Florida Power & Light Company, 6351 S. Ocean Drive, Jensen Beach, FL 34957

FPL

June 14, 2000

L-2000-112
10 CFR 50.90

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

RE: St. Lucie Units 1 and 2
Docket Nos. 50-335 and 50-389
Proposed License Amendment
EDG Risk Informed AOT Extension
Request for Additional Information Response

By letter L-99-228 dated November 17, 1999, Florida Power & Light Company (FPL) requested amendments to the Facility Operating Licenses for St. Lucie Units 1 and 2. The proposed license amendments (PLA) would increase the emergency diesel generator (EDG) allowed outage time (AOT) from the current 72-hour action statement to an action statement of 14 days.

By letter dated March 1, 2000, the NRC transmitted a request for FPL to provide additional information the NRC deemed necessary to complete its review. On May 4, 2000, the NRC Project Manger for St. Lucie concurred with a schedule change for FPL to provide the response by May 29, 2000. During a conference call to discuss the response with the NRC on May 17, 2000, the NRC Electrical Branch stated its position on the availability of an alternate AC source for St. Luice Unit 2 as a condition for approval of the extended AOT. FPL notified the NRC that the response to the revised Request 2 would cause an additional delay for the RAI response.

NRC Electrical Branch requires licensees to demonstrate the availability of an alternate AC power source as part of the review for a risk informed AOT extension. FPL was requested to confirm that a single Unit 1 EDG has the capacity to power its dedicated division of safety loads on Unit 1 the non-blackout unit (NBO Unit) and the necessary station blackout (SBO) loads on Unit 2 (SBO Unit) to maintain hot shutdown. As an alternative, FPL can commit to provide a temporary alternate AC power source that is capable of providing the SBO loads on St. Luice Unit 2 during planned EDG maintenance outages exceeding 72 hours in duration.

FPL is expediting the reanalysis of the Unit 1 EDG capability as an alternate AC power source for Unit 2. This reanalysis is anticipated to confirm the capability of a Unit 1 EDG to provide power to its dedicated division of safety loads on Unit 1 (NBO Unit) and the necessary SBO loads to maintain Unit 2 (SBO) in hot shutdown. The reanalysis will require an extensive engineering effort to complete. FPL will make every effort to submit the results of the reanalysis by October 17, 2000, but not later than December 8, 2000. FPL will keep the NRC Project Manager

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informed of the efforts to improve the schedule. As a result of this additional analysis, FPL agrees to change the requested amendment approval date for St. Lucie Unit 2 to February 28, 2001.

FPL requests that the NRC separate the St. Lucie Unit 1 and St. Lucie Unit 2 reviews and proceed with the St. Lucie Unit 1 review. FPL understands that the responses to this RAI resolve all the open issues for St. Lucie Unit 1. The St. Lucie Unit 1 approval is requested by November 30, 2000, to support plans for the Spring 2001 St. Lucie Unit 1 refueling outage (SL1-17).

In accordance with 10 CFR 50.91 (b)(1), a copy of this response is being forwarded to the State Designee for the State of Florida. Please allow an implementation period of 60 days from the date of receipt for this license amendment to allow sufficient time for procedure changes and implementation training.

Please 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

Attachment

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

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 14th day of June, 2000
by Rajiv S. Kundalkar, who is personally known to me.

Julie G. Mueller

Name of Notary Public - State of Florida

Julie G. Mueller
Commission # CC 781679
Expires OCT. 7, 2002
BONDED THRU
ATLANTIC BONDING CO., INC.

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

REQUEST FOR ADDITIONAL INFORMATION

RELATED TO THE AMENDMENT OF THE TECHNICAL SPECIFICATIONS

FOR THE EMERGENCY DIESEL GENERATORS

ST. LUCIE UNITS 1 AND 2

FLORIDA POWER AND LIGHT COMPANY

DOCKET NOS. 50-335 AND 50-389

NRC Request 1:

The staff is concerned over your use of "trigger values" to ensure that the emergency diesel generator (EDG) reliability for St. Lucie Units 1 and 2 remains greater than or equal to the target reliability chosen for your EDGs to meet station blackout (SBO) rule.

Please justify your amendment request without relying on the "trigger values."

FPL Response 1:

By NRC letter dated June 11, 1992 (Jan A. Norris to Mr. J. H. Goldberg), the NRC issued a supplemental safety evaluation (SSE) for the station blackout rule (10 CFR 50.63) for St. Lucie Units 1 and 2. In Section 2.4 of the SSE, EDG Reliability Program, the staff stated that it found acceptable FPL's commitment to implement, attain, and maintain an EDG reliability program for the St. Lucie Unit 1 EDGs for the targeted reliability. The targeted reliability for the St. Lucie Unit 1 EDGs is 0.975. The acceptance by the staff was based on the understanding that the EDG reliability program would meet the guidance of NRC Regulatory Guide (RG) 1.155, Section 1.2.

In Section 2.5 of the same SSE, the NRC evaluated FPL's response to an NRC recommendation concerning the reliability of the St. Lucie Unit 2 EDGs. The staff recommended that the St. Lucie Unit 2 EDGs be maintained at a reliability level of 0.974 or greater in accordance with the licensing basis for SBO for St. Lucie Unit 2. In response to the NRC's recommendation, FPL had committed to maintain the reliability of the St. Lucie Unit 2 EDGs at or greater than 0.974 by implementation of an EDG reliability program. The staff stated that, based in its review and FPL's commitment, FPL's response was acceptable.

With regard to the EDG reliability program for the EDGs at St. Lucie Units 1 and 2, FPL committed to implement an EDG reliability program that attains and maintains targeted EDG reliability. The EDG reliability program described in St. Lucie Administrative Procedure AP 0010022, *Emergency Diesel Generator Reliability Program*, meets the intent of NRC Regulatory guide (RG) 1.155, Section 1.2. As discussed in the NRC SSE Section 2.6, St. Lucie Unit 1 is a 4-hour SBO coping plant with EDG target reliability of 0.975 or greater. As discussed in the SSE Section 2.5, St. Lucie Unit 2 is a DC coping plant with EDG target reliability of 0.974 or greater.

The reliability program EDG target levels, equal to or greater than 0.975, are consistent with the plant category and coping duration approved by the NRC SSE. Surveillance testing and reliability monitoring programs are designed to track EDG performance and support maintenance. Maintenance programs ensure the EDG target reliability is being achieved and provide the capability for failure analysis and root-cause investigations. The programs include an information and data collection system that compares the elements of the reliability levels against the target values. The programs identify the responsibilities for the major program elements, the management oversight for reviewing the levels of reliability achieved and ensuring the program is functioning properly.

NRC Request 2:

Your staff indicated in a telephone conference on January 19, 2000, that each of the Unit 1 and Unit 2 EDGs is capable of powering its dedicated division of safety loads in addition to the complement of selected Unit 1 or Unit 2 loads necessary to maintain the units in Hot Standby through the duration of the SBO event. Your staff also indicated that procedures are in place to accomplish the above through the SBO crosstie.

Please clarify this aspect of the design for Unit 2 in your application. In addition, indicate that the time it takes to establish this connection satisfies the availability requirements of an alternate AC source used for the SBO event.

FPL Response 2:

St. Lucie Unit 2 was licensed before July 21, 1988, the capability to withstand station blackout was specifically addressed in the operating license proceeding and was explicitly approved by the NRC. Therefore, in accordance with 10 CFR 50.63(b), the requirements in 10 CFR 50.63(c) do not apply to St. Lucie Unit 2. For station blackout considerations, St. Lucie Unit 2 is currently licensed as a 4-hour DC coping plant. The acceptability of this approach was reconfirmed in the June 11, 1992, NRC SBO Safety Evaluation for St. Lucie Units 1 and 2.

The DC coping capability of Unit 2 is enhanced by the ability to provide power to one division of the Class 1E distribution system from a Unit 1 EDG. The amount of power available to the Unit 2 loads under a SBO scenario (only one Unit 1 EDG operational) is limited by plant procedures as not to affect Unit 1 safe shutdown. It is expected that AC power would be restored within 30 minutes to one hour by either restoration of off-site power or one or both of the Units 2 EDGs would be restarted.

During a conference call to discuss the response to the NRC RAI on May 17, 2000, the NRC Electrical Branch stated its position that the staff has required licensees to demonstrate the availability of an alternate AC power source as part of the review for a risk informed AOT extension. FPL was requested to confirm that a single Unit 1 EDG has the capacity to power its dedicated division of safety loads on Unit 1 (NBO Unit) and the necessary hot shutdown SBO loads on Unit 2 (SBO Unit).

FPL is expediting the reanalysis the Unit 1 EDG capability as an alternate AC power source for Unit 2. This reanalysis is anticipated to confirm the capability of a Unit 1 EDG to provide power to its dedicated division of safety loads on Unit 1 (NBO Unit) and the necessary SBO loads to maintain Unit 2 (SBO) in hot shutdown. The reanalysis will require an extensive engineering effort to complete. FPL will make every effort to submit the results of the reanalysis by October 17, 2000, but not later than December 8, 2000. FPL will keep the NRC Project Manager informed of the efforts to improve the schedule. As a result of this additional analysis, FPL agrees to change the requested amendment approval date for St. Lucie Unit 2 to February 28, 2001 since the Unit 2 amendment is required to support the Fall 2001 St. Lucie Unit 2 refueling outage (SL2-13).

FPL requests that the NRC separate the St. Lucie Unit 1 and St. Lucie Unit 2 reviews and proceed with the St. Lucie Unit 1 review. FPL understands that the responses to this RAI resolve all the open issues for St. Lucie Unit 1. The St. Lucie Unit 1 approval is requested by November 30, 2000, to support plans for the Spring 2001 St. Lucie Unit 1 refueling outage (SL1-17).

NRC Request 3:

Page 8, Table 4 - Explain the relationship among the early containment failure probability (0.01 or 0.1), core damage frequency (CDF), and large early release frequency (LERF).

FPL Response 3:

The LERF for St. Lucie was estimated as follows:

LERF = [(fraction of CDF leading to a large early release) * CDF] + [ISLOCA] + [SGTR]

Where: ISLOCA is the contribution from Interfacing System LOCAs
SGTR is the contribution from Steam Generator Tube Ruptures

The St. Lucie IPE results concluded that 1% (0.01) of the CDF leads to a large early release. Thus, the baseline fraction of CDF leading to a large early release used in the above equation would be 0.01. Since the level 2 analysis has not been updated, a sensitivity study using 0.1 as the fraction of CDF leading to a large early release was performed. It is judged that 0.1 would be a bounding value.

NRC Request 4:

Pages 6, 7, and 8, Tables 1, 2, and 3 - In Tables 1 and 2, 1.39E-5/yr was referred to as a conditional CDF based on zero EDG unavailability. The same value was referred to as an average baseline CDF in Table 3. Explain.

FPL Response 4:

The 1.39E-05/yr in Tables 1 and 2 was calculated based on one EDG not being out-of-service for maintenance (i.e., unavailability = 0). All other basic event probabilities, including the unavailability of the other EDG, were left at the baseline value. The 1.39E-05/yr in Table 3 is the baseline CDF assuming the same truncation used for the Tables 1 and 2 cases. Therefore, there is no, or at least a very small, change from baseline assuming one EDG is never out-of-service.

NRC Request 5:

The staff finds that the loss of grid initiating event frequency does not include plant-centered loss of offsite power (LOOP). Does the FPL's risk evaluation include the risk impact of the proposed change due to this plant-centered LOOP initiating event? Explain.

FPL Response 5:

The Loss of Grid initiating event represents the frequency of the loss of power from the system grid to the St. Lucie switchyard. Plant centered events (e.g., loss of power from the switchyard to a plant bus) would not be included in the calculation of the frequency for this initiating event. This event would be the same as LOOP if LOOP were defined as loss of power from the grid to the plant switchyard.

There are additional initiating events and failure modes modeled which account for other means of losing offsite power to safety related busses. The following summarizes the applicable initiating events and failure modes modeled:

Loss of power from the switchyard to the startup transformers

This initiating event represents an event in the switchyard that would induce a unit trip and loss of offsite power to the tripped unit. The 230kV switchyard consists of two full capacity operating buses. The switchyard is further divided into four bays. A bay consists of three circuit breakers tied between the East and West buses with a tap feeding one of three 230kV transmission lines (or a local distribution station line) and a tap from one of the main generators or to one of the startup transformers.

The offsite power system provides the following reliability and flexibility:

1. Any one transmission line may be interrupted with the remaining two circuits being capable of carrying full output of both Units 1 and 2.

2. Any circuit can be switched under normal conditions without affecting another circuit.

3. Any single circuit breaker can be isolated for maintenance without interrupting the power or protection to any circuit.

4. Short circuits in a single main bus will be isolated without interrupting service to any circuit.

5. Short circuit failure of a single bay breaker will not result in the permanent loss of any transmission line or any startup transformer.

6. Physical independence of power for the startup transformer is achieved by separating its switchyard connection into two different bays.

Two startup transformers are provided for each unit (1A (2A) and 1B (2B)). This initiator (designated T4) is thus divided into two events - T4A and T4B.

Multiple failures are required to cause a trip of one unit and a subsequent loss of offsite power to one train of each unit. The other offsite power source for the tripped unit and the operation of the other unit is not impacted. Additional failures would be required to cause a trip of one unit and a loss of offsite power to both trains of both units. This potential for a switchyard related failure that would trip both units and lose offsite power to both trains of both units is not considered credible.

Loss of non-vital 4kV bus initiating event:

The loss of a non-vital 4kV bus will likely result in a unit trip and a loss of offsite power to the vital 4kV bus of the affected train. Loss of a non-vital 4kV bus was, therefore, included in the model as a special initiator.

Hardware related failure modes:

> During power operation, power for plant loads is supplied from the output of the main generator via the auxiliary transformers (one per train). Following a turbine trip, the power source for plant loads is automatically transferred from the auxiliary transformers to the startup transformers (one per train). Power to the startup transformers is supplied from the plant grid via the switchyard. Hardware related failures that would result in failure to transfer plant loads to offsite power (startup transformers) following a trip are modeled. This would have the same immediate impact as loss of the grid (i.e., loss of offsite power to vital 4kV busses and a demand for the EDGs).

FPL's risk evaluation in support of the proposed AOT change does include the impact of plant-centered LOOP events/failures.

NRC Request 6:

Is the crosstie recovery event failure probability (0.1) identical for both units? Explain why the asymmetry in design between the units was not captured.

FPL Response 6:

The blackout crosstie recovery event probability is identical for both units. This event considers failures associated with both hardware (e.g., breaker failures) and the operator action. The design of the blackout crosstie and associated 4.16kV busses is symmetrical between the units. Figure 1 provides a simplified electrical diagram showing the blackout crosstie. The operator actions required are similar whether the crosstie is used to power a Unit 1 bus from Unit 2 or a Unit 2 bus from Unit 1. It is appropriate, therefore, to use the same blackout crosstie failure probability for both units.

In addition to the blackout crosstie, there is an alternate method of crosstying an EDG from one unit to a vital 4kV bus of the other unit. This crosstie is accomplished using the non-vital 4kV busses. This alternate crosstie capability was conservatively not credited in the St. Lucie Probabilistic Safety Assessment (PSA).

NRC Request 7:

Explain how the recommended Tier 2 restriction is going to be implemented.

FPL Response 7:

The Tier 2 restrictions will be included in the administrative procedure for implementation of the Configuration Risk Management Program and, for high winds, will also be included in the administrative procedure for severe weather preparations. Reference to the Tier 2 restrictions will also be included as part of the On-line Risk Monitor.

NRC Request 8:

Explain EOP-99, Appendix G for manual C auxiliary feedwater pump start, and justify the basic event failure probability used for it in your PRA.

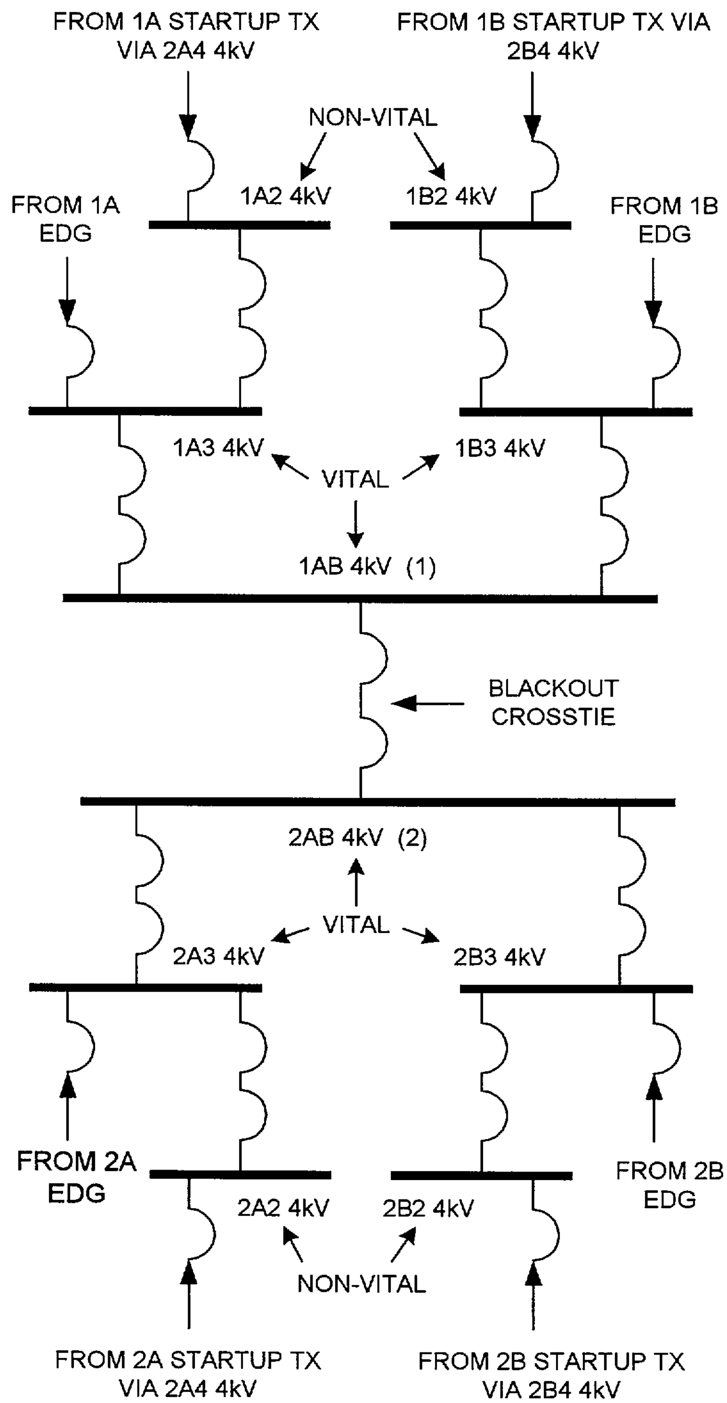
FPL Response 8:

1[2]-EOP-06, *Total Loss of Feedwater*, identifies local operation of the turbine driven ("C") AFW pump as one potential means of recovering feedwater. The operator is directed to Appendix G, *Local Operation of the 1[2]C Auxiliary Feedwater Pump*, of 1[2]-EOP-99, *Appendixes/Figures/Tables*. Appendix G provides the detailed steps for taking local control of the turbine driven AFW pump, including required breaker and valve manipulations.

For quantification of the operator non-recovery probability, a t=0 loss of all feedwater is assumed. For the baseline case, this basic event was quantified as an ex-control room action with 10 minutes assumed for diagnosis, a 13 minute response time, and 50 minutes available time (assumes feedwater must be restored within 60 minutes to prevent core damage). For the sensitivity case discussed in the EDG PLA, it is assumed that an additional 10 minutes is required for diagnosis (20 minutes total). Forty minutes would then be available to complete the action. Although this results in a calculated revised non-recovery probability of 0.12, an even more conservative value of 0.2 was used for the sensitivity study.

Local operation of the "C" AFW pump is also included in the operator AFW system training.

FIGURE 1
Blackout Crosstie Bus Arrangement



(1) 1AB is connected to either 1A3 or 1B3, but not both simultaneously
(2) 2AB is connected to either 2A3 or 2B3, but not both simultaneously