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

February 15, 2000

NRR-058

SUBJECT: ST. LUCIE UNITS 1 AND 2 - ISSUANCE OF AMENDMENTS REGARDING EXTENSION OF ALLOWED OUTAGE TIME (TAC NOS. M5678 AND M5679)

Dear Mr. Plunkett:

The Commission has issued the enclosed Amendment Nos. 164 and 106 to Facility Operating Licenses Nos. DPR-67 and NPF-16 for the St. Lucie Plant, Units Nos. 1 and 2. These amendments consist of changes to the Technical Specifications (TS) in response to your application dated June 1, 1999, as supplemented by letter dated September 25, 1999.

These amendments revise the St. Lucie, Units 1 and 2, TS 3.5.2 to allow up to 7 days to restore an inoperable low pressure safety injection train to operable status. This is a risk-informed TS amendment, based on a cooperative study by the Combustion Engineering Owners Group (CEOG) members. The work of the CEOG members culminated in a joint application report (CE NPSD-995) submitted to NRC on June 21,1995.

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,
/RA/
Kahtan N. Jabbour, Senior Project Manager, Section 2
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket Nos. 50-335
and 50-389

Enclosures: 1. Amendment No. 164 to DPR-67
2. Amendment No. 106 to NPF-16
3. Safety Evaluation w/Attachments 1 - 8

cc w/enclosures: See next page

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*See previous concurrence

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

February 15, 2000

Mr. T. F. Plunkett
President, Nuclear Division
Florida Power and Light Company
P.O. Box 14000
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Dear Mr. Plunkett:

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These amendments revise the St. Lucie, Units 1 and 2, TS 3.5.2 to allow up to 7 days to restore an inoperable low pressure safety injection train to operable status. This is a risk-informed TS amendment, based on a cooperative study by the Combustion Engineering Owners Group (CEOG) members. The work of the CEOG members culminated in a joint application report (CE NPSD-995) submitted to NRC on July 10, 1995.

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,

Kahtan N. Jabbour

Kahtan N. Jabbour, Senior Project Manager, Section 2
Project Directorate II
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

Docket Nos. 50-335
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cc w/enclosures: See next page

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

FLORIDA POWER & LIGHT COMPANY

DOCKET NO. 50-335

ST. LUCIE PLANT UNIT NO. 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 164
License No. DPR-67

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 June 1, 1999, as supplemented by letter dated September 25, 1999, 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. DPR-67 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. 164 , 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 30 days.

FOR THE NUCLEAR REGULATORY COMMISSION

Jed Wu for

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: **February 15, 2000**

ATTACHMENT TO LICENSE AMENDMENT NO. 164

TO FACILITY OPERATING LICENSE NO. DPR-67

DOCKET NO. 50-335

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 in the margins that show the changes.

Remove Pages	Insert Pages
3/4 5-3	3/4 5-3
3/4 5-5	3/4 5-5
B 3/4 5-1	B 3/4 5-1

ECCS SUBSYSTEMS - $T_{avg} \geq 325$ °F

LIMITING CONDITION FOR OPERATION

3.5.2 Two independent ECCS subsystems shall be OPERABLE with each subsystem comprised of:

a. One OPERABLE high-pressure safety injection (HPSI) pump,

b. One OPERABLE low-pressure safety injection pump, and

c. An independent OPERABLE flow path capable of taking suction from the refueling water tank on a Safety Injection Actuation Signal and automatically transferring suction to the containment sump on a Recirculation Actuation Signal.

APPLICABILITY: MODES 1, 2 and 3*.

ACTION:

a. 1. With one ECCS subsystem inoperable only because its associated LPSI train is inoperable, restore the inoperable subsystem to OPERABLE status within 7 days or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

2. With one ECCS subsystem inoperable for reasons other than condition a.1., restore the inoperable subsystem to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. In the event the ECCS is actuated and injects water into the Reactor Coolant System, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date.

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* With pressurizer pressure $\geq$ 1750 psia.

EMERGENCY CORE COOLING SYSTEMS

SURVEILLANCE REQUIREMENTS (continued)

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

1. Verifying that each automatic valve in the flow path actuates to its correct position on a Safety Injection Actuation Signal.

2. Verifying that each of the following pumps start automatically upon receipt of a Safety Injection Actuation Signal;

   a. High-Pressure Safety Injection Pump.

   b. Low-Pressure Safety Injection Pump.

3. Verifying that upon receipt of an actual or simulated Recirculation Actuation Signal: each low-pressure safety injection pump stops, each containment sump isolation valve opens, each refueling water tank outlet valve closes, and each safety injection system recirculation valve to the refueling water tank closes.

f. By verifying that each of the following pumps develops the specified total developed head on recirculation flow when tested pursuant to the Inservice Testing Program.

1. High-Pressure Safety Injection pumps: greater than or equal to 2571 ft.

2. Low-Pressure Safety Injection pumps: greater than or equal to 350 ft.

3/4.5.1 SAFETY INJECTION TANKS

The OPERABILITY of each of the RCS safety injection tanks ensures that a sufficient volume of borated water will be immediately forced into the reactor core through each of the cold legs in the event the RCS pressure falls below the pressure of the safety injection tanks. This initial surge of water into the core provides the initial cooling mechanism during large RCS pipe ruptures.

The limits on safety injection tank volume, boron concentration and pressure ensure that the assumptions used for safety injection tank injection in the accident analysis are met.

The limit of 72 hours for operation with an SIT that is inoperable due to boron concentration not within limits, or due to the inability to verify liquid volume or cover-pressure, considers that the volume of the SIT is still available for injection in the event of a LOCA. If one SIT is inoperable for other reasons, the SIT may be unable to perform its safety function and, based on probability risk assessment, operation in this condition is limited to 24 hours.

3/4.5.2 and 3/4.5.3 ECCS SUBSYSTEMS

The OPERABILITY of two separate and independent ECCS subsystems ensures that sufficient emergency core cooling capability will be available in the event of a LOCA assuming the loss of one subsystem through any single failure consideration. Either subsystem operating in conjunction with the safety injection tanks is capable of supplying sufficient core cooling to limit the peak cladding temperatures within acceptable limits for all postulated break sizes ranging from the double ended break of the largest RCS cold leg pipe downward. In addition, each ECCS subsystem provides long term core cooling capability in the recirculation mode during the accident recovery period.

TS 3.5.2, ACTION a.1. provides an allowed outage/action completion time (AOT) of up to 7 days from initial discovery of failure to meet the LCO provided the affected ECCS subsystem is inoperable only because its associated LPSI train is inoperable. This 7 day AOT is based on the findings of a deterministic and probabilistic safety analysis and is referred to as a "risk-informed" AOT extension. 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 (ADM-17.08) that implements the Maintenance Rule pursuant to 10 CFR 50.65.

The Surveillance Requirements provided to ensure OPERABILITY of each component ensure that at a minimum, the assumptions used in the accident analyses are met and that subsystem OPERABILITY is maintained.

The limitations on HPSI pump operability when the RCS temperature is $\leq$ 270°F and $\leq$ 236°F, and the associated Surveillance Requirements provide additional administrative assurance that the pressure/temperature limits (Figures 3.4-2a and 3.4-2b) will not be exceeded during a mass addition transient mitigated by a single PORV. A limit on the maximum number of operable HPSI pumps is not necessary when the pressurizer manway cover or the reactor vessel head is removed.

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

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. 106
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 June 1, 1999, as supplemented by letter dated September 25, 1999, 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. **106**, 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 30 days.

FOR THE NUCLEAR REGULATORY COMMISSION

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: **February 15, 2000**

ATTACHMENT TO LICENSE AMENDMENT NO. 106

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 in the margins that show the changes.

Remove Pages	Insert Pages
3/4 5-3	3/4 5-3
3/4 5-5	3/4 5-5
B 3/4 5-1	B 3/4 5-1

3/4.5.2 ECCS SUBSYSTEMS - T_{avg} GREATER THAN OR EQUAL TO 325°F

LIMITING CONDITION FOR OPERATION

3.5.2 Two independent Emergency Core Cooling System (ECCS) subsystems shall be OPERABLE with each subsystem comprised of:

a. One OPERABLE high pressure safety injection pump,

b. One OPERABLE low pressure safety injection pump, and

c. An independent OPERABLE flow path capable of taking suction from the refueling water tank on a Safety Injection Actuation Signal and automatically transferring suction to the containment sump on a Recirculation Actuation Signal, and

d. One OPERABLE charging pump.

APPLICABILITY: MODES 1, 2, and 3*.

ACTION:

a. 1. With one ECCS subsystem inoperable only because its associated LPSI train is inoperable, restore the inoperable subsystem to OPERABLE status within 7 days or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

2. With one ECCS subsystem inoperable for reasons other than condition a.1., restore the inoperable subsystem to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. In the event the ECCS is actuated and injects water into the Reactor Coolant System, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date. The current value of the usage factor for each affected safety injection nozzle shall be provided in this Special Report whenever its value exceeds 0.70.

* With pressurizer pressure greater than or equal to 1750 psia.

SURVEILLANCE REQUIREMENTS (continued)

2. A visual inspection of the containment sump and verifying that the subsystem suction inlets are not restricted by debris and that the sump components (trash racks, screens, etc.) show no evidence of structural distress or corrosion.

3. Verifying that a minimum total of 173 cubic feet of solid granular trisodium phosphate dodecahydrate (TSP) is contained within the TSP storage baskets.

4. Verifying that when a representative sample of 70.5 $\pm$ 0.5 grams of TSP from a TSP storage basket is submerged, without agitation, in 10.0 $\pm$ 0.1 gallons of 120 $\pm$ 10°F borated water from the RWT, the pH of the mixed solution is raised to greater than or equal to 7 within 4 hours.

f. At least once per 18 months, during shutdown, by:

1. Verifying that each automatic valve in the flow path actuates to its correct position on SIAS and/or RAS test signals.

2. Verifying that each of the following pumps start automatically upon receipt of a Safety Injection Actuation Test Signal:

a. High-Pressure Safety Injection pump.

b. Low-Pressure Safety Injection pump.

3. Verifying that upon receipt of an actual or simulated Recirculation Actuation Signal: each low-pressure safety injection pump stops, each containment sump isolation valve opens, each refueling water tank outlet valve closes, and each safety injection system recirculation valve to the refueling water tank closes.

g. By verifying that each of the following pumps develops the specified total developed head on recirculation flow when tested pursuant to the Inservice Testing Program:

1. High-Pressure Safety Injection pumps: greater than or equal to 2854 ft.

2. Low-Pressure Safety Injection pump: greater than or equal to 374 ft.

h. By verifying the correct position of each electrical and/or mechanical position stop for the following ECCS throttle valves:

1. During valve stroking operation or following maintenance on the valve and prior to declaring the valve OPERABLE when the ECCS subsystems are required to be OPERABLE.

3/4.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

BASES

3/4.5.1 SAFETY INJECTION TANKS

The OPERABILITY of each of the Reactor Coolant System (RCS) safety injection tanks ensures that a sufficient volume of borated water will be immediately forced into the reactor core through each of the cold legs in the event the RCS pressure falls below the pressure of the safety injection tanks. This initial surge of water into the core provides the initial cooling mechanism during large RCS pipe ruptures.

The limits on safety injection tank volume, boron concentration, and pressure ensure that the assumptions used for safety injection tank injection in the safety analysis are met.

The safety injection tank power-operated isolation valves are considered to be "operating bypasses" in the context of IEEE Std. 279-1971, which requires that bypasses of a protective function be removed automatically whenever permissive conditions are not met. In addition, as these safety injection tank isolation valves fail to meet single failure criteria, removal of power to the valves is required.

The limit of 72 hours for operation with an SIT that is inoperable due to boron concentration not within limits, or due to the inability to verify liquid volume or cover-pressure, considers that the volume of the SIT is still available for injection in the event of a LOCA. If one SIT is inoperable for other reasons, the SIT may be unable to perform its safety function and, based on probability risk assessment, operation in this condition is limited to 24 hours.

3/4.5.2 and 3/4.5.3 ECCS SUBSYSTEMS

The OPERABILITY of two separate and independent ECCS subsystems ensures that sufficient emergency core cooling capability will be available in the event of a LOCA assuming the loss of one subsystem through any single failure consideration. Either subsystem operating in conjunction with the safety injection tanks is capable of supplying sufficient core cooling to limit the peak cladding temperatures within acceptable limits for all postulated break sizes ranging from the double-ended break of the largest RCS hot leg pipe downward. In addition, each ECCS subsystem provides long-term core cooling capability in the recirculation mode during the accident recovery period.

TS 3.5.2, ACTION a.1. provides an allowed outage/action completion time (AOT) of up to 7 days from initial discovery of failure to meet the LCO provided the affected ECCS subsystem is inoperable only because its associated LPSI train is inoperable. This 7 day AOT is based on the findings of a deterministic and probabilistic safety analysis and is referred to as a "risk-informed" AOT extension. 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 (ADM-17.08) that implements the Maintenance Rule pursuant to 10 CFR 50.65.

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENTS NOS.164 AND 106

TO FACILITY OPERATING LICENSES NOS. DPR-67 AND NPF-16

FLORIDA POWER AND LIGHT COMPANY, ET AL.

ST. LUCIE PLANT, UNITS NOS. 1 AND 2

DOCKET NOS. 50-335 AND 50-389

1.0 INTRODUCTION

By application dated June 1, 1999, as supplemented by letter dated September 25, 1999, regarding the low pressure safety injection (LPSI) system, the Florida Power and Light Company, et al., (licensee, FPL) requested changes to the Technical Specifications (TSs) (Appendix A to Facility Operating Licenses Nos. DPR-67 and NPF-16) for the St. Lucie Plant, Units 1 and 2.

The proposed changes would modify the TSs to extend the allowed outage times (AOTs) for a single LPSI train from 72 hours to 7 days. As part of its amendment request, the licensee has also committed to implement a Configuration Risk Management Program (CRMP) that puts a proceduralized probabilistic risk assessment-informed process in place that ensures the licensee assesses the overall impact of plant maintenance on plant risk. The supplemental September 25, 1999, letter provided additional information that did not expand the scope of the Amendment request beyond the initial notice or change the initial proposed no significant hazards consideration determination.

2.0 BACKGROUND

Since the mid-1980s, the U.S. Nuclear Regulatory Commission (NRC) has been reviewing and granting improvements to TSs that are based, at least in part, on probabilistic risk assessment (PRA) insights. In its final policy statement on TS improvements of July 22, 1993, the Commission stated:

> "licensees, in preparing their Technical Specification related submittals, will utilize any plant-specific probabilistic safety assessment[1] (PSA) or risk survey and any available literature on risk insights and PSAs. . . . Similarly, the NRC staff will also employ risk insights and PSAs in evaluating Technical Specifications related submittals. Further, as a part of the Commission's ongoing program of improving Technical Specifications, it will continue to consider methods to make better use of risk and reliability information for defining future generic Technical Specification requirements."

[1]PSA and PRA are used interchangeably herein.

The NRC reiterated these points when it issued the revision to Title 10, Code of Federal Regulations (10 CFR) Section 50.36, "Technical Specifications," in July 1995 (60 FR 36953). In August 1995, the NRC adopted a final policy statement on the use of PRA methods in nuclear regulatory activities that encouraged greater use of PRA to improve safety decision-making and regulatory efficiency (60 FR 42622). The PRA policy statement included the following points:

1. The use of PRA technology should be increased in all regulatory matters to the extent supported by the state of the art in PRA methods and data and in a manner that complements the NRC's deterministic approach and supports the NRC's traditional defense-in-depth philosophy.

2. PRA and associated analyses (e.g., sensitivity studies, uncertainty analyses, and importance measures) should be used in regulatory matters, where practical within the bounds of the state of the art, to reduce unnecessary conservatism associated with current regulatory requirements.

3. PRA evaluations in support of regulatory decisions should be as realistic as practicable and appropriate supporting data should be publicly available for review.

In August 1995, the Combustion Engineering Owners Group (CEOG) submitted several Joint Application Reports for staff's review. Two of the CEOG Joint Application Reports provided justifications for extensions of the TS AOTs for safety injection tanks (SITs) and for the LPSI system.[2] The justifications for these extensions are based on a balance of probabilistic considerations, traditional engineering considerations, including defense-in-depth, and operating experience. Risk assessments for all of the Combustion Engineering (CE) plants are contained in the reports. The staff first reviewed the Joint Application Reports and then reviewed the licensee's plant-specific amendment request which incorporated the Joint Application Reports by reference.

Arkansas Nuclear One, Unit 2 (ANO-2), had been the lead CE plant for the SIT and LPSI system TS changes. The staff performed an in-depth review of the ANO-2 PRA methodology relating to these changes, as the lead plant for all of the CEOG. Therefore, a portion of the review of this amendment request was based on a comparison of the St. Lucie, Units 1 and 2, PRA results with those from ANO-2.

3.0 PROPOSED CHANGES

3.1 TS 3.5.2 - "ECCS Subsystems - $T_{avg} \geq 325°F$"

The licensee proposes extending the TS completion time for one inoperable LPSI train from 72 hours to 7 days.

TS 3.5.2, ACTION a., for St. Lucie, Unit 1, currently reads as follows:

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[2]CE NPSD-994, "Joint Application Report for Safety Injection Tank AOT/STI Extension," May 1995, and CE NPSD-995, "Joint Application Report for Low Pressure Safety Injection System AOT Extension," May 1995.

a.1. With one ECCS subsystem inoperable, restore the inoperable subsystem to OPERABLE status within 72 hours or be in HOT STANDBY within the next 12 hours (St. Lucie, Unit 2, TS adds: and in HOT SHUTDOWN within the following 6 hours).

TS 3.5.2, ACTION a. will be revised to include a 7-day risk-informed AOT as follows:

a.1. With one ECCS subsystem inoperable only because its associated LPSI train is inoperable, restore the inoperable subsystem to OPERABLE status within 7 days or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

a.2. With one ECCS subsystem inoperable for reasons other than condition a.1., restore the inoperable subsystem to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

3.2 TS Bases 3/4.5.2 and 3/4.5.3 - "ECCS SUBSYSTEMS"

The licensee proposes adding a reference to a CRMP to TS Bases Sections 3/4.5.2 and 3/4.5.3, "ECCS SUBSYSTEMS," of the St. Lucie TSs. The purpose of the CRMP is to ensure that a proceduralized PRA-informed process is in place that assesses the overall impact of plant maintenance on plant risk. The proposed paragraph to be added reads as follows:

TS 3.5.2, ACTION a.1. provides an allowed outage/action completion time (AOT) of up to 7 days from initial discovery of failure to meet the LCO provided the affected ECCS subsystem is inoperable only because its associated LPSI train is inoperable. This 7-day AOT is based on the findings of a deterministic and probabilistic safety analysis and is referred to as a "risk-informed" AOT extension. 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 (ADM-17.08) that implements the Maintenance Rule pursuant to 10 CFR 50.65.

4.0 EVALUATION

The staff evaluated the licensee's proposed amendment to the TSs using a combination of evaluation tools including traditional engineering considerations, PRA methods, and a review of operating experience. The staff used insights derived from both traditional engineering considerations and the use of PRA methods to determine the safety impact of extending the AOTs for one inoperable LPSI train.

4.1 Justification for Proposed Change to LPSI Train Completion Time from 72 Hours to 7 Days

The current St. Lucie, Units 1 and 2, TSs address the LPSI system as a portion of the emergency core cooling system (ECCS). TS 3.5.2 requires two independent ECCS subsystems (trains) to be operable. One operable ECCS train is made up of one operable high pressure safety injection pump, one operable LPSI pump, and an operable independent flow path from the refueling water storage tank on a safety injection actuation signal, or from the containment sump on a recirculation actuation signal. With one ECCS train inoperable, on the basis of any component inoperability but at least 100 percent of the ECCS flow equivalent to a single operable ECCS train available, the train must be returned to operable status within 72 hours or a plant shutdown is required. The proposed change will allow up to 7 days for the licensee to restore operability to the inoperable LPSI train that is the cause of ECCS train inoperability.

The primary role of the LPSI system during power operation is to contribute to the mitigation of a large loss-of-coolant accident (LOCA). The postulated frequency of a large LOCA event is on the order of 10^{-4} per year. In contrast, during Modes 5 and 6, the operability of at least one LPSI train operating in the shutdown cooling mode is required at all times for reactor coolant system (RCS) heat removal. Thus, in the broad view, performing preventive and corrective maintenance at power on the LPSI system can contribute to an overall enhancement of plant safety by increasing the availability of at least one LPSI train for shutdown cooling (SDC) when it is needed in Modes 5 and 6.

In some instances, corrective maintenance of the LPSI pump and valves and testing of valves may require taking one train of LPSI out of service for more than several days. Thus, repair within the allowed outage time cannot be ensured and may result in an unscheduled plant shutdown or a request for NRC enforcement discretion to allow continued plant operation while repairs are completed. To avoid these situations, the licensee is requesting a longer AOT. On the basis of the review of maintenance requirements of the LPSI train for CE pressurized water reactors, the licensee determined that a 7-day AOT would provide sufficient margin to effect most anticipated preventive and corrective maintenance activities and LPSI train valve surveillance tests at power.

4.2 LPSI System Evaluation

The two trains of the LPSI system, in combination with the two trains of the high pressure safety injection (HPSI) system, form two redundant ECCS trains. The two LPSI pumps are high volume, low head centrifugal pumps designed to supplement the SIT inventory in reflooding the reactor vessel to ensure core cooling during the early stages of a large break LOCA. The LPSI pumps take suction from the refueling water storage tank (RWST), during the injection phase of a LOCA event, and pump the water through a common discharge header. Once inside containment, the LPSI headers combine with HPSI and SIT discharge piping, and flow is directed through independent injection headers into each of the four reactor coolant system (RCS) cold legs and into the reactor vessel. The LPSI system pumps start and valves open upon receipt of a safety injection actuation signal. When the RWST level is drawn down by inventory transfer during the injection phase, a low RWST level actuates a recirculation actuation signal which stops the LPSI pumps. This step is necessary to ensure adequate net positive suction head remains available for the HPSI pumps and the containment spray pumps. By design, post-LOCA long term core cooling is supplied by the HPSI pumps and containment spray pumps taking suction from the containment sump.

Another role of the LPSI system is defining the end state for a design basis steam generator tube rupture (SGTR) event. In this design basis event, the HPSI functions to keep the core covered at all times, and the LPSI system is required to effect SDC and thereby terminate the event. SDC is initiated after the break has been isolated and the radioactive releases have been controlled within the containment building.

In the event that one LPSI train is out of service and the second LPSI train fails, the operator can continue to control the plant during an SGTR event by drawing steam off of the unaffected steam generator. Even though loss of both LPSI trains is beyond the design basis accident assumptions, this cooling mechanism can be maintained indefinitely, provided condensate is available to the unaffected steam generator. Without considering condensate storage tank replenishment, St. Lucie, Units 1 and 2, have a sufficient inventory to steam the unaffected steam generator for more than 24 hours. St. Lucie, Units 1 and 2, also have the ability to realign the containment spray pumps to provide RCS SDC capability. Therefore, having one LPSI train out of service should not affect the licensee's ability to mitigate an SGTR event, including conditions beyond design basis.

In addition to responding to accidents, the most common use of the LPSI system is during normal shutdown operations (Modes 4, 5, and 6), when the LPSI system is used for decay heat removal in the SDC alignment. The fact that the LPSI system is required for decay heat removal every time the plant is placed in cold shutdown indicates that it would be prudent to perform maintenance on the LPSI system during power operations rather than during shutdown when the demand for the system is at its highest.

Based on the above, the staff concludes that extending the completion time for one inoperable LPSI train from 72 hours to 7 days should continue to ensure defense-in-depth is maintained and sufficient safety margin exists to meet the design basis analysis for the St. Lucie, Units 1 and 2, ECCS.

4.3 Evaluation of the PRA Used to Support the Proposed TS Changes

The staff used a three-tiered approach to evaluate the risk associated with the proposed TS changes. The first tier evaluated the PRA model and the impact of the completion time extensions for the LPSI system and SITs on plant operational risk. The second tier addressed the need to preclude potentially high risk configurations by identifying the need for any additional constraints or compensatory actions that, if implemented, would avoid or reduce the probability of a risk-significant configuration during the time when one LPSI train is out of service. The third tier evaluated the licensee's configuration risk management program to ensure that the applicable plant configuration will be appropriately assessed from a risk perspective before entering into or during the proposed AOTs. Each tier and the associated findings are discussed below.

4.3.1 Cross Comparison Approach

After completing a detailed evaluation for the tentative approval of SIT and LPSI TS AOT extensions for ANO-2, the original CEOG lead plant for the risk-informed TS pilot project, the staff used a cross-comparison approach to consider the viability of similar AOT relaxations for other participating CEOG plants, including St. Lucie, Units 1 and 2. The pilot technical evaluation report[3] used in support of the staff's draft safety evaluation for ANO-2[4] focused on:

- the process adopted by the CEOG to assess single AOT risk,
- the identification of ANO-2 accident sequences in which credit was taken for SITs and LPSI,
- independent verification of the single AOT risk [essentially equivalent to incremental conditional core damage probability (ICCDP)[5]], and
- determination of the significance of single AOT risk relative to an acceptance guideline value.

The objective of this cross-comparison evaluation is to use insights derived from the ANO-2 technical evaluation to examine the validity of the conclusions drawn in the joint submittals. Because a common methodology was employed by the CEOG to quantify AOT risk and because CE plants generally have similar design characteristics, the staff believes that the findings of the lead pilot plant evaluation will be generally applicable to other CE plants. The staff confirmed that differences in the underlying PRA models are chiefly attributed to:

- minor design differences,
- operational differences,
- success criteria assumptions, and
- common cause failure β-factor assumptions.

The cross comparison draws on information contained in the CEOG Joint Application Reports, the licensees' responses to the staff's requests for additional information, the licensees' individual plant examinations (IPEs) performed in response to Generic Letter (GL) 88-20, "Individual Plant Examination for Severe Accident Vulnerabilities," and the corresponding IPE evaluations performed by the staff.

4.3.2 Impact of LPSI on Tier 1, 2, and 3 Requirements

The following factors are chiefly responsible for the differences in LPSI AOT risks among the CE plants:

- use of LPSI to mitigate multiple initiating events,
- HPSI redundancies, and
- LPSI common cause β-factor assumptions.

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[3]SCIE-NRC-318-97, "Technical Evaluation of Combustion Engineering Owners Group (CEOG) Joint Application for Safety Injection Tanks and Low Pressure Safety Injection System Allowed Outage Time (AOT) Extension," July 21, 1997.

[4]SECY-97-095, "Probabilistic Risk Assessment Implementation Plan Pilot Application for Risk-Informed Technical Specifications," April 30, 1997.

[5]ICCDP = [(conditional CDF with the subject equipment out of service) - (baseline CDF with nominal expected equipment unavailabilities)] X (duration of single AOT under consideration).

The LPSI preventive and corrective maintenance (staff-estimated) weighted average single AOT risks for St. Lucie, Units 1 and 2, are 8.74E-08 for Unit 1 and 8.36E-08 for Unit 2, and are less than the acceptance guideline value 5.0E-07 from Regulatory Guide (RG) 1.177. In addition, the change in the St. Lucie, Units 1 and 2, updated baseline core damage frequency (CDF) (as reported in the CEOG Joint Application Report) due to the LPSI AOT change is about 3%, i.e., from 2.14E-05 per year for Unit 1 and 2.35E-05 per year for Unit 2 to 2.2E-05 per year for Unit 1 and 2.4E-05 per year for Unit 2. The change in CDF of 6E-07 per year for Unit 1 and 5E-07 per year for Unit 2 is within the acceptance guidelines published in RG 1.174. The staff-estimated weighted average incremental conditional large early release probabilities (ICLERPs) are 2.12E-09 for Unit 1 and 1.46E-09 for Unit 2, assuming a baseline early containment failure probability (ECFP) of 0.01. Corresponding ICLERPs for an ECFP of 0.1 are 9.95E-09 for Unit 1 and 8.95E-09 for Unit 2. All of these ICLERP values are within the RG 1.177 guideline of 5.0E-08.

The Tier 2 evaluation did not identify the need for any additional constraints or compensatory actions that, if implemented, would avoid or reduce the probability of a risk-significant configuration.

The Tier 3 requirements for configuration risk management are considered to be adequately satisfied, since the licensee has an on-line PRA-based monitor, called the Safety Monitor, to analyze the risk impact of outage configurations in a timely manner. Procedures related to use of the Safety Monitor are St. Lucie, Units 1 and 2, Plant Administrative Procedure, ADM-17.08, "Implementation of 10 CFR 50.65, the Maintenance Rule." The licensee has proposed adding TS Bases 3/4.5.2 and B 3/4.5.3, "ECCS SUBSYSTEMS," to provide a means of implementing and controlling their Tier 3 process. The licensee and the staff have agreed to implementation of the CRMP as described below.

Purpose of CRMP

The purpose of the CRMP is to ensure that a proceduralized PRA-informed process is in place that assesses the overall impact of plant maintenance on plant risk. Implementation of the CRMP will enable appropriate actions to be taken or decisions to be made to minimize and control risk when performing on-line maintenance for systems, structures, and components (SSCs) with a risk-informed completion time.

Scope of CRMP

The scope of the SSCs included in the CRMP are those SSCs modeled in the licensee's plant PRA in addition to those SSCs considered of high safety significance per RG 1.160, Revision 2, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," that are not modeled in the PRA.

The CRMP includes the following components and key elements:

a. Provisions for the control and implementation of a Level 1 at-power internal events PRA-informed methodology. The assessment is to be capable of evaluating the applicable plant configuration.

b. Provisions for performing an assessment prior to entering the plant configuration described by the Limiting Conditions for Operation (LCO) Action Statement for preplanned activities.

c. Provisions for performing an assessment after entering the plant configuration described by the LCO Action Statement for unplanned entry into the LCO Action Statement.

d. Provisions for assessing the need for additional actions after the discovery of additional equipment out-of-service conditions while in the plant configuration described by the LCO Action Statement.

e. Provisions for considering other applicable risk-significant contributors such as Level 2 issues and external events, qualitatively or quantitatively.

Key Element 1. Implementation of CRMP

The intent of the CRMP is to implement Maintenance Rule, Section 50.65(a)(4) of 10 CFR with respect to on-line maintenance for risk-informed technical specifications, with the following additions and clarifications:

a. The scope of the SSCs to be included in the CRMP will be those SSCs modeled in the licensee's plant PRA in addition to those SSCs considered to be of high safety significance per RG 1.160, Revision 2, that are not modeled in the PRA.

b. The CRMP assessment tool is PRA informed, and may be in the form of either a risk matrix, an on-line assessment, or a direct PRA assessment.

c. CRMP will be invoked as follows for:

   Risk-Informed Inoperability: A risk assessment will be performed prior to entering the LCO condition for preplanned activities. For unplanned entry into the LCO condition, a risk assessment will be performed in a time frame consistent with the plant's Corrective Action Program.

   Additional SSC Inoperability and/or Loss of Functionality: When in the risk-informed completion time, if an additional SSC within the scope of the CRMP becomes inoperable/non-functional, a risk assessment shall be performed in a time frame consistent with the plant's Corrective Action Program.

d. Tier 2 commitments apply to planned maintenance only, but will be evaluated as part of the Tier 3 assessment for unplanned occurrences.

Key Element 2. Control & Use of the CRMP Assessment Tool

a. Plant modifications and procedure changes will be monitored, assessed, and dispositioned.

- Evaluation of changes in plant configuration or PRA model features can be dispositioned by implementing PRA model changes or by the qualitative assessment of the impact of the changes on the CRMP assessment tool. This qualitative assessment recognizes that changes to the PRA take time to implement and that changes can be effectively compensated for without compromising the ability to make sound engineering judgments.

- Limitations of the CRMP assessment tool are identified and understood for each specific completion time extension.

b. Procedures exist for the control and application of CRMP assessment tools, including description of the process when outside the scope of the CRMP assessment tool.

Key Element 3. Level 1 Risk-Informed Assessment

The CRMP assessment tool is based on a Level 1, at power, internal events PRA model. The CRMP assessment may use any combination of quantitative and qualitative input. Quantitative assessments can include reference to a risk matrix, pre-existing calculations, or new PRA analyses.

a. Quantitative assessments should be performed whenever necessary for sound decision making.

b. When quantitative assessments are not necessary for sound decision making, qualitative assessments will be performed. Qualitative assessments will consider applicable, existing insights from quantitative assessments previously performed.

Key Element 4. Level 2 Issues/External Events

External events and Level 2 issues are treated qualitatively and/or quantitatively.

Guidance for implementing the CRMP is provided by plant procedures.

4.3.3 <u>Evaluation of PRA Quality</u>

a. Verification that the PRA reflects the as-built/as-operated plant:

Section 3.2.2 of the licensee's original submittal addressed this subject as follows:

The St. Lucie contribution to the 1995 preparation of CE NPSD-995 (Reference 2) was generated using the IPE models developed in response to GL 88-20, *Individual Plant Examination for Severe Accident Vulnerabilities,* and associated supplements. Subsequently, in 1997 the NRC completed its review of the GL 88-20 submittals and in a letter to FPL dated July 21, 1997, Subject: Staff Evaluation Report of St. Lucie, Units 1 and 2, Individual Plant Examination (IPE) Submittal - TAC Nos. M74473 and M74474, the NRC staff stated, "The NRC staff concluded that the FPL IPE process is capable of identifying the most likely severe accident vulnerabilities for St. Lucie, Units 1 and 2, and, therefore, meets the intent of GL 88-20."

Since then, FPL has updated both the models and the reliability/unavailability databases for St. Lucie, Units 1 and 2. The updated models and databases were then used to re-calculate the risk numbers for the units. A summary of the major changes (also discussed in Reference 1) is provided in the response to part b., below, and additional discussion regarding PSA updates is provided in part d., below.

The licensee's September 25, 1999, letter provided the following additional information:

Before performing the risk assessment, the licensee reviewed all design changes implemented since the last PRA update and reviewed current revisions of the critical procedures which establish requirements and timing for operator recovery actions. No model changes were required as a result of this review.

b. Updates of the PRA since the last review cycle, including corrections of weaknesses identified by past reviews:

The original licensee's submittal provided a summary of the model updates. This includes several items previously considered to be weaknesses. The most significant change included with each model update is the creation of a "one-top" model which is constructed from the original model's individual top events for various initiators, e.g., small LOCA, large LOCA, SGTR, reactor trips, etc. The one-top model allows rapid quantification, and each case for this re-evaluation of LPSI was individually quantified. The truncation used for quantification was 2E-10 or lower. This replaces the use of one master cutset file (per unit) in the original (1995) CEOG evaluation.

The model update process included a review of all plant design changes that were implemented since creation of the original models. Due to the maturity of the St. Lucie units, only one plant design change was implemented (Unit 2) that resulted in a notable impact on the analysis results, and is discussed in the following summary of significant changes. For the reliability/unavailability database update, the licensee was able to use the last 3 years of data gathered, pursuant to the Maintenance Rule (10 CFR 50.65), which provided concise, high-quality unavailability and reliability data for the risk-significant systems. Outside peer review was not performed for the update because creating a one-top model essentially involved combining the existing tops for the various scenarios, and other model changes that were implemented were not extensive. A summary of significant model changes relevant to the LPSI AOT extension follows:

Test & Maintenance (T&M) events for selected equipment were added to better support Maintenance Rule implementation and related risk evaluations. Minor improvements were made in the modeling of instrument air systems and in the handling of common cause events.

New initiating event (IE) frequencies were calculated for all LOCAs. This was done in accordance with CEOG Probabilistic Safety Assessment Working Group (PSAWG) Technical Position Paper, "*Evaluation of the Initiating Event Frequency for the Loss of Coolant Accident*," CEOG Task 941, January 1997. Although the IE frequency for two LOCA sizes (large and small) decreased, the net impact was an increase in the total LOCA IE frequency of nearly 48%, i.e., from 2.09E-3 to 3.09E-3 per year.

The process of adding recoveries is now automated using a recovery "rule file." The rule file utilizes a manual recovery action process in that recovery actions are added to each cutset rather than being generated from the model, but the process is automated such that all the similar cutset scenarios are recovered automatically. This automatic feature ensures uniform and complete inclusion of recovery actions throughout all of the generated cutsets, and yields more realistic and consistent results.

The licensee re-evaluated all offsite power recovery cases for both St. Lucie units. One case was added to the Unit 1 analysis for recovery of offsite power in 9 hours (approximately 1 hour before the Unit 1 condensate storage tank (CST) would deplete without condensate replenishment). The non-recovery probability for one case was increased for both units due to an incorrect assumption that was used in the original analysis. In addition, the related recovery for getting power from the alternate unit was increased due to timing considerations. Although 60 minutes total is available (as assumed in the original evaluation), only 45 minutes remain for power recovery after diagnosis of the event per the plant Emergency Procedures. This factor was combined with hardware-related failures to calculate the total non-recovery probability of 0.1 for the crosstie recovery event.

For Unit 2, a plant design change was made that requires the SDC suction cross-connect valve to be locked open. The valve was normally closed during power operations, and this action was taken in response to concerns raised by GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power Operated Gate Valves." The modification also included a requirement to remove electrical power from each of the SDC suction isolation valve actuators by locking open their associated motor control circuit breakers. The intersystem-LOCA (ISLOCA) calculations were revised to include the plant design change. This resulted in an increase in the ISLOCA frequency. However, the plant design change prevents inadvertent opening of the SDC suction valves during power operations and improves the ability to initiate shutdown cooling operations for events involving loss of one train of electrical power. These factors were judged to offset the calculated risk increase such that the net change to ISLOCA is at least risk neutral.

The net effect of the modeling changes caused a slight increase in the calculated CDF. However, when the data update was completed, including all other initiating events, the final result was a decrease in the calculated CDF for both units.

The licensee's September 25, 1999, letter provided the following additional information:

The licensee addressed an issue in the NRC SER for the IPE regarding the IE frequency used for loss of a DC bus. The IE frequency used in the IPE was based on the generic bus failure probability over a year. As part of the PSA update, a fault tree was used to assess a new IE frequency for loss of a DC bus. The revised loss of DC bus IE frequency was incorporated in the previous PSA update and is, therefore, reflected in the LPSI AOT extension evaluation. The new Loss of DC Bus IE frequency is 1.07E-03 per year compared to the IPE value of 3.94E-04 per year. It is judged that this re-assessment corrects the perceived deficiency identified by the staff and thus no further action is required.

The licensee performed a sensitivity study covering selected operator actions. The actions chosen were either related to LPSI system operation or were questioned by the staff in the SER for the St. Lucie IPE. The operator actions modified are listed in the following table.

Operator Actions Reviewed for LPSI Sensitivity Study			
Operator Action	Description (Probabilities)	Old Value	New Value for Sensitivity Study
RTOP1[2]RLTC	Failure to initiate shutdown cooling for SGTR	7.5E-04	1.0E-02
RTOP1TLTC (N/A ON UNIT 2)	Failure to initiate shutdown cooling for transients	1.22E-02	1.22E-02
RTOP1[2]S1LTC	Failure to initiate shutdown cooling for S1 LOCA	7.5E-04	1.0E-02
RTOP1[2]ROTC	Failure to initiate once- through cooling for SGTR	7.5E-03	5.0E-02
RTOP1[2]TOTC	Failure to initiate once- through cooling - transients	7.5E-03	5.0E-02
RTOP1[2]S1OTC	Failure to initiate once- through cooling - S1 LOCA	7.5E-03	5.0E-02
R#CAFWMAN	Failure to manually operate steam driven AFW pump	7.88E-02	2.0E-01
R#AFXVLVS	Failure to manually operate AFW cross-connect valves	3.68E-02	1.0E-01
R#AFWCMP	Failure to manually actuate AFW components (Control Room action)	3.0E-03	3.0E-02
RTOP1[2]S1RCP	Failure to stop RCPs on loss of sealing water	3.0E-4	1.0E-02
U2XTSDC	U2 SDC Failure on LOG, no CST water for U1 LTC	5.58E-02	2.43E-01

For this operator action sensitivity study, three operator actions directly related to SDC were evaluated. These are the first three in the table of Operator Actions Reviewed for LPSI Sensitivity Study above (RTOP1[2]RLTC, RTOP1TLTC, and RTOP1[2]S1LTC, where [2] indicates Unit 2). New values for these actions were chosen by the licensee to give a significant increase (approximately two orders of magnitude) to the failure probabilities for initiating SDC for SGTR and S1 (small small LOCA). It should be noted that RTOP1TLTC (not used for Unit 2) was originally quantified as a time-dependent action whereas the other two were initially considered as time independent, causing the original values to be smaller. Using a time-dependent approach brings those two in line with the failure probability for SDC initiation following transients (RTOP1TLTC).

The next three operator actions (RTOP1[2]ROTC, RTOP1[2]TOTC, and RTOP1[2]S1OTC) are not directly related to SDC. However, once-through cooling (OTC) is one means of cooling down to SDC conditions. The above actions were quantified as "slips" (i.e., time-independent actions) for the St. Lucie IPE. The staff concluded in the St. Lucie IPE SER that treating post-initiator human actions with a time-independent approach is "troublesome" since the approach does not model diagnosis and decision-making and has the potential to over-estimate the likelihood of success. Another observation made by the staff was that the quantification of the above actions was not sequence-specific, i.e., the same probability was used for all sequences thus not considering potential differences in time for diagnosis and the available time to complete the action. Although these actions are not specifically related to an LPSI pump/system being out-of-service in most cases, they could have an impact on the overall PSA results and are thus included in this study.

For OTC initiation, the licensee agrees with the staff conclusion that the timing is scenario-specific. The most limiting case would be a total loss of main feedwater resulting in a unit trip on low SG level. OTC must be initiated before SG dryout (approximately 19-20 minutes). The only IEs that would result in this scenario are related to loss of main feedwater. For all other IEs, the reactor trip would occur with at least normal operating SG level and, thus, the available time to initiate OTC would be lengthened. For some scenarios, the initiation of OTC may be several hours after shutdown, when the decay heat is substantially lower than immediately after the trip. Since analysis of multiple OTC recovery actions based on various OTC timing assumptions will not be completed in time to support this amendment request, a representative and conservative timing assumption will be used for this sensitivity study. Applying the time-dependent technique used for the St. Lucie IPE and assuming 20 minutes to SG dryout, a conservative 15-minute diagnosis time (thus 5 minutes available for performing the action), and a 2-minute response time, the estimated non-recovery probability would be approximately 2E-02. This timing would actually only apply to the t=0 loss of all feedwater events (i.e., reactor trip on low SG level). For longer-term loss of feedwater scenarios, the available time would be longer. For this operator action sensitivity study, a conservative value of 5E-02 for all OTC recovery events was used. The benefit of performing sequence-specific quantification of OTC recovery events will be evaluated as part of a future PSA update.

The next three selected operator actions (R#CAFMAN, R#AFXVLVS, and R#AFWCMP) are for the Auxiliary Feedwater (AFW) system. The non-recovery probability for these events was increased to address NRC concerns expressed in the IPE SER regarding timing. R#CAFWMAN involves manual local operation of the turbine driven ("C") AFW pump. The action is primarily associated with loss of DC control power to the pump. The dominant method of losing power would be battery depletion following loss of AC power to the battery chargers or charger failure. Battery depletion would be at least 4 hours after loss of the chargers. Decay heat level would be less than that immediately after a unit trip. The available time to recovery feedwater would, thus, be greater than the 60 minutes assumed for a t=0 loss of all feedwater. This basic event was originally quantified as an ex-control room action with a 10-minute diagnosis time, a 13-minute response time, and 50 minutes available time (assuming 60 minutes to recover feedwater). If it is assumed for this study that an additional 10 minutes is required for diagnosis (20 minutes total), 40 minutes would then be available to complete the action. This results in a revised probability of 0.12. A conservative value of 0.2 was used for this study. R#AFXVLVS involves opening (locally) AFW cross-connect valves after failure of a motor-driven AFW pump on one train and the failure of the AFW flow path to the SG on the other train. This action was quantified assuming a 10-minute response time and 55-minute available time. For this study, the response time was increased to 15 minutes and the available time was reduced to 50 minutes (i.e., 5 additional minutes assumed for diagnosis and 5 fewer minutes assumed for response). This results in a non-recovery probability of approximately 0.1 (baseline is 3.68E-02). R#AFWCMP involves the operator manually activating AFW components from the control room in the event of an automatic actuation failure. Since this action is well covered by procedures and training, it is judged that a one-decade increase, from 3E-03 to 3E-02, is conservative and is adequate for this study.

Action RTOP1S1RCP (RTOP2S1RCP) involves the operator securing the reactor coolant pumps (RCPs) after loss of Component Cooling Water (CCW) cooling to the pumps. It is assumed that the pumps must be secured within 10 minutes to prevent a seal LOCA, although industry events have shown that the pumps could operate longer than 10 minutes without catastrophic seal damage. Since this is an in-control room action clearly addressed by procedures, the operator action was assumed to be time-independent ("slip") for the St. Lucie IPE. For this study, it was assumed that this is a time-dependent in-control room response action requiring 3 minutes to diagnose (thus a 7-minute available time) and a 1-minute response time. The resulting non-recovery probability would be approximately 7E-03. For this study, a conservative value of 1E-02 was used.

The last event is U2XTSDC. This represents the probability of Unit 2 failing to reach shutdown cooling on a Loss of Grid thereby being unable to supply water from the Unit 2 CST to the Unit 1 AFW pump suction for long-term cooling (beyond about 9 hours). This was re-calculated assuming Unit 2 had one LPSI (SDC) pump out for maintenance. The new value for this basic event would become 2.43E-01 using this assumption. Although this is not an operator action, it is directly related to LPSI (SDC) operation and is appropriate for inclusion in this sensitivity study.

The sensitivity study results are shown in the following tables. All table numbers used correspond to the equivalent tables in the submittal with the addition of an "S" (for sensitivity), except Tables 1 and 2 are combined for this study.

TABLE 1S and 2S - CONDITIONAL CDF CONTRIBUTIONS OPERATOR ACTION SENSITIVITY STUDY		
	UNIT 1	UNIT 2
CURRENT AOT (DAYS)	3	3
PROPOSED AOT (DAYS)	7	7

TABLE 1S and 2S - CONDITIONAL CDF CONTRIBUTIONS OPERATOR ACTION SENSITIVITY STUDY				
BASELINE			3.47E-05	2.90E-05
(1)	CCDF/YR (1 TRAIN AVAILABLE)	CM (CASE 1A)	6.13E-05	4.59E-05
	PM (CASE 1B)	3.92E-05	3.21E-05	
(2)	CCDF/YR (1 TRAIN NEVER OUT FOR T/M)	CASE 2	3.47E-05	2.89E-05
(3)	INCREASE IN CDF/YR [= (1) - (2)]	CM	2.67E-05	1.70E-05
	PM	4.52E-06	3.24E-06	
(4)	SINGLE AOT RISK (CURRENT AOT) [= (3)/HR * CURRENT AOT HRS]	CM	2.19E-07	1.40E-07
	PM	3.71E-08	2.66E-08	
(5)	SINGLE AOT RISK (PROPOSED AOT) [= (3)/HR * PROPOSED AOT HRS]	CM	5.11E-07	3.26E-07
	PM	8.68E-08	6.21E-08	
(6)	ASSUMED DOWNTIME FREQUENCY (/YR/LPSI TRAIN)	CM	1	1
	PM	3	3	
(7)	YEARLY AOT RISK (CURRENT AOT) [= (4) * (6) * 2 TRAINS]	CM	4.38E-07	2.79E-07
	PM	2.23E-07	1.60E-07	
TABLE 1S and 2S - CONDITIONAL CDF CONTRIBUTIONS OPERATOR ACTION SENSITIVITY STUDY				
(8)	YEARLY AOT RISK (PROPOSED AOT) [= (5) * (6) * 2 TRAINS]	CM	1.02E-06	6.52E-07
	PM	5.20E-07	3.73E-07	

TABLE 1S and 2S - CONDITIONAL CDF CONTRIBUTIONS OPERATOR ACTION SENSITIVITY STUDY				
(9)	PROPOSED TOTAL DOWNTIME (HRS/YR/TRAIN)	CM	24	24
	PM	208	208	
(10)	ASSUMED MEAN DURATION (HRS/DOWNTIME EVENT) [= (9) / (6)]	CM	24	24
	PM	69	69	
(11)	SINGLE AOT RISK FOR ASSUMED MEAN DURATION [= (3)/HR * (10)]	CM	7.30E-08	4.66E-08
	PM	3.56E-08	2.55E-08	
(12)	YEARLY AOT RISK FOR ASSUMED MEAN DURATION [= (11) * (6) * 2 TRAINS]	CM	1.46E-08	9.31E-8
	PM	2.13E-07	1.53E-07	

RG 1.174 (Reference 3) discusses acceptance criteria for changes in CDF and large early release frequency (LERF). RG 1.174 indicates that a change in CDF of <1E-06 with a total CDF of <1E-04 and a change in LERF of <1E-7 with a total LERF of <1E-05 is considered very small. As shown in Table 3S, the change in the average CDF assuming the proposed LPSI unavailability is <1E-06 for the sensitivity study results. Table 4S shows that the change in the average LERF assuming the proposed LPSI unavailability is <1E-07 for the sensitivity study. The proposed change in CDF and LERF due to the proposed AOT extension is, therefore, considered very small.

Table 3S (Operator Action Sensitivity Study) PROPOSED AVERAGE CDF		
Parameter	St. Lucie Unit 1	St. Lucie Unit 2
LPSI System Success Criteria	1 of 2	1 of 2
Present AOT, days	3	3
Proposed AOT, days	7	7

Table 3S (Operator Action Sensitivity Study) PROPOSED AVERAGE CDF		
Proposed Downtime, hrs/train/yr.	232	232
Average CDF, base, per yr.	3.47E-05	2.90E-05
Proposed Average CDF, per yr., using LPSI T/M set at Proposed Downtime-value	3.49E-05	2.91E-05

Table 4S (Operator Action Sensitivity Study) PROPOSED AVERAGE LERF				
	Early Containment Failure Probability = 0.01 (baseline)		* Early Containment Failure Probability = 0.1	
Parameter	St. Lucie Unit 1	St. Lucie Unit 2	St. Lucie Unit 1	St. Lucie Unit 2
Avg. base LERF per yr.	3.77E-06	6.18E-06	6.85E-06	8.76E-06
Proposed LERF, per yr., using LPSI T/M set at proposed downtime value	3.77E-06	6.18E-06	6.86E-06	8.78E-06

* Sensitivity evaluation (factor of 10 increase)

RG 1.177 (Reference 4) states that the licensee must demonstrate that the proposed AOT change has only a small quantitative impact on plant risk. Per Reference 4, an ICCDP of less than 5.0E-07 is considered small for a single AOT change. As shown in Table 5S, the ICCDP values for the proposed AOT extension are below the RG 1.177 specified values except for the Unit 1 CM case which is only slightly above 5E-07 (i.e., 5.11E-07). The ICCDP results for this study are considered small. Also per NRC RG 1.177, an ICLERP of less than 5.0E-08 is considered small for a single AOT change. For ICLERP, the Unit 1 CM case is slightly above these guidelines. However, this case also includes an increased early containment failure probability of 0.1, which is ten times the baseline assumption. Additionally, this potential risk increase must be balanced against the risks inherent in maneuvering the plant for a shutdown and potentially having to enter a mode where the LPSI pump is the only means of cooling, i.e., with one pump already out-of-service. This is especially true since the only case at issue is unplanned corrective maintenance, which implies a pump or train has failed and requires repair. It is arguable that it is safer to do so on line rather than to shutdown and be forced to rely on the only remaining pump or train. This study was intentionally quite conservative.

Table 5S (Operator Action Sensitivity Study) ICCDP RESULTS		
Parameter	St. Lucie Unit 1	St. Lucie Unit 2
ICCDP for Corrective Maintenance (CM) case	5.11E-07	3.24E-07
ICCDP for Preventive Maintenance (PM) case	8.64E-08	5.95E-08

Table 6S (Operator Action Sensitivity Study) ICLERP RESULTS				
	Early Containment Failure Probability = 0.01 (baseline)		*Early Containment Failure Probability = 0.1	
Case	St. Lucie Unit 1	St. Lucie Unit 2	St. Lucie Unit 1	St. Lucie Unit 2
CM	1.88E-08	5.94E-09	6.42E-08	3.53E-08
PM	2.11E-09	7.67E-10	9.78E-09	6.32E-09

* Sensitivity evaluation (factor of 10 increase)

It is judged that appropriate uncertainty issues are addressed by the combination of the sensitivity studies provided in the submittal and the additional sensitivity studies documented above.

c. Details of the peer review process, a summary of peer review findings, and a discussion of the independence of internal reviews/reviewers.

Reference 5, section 5.2, and the discussion of Reference 6 in part b., above, provide a summary of the original IPE model peer review process. This information is repeated below:

Three levels of review were used for the St. Lucie PRA. The first consisted of normal engineering quality assurance carried out by the organization performing the analysis. A qualified individual with knowledge of PRA methods and plant systems performed an independent review of the results for each task. This represents a detailed check of the input to the PRA model and provides a high degree of quality assurance.

The second level of review was performed by licensee plant personnel not directly involved with the development of the PRA model. This consisted of individuals from Operations, Technical, Training, and independent safety engineering groups who reviewed the system description notebooks and accident sequence description. This provided diverse expertise with plant design and operations knowledge to review the system descriptions for accuracy.

The third level of review was performed for the licensee by PRA experts from ERIN Engineering, FRH, Inc., NUS, and Baltimore Gas & Electric. This review provided broad insights on techniques and results based on experience from other plant PRAs. The review team concentrated on the overall PRA methodology, accident sequence analysis, system fault trees and draft quantification results. The intent was to provide early feedback to the St. Lucie staff concerning the adequacy and accuracy of the reviewed products.

It should be noted that the methodologies used for the St. Lucie Level I and Level II analyses were similar to those used for the Turkey Point PRA. The Turkey Point IPE submittal was thoroughly reviewed by the NRC staff and its contractors. The staff review concluded that the process used to develop the Turkey Point PRA was acceptable in meeting the intent of GL 88-20.

The general areas of review were described above. The overall purpose of the review was to ensure the quality of the PRA project and to ensure that the project objectives were being met. The review team found that the project was successfully meeting those objectives with a sound methodology.

A summary of the peer review comment areas is as follows:

- The overall methodology reflects the current state of the art for PRAs and will meet the requirements of GL-88-20 (confirmed by the NRC St. Lucie IPE SER).
- The system description notebooks were very well organized and very complete.
- The event trees and success criteria used to support the systems analysis interface are consistent with those of other similar analyses.
- CST replenishment should be included for sequences where long-term cooling via AFW may be required (this was included for Unit1, not applicable for Unit 2).
- Units 1 and 2 data should be combined to formulate the plant-specific history (this was incorporated).

Another level of peer review is accomplished through the CEOG joint comparison process. The intent of this process is to provide a cross comparison of CE units PSA results to validate the plant specific results and conclusions. An example of the joint comparison process related to the proposed LPSI AOT change is provided in Reference 6. Additional CEOG cross comparisons have been performed since issuance of Reference 6. A sensitivity study was performed to address differences identified in these cross comparisons that are judged to have the potential to impact the conclusions of the St. Lucie LPSI AOT evaluation. See part b., above, for additional information regarding the St. Lucie sensitivity study performed.

The licensee has updated both the models and the reliability/unavailability databases for St. Lucie Units 1 and 2. The updated models and databases were then used to re-calculate the risk numbers in support of the requested St. Lucie LPSI AOT extension. The significant model and data changes are summarized in Section 3.2.2 of the St. Lucie proposed license amendment (Reference 1) and in part b., above. As discussed in Reference 1, outside peer review was not performed for the update because changes that were implemented are not extensive. One or more licensee PSA engineers implemented the changes, and a licensee PSA engineer not involved with implementation of the changes performed an independent review.

d. Description of PRA Quality Assurance methods.

As noted in paragraph b. above and in Reference 1, the models used in the licensee's analyses were generated using the IPE models developed in response to GL 88-20, Individual Plant Examination for Severe Accident Vulnerabilities, and associated supplements. The original development work was classified and performed as "Quality Related" under the FPL 10 CFR Appendix B quality assurance program. The revision and applications of the PRA models and associated databases continue to be handled as Quality Related. Since the approval of the IPE, the FPL Reliability and Risk Assessment Group (RRAG) has maintained the PSA models consistent with the current plant configuration such that they are considered "living" models. The PSA models are updated for different reasons, including plant changes and modifications, procedure changes, accrual of new plant data, discovery of modeling errors, advances in PSA technology, and issuance of new industry PSA standards.

The update process ensures that the applicable changes are implemented and documented timely so that risk analyses performed in support of plant operation reflect the plant configuration, operating philosophy, and transient and component failure history. The PSA maintenance and update process is described in the licensee RRAG standard, "PSA Update and Maintenance Procedure." This standard defines two different types of periodic updates: 1) a data analysis update, and 2) a model update. The data analysis update is performed at least every 5 years. Model updates consist of either single or multiple PSA changes and are performed at a frequency dependent on the estimated impact of the accumulated changes. Guidelines to determine the need for a model update are provided in the standard. This includes written procedures, independent review of all model changes, data updates and risk assessments performed using PSA methods and models. Risk assessments are performed by one individual, independently reviewed by another and approved by the Department Head or designee. The PSA group falls under the licensee Engineering Quality Instructions (QIs) with written procedures derived from those QIs. Procedures, risk assessment documentation, and associated records are controlled and retained as quality assurance (QA) records.

All computer programs that process PSA model inputs are verified and validated as needed. The RRAG 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 RRAG standard, "PSA 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. Software verification is the process used to ensure the software meets the software requirement specifications. The PSA software that is procured with a QA option and is developed under a 10 CFR Part 50, Appendix B, QA program, does not require further software verification by the RRAG. However, the PSA software, which is not procured with a QA option can be verified by comparison of results to previously approved software. Validation of software is performed for different conditions such as: 1) a new installation of software, 2) any new database or configuration file changes issued by the RRAG, 3) unreasonable results, 4) change in computer configuration (software, hardware), and 5) use of software for Quality Related applications for the first time. Validation requirements for each Quality Related PSA computer program are documented in a Software Verification/Validation Plan (SVVP) procedure. These requirements include the method of validation, the frequency of validation, the documentation required and the acceptance criteria. An SVVP procedure is submitted for each program. Actual validation benchmark problems can exercise more than one program, but a separate Software Verification/ Validation Report (SVVR) must be submitted for each program. Each SVVP procedure and SVVR is independently reviewed and then approved by the RRAG supervisor. Software validation tests both the software and the hardware. Validation tests are also performed following any significant change in the hardware, operating system, or program or if the validation period established in the SVVP procedure expires. Sample formats for the SVVP and SVVR are provided in the Engineering Quality Instruction (conforming to the pertinent 10 CFR Part 50, Appendix B, requirements) for computer software control.

e. Results of reviews of pertinent accident sequences and cut sets for modeling adequacy and completeness (with respect to this application)

The results of the evaluations performed in support of the St. Lucie LPSI AOT extension request were reviewed by two PSA engineers (a preparer and an independent reviewer). Both concluded that the results were appropriate considering the inputs and assumptions used. It is judged, based on a review of the results, that the models are adequate for this application. The following summarizes the dominant cutsets:

Unit 1:

- Attachment 1 lists the top 10 Unit 1 baseline cutsets. This is the value shown in the Tables 1 and 2 as the "Conditional CDF, per year, 1 LPSI train not out for T/M." The dominant accident sequence is related to a "Small-Small" (½" to 3") LOCA initiating event with failures related to high pressure safety injection. Other cutsets in the top 10 are related to ATWS.

- Attachment 2 lists the top 10 Unit 1 cutsets for the corrective maintenance (CM) case. This is the value shown in Table 1 for "Conditional; CDF, per year, 1 LPSI train unavailable." For this case, one LPSI train is assumed out-of-service for corrective maintenance and the common cause LPSI failures are set to the beta factor. The dominant sequence is related to a "Large" (>5") LOCA with common cause failure of LPSI pumps. Additional cutsets that are now in the top 10 (i.e., not in the baseline top 10) are related to a "Large" LOCA, one LPSI train out-of-service, and failures in the other LPSI train.

- Attachment 3 lists the top 10 Unit 1 cutsets for the preventive maintenance (PM) case. This is the value shown in the Table 2 for "Conditional; CDF, per year, 1 LPSI train unavailable." For this case, one LPSI train is assumed out-of-service for preventive maintenance and the common cause LPSI failures are set to 0.0. The dominant sequence is the same as the baseline case. Additional cutsets that are now in the top 10 (i.e., not in the baseline top 10) are related to a "Large" LOCA, one LPSI train out-of-service, and failures in the other LPSI train.

- Attachment 4 lists the top 10 Unit 1 cutsets for the new average CDF assuming the proposed LPSI downtime. This is the value shown in Table 3 for "Proposed Average CDF, per year, using LPSI T/M set at proposed downtime value." For this case, the LPSI unavailability was changed based on the proposed downtime assuming an increased AOT. The dominant sequences are the same as the baseline case.

Unit 2:

- Attachment 5 lists the top 10 Unit 2 baseline cutsets. This is the value shown in Tables 1 and 2 as the "Conditional CDF, per year, 1 LPSI train not out for T/M." The dominant accident sequence is related to a "Small-Small" LOCA with failures related to high pressure safety injection.

- Attachment 6 lists the top 10 Unit 2 cutsets for the CM case. The dominant sequences are the same as discussed above for the Unit 1 CM case.

- Attachment 7 lists the top 10 Unit 2 cutsets for the PM case. The dominant sequences are the same as discussed above for the Unit 1 PM case.

- Attachment 8 lists the top 10 Unit 2 cutsets for the new average CDF assuming the proposed LPSI downtime. The dominant sequences are the same as the baseline case.

4.3.4 External Events

The licensee's Administrative Procedure entitled, "Hurricane Season Preparation," outlines the actions to be reviewed prior to the start of hurricane season, and the Administrative Procedure entitled, "Severe Weather Preparations," provides instructions to be followed to prepare for severe weather (including tornadoes) or in response to a hurricane watch or warning. Actions to be taken include, but are not limited to:

- Installing intake structure missile shielding if removed,
- Topping off the diesel oil storage tanks,
- Removing the stoplogs from storage and prepare them for installation,
- Surveying the plant site, removing trash and debris, and secure loose equipment,
- Closing Reactor Auxiliary Building outside doors and roof hatches, and
- Placing station batteries on equalizing charge.

The Administrative Procedure entitled "Hurricane Staffing" provides instructions for staffing in preparation of a hurricane.

The Emergency Plan Implementing Procedure entitled "Duties and Responsibilities of the Emergency Coordinator" provides the criteria for unit shutdown if a hurricane warning is in effect, and either one or both unit(s) is/are in Mode 1, 2 or 3. The shutdown criteria are as follows:

- For storms projected to reach a Category 1 or 2, the unit(s) shall be placed in HOT STANDBY (Mode 3) or below at least 2 hours before the projected onset of sustained hurricane force winds at the site and both units shall remain off-line for the duration of the hurricane force winds (or restoration of reliable offsite power).

- For storms projected to reach Category 3, 4 and 5 prior to landfall, the units shall be shut down to a temperature less than 350 degrees T_{avg} at least 2 hours before the projected onset of sustained hurricane force winds at the site and both units shall remain off-line for the duration of the hurricane force winds (or restoration of reliable offsite power).

The licensee's Emergency Plan Implementing Procedure, entitled, "Classification of Emergencies," provides instructions on the classification of emergencies at the St. Lucie plant. The procedure includes criteria for emergency classification of events related to hurricanes, tornadoes, abnormal water level, and fires.

The Off-Normal Operating Procedure, entitled, "Response to Fire," provides operator actions for responding to a fire at each St. Lucie unit. These procedures provide specific guidance to the operator for performing a safe shutdown fire impact assessment and direction as to which mode to place the unit in if the fire challenges continued unit operation or stable plant conditions. Additional procedures provide firefighting strategies to assist the fire brigade in combating the fire.

4.3.5 Conclusions Regarding the Licensee's LPSI Design Similarities to ANO-2 and PRA Used to Support the Proposed Amendment

St. Lucie, Units 1 and 2, have strong LPSI design similarities to ANO-2, the original CEOG lead pilot plant for this project. Therefore, the staff believes that, on the basis of the three-tiered approach, cross-comparative results provide sufficient validation for the following conclusions:

- The proposed TS AOT modifications have only a minimal quantitative impact on plant risk. The calculated ICCDPs are small, primarily because of the association of LPSI with low probability initiating events and limited impact on the success criteria of other mitigation systems (Tier 1).

- The review did not identify the need for any additional constraints or compensatory actions that, if implemented, would avoid or reduce the probability of a risk-significant configuration (Tier 2).

- The licensee has implemented a risk-informed Configuration Risk Management Program to assess the risk associated with the removal of equipment from service during the proposed LPSI AOT. The program provides the necessary assurances that appropriate assessments of plant risk configurations using the Safety Monitor, augmented by additional analysis, when appropriate, are sufficient to support the present AOT extension requests for the LPSI system (Tier 3).

4.4 Implementation and Monitoring

The staff expects the licensee to implement these TS changes in accordance with the three-tiered approach described above. In addition, the licensee has endorsed the CEOG Joint Application Reports that the Maintenance Rule (10 CFR 50.65) will be the vehicle that controls the actual equipment maintenance cycle by defining unavailability performance criteria for the LPSI system. The AOT extensions will allow efficient scheduling of maintenance within the boundaries established by implementing the Maintenance Rule. The effect of the AOT extensions should be considered if any adverse trends in meeting established performance criteria are identified for the LPSI system. The Maintenance Rule will thereby be the vehicle that monitors the effectiveness of the AOT extensions. Application of these implementation and monitoring strategies will help to ensure that extension of TS AOTs for the LPSI system does not degrade operational safety over time. And these strategies will also ensure that the risk incurred when an LPSI train is taken out of service is minimized.

5.0 STAFF CONCLUSION

The staff has evaluated the licensee's proposed changes for compliance with regulatory requirements as documented in this evaluation and has determined that they are acceptable. This determination is based on the following:

1. The need to maintain reliable safety systems.

2. Consideration of the design basis requirements for the LPSI system.

3. Insights gained from the quantitative evaluation of the risk associated with having one LPSI train out of service.

4. A three-tiered implementation strategy that ensures that the risk incurred when the LPSI system is taken out of service is minimized.

5. Performance monitoring through the Maintenance Rule to ensure that extension of TS AOTs for the LPSI system does not degrade operational safety over time.

The staff therefore finds that the AOT for one inoperable LPSI system may be extended to 7 days, with a negligible impact on risk.

6.0 STATE CONSULTATION

By letter dated March 8, 1991, Mary E. Clark of the State of Florida, Department of Health and Rehabilitative Services, informed Deborah A. Miller, Licensing Assistant, U.S. NRC, that the State of Florida does not desire notification of issuance of license amendments. Thus, the State official had no comments.

7.0 ENVIRONMENTAL CONSIDERATION

The amendments change a requirement with respect to the 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 amendments involve 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 amendments involve no significant hazards consideration, and there has been no public comment on such finding (64 FR 35206). Accordingly, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). The amendments also involve changes in recordkeeping, reporting or administrative procedures or requirements. Accordingly, with respect to these items, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(10). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendments.

8.0 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 amendments will not be inimical to the common defense and security or to the health and safety of the public.

Principal Contributor: W. Gleaves, NRR
M. Wohl, NRR

Date: **February 15, 2000**

Attachments: As stated (8)

9.0 REFERENCES

1) FPL letter L-99-079, J.A. Stall (FPL) to NRC (DCD), St. Lucie Unit 1 and Unit 2, Docket Nos. 50-335 and 50-389, Proposed License Amendments, *"LPSI System Risk Informed AOT Extension,"* June 1, 1999.

2) CE NPSD-995, *"Joint Applications Report For Low Pressure Safety Injection System AOT Extension,"* May 1995.

3) RG 1.174, *"An Approach for Using Probabilistic Risk Assessment in Decisions on Plant Specific Changes to the Licensing Basis,"* July 1998.

4) RG 1.177, *"An Approach for Plant-Specific Risk-Informed Decisionmaking: Technical Specifications,"* August 1998.

5) FPL letter L-93-301, D.A. Sager (FPL) to NRC (DCD), St. Lucie Units 1 and 2, Docket Nos. 50-335 and 50-389, *"Summary Report of Individual Plant Examination for Severe Accident Vulnerabilities - Generic Letter 88-20,"* December 9, 1993.

6) CEOG letter CEOG-96-254, D.F. Pilmer (CEOG) to Christopher I. Grimes (NRC), *"CEOG Response To Request For Additional Information (RAI) Related To The CEOG Joint Applications Reports,"* June 14, 1996.

ATTACHMENT 1

Unit 1 Conditional CDF w/1 LPSI Train Not Out for T/M (Baseline)

Total Frequency = 1.44E-05/yr.
Cutset

#	Inputs Probability	Description	Event Prob
1	%ZZS1U1 1.64E-06	SMALL-SMALL LOCA	3.01E-03
	CMM1AVCCCF	N-HEADER AIR OPERATED ISOLATION VALVES FTC DUE TO COMMON CAUSES	5.44E-04
2	%ZZS1U1 1.26E-06	SMALL-SMALL LOCA	3.01E-03
	GMM1MRMOV	MINIMUM RECIRC LINE MOTOR VALVES TRANSFER CLOSED	4.19E-04
3	%ZZS1U1 8.87E-07	SMALL-SMALL LOCA	3.01E-03
	GMM1FTRCFI	COMMON CAUSE FAILURE OF HPSI PUMPS TO RUN DURING INJECTION	2.95E-04
4	%ZZT1U1 8.38E-07	REACTOR TRIPS	1.90E+00
	NMM1CEDM	MECHANICAL FAULT PREVENTING ROD INSERTION	2.10E-06
	ZZMTCUNF1	MODERATOR TEMPERATURE COEFFICIENT UNFAVORABLE (UNIT 1)	2.10E-01
5	%ZZS1U1 5.78E-07	SMALL-SMALL LOCA	3.01E-03
	QMM1MVCCCF	ICW MOTOR OPERATED VALVES FAIL TO CLOSE DUE TO COMMON CAUSE FAILURES	1.92E-04
6	%ZZS1U1 4.17E-07	SMALL-SMALL LOCA	3.01E-03
	GMM1MPACCF	COMMON CAUSE FAILURE OF HPSI PUMPS TO START	1.38E-04
7	%ZZCCWU1 2.82E-07	LOSS OF CCW	9.41E-04
	RTOP1S1RCP	OPERATOR FAILS TO SECURE RCPS FOLLOWING LOSS OF SEAL COOLING	3.00E-04
8	%ZZS1U1 2.28E-07	SMALL-SMALL LOCA	3.01E-03
	GMM1HCVCCF	COMMON CAUSE FAILURE OF HPSI INJECTION VALVES TO OPEN	7.58E-05

9	%ZZT3AU1	LOSS OF MAIN FEEDWATER BUT RECOVERABLE	4.34E-01
	1.91E-07		
	NMM1CEDM	MECHANICAL FAULT PREVENTING ROD INSERTION	2.10E-06
	ZZMTCUNF1	MODERATOR TEMPERATURE COEFFICIENT UNFAVORABLE (UNIT 1)	2.10E-01
10	%ZZT1U1	REACTOR TRIPS	1.90E+00
	1.38E-07		
	NMM1CEDM	MECHANICAL FAULT PREVENTING ROD INSERTION	2.10E-06
	ZZ1ABKSHUT	'A' BLK VLV CLOSE W/POWER	4.36E-02
	ZZMTCNUNF1	MTC NOT UNFAVORABLE (UNIT 1)	7.90E-01

ATTACHMENT 2

Unit 1 Conditional CDF w/1 LPSI Train Unavailable for CM Case

Total Frequency = 3.21E-05/yr.

#	Inputs Probability	Cutset Description	Event Prob
1	%ZZAU1 6.44E-06	LARGE LOCA	5.85E-05
	JMM1MPACFI	COMMON CAUSE FAILURE OF LPSI PUMPS TO START DURING INJECTION	1.10E-01
2	%ZZAU1 6.44E-06	LARGE LOCA	5.85E-05
	JMM1MPFCFI	COMMON CAUSE FAILURE OF LPSI PUMPS TO RUN DURING INJECTION	1.10E-01
3	%ZZS1U1 1.64E-06	SMALL-SMALL LOCA	3.01E-03
	CMM1AVCCCF	N-HEADER AIR OPERATED ISOLATION VALVES FTC DUE TO COMMON CAUSES	5.44E-04
4	%ZZS1U1 1.26E-06	SMALL-SMALL LOCA	3.01E-03
	GMM1MRMOV	MINIMUM RECIRC LINE MOTOR VALVES TRANSFER CLOSED	4.19E-04
5	%ZZS1U1 8.87E-07	SMALL-SMALL LOCA	3.01E-03
	GMM1FTRCFI	COMMON CAUSE FAILURE OF HPSI PUMPS TO RUN DURING INJECTION	2.95E-04
6	%ZZT1U1 8.38E-07	REACTOR TRIPS	1.90E+00
	NMM1CEDM	MECHANICAL FAULT PREVENTING ROD INSERTION	2.10E-06
	ZZMTCUNF1	MODERATOR TEMPERATURE COEFFICIENT UNFAVORABLE (UNIT 1)	2.10E-01
7	%ZZS1U1 5.78E-07	SMALL-SMALL LOCA	3.01E-03
	QMM1MVCCCF	ICW MOTOR OPERATED VALVES FAIL TO CLOSE DUE TO COMMON CAUSE FAILURES	1.92E-04
8	%ZZAU1 5.76E-07	LARGE LOCA	5.85E-05
	JMVK13207S	MOTOR-OPERATED VALVE V3207 TRANSFERS CLOSED DURING STANDBY	9.85E-03
	JTM1PUMPA	LPSI PUMP A IN TEST OR MAINTENANCE	1.00E+00
9	%ZZAU1 5.52E-07	LARGE LOCA	5.85E-05

	JMM1PBFTRI	FAILURE OF LPSI PUMP B TO RUN DURING INJECTION	9.44E-03
	JTM1PUMPA	LPSI PUMP A IN TEST OR MAINTENANCE	1.00E+00
10	%ZZAU1	LARGE LOCA	5.85E-05
	5.16E-07		
	JMVR13-1BS	MOTOR-OPERATED VALVE MV-03-1B TRANSFERS OPEN DURING STANDBY	8.81E-03
	JTM1PUMPA	LPSI PUMP A IN TEST OR MAINTENANCE	1.00E+00

ATTACHMENT 3

Unit 1 Conditional CDF w/1 LPSI Train Unavailable for PM Case

Total Frequency = 1.75E-05/yr.
Cutset

#	Inputs Probability	Description	Event Prob
1	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03
	1.64E-06		
	CMM1AVCCCF	N-HEADER AIR OPERATED ISOLATION VALVES FTC DUE TO COMMON CAUSES	5.44E-04
2	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03
	1.26E-06		
	GMM1MRMOV	MINIMUM RECIRC LINE MOTOR VALVES TRANSFER CLOSED	4.19E-04
3	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03
	8.87E-07		
	GMM1FTRCFI	COMMON CAUSE FAILURE OF HPSI PUMPS TO RUN DURING INJECTION	2.95E-04
4	%ZZT1U1	REACTOR TRIPS	1.90E+00
	8.38E-07		
	NMM1CEDM	MECHANICAL FAULT PREVENTING ROD INSERTION	2.10E-06
	ZZMTCUNF1	MODERATOR TEMPERATURE COEFFICIENT UNFAVORABLE (UNIT 1)	2.10E-01
5	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03
	5.78E-07		
	QMM1MVCCCF	ICW MOTOR OPERATED VALVES FAIL TO CLOSE DUE TO COMMON CAUSE FAILURES	1.92E-04
6	%ZZAU1	LARGE LOCA	5.85E-05
	5.76E-07		
	JMVK13207S	MOTOR-OPERATED VALVE V3207 TRANSFERS CLOSED DURING STANDBY	9.85E-03
	JTM1PUMPA	LPSI PUMP A IN TEST OR MAINTENANCE	1.00E+00
7	%ZZAU1	LARGE LOCA	5.85E-05
	5.52E-07		
	JMM1PBFTRI	FAILURE OF LPSI PUMP B TO RUN DURING INJECTION	9.44E-03
	JTM1PUMPA	LPSI PUMP A IN TEST OR MAINTENANCE	1.00E+00
8	%ZZAU1	LARGE LOCA	5.85E-05
	5.16E-07		
	JMVR13-1BS	MOTOR-OPERATED VALVE MV-03-1B TRANSFERS OPEN DURING STANDBY	8.81E-03
	JTM1PUMPA	LPSI PUMP A IN TEST OR MAINTENANCE	1.00E+00

9	%ZZS1U1 4.17E-07	SMALL-SMALL LOCA	3.01E-03
	GMM1MPACCF	COMMON CAUSE FAILURE OF HPSI PUMPS TO START	1.38E-04
10	%ZZAU1 3.34E-07	LARGE LOCA	5.85E-05
	JMM1PBFTSI	FAILURE OF LPSI PUMP B TO START DURING INJECTION	5.72E-03
	JTM1PUMPA	LPSI PUMP A IN TEST OR MAINTENANCE	1.00E+00

ATTACHMENT 4

Unit 1 Proposed Average CDF Using LPSI T/M Set at Proposed Downtime Value

Total Frequency = 1.45E-05/yr.

Cutset

#	Inputs Probability	Description	Event Prob
1	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03
	1.64E-06		
	CMM1AVCCCF	N-HEADER AIR OPERATED ISOLATION VALVES FTC DUE TO COMMON CAUSES	5.44E-04
2	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03
	1.26E-06		
	GMM1MRMOV	MINIMUM RECIRC LINE MOTOR VALVES TRANSFER CLOSED	4.19E-04
3	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03
	8.87E-07		
	GMM1FTRCFI	COMMON CAUSE FAILURE OF HPSI PUMPS TO RUN DURING INJECTION	2.95E-04
4	%ZZT1U1	REACTOR TRIPS	1.90E+00
	8.38E-07		
	NMM1CEDM	MECHANICAL FAULT PREVENTING ROD INSERTION	2.10E-06
	ZZMTCUNF1	MODERATOR TEMPERATURE COEFFICIENT UNFAVORABLE (UNIT 1)	2.10E-01
5	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03
	5.78E-07		
	QMM1MVCCCF	ICW MOTOR OPERATED VALVES FAIL TO CLOSE DUE TO COMMON CAUSE FAILURES	1.92E-04
6	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03
	4.17E-07		
	GMM1MPACCF	COMMON CAUSE FAILURE OF HPSI PUMPS TO START	1.38E-04
7	%ZZCCWU1	LOSS OF CCW	9.41E-04
	2.82E-07		
	RTOP1S1RCP	OPERATOR FAILS TO SECURE RCPS FOLLOWING LOSS OF SEAL COOLING	3.00E-04
8	%ZZS1U1	SMALL-SMALL LOCA	3.01E-03
	2.28E-07		
	GMM1HCVCCF	COMMON CAUSE FAILURE OF HPSI INJECTION VALVES TO OPEN	7.58E-05

9	%ZZT3AU1	LOSS OF MAIN FEEDWATER BUT RECOVERABLE	4.34E-01
	1.91E-07		
	NMM1CEDM	MECHANICAL FAULT PREVENTING ROD INSERTION	2.10E-06
	ZZMTCUNF1	MODERATOR TEMPERATURE COEFFICIENT UNFAVORABLE (UNIT 1)	2.10E-01
10	%ZZT1U1	REACTOR TRIPS	1.90E+00
	1.38E-07		
	NMM1CEDM	MECHANICAL FAULT PREVENTING ROD INSERTION	2.10E-06
	ZZ1ABKSHUT	'A' BLK VLV CLOSE W/POWER	4.36E-02
	ZZMTCNUNF1	MTC NOT UNFAVORABLE (UNIT 1)	7.90E-01

ATTACHMENT 5

Unit 2 Conditional CDF w/1 LPSI Train Not Out for T/M (Baseline)

Total Frequency = 1.25E-05/yr.
Cutset

#	Inputs Probability	Description	Event Prob
1	%ZZS1U2 1.64E-06	SMALL-SMALL LOCA	3.01E-03
	CMM2AVCCCF	N-HEADER AIR OPERATED ISOLATION VALVES FAIL TO CLOSE DUE TO COMMON CAUSES	5.44E-04
2	%ZZS1U2 9.90E-07	SMALL-SMALL LOCA	3.01E-03
	GMM2SMVCCF	COMMON CAUSE FAILURE OF SUMP OUTLET MOTOR VALVES TO OPEN	3.29E-04
3	%ZZS1U2 8.87E-07	SMALL-SMALL LOCA	3.01E-03
	GMM2FTRCFI	COMMON CAUSE FAILURE OF HPSI PUMPS TO RUN DURING INJECTION	2.95E-04
4	%ZZS1U2 5.78E-07	SMALL-SMALL LOCA	3.01E-03
	QMM2MVCCCF	ICW MOTOR OPERATED VALVES FAIL TO CLOSE DUE TO COMMON CAUSE FAILURES	1.92E-04
5	%ZZS1U2 4.17E-07	SMALL-SMALL LOCA	3.01E-03
	GMM2MPACCF 1.38E-04	COMMON CAUSE FAILURE OF HPSI PUMPS TO START	1.38E-04
6	%ZZCCWU2	LOSS OF CCW	9.41E-04 2.82E-07
	RTOP2S1RCP	OPERATOR FAILS TO SECURE RCPS FOLLOWING LOSS OF SEAL COOLING	3.00E-04
7	%ZZS1U2 2.28E-07	SMALL-SMALL LOCA	3.01E-03
	GMM2HCVCCF	COMMON CAUSE FAILURE OF HPSI INJECTION VALVES TO OPEN	7.58E-05
8	%ZZS1U2 1.56E-07	SMALL-SMALL LOCA	3.01E-03
	GMVR23523 8.81E-03	MOTOR-OPERATED VALVE V3523 TRANSFERS OPEN DURING STANDBY	1.80E+01
	GMVR23551 5.88E-03	MOTOR-OPERATED VALVE V3551 TRANSFERS OPEN	6.00E+00

9	%ZZS1U2 1.56E-07	SMALL-SMALL LOCA	3.01E-03
	GMVR23540 8.81E-03	MOTOR-OPERATED VALVE 3540 TRANSFERS OPEN DURING STANDBY	1.80E+01
	GMVR23550 5.88E-03	MOTOR-OPERATED VALVE V3550 TRANSFERS OPEN	6.00E+00
10	%ZZDC2B 1.03E-07	LOSS OF DC BUS 2B FOR UNIT 2	1.07E-03
	NMM2TCBCCF	COMMON CAUSE FAILURE OF THE TRIP CIRCUIT BREAKERS	9.60E-05

ATTACHMENT 6

Unit 2 Conditional CDF w/1 LPSI Train Unavailable for CM Case

Total Frequency = 2.91E-05/yr.
Cutset

#	Inputs Probability	Description	Event Prob
1	%ZZAU2	LARGE LOCA	5.85E-05
	6.44E-06		
	JMM2MPACFI	COMMON CAUSE FAILURE OF LPSI PUMPS TO START DURING INJECTION	1.10E-01
2	%ZZAU2	LARGE LOCA	5.85E-05
	6.44E-06		
	JMM2MPFCFI	COMMON CAUSE FAILURE OF LPSI PUMPS TO RUN DURING INJECTION	1.10E-01
3	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03
	1.64E-06		
	CMM2AVCCCF	N-HEADER AIR OPERATED ISOLATION VALVES FAIL TO CLOSE DUE TO COMMON CAUSES	5.44E-04
4	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03
	9.90E-07		
	GMM2SMVCCF	COMMON CAUSE FAILURE OF SUMP OUTLET MOTOR VALVES TO OPEN	3.29E-04
5	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03
	8.87E-07		
	GMM2FTRCFI	COMMON CAUSE FAILURE OF HPSI PUMPS TO RUN DURING INJECTION	2.95E-04
6	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03
	5.78E-07		
	QMM2MVCCCF	ICW MOTOR OPERATED VALVES FAIL TO CLOSE DUE TO COMMON CAUSE FAILURES	1.92E-04
7	%ZZAU2	LARGE LOCA	5.85E-05
	5.76E-07		
	JMVK23306S	MOTOR-OPERATED VALVE FCV-3306 TRANSFERS CLOSED DURING STANDBY	1.80E+01
	9.85E-03		
	JTM2PUMPB	2B LPSI/SDC PUMP OUT FOR TEST OR MAINTENANCE	1.00E+00
8	%ZZAU2	LARGE LOCA	5.85E-05
	5.16E-07		
	JMVR23536S	MOTOR-OPERATED VALVE V3536 TRANSFERS OPEN DURING STANDBY	1.80E+01
	8.81E-03		

	JTM2PUMPB	2B LPSI/SDC PUMP OUT FOR TEST OR MAINTENANCE	1.00E+00
9	%ZZS1U2 4.17E-07	SMALL-SMALL LOCA	3.01E-03
	GMM2MPACCF	COMMON CAUSE FAILURE OF HPSI PUMPS TO START	1.38E-04
10	%ZZAU2 3.34E-07	LARGE LOCA	5.85E-05
	JMM2PAFTSI	FAILURE OF LPSI PUMP A TO START DURING INJECTION	5.72E-03
	JTM2PUMPB	2B LPSI/SDC PUMP OUT FOR TEST OR MAINTENANCE	1.00E+00

ATTACHMENT 7

Unit 2 Conditional CDF w/1 LPSI Train Unavailable for PM Case

Total Frequency = 1.55E-05/yr.
Cutset

#	Inputs Probability	Description	Event Prob
1	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03
	1.64E-06		
	CMM2AVCCCF	N-HEADER AIR OPERATED ISOLATION VALVES FAIL TO CLOSE DUE TO COMMON CAUSES	5.44E-04
2	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03
	9.90E-07		
	GMM2SMVCCF	COMMON CAUSE FAILURE OF SUMP OUTLET MOTOR VALVES TO OPEN	3.29E-04
3	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03
	8.87E-07		
	GMM2FTRCFI	COMMON CAUSE FAILURE OF HPSI PUMPS TO RUN DURING INJECTION	2.95E-04
4	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03
	5.78E-07		
	QMM2MVCCCF	ICW MOTOR OPERATED VALVES FAIL TO CLOSE DUE TO COMMON CAUSE FAILURES	1.92E-04
5	%ZZAU2	LARGE LOCA	5.85E-05
	5.76E-07		
	JMVK23306S	MOTOR-OPERATED VALVE FCV-3306 TRANSFERS CLOSED DURING STANDBY	9.85E-03
	JTM2PUMPB	2B LPSI/SDC PUMP OUT FOR TEST OR MAINTENANCE	1.00E+00
6	%ZZAU2	LARGE LOCA	5.85E-05
	5.16E-07		
	JMVR23536S	MOTOR-OPERATED VALVE V3536 TRANSFERS OPEN DURING STANDBY	8.81E-03
	JTM2PUMPB	2B LPSI/SDC PUMP OUT FOR TEST OR MAINTENANCE	1.00E+00
7	%ZZS1U2	SMALL-SMALL LOCA	3.01E-03
	4.17E-07		
	GMM2MPACCF	COMMON CAUSE FAILURE OF HPSI PUMPS TO START	1.38E-04
8	%ZZAU2	LARGE LOCA	5.85E-05
	3.34E-07		
	JMM2PAFTSI	FAILURE OF LPSI PUMP A TO START DURING INJECTION	5.72E-03

	JTM2PUMPB	2B LPSI/SDC PUMP OUT FOR TEST OR MAINTENANCE	1.00E+00
9	%ZZAU2 3.16E-07	LARGE LOCA	5.85E-05
	JMM2PAFTRI	FAILURE OF LPSI PUMP A TO RUN DURING INJECTION	5.40E-03
	JTM2PUMPB	2B LPSI/SDC PUMP OUT FOR TEST OR MAINTENANCE	1.00E+00
10	%ZZCCWU2 2.82E-07	LOSS OF CCW	9.41E-04
	RTOP2S1RCP	OPERATOR FAILS TO SECURE RCPS FOLLOWING LOSS OF SEAL COOLING	3.00E-04

ATTACHMENT 8

Unit 2 Proposed Average CDF Using LPSI T/M Set at Proposed Downtime Value

Total Frequency = 1.26E-05/yr.
Cutset

#	Inputs Probability	Description	Event Prob
1	%ZZS1U2 1.64E-06	SMALL-SMALL LOCA	3.01E-03
	CMM2AVCCCF	N-HEADER AIR OPERATED ISOLATION VALVES FAIL TO CLOSE DUE TO COMMON CAUSES	5.44E-04
2	%ZZS1U2 9.90E-07	SMALL-SMALL LOCA	3.01E-03
	GMM2SMVCCF	COMMON CAUSE FAILURE OF SUMP OUTLET MOTOR VALVES TO OPEN	3.29E-04
3	%ZZS1U2 8.87E-07	SMALL-SMALL LOCA	3.01E-03
	GMM2FTRCFI	COMMON CAUSE FAILURE OF HPSI PUMPS TO RUN DURING INJECTION	2.95E-04
4	%ZZS1U2 5.78E-07	SMALL-SMALL LOCA	3.01E-03
	QMM2MVCCCF	ICW MOTOR OPERATED VALVES FAIL TO CLOSE DUE TO COMMON CAUSE FAILURES	1.92E-04
5	%ZZS1U2 4.17E-07	SMALL-SMALL LOCA	3.01E-03
	GMM2MPACCF	COMMON CAUSE FAILURE OF HPSI PUMPS TO START	1.38E-04
6	%ZZCCWU2 2.82E-07	LOSS OF CCW	9.41E-04
	RTOP2S1RCP	OPERATOR FAILS TO SECURE RCPS FOLLOWING LOSS OF SEAL COOLING	3.00E-04
7	%ZZS1U2 2.28E-07	SMALL-SMALL LOCA	3.01E-03
	GMM2HCVCCF	COMMON CAUSE FAILURE OF HPSI INJECTION VALVES TO OPEN	7.58E-05
8	%ZZS1U2 1.56E-07	SMALL-SMALL LOCA	3.01E-03
	GMVR23523	MOTOR-OPERATED VALVE V3523 TRANSFERS OPEN DURING STANDBY	8.81E-03
	GMVR23551	MOTOR-OPERATED VALVE V3551 TRANSFERS OPEN	5.88E-03
9	%ZZS1U2 1.56E-07	SMALL-SMALL LOCA	3.01E-03

	GMVR23540	MOTOR-OPERATED VALVE 3540 TRANSFERS OPEN DURING STANDBY	8.81E-03
	GMVR23550	MOTOR-OPERATED VALVE V3550 TRANSFERS OPEN	5.88E-03
10	%ZZDC2B 1.03E-07	LOSS OF DC BUS 2B FOR UNIT 2	1.07E-03
	NMM2TCBCCF	COMMON CAUSE FAILURE OF THE TRIP CIRCUIT BREAKERS	9.60E-05

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