSA Reviews

FPL letter L-99-228 dated November 17, 1999 provided a detailed discussion of the St. Lucie PSA reviews. That submittal is under review by the NRC staff, and the discussion related to PSA reviews therein is considered part of this proposed license amendment by reference.

Tier 2, Avoidance of Risk-Significant Plant Configurations

No EDG Tier 2 restrictions beyond those previously proposed in FPL letters L-99-228 dated November 17, 1999 and L-2000-250 dated December 4, 2000 are required as a result of this proposed license amendment.

Tier 3, Configuration Risk Management

Tier 3 is the development of a procedure-based program, which ensures the risk impact of out-of-service equipment is appropriately evaluated prior to performing a maintenance activity. A viable program, that is able to uncover risk-significant plant equipment outage configurations in a timely manner during normal plant operation, is in place at St. Lucie. RG 1.177 describes this as the configuration risk management program (CRMP). The need for this third tier stems from the difficulty of identifying all possible risk-significant configurations under Tier 2 that will be encountered over extended periods of plant operation.

A CRMP based on the model program described in RG 1.177 and the requirements of Section (a)(4) of 10 CFR 50.65 has been implemented at St. Lucie. The primary tool for performing CRMP risk assessments for St. Lucie Unit 1 is the PSA-informed on-line risk monitor (OLRM). The CRMP and its essential elements are described in the St. Lucie Plant Administrative Procedure (ADM) that ensures compliance with the Maintenance Rule (currently identified as ADM-17.08, *Implementation of 10 CFR 50.65, The Maintenance Rule*).

The St. Lucie CRMP is described in FPL Letter L-99-079 dated June 1, 1999. Implementation methodology, control and use of the CRMP assessment tools, maintenance rule control as discussed in RG 1.177, the OLRM, and requirements for FPL Reliability and Risk Assessment Group specific evaluations associated with the CRMP are described therein. That proposed license amendment was approved by the NRC February 15, 2000, and the CRMP, as described therein, is considered part of this proposed license amendment by reference. The St. Lucie CRMP also meets the requirements of Section (a)(4) of 10 CFR 50.65.

Electrical System Response to Design Bases Events

The following paragraph provides an evaluation of the impact to the worst-case design basis events to establish the acceptability of completing the EDG 24-hour surveillance run online. The events to be discussed are:

- Loss of Coolant Accident (LOCA)
- Loss of Off-Site Power (LOOP)
- LOCA Coincident with LOOP (LOCA/LOOP)

Response to LOCA Signal

In Modes 1 and 2, receipt of a LOCA signal with an EDG operating in parallel with off-site power (i.e., EDG output breaker closed) results in the diesel output breaker immediately tripping. Due to the LOCA signal, a trip of the reactor, turbine and main generator occurs. The main turbine trip causes a fast bus transfer from the auxiliary transformer (on-site power) to the startup transformer (off-site power). Following bus transfer loads on the 6.9 kV and 4.16 kV busses are powered from the startup transformer. Since no loss of voltage is present on the 4.16 kV emergency bus, load shedding is not initiated and the EDG output breaker remains open with its EDG running in standby mode at full frequency and voltage. All required safety-related LOCA loads are subsequently connected to the emergency bus.

The redundant EDG and engineered safeguards actuation equipment train responds in a similar manner to a LOCA signal by starting its EDG and leaving it disconnected from the emergency bus since off-site power is available. All LOCA response loads subsequently start.

Occurrence of a LOCA event without a LOOP and with an EDG operating in parallel with off-site has no affect on the design basis LOCA response. Failure of the EDG output breaker to open and isolate the EDG from the emergency bus when in test mode would not affect LOCA load sequencing. LOCA response loads would be connected to the emergency bus with total load shared between the EDG and off-site power.

Response to LOOP Signal

In Modes 1 and 2, receipt of a LOOP signal with an EDG operating in parallel with off-site power results in the diesel output breaker not immediately tripping and separating the EDG from off-site power due to breaker position. The closed EDG output breaker blocks the undervoltage protective relays that initiate load shed on the associated emergency bus. As the only source of power for loads connected to the emergency (safety) and normal (nonsafety) 4.16 kV busses, the EDG under test trips its output breaker on over-current. Tripping on over-current protection generates an EDG lockout signal, which causes the EDG to shutdown, and trips its output breaker eliminating the over-current condition. With the output breaker open, the load shed 4.16 kV undervoltage protective relays are automatically unblocked. Loss of voltage detected by the protective relays causes the emergency bus to automatically separate from the normal supply bus and strip its loads isolating the emergency bus. A trip of the reactor, turbine, and main generator occurs due to the LOOP signal.

The EDG is prevented from starting and the output breaker is prevented from closing and supplying power to the emergency bus due to the lockout signal. Certain safe shutdown equipment such as intake cooling water (ICW) and component cooling water (CCW) are not available to respond to the LOOP event.

The lockout relay must be manually reset at the local EDG control panel to permit restarting the EDG and allow automatic closure of the output breaker. After resetting the lockout, the EDG is started. After it reaches normal frequency and voltage, the EDG output breaker closes automatically and supplies power to the emergency bus. Loads belonging to the first load block are automatically started. Subsequent LOOP load blocks are started as designed to prevent overloading the EDG.

Because administrative controls only allow parallel operation for one EDG at a time, failure of the EDG in test to power its train of safe shutdown equipment in response to a LOOP would not affect the redundant EDG and engineered safeguards equipment train from responding. The redundant train of safeguards equipment would respond to the LOOP event by starting its EDG and load shedding its buses, as designed. After getting up to normal frequency and voltage, the EDG output breaker would close and supply power to the emergency bus. Required safe shutdown loads would then be sequenced onto the bus.

Occurrence of a LOOP event with an EDG operating in parallel with off-site power results in a lockout that prevents the EDG from powering its respective train of safeguards equipment. Given that an operator will be stationed in close proximity to the EDG during testing, the lockout relay can be promptly reset restoring the engineered safeguards equipment train. St. Lucie would remain within its design basis since safe shutdown can be achieved with the redundant engineered safeguards train.

Response to LOCA/LOOP Signal

In Modes 1 and 2, receipt of a LOCA/LOOP signal with an EDG operating in parallel with off-site power results in the diesel output breaker tripping. Due to the LOCA/LOOP signal, a trip of the reactor, turbine and main generator occurs. Loss of voltage detected on the 4.16 kV emergency bus causes it to automatically separate from the normal supply bus and trip its loads. With the EDG running at normal frequency and voltage, its output breaker recloses in 1.2 seconds and starts all loads belonging to the first load block. The starting of subsequent LOCA loads is delayed by timing relays that provide sufficient intervals between load blocks to prevent overloading the EDG.

The redundant EDG and engineered safeguards actuation equipment train will respond to a LOCA/LOOP condition by starting its EDG and shedding the emergency bus. After the EDG reaches normal frequency and voltage, its output breaker closes and starts all loads belonging to the first load block. Subsequent loads required to mitigate the LOCA event are sequenced back onto the bus in a predetermined order to prevent overloading the EDG.

Occurrence of a LOCA/LOOP event with an EDG operating in parallel with off-site power has no affect on the design basis LOCA response.

Additional Considerations

NUREG-1432, Revision 1, contains the following reviewer's note for removal of the Mode restrictions for certain surveillance requirements. The Mode restrictions may be deleted if it can be demonstrated to the NRC, on a plant specific basis, that performing the surveillance test with the reactor in any of the restricted Modes (Mode 1 or 2) can satisfy the following applicable criteria.

1) Performance of the surveillance will not render any safety system or component inoperable; and

2) Performance of the surveillance will not cause perturbations to any of the electrical distribution systems that could result in a challenge to steady state operation or plant systems; and

3) Performance of the surveillance or failure of the surveillance will not cause, or result in, anticipated operational occurrences (AOO) with attendant challenges to plant safety systems. Note that only one EDG is permitted to undergo surveillance testing at any given time.

Response to 1:

During surveillance testing, occurrence of a LOCA or LOCA/LOOP event would not render any safety system or component inoperable. However, a LOOP only event with the EDG output breaker closed would result in the EDG output breaker initially remaining closed and then tripping on over-current. Tripping on over-current protection generates an EDG lockout signal, which causes the EDG to shutdown, and trips its output breaker eliminating the over-current condition. The tripped output breaker automatically unblocks the load shed 4.16 kV undervoltage protective relays. Loss of voltage detected by the protective relays causes the emergency bus to automatically separate from the normal supply bus and strip its loads isolating the emergency bus. Manual action to clear the lockout and restart the EDG is required for the LOOP only scenario.

The electrical lineup for performing surveillance TS 4.8.1.1.2.e.6 is the same as the lineup used during performance of monthly surveillance TS 4.8.1.1.2.a.5. The only difference between the two surveillance technical specifications is the duration. TS 4.8.1.1.2.a.5 requires that the EDG be operated in a loaded condition with off-site power for at least 60 minutes, whereas TS 4.8.1.1.2.e.6 requires parallel operation for at least 24 hours. The automatic response of the electrical distribution system to electrical disturbances and/or accidents, including EDG performance, is the same regardless of the test duration.

Declaring the EDG under test out-of-service allows relaxing the single failure criterion (SFC) for the EDG not in test and its associated train of engineered safeguards equipment. NRC Generic Letter 80-30 allows a licensee to temporarily relax the requirements of SFC by declaring equipment out-of-service and entering the Technical Specification limiting condition for operation (LCO) associated with that equipment. The logic behind this relaxation is that the LCO time frame has been formulated to assure that no set of equipment outages would be allowed to persist that would result in the facility being in an unprotected condition.

Prompt action by Operations stationed at the EDG resetting the lockout relay and restarting the EDG on the diesel control panel allows the output breaker to automatically close and provide power to the emergency bus once the EDG reaches normal frequency and voltage. After power is restored, loads belonging to the first load block are immediately started. Subsequent LOOP load blocks are started as designed to prevent overloading the EDG.

Response to 2:

The electrical lineup for performing surveillance TS 4.8.1.1.2.e.6 is the same as the lineup used during performance of monthly surveillance TS 4.8.1.1.2.a.5. The only difference between the two surveillance Technical Specifications is the duration. TS 4.8.1.1.2.a.5 requires that the EDG be operated in a loaded condition with off-site power for at least 60 minutes, whereas TS 4.8.1.1.2.e.6 requires parallel operation for at least 24 hours. The automatic response of the electrical distribution system to electrical disturbances and/or accidents, including EDG performance, is the same regardless of the test duration.

Performance of the surveillance test in and of itself will not cause perturbations to the electrical distributions systems. However, any disturbance of off-site power may result in loss of the EDG because of over-current or reverse power which would necessitate local operator action to reset the lockout. Actuation of the EDG over-current or EDG differential current protection relays actuates the EDG lockout relay. Administrative controls prevent paralleling both EDGs at the same time. As such, only one EDG can potentially be affected by the assumed disturbance.

Response to 3:

The impact of single failures on the EDG under test such as failure of the feeder isolation tie breakers between the normal and emergency busses to open or failure of the EDG output breaker to open or reclose will not effect the proper response of the redundant EDG/Train. Therefore, when performing TS 4.8.1.1.2.e.6 for a 24-hour period, at least one EDG will adequately respond within the time necessary to mitigate anticipated operational occurrences or postulated design basis accidents.

Special Provisions for the EDG 24-hour Endurance Test

In addition to the special provisions based on the CRMP, FPL will take specific provisions or limitations to appropriately manage the on-line performance of the EDG 24-hour endurance run during Modes 1 and 2.

1. The EDG under test will be declared out-of-service, during the 24-hour surveillance test, based on load shedding being disabled during a LOOP event.

2. Only one EDG can be tested at a time in parallel with off-site power in accordance with TS Surveillance Requirement 4.8.1.1.2.e.6.

3. Appropriate precautions/limitations will be provided that caution against conducting the 24-hour test during periods of unstable off-site grid conditions, or maintenance and test conditions that have an adverse affect on the test.

4. No additional maintenance or testing will be performed on required safety systems, subsystems, trains, components, and devices that depend on the remaining EDG as a source of emergency power.

5. An operator will be stationed in close proximity to the EDG during testing.

6. The operability of the redundant EDG will be confirmed prior to commencing the 24-hour surveillance test.

The provisions/limitations discussed above will be included in the appropriate plant procedures following approval of the Technical Specification change and prior to performing the 24-hour surveillance test in either Mode 1 or 2.

Declaring the EDG under test out-of-service allows relaxing the single failure criterion (SFC) for the EDG not in test and its associated train of engineered safeguards equipment. NRC Generic Letter 80-30 allows a licensee to temporarily relax the requirements of SFC by declaring equipment out-of-service and entering the Technical Specification limiting condition for operation (LCO) associated with that equipment. The logic behind this relaxation is that the LCO time frame has been formulated to assure that no set of equipment outages would be allowed to persist that would result in the facility being in an unprotected condition.

Conclusion

Performance of the EDG 24-hour endurance run during power operation will not affect the availability of any required power sources, nor the capability of the EDGs to perform their intended safety function during a LOCA or LOCA/LOOP scenario. However, performance of the endurance run during power operation affects the availability of on-site power and the capability of the EDG to perform its intended safety function during a LOOP scenario. This type scenario causes an over-current trip lockout which shuts down the EDG and trips its output breaker. The lockout can be promptly reset by the stationed operator allowing the EDG to be restarted and its output breaker to close automatically when the EDG reaches normal frequency and voltage. Required safe shutdown loads would then be sequenced on the bus.

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

1) The design features described above and their response to credible postulated events, and
2) The administrative controls or special provisions to be imposed during performance of the EDG 24-hour endurance run.

ATTACHMENT 2

DETERMINATION OF NO SIGNIFICANT HAZARDS CONSIDERATION

The proposed amendment consists of two changes. The first change revises Unit 1 Technical Specification (TS) Section 4.8.1.1.2.e by relocating the restriction to perform the 18-month emergency diesel generator (EDG) surveillance tests during shutdown to individual surveillance requirements under the TS 4.8.1.1.2.e. The second change revises Unit 1 TS 4.8.1.1.2.e.6 to remove the restriction to perform the EDG 24-hour endurance test during shutdown. Approval of this license amendment is expected to reduce the complexity of activities performed during refueling outages, therefore, reducing human performance errors and the duration of refueling outages, while not adversely impacting the margin of safety.

The standards used to arrive at a determination that the request for an amendment involves no significant hazards consideration are included in the Commission's regulations, 10 CFR 50.92, which states that no significant hazard considerations are involved if 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; or (2) create the possibility of a new or different kind of accident from any accident previously evaluated; or (3) involve a significant reduction in a margin of safety. Each standard is discussed as follows:

1) Operation of the facility in accordance with the proposed amendment would not involve a significant increase in the probability or consequences of an accident previously evaluated.

   The proposed amendment does not involve a significant increase in the probability or consequences of an accident previously evaluated for the following reasons:

   The change relocating the "during shutdown" requirement from TS 4.8.1.1.2.e to the individual surveillance requirements under TS 4.8.1.1.2.e is strictly administrative in nature. Therefore, it does not involve any increase in the probability or consequences of an accident previously evaluated.

   For the change that revises Unit 1 TS 4.8.1.1.2.e.6 to remove the restriction to perform the EDG 24-hour endurance test during shutdown, The emergency diesel generators (EDG) and their associated emergency busses are not accident initiating equipment. Therefore, there will be no impact on any accident probabilities by the approval of this amendment. The design of this equipment is not being modified by these proposed changes. In addition, the ability of the EDGs to respond to a design basis accident will not be significantly impacted by these proposed changes. Consequences are no different than presently when an EDG is out-of-service in the current TS allowed outage time during operation in Modes 1 and 2.

Therefore, performing the EDG 24-hour endurance test in Modes 1 and 2 does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2) Use of the modified specification would not create the possibility of a new or different kind of accident from any previously evaluated.

The proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated for the following reasons:

No new accident causal mechanisms are created as a result of this amendment request. Equipment will be operated in the same configuration with the exception of the plant Mode in which testing is conducted. No changes are being made to the plant which introduce any new accident causal mechanisms. This amendment request does not impact any plant systems that are accident initiators; neither does it adversely impact accident mitigating systems.

The changes removing the restriction to perform the tests during shutdown for Unit 1 TS 4.8.1.1.2.e.6, in its simplest form, is just a request to extend the amount of time the EDG is synchronized to the grid in Modes 1 and 2 from approximately 18 hours (one hour per month) to approximately 42 hours per cycle. The existing surveillance requirement TS 4.8.1.1.2.a.5 requires, in part, that every 31 days each EDG be demonstrated operable by synchronizing to the grid for at least an hour. It is simply a time extension of the existing surveillance requirement. Therefore, performing the EDG 24-hour endurance test in Modes 1 and 2 does not create the possibility of a new or different kind of accident from any previously evaluated.

3) Use of the modified specification would not involve a significant reduction in a margin of safety.

The AC electrical distribution system has been designed to provide sufficient redundancy and reliability to ensure the availability of the EDGs to provide the required safety function under design basis events to protect the power plant, the public, and plant personnel.

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 not risk significant. The proposed activity involves changes to the allowed plant mode for the performance specific Technical Specification surveillance requirements.

During the performance of the EDG endurance surveillance test for a 24-hour period, at least one EDG will be available and will adequately respond within the time necessary to mitigate anticipated operational occurrences or postulated design basis accidents.

The calculated total change in CDF, including the conservatively estimated fire risk contribution, is less than 1E-06 per reactor year and the calculated total change in the LERF, including the conservatively estimated fire risk contribution, is less than 1E-07 per reactor year. The change in CDF and LERF is, therefore, within Region III of Regulatory Guide 1.174 Figures 3 and 4, and is considered very small. When the full scope of plant risk is considered, the risks incurred by performing the EDG 24-hour surveillance test during power operation will be substantially offset by plant benefits associated with avoiding unnecessary plant transitions and/or reducing risks during shutdown operations.

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 significant reduction of the margin of safety.

Based on the above, FPL has determined that the proposed amendment does not involve a significant increase in the probability or consequences of an accident previously evaluated; or create the possibility of a new or different kind of accident from any accident previously evaluated; or involve a significant reduction in a margin of safety; and therefore, does not involve a significant hazards consideration.

Environmental Consideration

The proposed license amendment changes requirements with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20. The proposed amendment involves no significant increase in the amounts and no significant change in the types of any effluents that may be released off-site, and no significant increase in individual or cumulative occupational radiation exposure. FPL has concluded that the proposed amendment involves no significant hazards consideration and meet the criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), an environmental impact statement or environmental assessment need not be prepared in connection with issuance of the amendment.

ATTACHMENT 3

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ELECTRICAL POWER SYSTEMS

SURVEILLANCE REQUIREMENTS (Continued)

c. By sampling new fuel in accordance with ASTM D4057-81 prior to addition to the storage tanks and:

1. By verifying in accordance with the tests specified in ASTM D975-81 prior to addition to the storage tanks that the sample has:

a) API Gravity within 0.3 degrees at 60°F or a specific gravity of within 0.0016 at 60/60°F, when compared to the supplier's certificate or an absolute specific gravity at 60/60°F of greater than or equal to 0.83 but less than or equal to 0.89 or an API gravity of 60°F of greater than or equal to 27 degrees but less than or equal to 39 degrees.

b) A kinematic viscosity at 40°C of greater than or equal to 1.9 centistokes, but less than or equal to 4.1 centistokes, if gravity was not determined by comparison with the supplier's certification.

c) A flash point equal to or greater than 125°F, and

d) A clear and bright appearance with proper color when tested in accordance with ASTM D4176-82.

2. By verifying within 31 days of obtaining the sample that the other properties specified in Table 1 of ASTM D975-81 are met when tested in accordance with ASTM D975-81 except that the analysis for sulfur may be performed in accordance with ASTM D1552-79 or ASTM D2622-82.

d. At least once every 31 days by obtaining a sample of fuel oil from the storage tanks in accordance with ASTM D2276-83 and verifying that total particulate contamination is less than 10 mg/liter when checked in accordance with ASTM D2276-83, Method A, or Annex A-2.

e. At least once per 18 months ~~during shutdown by~~:

1. DELETED

During shutdown by

2. Verifying generator capability to reject a load of greater than or equal to 600 hp while maintaining voltage at 4160 ± 420 volts and frequency at 60 ± 1.2 Hz.

3. Simulating a loss of offsite power by itself, and:

a) Verifying deenergization of the emergency busses and load shedding from the emergency busses.

ELECTRICAL POWER SYSTEMS

SURVEILLANCE REQUIREMENTS (Continued)

b) Verifying the diesel starts on the auto-start signal****, energizes the emergency busses with permanently connected loads within 10 seconds, energizes the auto-connected shutdown loads through the load sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the shutdown loads. After energization, the steady-state voltage and frequency of the emergency busses shall be maintained at 4160 ± 420 volts and 60 ± 1.2 Hz during this test.

During shutdown by

4. Verifying that on an ESF actuation test signal (without loss-of-offsite power) the diesel generator starts**** on the auto-start signal and operates on standby for greater than or equal to 5 minutes. The steady state generator voltage and frequency shall be 4160 ± 420 volts and 60 ± 1.2 Hz within 10 seconds after the auto-start signal; the generator voltage and frequency shall be maintained within these limits during this test.

5. Simulating a loss-of-offsite power in conjunction with an ESF actuation test signal, and

a) Verifying deenergization of the emergency busses and load shedding from the emergency busses.

b) Verifying the diesel starts on the auto-start signal****, energizes the emergency busses with permanently connected loads within 10 seconds, energizes the auto-connected emergency (accident) loads through the auto-sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the emergency loads. After energization, the steady-state voltage and frequency of the emergency busses shall be maintained at 4160 ± 420 volts and 60 ± 1.2 Hz during this test.

c) Verifying that all automatic diesel generator trips, except engine overspeed and generator differential, are automatically bypassed upon loss of voltage on the emergency bus concurrent with a safety injection signal.

****This test may be conducted in accordance with the manufacturer's recommendations concerning engine prelube period.

SURVEILLANCE REQUIREMENTS (Continued)

6. Verifying the diesel generator operates for at least 24 hours****. During the first 2 hours of this test, the diesel generator shall be loaded within a load band of 3800 to 3960 kW# and during the remaining 22 hours of this test, the diesel generator shall be loaded within a load band of 3300 to 3500 kW#. The generator voltage and frequency shall be 4160 ± 420 volts and 60 ± 1.2 Hz within 10 seconds after the start signal; the steady state generator voltage and frequency shall be maintained within these limits during this test.

During shutdown by

7. Verifying that the auto-connected loads do not exceed the 2000-hour rating of 3730 kW.

8. Verifying the diesel generator's capability to:

   a) Synchronize with the offsite power source while the generator is loaded with its emergency loads upon a simulated restoration of offsite power.

   b) Transfer its loads to the offsite power source, and

   c) Be restored to its standby status.

9. Verifying that with the diesel generator operating in a test mode (connected to its bus), a simulated safety injection signal overrides the test mode by (1) returning the diesel generator to standby operation and (2) automatically energizes the emergency loads with offsite power.

10. Verifying that the fuel transfer pump transfers fuel from each fuel storage tank to the engine-mounted tanks of each diesel via the installed cross connection lines.

11. Verifying that the automatic load sequence timers are operable with the interval between each load block within ± 1 second of its design interval.

f. At least once per ten years or after any modification which could affect diesel generator independence by starting**** the diesel generators simultaneously, during shutdown, and verifying that the diesel generators accelerate to approximately 900 rpm in less than or equal to 10 seconds.

#This band is meant as guidance to avoid routine overloading of the engine. Variations in load in excess of this band due to changing bus loads shall not invalidate this test.

****This test may be conducted in accordance with the manufacturer's recommendations concerning engine prelube period.