UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

April 26, 2001

Mr. T. F. Plunkett
President - Nuclear Division
Florida Power and Light Company
P.O. Box 14000
Juno Beach, Florida 33408-0420

SUBJECT: ST. LUCIE PLANT, UNIT NO. 2 - ISSUANCE OF AMENDMENT REGARDING DIESEL GENERATOR ALLOWED OUTAGE TIME EXTENSION (TAC NO. MA7206)

Dear Mr. Plunkett:

The U.S. Nuclear Regulatory Commission has issued the enclosed Amendment No. 115 to Facility Operating License No. NPF-16 for the St. Lucie Plant, Unit No. 2. This amendment consists of changes to the Technical Specifications in response to your application dated November 17, 1999, as supplemented by letters dated June 14, November 13, and December 4, 2000, and February 21, 2001.

This amendment changes the allowed outage time to restore an inoperable diesel generator set to operable status from 72 hours to 14 days. Implementation shall include incorporation into the St. Lucie Configuration Risk Management Program four conditions relating to station blackout and four conditions relating to fire risk, as described in your application submittals and the Safety Evaluation supporting the amendment.

A copy of the Safety Evaluation is also enclosed. The Notice of Issuance will be included in the Commission's biweekly Federal Register notice.

Sincerely,

Brendan T. Moroney, Project Manager, Section 2
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket No. 50-389

Enclosures:
1. Amendment No. 115 to NPF-16
2. Safety Evaluation

cc w/enclosures: See next page

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NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C.

FLORIDA POWER & LIGHT COMPANY

ORLANDO UTILITIES COMMISSION OF

THE CITY OF ORLANDO, FLORIDA

AND

FLORIDA MUNICIPAL POWER AGENCY

DOCKET NO. 50-389

ST. LUCIE PLANT UNIT NO. 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 115
License No. NPF-16

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

   A. The application for amendment by Florida Power & Light Company, et al. (the licensee), dated November 17, 1999, as supplemented by letters dated June 14, November 13, and December 4, 2000, and February 21, 2001, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's rules and regulations set forth in 10 CFR Chapter I;

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

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

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

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

2. Accordingly, Facility Operating License No. NPF-16 is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and by amending paragraph 2.C.2 to read as follows:

   2. Technical Specifications

      The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 115, are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of its date of issuance and shall be implemented within 60 days of the date of issuance. Implementation shall include incorporation into the licensee's Configuration Risk Management Program of four conditions relating to station blackout and four conditions relating to fire risk, as described in the licensee's application dated November 17, 1999, as supplemented by letters dated June 14, November 13, and December 4, 2000, and February 21, 2001, and reviewed in the staff's Safety Evaluation dated April 26, 2001.

FOR THE NUCLEAR REGULATORY COMMISSION

Richard P. Correia

Richard P. Correia, Chief, Section 2
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Technical Specifications

Date of Issuance: April 26, 2001

ATTACHMENT TO LICENSE AMENDMENT NO. 115

TO FACILITY OPERATING LICENSE NO. NPF-16

DOCKET NO. 50-389

Replace the following pages of the Appendix "A" Technical Specifications with the attached pages. The revised pages are identified by amendment number and contain vertical lines indicating the area of change.

Remove Pages	Insert Pages
3/4 8-1	3/4 8-1
B3/4 8-1	B3/4 8-1

3/4.8 ELECTRICAL POWER SYSTEMS

3/4.8.1 A.C. SOURCES

OPERATING

LIMITING CONDITION FOR OPERATION

3.8.1.1 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. Two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system, and

b. Two separate and independent diesel generators, each with:

1. Two separate engine-mounted fuel tanks containing a minimum volume of 200 gallons of fuel each,

2. A separate fuel storage system containing a minimum volume of 40,000 gallons of fuel, and

3. A separate fuel transfer pump.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

a. With one offsite circuit of 3.8.1.1.a inoperable, except as provided in Action f. below, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. Restore the offsite circuit to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

b. With one diesel generator of 3.8.1.1.b inoperable, demonstrate the OPERABILITY of the A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter; and if the EDG became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventative maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE EDG by performing Surveillance Requirement 4.8.1.1.2a.4 within 8 hours, unless it can be confirmed that the cause of the inoperable EDG does not exist on the remaining EDG*; restore the diesel generator to OPERABLE status within 14 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. Additionally, verify within 2 hours or be in HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours that:

---

* If the absence of any common-cause failure cannot be confirmed, this test shall be completed regardless of when the inoperable EDG is restored to OPERABILITY.

3/4.8.1, 3/4.8.2 and 3/4.8.3 A.C. SOURCES, D.C. SOURCES and ONSITE POWER DISTRIBUTION SYSTEMS

The OPERABILITY of the A.C. and D.C. power sources and associated distribution systems during operation ensures that sufficient power will be available to supply the safety related equipment required for 1) the safe shutdown of the facility and 2) the mitigation and control of accident conditions within the facility. The minimum specified independent and redundant A.C. and D.C. power sources and distribution systems satisfy the requirements of General Design Criteria 17 of Appendix "A" to 10 CFR 50.

The ACTION requirements specified for the levels of degradation of the power sources provide restriction upon continued facility operation commensurate with the level of degradation. The OPERABILITY of the power sources are consistent with the initial condition assumptions of the safety analyses and are based upon maintaining at least one redundant set of onsite A.C. and D.C. power sources and associated distribution systems OPERABLE during accident conditions coincident with an assumed loss of offsite power and single failure of the other onsite A.C. source. The A.C. and D.C. source allowable out-of-service times are based on Regulatory Guide 1.93, "Availability of Electrical Power Sources," December 1974. When one diesel generator is inoperable, there is an additional ACTION requirement to verify that all required systems, subsystems, trains, components and devices, that depend on the remaining OPERABLE diesel generator as a source of emergency power, are also OPERABLE, and that the steam-driven auxiliary feedwater pump is OPERABLE. This requirement is intended to provide assurance that a loss of offsite power event will not result in a complete loss of safety function of critical systems during the period one of the diesel generators is inoperable. The term verify as used in this context means to administratively check by examining logs or other information to determine if certain components are out-of-service for maintenance or other reasons. It does not mean to perform the surveillance requirements needed to demonstrate the OPERABILITY of the component.

TS 3.8.1.1, ACTION "b" provides an allowed outage/action completion time (AOT) of up to 14 days to restore a single inoperable diesel generator to operable status. This AOT is based on the findings of a deterministic and probabilistic safety analysis and is referred to as a "risk-informed" AOT. Entry into this action requires that a risk assessment be performed in accordance with the Configuration Risk Management Program (CRMP), which is described in the Administrative Procedure that implements the Maintenance Rule pursuant to 10 CFR 50.65.

All EDG inoperabilities must be investigated for common-cause failures regardless of how long the EDG inoperability persists. When one diesel generator is inoperable, required ACTIONS 3.8.1.1.b and 3.8.1.1.c provide an allowance to avoid unnecessary testing of EDGs. If it can be determined that the cause of the inoperable EDG does not exist on the remaining OPERABLE EDG, then SR 4.8.1.1.2.a.4 does not have to be performed. Eight (8) hours is reasonable to confirm that the OPERABLE EDG is not affected by the same problem as the inoperable EDG. If it cannot otherwise be determined that the cause of the initial inoperable EDG does not exist on the remaining EDG, then satisfactory performance of SR 4.8.1.1.2.a.4 suffices to provide assurance of continued OPERABILITY of that EDG. If the cause of the initial inoperability exists on the remaining OPERABLE EDG, that EDG would also be declared inoperable upon discovery, and ACTION 3.8.1.1.e would be entered. Once the failure is repaired (on either EDG), the common-cause failure no longer exists.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 115 TO FACILITY OPERATING LICENSE NO. NPF-16

FLORIDA POWER AND LIGHT COMPANY, ET AL.

ST. LUCIE PLANT, UNIT NO. 2

DOCKET NO. 50-389

1.0 INTRODUCTION

By letter dated November 17, 1999, as supplemented by letters dated June 14, November 13, and December 4, 2000, and February 21, 2001, Florida Power & Light Company (FPL) proposed changes to St. Lucie Units 1 and 2 Technical Specifications (TS) related to emergency diesel generator (EDG) limiting conditions for operation (LCO) action statements. The proposed change would revise the current 72-hour action completion time/allowed outage time (AOT) specified in TS 3.8.1.1, Action "b," to allow 14 days to restore an inoperable EDG to operable status. The purpose of this proposed change is to avert a potential unplanned shutdown by providing margin for the performance of corrective maintenance that may be needed to resolve EDG deficiencies that are discovered during equipment surveillances or scheduled preventive maintenance activities. In addition, the proposed AOT of 14-days for a single inoperable EDG would allow the licensee to perform preventive maintenance work on-line that currently can only be performed during shutdown.

The proposed AOT is based on the findings of a deterministic and probabilistic risk assessment. In a response to a request for additional information (RAI) dated June 14, 2000, the licensee requested that we separate the St. Lucie Unit 1 and St. Lucie Unit 2 reviews and proceed with the St. Lucie Unit 1 review first, because additional analysis was needed for Unit 2. The staff subsequently issued an amendment granting the AOT extension for St. Lucie Unit 1 EDGs on January 19, 2001. Information needed to complete the Unit 2 evaluation was provided in letters dated November 13, and December 4, 2000, and February 21, 2001. Information provided in the letters supplementing the original request did not affect the original proposed no significant hazards determination, or expand the scope of the request as noticed in the *Federal Register*.

The U.S. Nuclear Regulatory Commission (NRC) staff has reviewed the proposed changes to St. Lucie Unit 2 TS 3.8.1.1 and the associated changes to the corresponding Bases Section and find them acceptable as discussed in the following evaluation.

2.0 BACKGROUND

This application originated from the Combustion Engineering Owners Group (CEOG) Joint Application Report for EDG AOT extension (CE NPSD-996) submitted for staff review in May 1995. The report requested an extension of a single EDG AOT from 3 to 7 days and, in addition, the extension of the same AOT to 10 days on a once-per-cycle frequency for participating CE plants. Later, in their response to the staff RAI, CEOG revised the proposal to remove the once-per-cycle AOT and requested a single, permanent 10-day AOT for a single EDG. Based on the review of the report, the staff determined that the proposal could not be generically approved for all participating CE plants due to diversity in plant design, operating experience, and probabilistic risk assessment (PRA) modeling. In some cases, the risk implications associated with the proposal were determined to be potentially significant. In this application, FPL requested an extension of the EDG AOT from 72 hours to 14 days for St. Lucie Unit 2 and referenced CE NPSD-996 for justification.

St. Lucie Unit 2 is equipped with two Class 1E EDG sets to provide onsite emergency ac power to essential safety systems in the event of a loss of offsite power (LOOP). Each EDG set consists of two diesel engines mounted in tandem with a 4.16 kV, 60 Hz, 3-phase, 3500 kW ac generator coupled directly between the engines. Each EDG set is complete with its own air starting system, fuel supply system, and automatic control circuitry. The design also includes a station blackout (SBO) cross-tie that connects the two safety-related 4.16 kV "swing" busses between St. Lucie Units 1 and 2.

The current St. Lucie Unit 2 TS 3.8.1.1, Action "b," requires two separate and independent EDGs to be operable in Modes 1, 2, 3, and 4. This redundancy ensures that at least one of the onsite ac power sources will be operable during accident conditions, coincident with an assumed LOOP and single failure of the other onsite ac power source. If one EDG becomes inoperable, Action "b" of the LCO requires, in part, that the inoperable EDG be restored to operable status within 72 hours; otherwise, the plant must transition to Hot Standby within the next 6 hours and to Cold Shutdown within the following 30 hours. The licensee has proposed to restore the inoperable EDG to operable status within 14 days in lieu of the current 72 hours.

In addition to the above, the associated Bases Section 3/4.8.1 would be updated with the following paragraph:

> TS 3.8.1.1, ACTION "b" provides an allowed outage/action completion time (AOT) of up to 14 days to restore a single inoperable diesel generator to operable status. This AOT is based on the finding of a deterministic and probabilistic safety analysis and is referred to as a "risk-informed" AOT. Entry into this action requires that a risk assessment be performed in accordance with the Configuration Risk Management Program (CRMP), which is described in the Administrative Procedure that implements the Maintenance Rule pursuant to 10 CFR 50.65.

3.0 EVALUATION

The staff has evaluated the licensee's proposed revision to the TS using both deterministic analysis and probabilistic risk analysis methods, as discussed below:

3.1 Deterministic Evaluation

The purpose of the proposed change to TS 3.8.1.1, Action "b," is to extend the EDG AOT from the current 72 hours to 14 days to allow the licensee to perform preventive maintenance work on-line that currently can only be performed during shutdown. In addition, the longer AOT would help licensee to avert a potential unplanned shutdown by providing margin for the performance of corrective maintenance that may be needed to resolve EDG deficiencies that are discovered during surveillance or scheduled preventive maintenance activities.

The staff evaluated the licensee's request to extend the allowed AOT for EDGs to determine whether the decrease in severe accident risk achieved with the implementation of the SBO requirements in Title 10, *Code of Federal Regulations* (10 CFR), Section 50.63, would be eroded. The request was also evaluated to ensure that the overall availability of the EDGs will not be reduced significantly as a result of increased on-line preventive maintenance activities.

The issue of SBO for St. Lucie Unit 2 was considered by the Atomic Safety Licensing Board and a plant-specific analysis was performed by the licensee which demonstrated that the plant could successfully withstand a complete loss of all ac power for at least 4 hours. The use of Unit 1 EDGs was not credited in the Unit 2 coping analysis. The licensee states that the assumptions and the results of the SBO analysis are not changed by an extension of the AOT. In addition, the licensee states that the St. Lucie plant EDG reliability program ensures that EDG reliability is maintained at or above the SBO target level, and the effectiveness of maintenance on the EDGs and support systems is monitored pursuant to the Maintenance Rule (10 CFR 50.65).

During a conference call on May 17, 2000, the staff stated its position on the availability of an AAC power source for St. Lucie 2 as a condition for approval of the extended EDG AOT. It has been NRC's practice to require that an EDG must have an excess capacity in order to qualify as an AAC source to mitigate an SBO in one unit and provide power for safe shutdown of the other unit. The excess capacity of the EDG should not be the capacity made available by shedding loads or not powering the normally available capability for safe shutdown LOOP loads in the non-SBO unit. The licensee 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, and the necessary hot standby SBO loads on Unit 2 (SBO Unit).

In a letter dated November 13, 2001, the licensee provided the requested information. The licensee states that a single St. Lucie Unit 1 EDG has the capacity to power its dedicated division of safety loads required to respond to a LOOP loads on Unit 1 (the non-blackout unit), and the necessary SBO loads on Unit 2 (SBO Unit) to maintain Unit 2 in hot standby once the SBO cross-tie is established to respond to a Unit 2 SBO. The SBO cross-tie connects the two safety-related 4.16 kV "swing" busses between the units. It takes approximately 24 minutes to establish the SBO cross-tie and energize the selected Unit 2 safety busses. Therefore, in the event of a LOOP and failure of the Unit 2 operable EDG during the extended outage, power will be supplied from a Unit 1 EDG to one of the Unit 2 class 1E, 4.16kV safety busses via the SBO cross-tie. Procedures are in place to accomplish the above. Thus, the power source from Unit 1 EDGs can be made available to compensate for an EDG that is out-of-service in Unit 2, if needed.

The maximum loading applied to a Unit 1 EDG, given Unit 2 is in SBO and only one Unit 1 EDG operable, is 3292.4 kW. Since the 2000-hour rating of a Unit 1 EDG at 104°F is 3580.8 kW, there is a margin of 288.4 kW. The loading is also less than the continuous rating of 3360 kW of a Unit 1 EDG at 104°F. In addition, the licensee states that the EDG rating is considered conservative because it is calculated at 104°F which is less than the rating at 93°F (normal ambient conditions). The above demonstrates that Unit 1 EDGs have the required excess capacity to power their dedicated division of safety loads required to respond to a LOOP on

Unit 1, and the necessary SBO loads on Unit 2 to maintain Unit 2 in hot standby once the SBO cross-tie is established in response to a Unit 2 SBO.

In the event of just a LOOP at Unit 2 during the EDG extended outage, the offsite power from Unit 1 can also be made available through the SBO cross-tie.

Further, in the event that an EDG is inoperable in Modes 1-4, the existing Unit 2 TS 3.8.1.1 requires that within 2 hours all required systems, subsystems, trains, components and devices that depend on the remaining operable EDG as a source of emergency power be verified operable; and when in Mode 1, 2, or 3, the steam-driven auxiliary feedwater pump must also be verified operable. For planned outages of the EDG, this would be verified before the EDG was removed from service. The licensee states that it has always been its interpretation that these conditions must be maintained throughout the EDG outage (components in the other train must be maintained OPERABLE). This required action provides assurance that a LOOP event will not result in a complete loss of safety function of critical systems during the period one of the EDGs is inoperable.

Since the extension of the EDG AOT is based on the finding of a deterministic and probabilistic safety analysis, entry into this action requires that a risk assessment be performed in accordance with the CRMP, which is described in the licensee's Administrative Procedure that implements the Maintenance Rule pursuant to 10 CFR 50.65. The above ensures that PRA informed procedures are in place to assess the overall impact of plant maintenance on plant risk prior to entering the LCO Action statement for planned activities.

Additionally, the licensee has committed to implement the following compensatory measures during an extended EDG AOT, in order to restrict entering into the extended LCO if a Unit 1 EDG or the blackout cross-tie is unavailable:

> If a Unit 1 EDG is unavailable, a Unit 2 EDG will be removed from service only for corrective maintenance (i.e., maintenance required to ensure or restore operability of the Unit 2 EDG) and for a period not to exceed 72 hours.
>
> If the SBO cross-tie is unavailable, a Unit 2 EDG will be removed from service only for corrective maintenance (i.e., maintenance required to ensure or restore operability of the Unit 2 EDG) and for a period not to exceed 72 hours.
>
> If a Unit 2 EDG is unavailable, the SBO cross-tie will be removed from service only for corrective maintenance and for a period not to exceed 72 hours.
>
> If a condition is entered in which both a Unit 2 EDG and either the SBO cross-tie or a Unit 1 EDG becomes unavailable at the same time, the licensee will evaluate the plant conditions using the CRMP.

The licensee would add Unit 1 EDG and SBO cross-tie maintenance conditions to the administrative procedures for implementing the Configuration Risk Management Program and to the On-line Risk Monitor.

The NRC staff has determined that the four conditions relating to SBO stated above are always necessary to manage the increase in risk that may result from maintenance of the Unit 2 EDGs under the proposed TS changes. The Maintenance Rule (10 CFR 50.65(a)(4)) requires the licensee to manage such increases in risk. Accordingly, the licensee must incorporate those conditions into its CRMP, which is the licensee's program for complying with Section 50.65(a)(4). In view of the above, the licensee shall not change the above conditions without prior NRC approval.

In addition, positive measures exist in the form of administrative controls and guidelines that do not allow maintenance to be planned on EDGs when adverse weather conditions are expected, or if switchyard work, which increases the possibility of a plant trip, is being performed.

3.2 Deterministic Summary

The staff concludes that the licensee's request to extend the EDG AOT to 14-days is acceptable. This conclusion is based on the following: (1) the longer AOT would reduce the entries into the LCO and reduce the number of EDG starts for major EDG maintenance activities; (2) the Unit 1 EDGs will be available and have the capability of powering the complements of selected Unit 2 loads necessary to maintain Unit 2 in Hot Standby in the event of an SBO; and (3) the CRMP, including the conditions described above, will be implemented during extended outages. Further, precluding scheduling preplanned maintenance when adverse weather is expected will minimize the occurrence of SBO during the longer AOT. Also, we find the associated change to the Bases is consistent with the requested EDG AOT extension and is, therefore, acceptable.

3.3 Probabilistic Risk Assessment Evaluation

In the Regulatory Guide (RG) 1.177, the staff identified a three-tier approach for licensees and the staff to evaluate the risk associated with proposed TS AOT changes. 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 core damage probability (ICCDP[1]), and, where appropriate, the change in large early release frequency (LERF) and the incremental conditional large early release probability (ICLERP[2]). Tier 2 is an evaluation of the process used to address potentially high-risk configurations that could exist if equipment in addition to that associated with the change were to be taken out of service simultaneously, or other risk significant operational factors, such as concurrent system or equipment testing, were also involved. Tier 3 is an evaluation of the overall CRMP to ensure that adequate programs and procedures are in place to identify and compensate for other potentially lower probability, but nonetheless risk significant, configurations resulting from maintenance and other operational activities.

FPL used the three-tiered approach to evaluate the risk associated with the proposed EDG AOT extension from 3 to 14 days. The approach is generally consistent with RG 1.174 and

[1]ICCDP=[(conditional CDF with the subject equipm[illegible] out of service) - (baseline CDF with nominal equipment unavailabilities)] x (duration of sing[illegible] AOT under consideration)

[2]ICLERP = [(conditional LERF with the subject equipment out of service) - (baseline LERF with nominal equipment unavailabilities)] x (duration of single AOT under consideration)

RG 1.177, and the staff evaluated whether FPL's application has met the intent of these RGs.

Tier 1: Probabilistic Risk Analysis (PRA) Capability and Insights

Evaluation of PRA Model and Application to the Proposed Change

The staff's review focused on the capability of FPL's PRA model to analyze the risk stemming from the extended AOT for EDGs. This activity, however, did not involve an in-depth review of the licensee's PRA to the extent necessary to validate the overall quantitative estimates. The purpose was to confirm that the licensee's risk analysis used to support the proposal was of sufficient quality, detail and scope for the proposed application.

(1) Internal initiating events

FPL's Individual Plant Examination (IPE) for internal initiating events was submitted to the NRC in December 1993. The staff's evaluation report of the IPE concluded that the licensee has met the intent of Generic Letter (GL) 88-20; however, the staff identified weaknesses in the licensee's IPE analysis which would limit its future application to other risk-informed regulatory initiatives. Some of these weaknesses would have a direct impact on the analysis required to assess the risk of the proposed change. To address these weaknesses, the licensee (a) updated its PRA since the original IPE, and (b) performed a sensitivity study of weaknesses that were not addressed during updates.
Significant model changes incorporated in the update include:

- Creation of single-top event model, which allows fast quantification;
- Addition of test and maintenance events for selected equipment to better support the implementation of Maintenance Rule (10 CFR 50.65);
- Re-calculation of many of the initiating event frequencies;
- Re-evaluation of all offsite power recovery cases; and
- The assumption that the conditional seal loss of coolant accident probability is about $1x10^{-4}$ per reactor coolant pump when pumps are secured, given loss of seal cooling.

The original IPE was reviewed by FPL's internal and external organizations. The licensee states that it has maintained the PRA consistent with the current plant configuration such that it is considered a "living" PRA. The licensee has proceduralized administrative controls on independent review of all model changes, data updates and risk assessments performed using PRA methods and models. The revision and application of the PRA models and associated databases are handled as Quality Related under 10 CFR Part 50, Appendix B, Quality Assurance program. Prior to performing the risk assessment for this proposal, the licensee reviewed all design changes implemented since the last PRA update, and current revisions of the critical procedures that establish appropriate operator recovery actions and their timing. As a result of this review, no changes to the PRA were necessary. The staff finds that the licensee's internal initiating events PRA used to support this proposed change has been subjected to internal and external peer reviews.

Additionally, changes to and applications of the PRA model have been subject to the licensee's administrative controls for quality assurance.

One of the key weaknesses identified in the staff evaluation of the IPE was the human reliability analysis (HRA). The staff identified that treating post-initiator human actions with a time-independent approach has the potential to overestimate the likelihood of success. In this submittal, FPL performed a sensitivity study in which several operator non-recovery probabilities were increased to assess the robustness of the impact on risk due to that changes in human error probabilities. The ICCDP and ICLERP results of the study were near or slightly above the numerical thresholds prescribed in RG 1.177. The licensee indicated that the results were conservative since each of the non-recovery probabilities was set to be conservative. The staff evaluated the licensee's approach and found it to be reasonable for this particular application.

The staff reviewed CE NPSD-996 and its subsequent RAIs to compare the key data and modeling assumptions used in other CE plants with those applicable to St. Lucie Units 1 and 2. In addition, the plant-specific risk assessments provided in the submittal were also reviewed in detail. The staff finds that FPL's key data and assumptions used in the risk analysis are not outliers and that the results of the licensee's risk assessment in the submittal are mostly comparable with the results obtained for other CE plants.

In its submittal, FPL provided the top ten cutsets calculated for both the baseline and conditional cases relevant to this application. The staff's evaluation found that these dominant cutsets were typical for a CE plant. For conditional cases, the behavior of the dominant cutsets was generally consistent with the staff's expectation, as the cutsets associated with the LOOP sequences emerged in the top-ten cutset list. The staff also evaluated the basic event data and the initiating event frequency for LOOP in the cutsets and found them to be reasonable. Specifically, the basic events for EDG test and maintenance outage, EDG failure to start, EDG failure to run, operator failure to cross-tie the EDGs, and offsite power recovery were separately modeled. The staff finds that the requisite elements of a PRA required in modeling the LOOP sequences were included in the licensee's PRA. The staff considers the level of detail of the licensee's PRA for internal initiating events used for this application appropriate.

In summary, FPL's current PRA used to assess the risk due to internal initiating events has been updated from the original IPE. The risk assessments performed to estimate the impact on plant risk used the updated PRA. The weaknesses that were not resolved during the updates were separately addressed in the submittal. The staff did not identify any other significant shortcomings in the licensee's internal events PRA that could have a significant impact on the overall results of this application. The staff finds that the licensee's risk analysis of internal initiating events performed to assess the risk impact of the proposed change is generally of sufficient detail and quality for the proposed application.

(2) External initiating events

The staff evaluated the potential impact on plant risk due to the proposed change stemming from external initiating events. FPL's risk analysis in its original submittal did not include the contribution stemming from external initiating events since FPL judged any potential risk impact the EDG AOT extension might have on the risk due to external initiating events to be very small.

FPL submitted the seismic portion of its IPE for external events (IPEEE) in September 1992 and the non-seismic portion in December 1994. The staff's evaluation report of the St. Lucie IPEEE submittal concluded that the licensee's IPEEE met the intent of Supplement 4 to GL 88-20. See Safety Evaluation dated January 25, 1999. For this application, the staff evaluated the licensee's IPEEE submittal to confirm the licensee's judgment that the potential risk impact of the proposed AOT extension stemming from external initiating events would be very small. The staff found that all external initiating events other than fire would not be a risk significant contributor to the proposed change. For fire, the staff's evaluation identified that the CDF contribution from fire in the St. Lucie IPEEE was significant (greater than 1E-4). Additionally, a fire in rooms or areas such as the Control Room and Cable Spreading Room could have an impact on both the emergency and preferred power sources for the plant. Based on this information, the staff questioned the licensee's qualitative judgment that the risk impact of the proposed change due to fire was of very small significance.

Most importantly, a concern was raised that if an EDG were taken out of service for maintenance, a large fire in Control Room or Cable Spreading Room could result in an SBO with little mitigation capability. Using the approach and data used in the NUREG/CR-4832, the staff estimated the ICCDP for Control Room and Cable Spreading Room to be significant, potentially exceeding the thresholds for ICCDP and ICLERP set forth in RG 1.177. Subsequently, the staff requested the licensee to provide additional information to address the concern.

In response, FPL indicated that its IPEEE both lacked realism and was of insufficient detail and quality for purposes other than meeting the intent of Supplement 4 to GL 88-20. The licensee provided a simplistic fire risk analysis to address the staff's concern. The analysis evaluated the risk contribution due to fire in four rooms in which the licensee postulated the risk to be potentially significant - the Control Room, the Cable Spreading Room, the B Switchgear Room and the Turbine Building Switchgear Room. It concluded that the risk contribution was small compared with the numerical thresholds prescribed in RG 1.177.

The staff agrees that the fire risk analysis in FPL's IPEEE submittal was generally conservative. However, the IPEEE itself is not considered adequate to be used for this TS application. It generally lacks the necessary level of detail and quality because the licensee used the fire-induced vulnerability evaluation (FIVE) methodology and no additional work has been done to either update it or perform a detailed fire PRA since the completion of the IPEEE. The licensee's simplistic risk analysis performed in response to the staff's RAI reduced the degree of conservatism, but the degree of uncertainty of the analysis was high and some of the assumptions were considered overly optimistic. Subsequently, the staff found that the licensee's simplistic risk analysis alone failed to fully demonstrate that the fire risk impact on the proposed change would be small. Understanding the potential risk implications and the absence of a detailed fire risk analysis of sufficient detail and quality, the licensee also proposed several important compensatory measures (discussed later in the Tier 2 section) to reduce the fire risk impact. As set forth below, the staff finds that the licensee's approach to include these compensatory measures to address the concern associated with the fire risk contribution to be reasonable for this particular application.

In summary, the staff finds that the licensee's internal events PRA and additional risk assessments performed in support of the proposed change, with the exception of the fire risk analysis, are of sufficient detail and quality for the application. The scope and detail of the PRA is found to be compatible with the risk implications of the change being requested. For external events, the licensee's approach to blend a simplistic risk analysis with several important compensatory measures is concluded to be reasonable for this particular application.

Evaluation of PRA Results and Insights Associated with the Proposed Change

(1) Internal initiating events

FPL evaluated the impact on plant risk of the proposed change as expressed by the change in CDF (ΔCDF), the ICCDP for a single outage, the change in LERF (ΔLERF), and the ICLERP for a single outage. The licensee also performed a sensitivity study in order to address the potential risk impact of the weaknesses identified during the IPE review. The following sections summarize the licensee's calculated results.

(a) ΔCDF and ΔLERF

The new proposed CDFs were based on the expected outage frequency and duration given the 14-day AOT for EDGs. The LERFs were calculated assuming an large early containment failure probability of 0.1, as compared with the baseline value of 0.01. These results are provided by the licensee, and the staff's evaluation of this application did not attempt to validate these quantitative estimates.

Current CDF	1.23×10^{-5}
Proposed CDF	1.24×10^{-5}
ΔCDF	less than 1×10^{-6}
Current LERF	7.07×10^{-6}
Proposed LERF	7.08×10^{-6}
ΔLERF	less than 1×10^{-7}

FPL's submittal included a study performed to assess the sensitivity of the risk impact of an extended EDG AOT to changes in offsite power recovery and select HRA non-recovery probabilities. This study was performed to address the weaknesses identified in the staff review of the IPE. The calculated increase in CDF and LERF of the proposed change that would result from this sensitivity case was within the acceptable guidelines the staff uses in the review of risk-informed TS submittals.

(b) ICCDP and ICLERP for a single outage

FPL provided the calculated ICCDPs and ICLERPs for both a preventive maintenance outage and a corrective maintenance outage for Unit 2. These ICCDPs and ICLERPs were based on the full 14-day duration of an EDG outage. A large early containment failure probability of 0.1 was assumed to calculate the ICLERPs, as compared with the baseline probability of 0.01.

ICCDP	(Corrective Maintenance)	2.30×10^{-7}
	(Preventive Maintenance)	1.34×10^{-7}
ICLERP	(Corrective Maintenance)	2.53×10^{-8}
	(Preventive Maintenance)	1.57×10^{-8}

As for the sensitivity case stated earlier, the calculated ICCDP and ICLERP of the proposed EDG AOT were within the acceptable guidelines set forth in RG 1.177. The licensee indicated the results were conservative since each of the operator non-recovery probabilities was conservative in the sensitivity study.

The staff finds that FPL used appropriate risk measures consistent with the applicable RGs to assess the risk of the proposed change due to internal initiating events. The calculated risk impact of the change was estimated to be small.

(2) External initiating events

The absence of a PRA for external initiating events can pose a significant limitation on gaining accurate quantitative risk results and insights necessary to evaluate the risk impact of the proposed licensing changes. FPL's submittal is typical of such a case. In order to meet the intent of Supplement 4 to GL 88-20, many licensees opted to use non-PRA methodologies. For example, many licensees, including FPL, used the Seismic Margin Method for earthquakes and the FIVE Methodology for fire to identify plant-specific vulnerabilities to severe accidents. Although the licensee succeeded in meeting the intent of the IPEEE program, the use of its IPEEE for other purposes would generally be inappropriate. These non-PRA methodologies either make obtaining the baseline CDF very difficult or produce unrealistically conservative results. On the other hand, the overall risk impact of the changes in licensing applications could be underestimated without including the contribution stemming from external initiating events. The staff's initial evaluation of the potential risk impact due to external initiating events found that earthquakes are a small risk contributor at St. Lucie Unit 2 for the proposed change in EDG AOT extension. However, the staff found that the potential risk impact due to fire could be significant. The staff's simplified independent calculation estimated the ICCDP due to fire to be above 5E-7 using a method similar to the NUREG/CR-4832 approach. The room fire initiating event frequencies were based on the licensee's IPEEE. The IPEEE reported the fire CDF to be 1.9E-4/yr for Unit 2. However, when the licensee's proposed compensatory measures that reduce the fire risk contribution are considered, the staff judges that the potential risk increase due to fire to be small. These measures are described in the Tier 2 discussion below.

In summary, the staff did not combine the CDF and LERF contributions stemming from external initiating events with those from internal initiating events. The staff did not do so due to several factors including the absence of the external initiating events PRA and the role of significant compensatory measures. Nonetheless, the staff finds that with the compensatory measures properly in place, the risk impact of the proposed change due to external initiating events would meet the acceptable guidelines of the Tier 1 requirements prescribed in the applicable RGs 1.177 and 1.174.

Tier 2: Avoidance of Risk Significant Plant Configurations

The licensee is expected to provide reasonable assurance that risk significant plant equipment outage configurations will not occur when specific plant equipment is out of service, consistent with the proposed TS change. FPL evaluated several potential configurations in which an additional equipment unavailability concurrent with an EDG outage was assumed. The equipment evaluated included the Startup Transformers, Blackout Cross-tie, and offsite grid. The evaluation resulted in several recommended Tier 2 restrictions, which will be included in procedures that implement the licensee's CRMP discussed in Tier 3. These restrictions are summarized as follows:

- If a Unit 1 EDG is unavailable, a Unit 2 EDG will be removed from service only for corrective maintenance and for a period not to exceed 72 hours.

- If the Blackout Cross-tie is unavailable, a Unit 2 EDG will be removed from service only for corrective maintenance and for a period not to exceed 72 hours.

- If a Unit 2 EDG is unavailable, the Blackout Cross-tie will be removed from service only for corrective maintenance and for a period not to exceed 72 hours.

- If a condition is entered in which both a Unit 2 EDG and either the Blackout Cross-tie or a Unit 1EDG become unavailable at the same time, FPL will evaluate the plant conditions using the CRMP.

- If a hurricane warning has been issued in an area which may impact the grid, an EDG or the Blackout Cross-tie should be removed from service only for corrective maintenance required to ensure or restore operability.

- If an EDG or the Blackout cross-tie is unavailable when a hurricane warning in an area that may impact the grid is issued, restore the unavailable component(s) to service as soon as possible.

- If a tornado warning has been issued for an area that includes the St. Lucie plant site, Midway substation, or the transmission lines between the Midway substation and the St. Lucie Plant switchyard, then an EDG or the Blackout Cross-tie will be removed from service only for corrective maintenance required to ensure or restore operability.

- If an EDG or the Blackout Cross-tie is unavailable when a tornado warning is issued for an area that includes the St. Lucie Plant site, Midway substation, or the transmission lines between the Midway substation and the St. Lucie Plant switchyard, restore the unavailable component(s) to service as soon as possible.

Regarding the Steam Driven Auxiliary Feedwater (SDAFW) pump, the current St. Lucie Units 1 and 2 TS require that within 2 hours of an EDG being declared inoperable in Mode 1, 2, or 3, the SDAFW pump be verified to be operable.

To address the potential fire risk implications, FPL committed to incorporate the following Unit 2 fire protection Tier 2 restrictions into the administrative procedures for implementing its CRMP and the on-line risk monitor.

During Modes 1, 2, and 3, if a Unit 2 EDG is to be removed from service for maintenance for a period scheduled to exceed 72 hours, the following actions will be completed:

- conduct a plant fire protection walkdown of the areas that could impact EDG availability, offsite power availability, or the ability to use the SBO cross-tie prior to entering the extended AOT;
- perform a thermographic examination of high risk potential ignition sources in the cable spreading room and the control room prior to entering the extended AOT;
- restrict planned hot work in the cable spreading room and control room during the extended AOT; and
- establish a continuous fire watch in the cable spreading room when in the extended AOT.

The NRC staff has determined that the four conditions relating to fire risk stated above are necessary to address fire risk in view of the insufficient detail and quality of the licensee's IPEEE with respect to fire risk, as described above. Therefore, the licensee has agreed to incorporate those conditions into its CRMP, which is the licensee's program for complying with Section 50.65(a)(4). In view of the above, the licensee shall not change the above conditions without prior NRC approval.

The licensee stated that in addition to the pre-determined restrictions above, assessments performed in accordance with its proposed CRMP will further ensure that any other risk significant configurations are identified before removing an EDG from service for pre-planned maintenance.

The staff finds that FPL's Tier 2 analysis was reasonable in identifying and evaluating potential risk significant configurations for internal initiating events. For fire the licensee committed to implement several significant compensatory measures to address the uncertainty in its fire risk analysis. These Tier 2 restrictions compensate for the shortcomings of the Tier 1 assessment which roughly measures the expected risk stemming from the proposed change. The Tier 3 assessment in turn complements the analyses of Tiers 1 and 2.

Tier 3: Risk-informed Plant Configuration Management

RG 1.177 states that the licensee should develop a program that ensures the risk impact of out-of-service equipment is appropriately evaluated prior to performing any maintenance activity. A CRMP consistent with the description in RG 1.177 is currently under development by FPL. The licensee indicated the primary tool for its CRMP would be the risk informed On-Line Risk Monitor. The CRMP and its elements would be described in the licensee's Administrative Procedure that ensures compliance with the Maintenance Rule. The licensee described the proposed CRMP in a letter submitted for the staff's review of the proposed risk-informed Low Pressure Safety Injection (LPSI) system AOT extension. The CRMP proposed for LPSI is considered acceptable for this amendment.

Implementation and Monitoring

The staff expects the licensee to implement this TS change in accordance with the three-tiered approach described above. To ensure that extension of this EDG AOT does not degrade operational safety over time, FPL should ensure that when an EDG does not meet its performance criteria, the evaluation required under the Maintenance Rule includes this EDG AOT TS change in its scope. If the licensee concludes that the performance or condition of a TS system or component affected by a TS change does not meet established performance criteria, appropriate corrective action should be taken, in accordance with the Maintenance Rule. Such corrective action could include consideration of another TS change to shorten the revised AOT, or imposition of a more restrictive administrative limit, if the licensee determines this is an important factor in reversing the negative trend.

3.4 Probabilistic Summary

The quality of the FPL PRA, in conjunction with the supplemental information that FPL provided in support of the proposed change in EDG AOT is sufficient to support the proposed change in the EDG AOT. In addition, the level of detail and scope of the PRA are appropriate for the proposed application. The staff did not identify any significant weaknesses or deficiencies associated with the licensee's risk analysis used to support the proposed change that could impact the overall quantitative conclusion. The results of the risk analysis indicate that the risk impact of the proposed change would be small. The staff found that the licensee's application met the intent of the applicable RGs 1.174 and 1.177, therefore, the staff concludes that risk results and insights support the proposed EDG AOT extension.

4.0 STATE CONSULTATION

Based upon a letter dated March 8, 1991, from Mary E. Clark of the State of Florida, Department of Health and Rehabilitative Services, to Deborah A. Miller, Licensing Assistant, NRC, the State of Florida does not desire notification of issuance of license amendments.

5.0 ENVIRONMENTAL CONSIDERATION

This amendment changes a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration and there has been no public comment on such finding (64 FR 70089). Accordingly, this amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of this amendment.

6.0 CONCLUSION

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

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