



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

July 9, 2012

Mr. Mano Nazar  
Executive Vice President and  
Chief Nuclear Officer  
Florida Power and Light Company  
P.O. Box 14000  
Juno Beach, Florida 33408-0420

SUBJECT: ST. LUCIE PLANT, UNIT 1 - ISSUANCE OF AMENDMENT REGARDING  
EXTENDED POWER UPRATE (TAC NO. ME5091)

Dear Mr. Nazar:

The Commission has issued the enclosed Amendment No. 213 to Renewed Facility Operating License No. DPR-67 for the St. Lucie Plant, Unit No. 1. This amendment consists of changes to the Operating License and the Technical Specifications (TSs) in response to your application dated November 22, 2010, as supplemented by the letters listed in Attachment 1 of the enclosed safety evaluation.

This amendment increases the authorized maximum steady-state reactor core power level from 2700 megawatts thermal (MWt) to 3020 MWt, which is an increase of approximately 11.85 percent. The proposed increase in power level is considered an extended power uprate. By letter dated July 5, 2012, you requested to withdraw from consideration the associated TS change related to the Surveillance Requirement 4.8.1.1.2.e.6 for the 24-hour run of the emergency diesel generator. That TS change will be processed under separate correspondence.

The NRC staff has determined that the related safety evaluation (SE) contains proprietary information pursuant to Title 10 of the *Code of Federal Regulations*, Section 2.390, "Public Inspections, Exemptions, Requests for Withholding." Accordingly, the NRC staff has also prepared a redacted, publically-available, non-proprietary version of the SE. Copies of the proprietary and non-proprietary version the SE are enclosed.

M. Nazar

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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,

A handwritten signature in black ink, appearing to read "Tracy J. Orf", with a long horizontal flourish extending to the right.

Tracy J. Orf, Project Manager  
Plant Licensing Branch II-2  
Division of Operator Reactor Licensing  
Office of Nuclear Reactor Regulation

Docket No. 50-335

Enclosures:

1. Amendment No. 213 to DPR-67
2. Safety Evaluation

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**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 RENEWED FACILITY OPERATING LICENSE

Amendment No. 213  
Renewed License No. DPR-67

1. The Nuclear Regulatory Commission (the Commission) has found that:
  - A. The application for amendment by Florida Power & Light Company (the licensee), dated November 22, 2010, as supplemented by the letters listed in Attachment 1 of the enclosed safety evaluation, 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, Renewed Facility Operating License No. DPR-67 is amended by changes to the Operating License and the Technical Specifications as indicated in the attachment to this license amendment, and by amending paragraph 3.B to read as follows:

B. Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 213, are hereby incorporated in the renewed license. FPL shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of its date of issuance and shall be implemented within 60 days.

FOR THE NUCLEAR REGULATORY COMMISSION

A handwritten signature in black ink, appearing to read 'E. J. Leeds', is written over a horizontal line.

Eric J. Leeds, Director  
Office of Nuclear Reactor Regulation

Attachment:  
Changes to the Operating License  
and Technical Specifications

Date of Issuance: July 9, 2012

ATTACHMENT TO LICENSE AMENDMENT NO. 213  
TO RENEWED FACILITY OPERATING LICENSE NO. DPR-67  
DOCKET NO. 50-335

Replace Pages 3 and 5 of Renewed Operating License DPR-67 with the attached Pages 3 and 5. Insert the attached Page 6 of Renewed Operating License DPR-67.

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

Remove Pages

I  
III  
VIII  
1-3  
1-4  
1-6  
2-2  
2-4  
3/4 1-1  
3/4 1-3  
3/4 1-8  
3/4 1-9a  
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applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

A. Maximum Power Level

FPL is authorized to operate the facility at steady state reactor core power levels not in excess of 2700 megawatts (thermal).

B. Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 213 are hereby incorporated in the renewed license. FPL shall operate the facility in accordance with the Technical Specifications.

Appendix B, the Environmental Protection Plan (Non-Radiological), contains environmental conditions of the renewed license. If significant detrimental effects or evidence of irreversible damage are detected by the monitoring programs required by Appendix B of this license, FPL will provide the Commission with an analysis of the problem and plan of action to be taken subject to Commission approval to eliminate or significantly reduce the detrimental effects or damage.

C. Updated Final Safety Analysis Report

The Updated Final Safety Analysis Report supplement submitted pursuant to 10 CFR 54.21(d), as revised on March 28, 2003, describes certain future activities to be completed before the period of extended operation. FPL shall complete these activities no later than March 1, 2016, and shall notify the NRC in writing when implementation of these activities is complete and can be verified by NRC inspection.

The Updated Final Safety Analysis Report supplement as revised on March 28, 2003, described above, shall be included in the next scheduled update to the Updated Final Safety Analysis Report required by 10 CFR 50.71(e)(4), following issuance of this renewed license. Until that update is complete, FPL may make changes to the programs described in such supplement without prior Commission approval, provided that FPL evaluates each such change pursuant to the criteria set forth in 10 CFR 50.59 and otherwise complies with the requirements in that section.

D. Sustained Core Uncovery Actions

Procedural guidance shall be in place to instruct operators to implement actions that are designed to mitigate a small-break loss-of-coolant accident prior to a calculated time of sustained core uncovery.

- (c) Actions to minimize release to include consideration of:
  - 1. Water spray scrubbing
  - 2. Dose to onsite responders

H. Control Room Habitability

Upon implementation of Amendment No. 205, adopting TSTF-448, Revision 3, the determination of control room envelope (CRE) unfiltered air inleakage as required by SR 4.7.7.1.e, in accordance with TS 6.8.4.m, the assessment of CRE habitability as required by Specification 6.8.4.m.c. (ii), and the measurement of CRE pressure as required by Specification 6.8.4.m.d, shall be considered met. Following implementation:

- (a) The first performance of SR 4.7.7.1.e, in accordance with Specification 6.8.4.m.c(i), shall be within the specified Frequency of 6 years, plus the 18-month allowance of SR 4.0.2, as measured from September 2003, the date of the most recent successful tracer gas test, as stated in FPL letters to NRC dated December 9, 2003, and October 29, 2004, in response to Generic Letter 2003-01.
- (b) The first performance of the periodic assessment of CRE habitability, Specification 6.8.4.m.c(ii), shall be within 3 years, plus the 9-month allowance of SR 4.0.2, as measured from September 2003, the date of the most recent successful tracer gas test, as stated in FPL letters to NRC dated December 9, 2003, and October 29, 2004, in response to Generic Letter 2003-01, or within the next 9 months if the time period since the most recent successful tracer gas test is greater than 3 years.
- (c) The first performance of the periodic measurement of CRE pressure, Specification 6.8.4.c.d, shall be within 36 months in a staggered test basis, plus the 138 days allowed by SR 4.0.2, as measured from June 30, 2006, which is the date of the most recent successful pressure measurement test, or within 138 days if not performed previously.

I. RODEX2 Safety Analyses

RODEX2 has been specifically approved for use for St. Lucie Unit 1 licensing basis analyses. Upon NRC's approval of a generic supplement to the RODEX2 code and associated methods that accounts for thermal conductivity degradation (TCD), FPL will within six months:

- (a) Demonstrate that St. Lucie Unit 1 safety analyses remain conservatively bounded in licensing basis analyses when compared to the NRC-approved generic supplement to the RODEX2 methodology, or
- (b) Provide a schedule for the re-analysis using the NRC-approved generic supplement to the RODEX2 methodology for any of the affected licensing basis analyses.



4. This renewed license is effective as of the date of issuance and shall expire at midnight on March 1, 2036.

FOR THE NUCLEAR REGULATORY COMMISSION

ORIGINAL SIGNED BY  
J. E. Dyer, Director  
Office of Nuclear Reactor Regulation

Attachments:

1. Appendix A, Technical Specifications
2. Appendix B, Environmental Protection Plan

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## DEFINITIONS

### DOSE EQUIVALENT I-131

- 1.10 DOSE EQUIVALENT I-131 shall be that concentration of I-131 ( $\mu\text{Ci}/\text{gram}$ ) which alone would produce the same thyroid dose as the quantity and isotopic mixture of I-131, I-132, I-133, I-134 and I-135 actually present. The thyroid dose conversion factors used for this calculation shall be those listed in Federal Guidance Report 11, "Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion."

### DOSE EQUIVALENT XE-133

- 1.11 DOSE EQUIVALENT XE-133 shall be that concentration of Xe-133 ( $\mu\text{Ci}/\text{gram}$ ) that alone would produce the same acute dose to the whole body as the combined activities of noble gas nuclides Kr-85m, Kr-85, Kr-87, Kr-88, Xe-131m, Xe-133m, Xe-133, Xe-135m, Xe-135, and Xe-138 actually present. If a specific noble gas nuclide is not detected, it should be assumed to be present at the minimum detectable activity. The determination of DOSE EQUIVALENT XE-133 shall be performed using effective dose conversion factors for air submersion listed in Table III.1 of EPA Federal Guidance Report No. 12, 1993, "External Exposure to Radionuclides in Air, Water, and Soil."

### ENGINEERED SAFETY FEATURES RESPONSE TIME

- 1.12 The ENGINEERED SAFETY FEATURES RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ESF actuation setpoint at the channel sensor until the ESF equipment is capable of performing its safety function (i.e., the valves travel to their required positions, pump discharge pressures reach their required values, etc.). Times shall include diesel generator starting and sequence loading delays where applicable. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

### FREQUENCY NOTATION

- 1.13 The FREQUENCY NOTATION specified for the performance of Surveillance Requirements shall correspond to the intervals defined in Table 1.1.

### GASEOUS RADWASTE TREATMENT SYSTEM

- 1.14 A GASEOUS RADWASTE TREATMENT SYSTEM is any system designed and installed to reduce radioactive gaseous effluents by collecting primary coolant system offgases from the primary system and providing for delay or holdup for the purpose of reducing the total radioactivity prior to release to the environment.

## **DEFINITIONS**

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### **IDENTIFIED LEAKAGE**

1.15 IDENTIFIED LEAKAGE shall be:

- a. Leakage (except CONTROLLED LEAKAGE) into closed systems, such as pump seal or valve packing leaks that are captured, and conducted to a sump or collecting tank, or
- b. Leakage into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be PRESSURE BOUNDARY LEAKAGE, or
- c. Reactor Coolant System leakage through a steam generator to the secondary system (Primary-to-secondary leakage).

1.16 Deleted

### **MEMBER(S) OF THE PUBLIC**

1.17 MEMBER OF THE PUBLIC means an individual in a controlled or unrestricted area. However, an individual is not a member of the public during any period in which the individual receives an occupational dose.

### **OFFSITE DOSE CALCULATION MANUAL (ODCM)**

1.18 THE OFFSITE DOSE CALCULATION MANUAL (ODCM) shall contain the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluents, in the calculation of gaseous and liquid effluent monitoring Alarm/Trip Setpoints, and in the conduct of the Environmental Radiological Monitoring Program. The ODCM shall also contain (1) the Radioactive Effluent Controls and Radiological Environmental Monitoring Programs required by Section 6.8.4 and (2) descriptions of the information that should be included in the Annual Radiological Environmental Operating and Annual Radioactive Effluent Release Reports required by Specifications 6.9.1.7 and 6.9.1.8.

## DEFINITIONS

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### RATED THERMAL POWER

1.25 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 3020 MWt.

### REACTOR TRIP SYSTEM RESPONSE TIME

1.26 The REACTOR TRIP SYSTEM RESPONSE TIME shall be the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until electrical power to the CEA drive mechanism is interrupted. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured. In lieu of measurement, response time may be verified for selected components provided that the components and methodology for verification have been previously reviewed and approved by the NRC.

### REPORTABLE EVENT

1.27 A REPORTABLE EVENT shall be any of those conditions specified in Section 50.73 to 10 CFR Part 50.

### SHIELD BUILDING INTEGRITY

1.28 SHIELD BUILDING INTEGRITY shall exist when:

- a. Each door is closed except when the access opening is being used for normal transit entry and exit;
- b. The shield building ventilation system is in compliance with Specification 3.6.6.1, and
- c. The sealing mechanism associated with each penetration (e.g., welds, bellows or O-rings) is OPERABLE.

### SHUTDOWN MARGIN

1.29 SHUTDOWN MARGIN shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming all full-length control element assemblies (shutdown and regulating) are fully inserted except for the single assembly of highest reactivity worth which is assumed to be fully withdrawn.

### SITE BOUNDARY

1.30 SITE BOUNDARY means that line beyond which the land or property is not owned, leased, or otherwise controlled by the licensee.

### SOURCE CHECK

1.31 A SOURCE CHECK shall be the qualitative assessment of channel response when the channel sensor is exposed to a radioactive source.

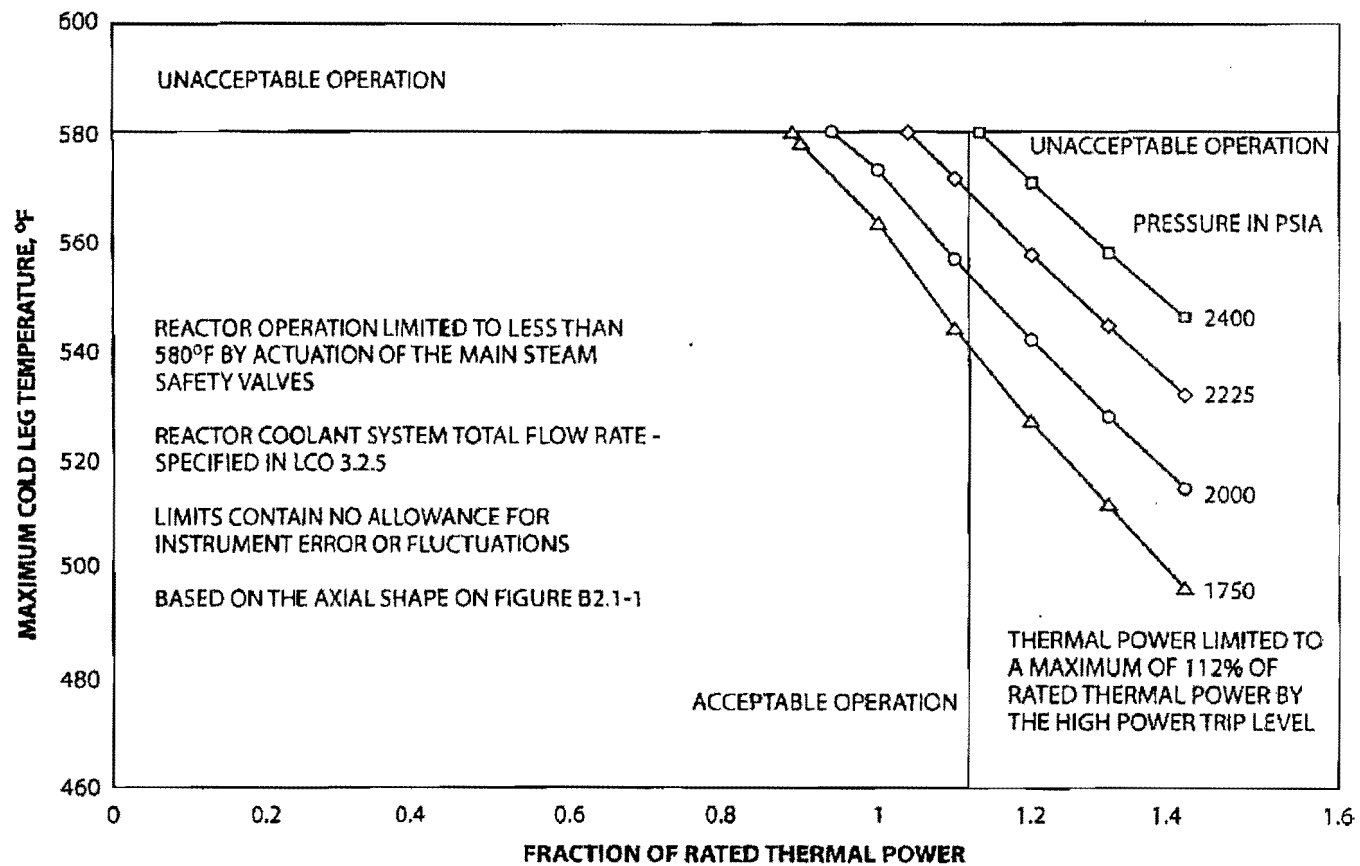


FIGURE 2.1-1: REACTOR CORE THERMAL MARGIN SAFETY LIMIT -  
FOUR REACTOR COOLANT PUMPS OPERATING



**TABLE 2.2-1**  
**REACTOR PROTECTIVE INSTRUMENTATION TRIP SETPOINT LIMITS**

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Manual Reactor Trip	Not Applicable	Not Applicable
2. Power Level – High (1) Four Reactor Coolant Pumps Operating	$\leq 9.61\%$ above THERMAL POWER, with a minimum setpoint of 15% of RATED THERMAL POWER, and a maximum of $< 107.0\%$ of RATED THERMAL POWER.	$\leq 9.61\%$ above THERMAL POWER, and a minimum setpoint of 15% of RATED THERMAL POWER and a maximum of $\leq 107.0\%$ of RATED THERMAL POWER.
3. Reactor Coolant Flow – Low (1) Four Reactor Coolant Pumps Operating	$\geq 95\%$ of minimum reactor coolant flow with 4 pumps operating *	$\geq 95\%$ of minimum reactor coolant flow with 4 pumps operating *
4. Pressurizer Pressure – High	$\leq 2400$ psia	$\leq 2400$ psia
5. Containment Pressure – High	$\leq 3.3$ psig	$\leq 3.3$ psig
6. Steam Generator Pressure – Low (2)	$\geq 600$ psia	$\geq 600$ psia
7. Steam Generator Water Level – Low	$\geq 35.0\%$ Water Level – each steam generator	$\geq 35.0\%$ Water Level – each steam generator
8. Local Power Density – High (3)	Trip setpoint adjusted to not exceed the limit lines of Figures 2.2-1 and 2.2-2.	Trip set point adjusted to not exceed the limit lines of Figures 2.2-1 and 2.2-2.

\* For minimum reactor coolant flow with 4 pumps operating, refer to Technical Specification LCO 3.2.5.

### 3/4.1 REACTIVITY CONTROL SYSTEMS

#### 3/4.1.1 BORATION CONTROL

SHUTDOWN MARGIN -  $T_{avg} > 200^{\circ}\text{F}$

#### LIMITING CONDITION FOR OPERATION

---

3.1.1.1 The SHUTDOWN MARGIN shall be within the limits specified in the COLR.

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

#### ACTION:

With the SHUTDOWN MARGIN not within limits immediately initiate and continue boration at  $\geq 40$  gpm of greater than or equal to 1900 ppm boron or equivalent until the required SHUTDOWN MARGIN is restored.

#### SURVEILLANCE REQUIREMENTS

---

4.1.1.1.1 The SHUTDOWN MARGIN shall be determined to be within the COLR limits:

- a. Within one hour after detection of an inoperable CEA(s) and at least once per 12 hours thereafter while the CEA(s) is inoperable. If the inoperable CEA is not fully inserted, and is immovable as a result of excessive friction or mechanical interference or is known to be untrippable, the above required SHUTDOWN MARGIN shall be increased by an amount at least equal to the withdrawn worth of the immovable or untrippable CEA(s).
- b. When in MODES 1 or 2\*, at least once per 12 hours by verifying that CEA group withdrawal is within the Power Dependent Insertion Limits of Specification 3.1.3.6.
- c. When in MODE 2\*\* at least once during CEA withdrawal and at least once per hour thereafter until the reactor is critical.
- d. Prior to initial operation above 5% RATED THERMAL POWER after each fuel loading, by consideration of the factors of e below, with the CEA groups at the Power Dependent Insertion Limits of Specification 3.1.3.6.

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\* See Special Test Exception 3.10.1.

# With  $K_{eff} \geq 1.0$ .

## With  $K_{eff} < 1.0$ .

## REACTIVITY CONTROL SYSTEMS

SHUTDOWN MARGIN -  $T_{avg} \leq 200$  °F

### LIMITING CONDITION FOR OPERATION

---

3.1.1.2 The SHUTDOWN MARGIN shall be:

Within the limits specified in the COLR, and in addition with the Reactor Coolant System drained below the hot leg centerline, one charging pump shall be rendered inoperable.\*

APPLICABILITY: MODE 5.

#### ACTION:

If the SHUTDOWN MARGIN requirements cannot be met, immediately initiate and continue boration at  $\geq 40$  gpm of greater than or equal to 1900 ppm boron or equivalent until the required SHUTDOWN MARGIN is restored.

### SURVEILLANCE REQUIREMENTS

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4.1.1.2 The SHUTDOWN MARGIN requirements of Specification 3.1.1.2 shall be determined:

- a. Within one hour after detection of an inoperable CEA(s) and at least once per 12 hours thereafter while the CEA(s) is inoperable. If the inoperable CEA is immovable or untrippable, the above required SHUTDOWN MARGIN shall be increased by an amount at least equal to the withdrawn worth of the immovable or untrippable CEA(s).
- b. At least once per 24 hours by consideration of the following factors:
  1. Reactor coolant system boron concentration,
  2. CEA position,
  3. Reactor coolant system average temperature,
  4. Fuel burnup based on gross thermal energy generation,
  5. Xenon concentration, and
  6. Samarium concentration.
- c. At least once per 24 hours, when the Reactor Coolant System is drained below the hot leg centerline, by consideration of the factors in 4.1.1.2.b and by verifying at least one charging pump is rendered inoperable.\*

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\* Breaker racked-out.

## REACTIVITY CONTROL SYSTEMS

### 3/4.1.2 BORATION SYSTEMS

#### FLOW PATHS – SHUTDOWN

#### LIMITING CONDITION FOR OPERATION

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- 3.1.2.1 As a minimum, one of the following boron injection flow paths shall be OPERABLE and capable of being powered from an OPERABLE emergency power source.
- a. A flow path from the boric acid makeup tank via either a boric acid pump or a gravity feed connection and any charging pump to the Reactor Coolant System if only the boric acid makeup tank in Specification 3.1.2.7a is OPERABLE, or
  - b. The flow path from the refueling water tank via either a charging pump or a high pressure safety injection pump\* to the Reactor Coolant System if only the refueling water tank in Specification 3.1.2.7b is OPERABLE.

**APPLICABILITY:** MODES 5 and 6.

#### ACTION:

With none of the above flow paths OPERABLE, suspend all operations involving CORE ALTERATIONS or positive reactivity changes\*\* until at least one injection path is restored to OPERABLE status.

#### SURVEILLANCE REQUIREMENTS

---

- 4.1.2.1 At least one of the above required flow paths shall be demonstrated OPERABLE:
- a. At least once per 31 days by verifying that each valve (manual, power operated or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

---

\* The flow path from the RWT to the RCS via a single HPSI pump shall only be established if: (a) the RCS pressure boundary does not exist, or (b) RCS pressure boundary integrity exists and no charging pumps are operable. In the latter case, all charging pumps shall be disabled.

\*\* Plant temperature changes are allowed provided the temperature change is accounted for in the calculated SHUTDOWN MARGIN.

DELETED

|

## REACTIVITY CONTROL SYSTEMS

### FLOW PATHS – OPERATING

#### LIMITING CONDITION FOR OPERATION

---

3.1.2.2 At least two of the following three boron injection flow paths shall be OPERABLE:

- a. One flow path from the boric acid makeup tank(s) with the tank meeting Specification 3.1.2.8 part a) or b), via a boric acid makeup pump through a charging pump to the Reactor Coolant System.
- b. One flow path from the boric acid makeup tank(s) with the tank meeting Specification 3.1.2.8 part a) or b), via a gravity feed valve through a charging pump to the Reactor Coolant System.
- c. The flow path from the refueling water storage tank via a charging pump to the Reactor Coolant System.

OR

At least two of the following three boron injection flow paths shall be OPERABLE:

- d. One flow path from each boric acid makeup tank with the combined tank contents meeting Specification 3.1.2.8 c), via both boric acid makeup pumps through a charging pump to the Reactor Coolant System.
- e. One flow path from each boric acid makeup tank with the combined tank contents meeting Specification 3.1.2.8 c), via both gravity feed valves through a charging pump to the Reactor Coolant System.
- f. The flow path from the refueling water storage tank, via a charging pump to the Reactor Coolant System.

APPLICABILITY: MODES 1, 2, 3 and 4.

#### ACTION:

With only one of the above required boron injection flow paths to the Reactor Coolant System OPERABLE, restore at least two boron injection flow paths to the Reactor Coolant System to OPERABLE status within 72 hours or make the reactor subcritical within the next 2 hours and borate to a SHUTDOWN MARGIN equivalent to the requirements of Specification 3.1.1.2 at 200°F; restore at least two flow paths to OPERABLE status within the next 7 days or be in COLD SHUTDOWN within the next 30 hours.

## REACTIVITY CONTROL SYSTEMS

### CHARGING PUMPS – SHUTDOWN

#### LIMITING CONDITION FOR OPERATION

---

- 3.1.2.3 At least one charging pump or high pressure safety injection pump\* in the boron injection flow path required OPERABLE pursuant to Specification 3.1.2.1 shall be OPERABLE and capable of being powered from an OPERABLE emergency bus.

APPLICABILITY: MODES 5 and 6.

#### ACTION:

With no charging pump or high pressure safety injection pump\* OPERABLE, suspend all operations involving CORE ALTERATIONS or positive reactivity changes\*\* until at least one of the required pumps is restored to OPERABLE status.

#### SURVEILLANCE REQUIREMENTS

---

- 4.1.2.3 At least one of the above required pumps shall be demonstrated OPERABLE by verifying the charging pump develops a flow rate of greater than or equal to 40 gpm or the high pressure safety injection pump develops a total head of greater than or equal to 2571 ft. when tested pursuant to the Inservice Testing Program.

---

\* The flow path from the RWT to the RCS via a single HPSI pump shall be established only if:  
(a) the RCS pressure boundary does not exist, or (b) RCS pressure boundary integrity exists and no charging pumps are operable. In the latter case, all charging pumps shall be disabled.

\*\* Plant temperature changes are allowed provided the temperature change is accounted for in the calculated SHUTDOWN MARGIN.

## REACTIVITY CONTROL SYSTEMS

### BORATED WATER SOURCES – SHUTDOWN

#### LIMITING CONDITION FOR OPERATION

---

3.1.2.7 As a minimum, one of the following borated water sources shall be OPERABLE:

- a. One boric acid makeup tank with a minimum borated water volume of 3650 gallons of 3.0 to 3.5 weight percent boric acid (5245 to 6119 ppm boron).
- b. The refueling water tank with:
  1. A minimum contained volume of 125,000 gallons,
  2. A minimum boron concentration of 1900 ppm, and
  3. A minimum solution temperature of 40°F.

APPLICABILITY: MODES 5 and 6.

#### ACTION:

With no borated water sources OPERABLE, suspend all operations involving positive reactivity changes\* until at least one borated water source is restored to OPERABLE status.

#### SURVEILLANCE REQUIREMENTS

---

4.1.2.7 The above required borated water source shall be demonstrated OPERABLE:

- a. At least once per 7 days by:
  1. Verifying the boron concentration of the water,
  2. Verifying the water level of the tank, and.
- b. At least once per 24 hours by verifying the RWT temperature when it is the source of borated water and the site ambient air temperature is < 40°F.
- c. At least once per 24 hours when the Reactor Auxiliary Building air temperature is less than 55°F by verifying that the Boric Acid Makeup Tank solution temperature is greater than 55°F when that Boric Acid Makeup Tank is required to be OPERABLE.

---

\* Plant temperature changes are allowed provided the temperature change is accounted for in the calculated SHUTDOWN MARGIN.



## REACTIVITY CONTROL SYSTEMS

### BORATED WATER SOURCES – OPERATING

#### LIMITING CONDITION FOR OPERATION

---

3.1.2.8 At least two of the following four borated water sources shall be OPERABLE:

- a. Boric Acid Makeup Tank 1A in accordance with Figure 3.1-1.
- b. Boric Acid Makeup Tank 1B in accordance with Figure 3.1-1.
- c. Boric Acid Makeup Tanks 1A and 1B with a minimum combined contained borated water volume in accordance with Figure 3.1-1.
- d. The refueling water tank with:
  1. A minimum contained volume of 477,360 gallons of water,
  2. A minimum boron concentration of 1900 ppm,
  3. A maximum solution temperature of 100°F,
  4. A minimum solution temperature of 55°F when in MODES 1 and 2, and
  5. A minimum solution temperature of 40°F when in MODES 3 and 4.

APPLICABILITY: MODES 1, 2, 3 and 4.

#### ACTION:

With only one borated water source OPERABLE, restore at least two borated water sources to OPERABLE status within 72 hours or make the reactor subcritical within the next 2 hours and borate to a SHUTDOWN MARGIN equivalent to the requirements of Specification 3.1.1.2 at 200°F; restore at least two borated water sources to OPERABLE status within the next 7 days or be in COLD SHUTDOWN within the next 30 hours.

#### SURVEILLANCE REQUIREMENTS

---

4.1.2.8 At least two borated water sources shall be demonstrated OPERABLE:

- a. At least once per 7 days by:
  1. Verifying the boron concentration of the water source,

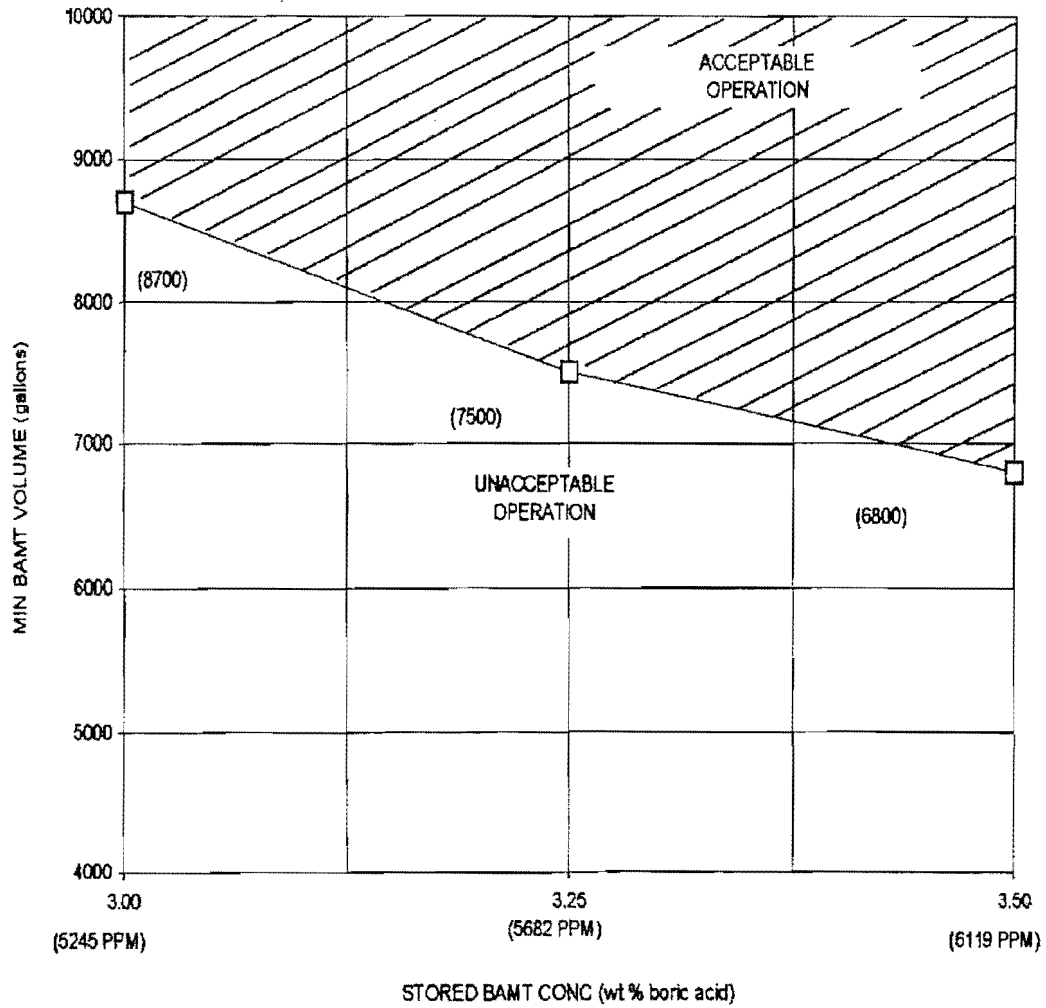
## REACTIVITY CONTROL SYSTEMS

### SURVEILLANCE REQUIREMENTS (Continued)

---

2. Verifying the water level in each water source:
  - b. At least once per 24 hours by verifying the RWT temperature.
  - c. At least once per 24 hours by verifying that the Boric Acid Makeup Tank solution temperature is greater than 55°F when the Reactor Auxiliary Building air temperature is below 55°F.

FIGURE 3.1-1 ST. LUCIE 1 MIN BAMT VOLUME  
VS STORED BAMT CONCENTRATION  
(MODES 1, 2, 3 and 4)



## POWER DISTRIBUTION LIMITS

### DNB PARAMETERS

#### LIMITING CONDITION FOR OPERATION

3.2.5 The following DNB related parameters shall be maintained within the limits:

- a. Cold Leg Temperature as shown on Table 3.2-1 of the COLR,
- b. Pressurizer Pressure\* as shown on Table 3.2-1 of the COLR,
- c. Reactor Coolant System Total Flow Rate - greater than or equal to 375,000 gpm, and
- d. AXIAL SHAPE INDEX as shown on Figure 3.2-4 of the COLR.

APPLICABILITY: MODE 1.

#### ACTION:

With any of the above parameters exceeding its limit, restore the parameter to within its limit within 2 hours or reduce THERMAL POWER to  $\leq 5\%$  of RATED THERMAL POWER within the next 4 hours.

#### SURVEILLANCE REQUIREMENTS

- 4.2.5.1 Each of the DNB related parameters shall be verified to be within their limits by instrument readout at least once per 12 hours.
- 4.2.5.2 The Reactor Coolant System total flow rate shall be determined to be within its limit by measurement\*\* at least once per 18 months.

\* Limit not applicable during either a THERMAL POWER ramp increase in excess of 5% per minute of RATED THERMAL POWER or a THERMAL POWER step increase of greater than 10% of RATED THERMAL POWER.

\*\* Not required to be performed until THERMAL POWER is  $\geq 90\%$  of RATED THERMAL POWER.

Relocated to the COLR

|

**TABLE 4.3-1**  
**REACTOR PROTECTIVE INSTRUMENTATION SURVEILLANCE REQUIREMENTS**

<b><u>FUNCTIONAL UNIT</u></b>	<b><u>CHANNEL CHECK</u></b>	<b><u>CHANNEL CALIBRATION</u></b>	<b><u>CHANNEL FUNCTIONAL TEST</u></b>	<b><u>MODES IN WHICH SURVEILLANCE REQUIRED</u></b>
1. Manual Reactor Trip	N/A	N.A.	S/U(1)	N/A
2. Power Level – High				
a. Nuclear Power	S	D(2), M(3), Q(5)	M	1, 2
b. $\Delta T$ Power	S	D(4), Q	M	1
3. Reactor Coolant Flow – Low	S	R	M	1, 2
4. Pressurizer Pressure – High	S	R	M	1, 2
5. Containment Pressure – High	S	R	M	1, 2
6. Steam Generator Pressure – Low	S	R	M	1, 2
7. Steam Generator Water Level – Low	S	R	M(6, 7)	1, 2
8. Local Power Density – High	S	R	M	1
9. Thermal Margin/Low Pressure	S	R	M	1, 2
9a. Steam Generator Pressure Difference – High	S	R	M	1, 2
10. Loss of Turbine -- Hydraulic Fluid Pressure – Low	N.A.	N.A.	S/U(1)	N.A.
11. Wide Range Logarithmic Neutron Flux Monitor	S	N.A.	S/U(1)	1, 2, 3, 4, 5 and *
12. Reactor Protection System Logic	N.A.	N.A.	M and S/U(1)	1, 2 and *
13. Reactor Trip Breakers	N.A.	N.A.	M	1, 2 and *

TABLE 4.3-1 (Continued)

TABLE NOTATION

- \* - With reactor trip breaker closed.
- (1) - If not performed in previous 7 days.
- (2) - Heat balance only, above 15% of RATED THERMAL POWER; adjust "Nuclear Power Calibrate" potentiometer to null "Nuclear Pwr –  $\Delta T$  Pwr." During PHYSICS TESTS, these daily calibrations of nuclear power and  $\Delta T$  power may be suspended provided these calibrations are performed upon reaching each major test power plateau and prior to proceeding to the next major test power plateau.
- (3) - Above 15% of RATED THERMAL POWER, recalibrate the excore detectors which monitor the AXIAL SHAPE INDEX by using the incore detectors or restrict THERMAL POWER during subsequent operations to  $\leq 90\%$  of the maximum allowed THERMAL POWER level with the existing Reactor Coolant Pump combination.
- (4) - Adjust " $\Delta T$  Pwr Calibrate" potentiometers to make  $\Delta T$  power signals agree with calorimetric calculation.
- (5) - Neutron detectors may be excluded from CHANNEL CALIBRATION.
- (6) - If the as-found setpoint is either outside its predefined as-found acceptance criteria band or is not conservative with respect to the Allowable Value, then the channel shall be declared inoperable and shall be evaluated to verify that it is functioning as required before returning the channel to service.
- (7) - The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the Field Trip Setpoint, otherwise that channel shall not be returned to OPERABLE status. The Field Trip Setpoint and the methodology used to determine the Field Trip Setpoint, the as-found acceptance criteria band, and the as-left acceptance criteria are specified in the UFSAR Section 7.2.

## REACTOR COOLANT SYSTEM

### SPECIFIC ACTIVITY

#### LIMITING CONDITION FOR OPERATION

---

3.4.8 The specific activity of the primary coolant shall be limited to:

- a.  $\leq 1.0 \mu\text{Ci/gram DOSE EQUIVALENT I-131}$ , and
- b.  $\leq 518.9 \mu\text{Ci/gram DOSE EQUIVALENT XE-133}$ .

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

#### ACTION:

- a. With the specific activity of the primary coolant  $> 1.0 \mu\text{Ci/gram DOSE EQUIVALENT I-131}$ , verify DOSE EQUIVALENT I-131 is  $\leq 60.0 \mu\text{Ci/gram}$  once per four hours.
- b. With the specific activity of the primary coolant  $> 1.0 \mu\text{Ci/gram DOSE EQUIVALENT I-131}$ , but  $\leq 60.0 \mu\text{Ci/gram DOSE EQUIVALENT I-131}$ , operation may continue for up to 48 hours while efforts are made to restore DOSE EQUIVALENT I-131 to within the  $1.0 \mu\text{Ci/gram}$  limit. Specification 3.0.4 is not applicable.
- c. With the specific activity of the primary coolant  $> 1.0 \mu\text{Ci/gram DOSE EQUIVALENT I-131}$  for greater than 48 hours during one continuous time interval, or  $> 60.0 \mu\text{Ci/gram DOSE EQUIVALENT I-131}$ , be in HOT STANDBY within 6 hours and COLD SHUTDOWN within the following 30 hours.
- d. With the specific activity of the primary coolant  $> 518.9 \mu\text{Ci/gram DOSE EQUIVALENT XE-133}$ , operation may continue for up to 48 hours while efforts are made to restore DOSE EQUIVALENT XE-133 to within the  $518.9 \mu\text{Ci/gram DOSE EQUIVALENT XE-133}$  limit. Specification 3.0.4 is not applicable.
- e. With the specific activity of the primary coolant  $> 518.9 \mu\text{Ci/gram DOSE EQUIVALENT XE-133}$  for greater than 48 hours during one continuous time interval, be in HOT STANDBY within 6 hours and COLD SHUTDOWN within the following 30 hours.

#### SURVEILLANCE REQUIREMENTS

---

4.4.8 The specific activity of the primary coolant shall be determined to be within the limits by performance of the sampling and analysis program of Table 4.4-4.



**TABLE 4.4-4**  
**PRIMARY COOLANT SPECIFIC ACTIVITY SAMPLE**  
**AND ANALYSIS PROGRAM**

<b><u>TYPE OF MEASUREMENT AND ANALYSIS</u></b>	<b><u>MINIMUM FREQUENCY</u></b>	<b><u>MODES IN WHICH SAMPLE AND ANALYSIS REQUIRED</u></b>
1. DOSE EQUIVALENT XE-133 Determination	1 per 7 days	1, 2, 3 and 4
2. Isotopic Analysis for DOSE EQUIVALENT I-131 Concentration	1 per 14 days	1
3. Isotopic Analysis for Iodine Including I-131, I-132, I-133, I-134, and I-135	a) Once per 4 hours, whenever the DOSE EQUIVALENT I-131 exceeds 1.0 $\mu$ Ci/gram, and	1 <sup>#</sup> , 2 <sup>#</sup> , 3 <sup>#</sup> , and 4 <sup>#</sup>
	b) One sample between 2 and 6 hours following a THERMAL POWER change exceeding 15 percent of the RATED THERMAL POWER within a one hour period.	1, 2, 3

# Until the specific activity of the primary coolant system is restored within its limits.

DELETED

## **REACTOR COOLANT SYSTEM**

### **3/4.4.9 PRESSURE/TEMPERATURE LIMITS**

## **REACTOR COOLANT SYSTEM**

### **LIMITING CONDITION FOR OPERATION**

---

- 3.4.9.1 The Reactor Coolant System (except the pressurizer) temperature and pressure shall be limited in accordance with the limit lines shown on Figures 3.4-2a and 3.4-2b during heatup, cooldown, criticality, and inservice leak and hydrostatic testing.

**APPLICABILITY:** At all times.\*

#### **ACTION:**

With any of the above limits exceeded, restore the temperature and/or pressure to within the limits within 30 minutes; perform an analysis to determine the effects of the out-of-limit condition on the fracture toughness properties of the Reactor Coolant System; determine that the Reactor Coolant System remains acceptable for continued operations or be in at least HOT STANDBY within the next 6 hours and reduce the RCS T<sub>avg</sub> to less than 200°F within the following 30 hours in accordance with Figure 3.4-2b.

- 
- \* During hydrostatic testing operations above system design pressure, a maximum temperature change in any one hour period shall be limited to 5°F.

## REACTOR COOLANT SYSTEM

### SURVEILLANCE REQUIREMENTS

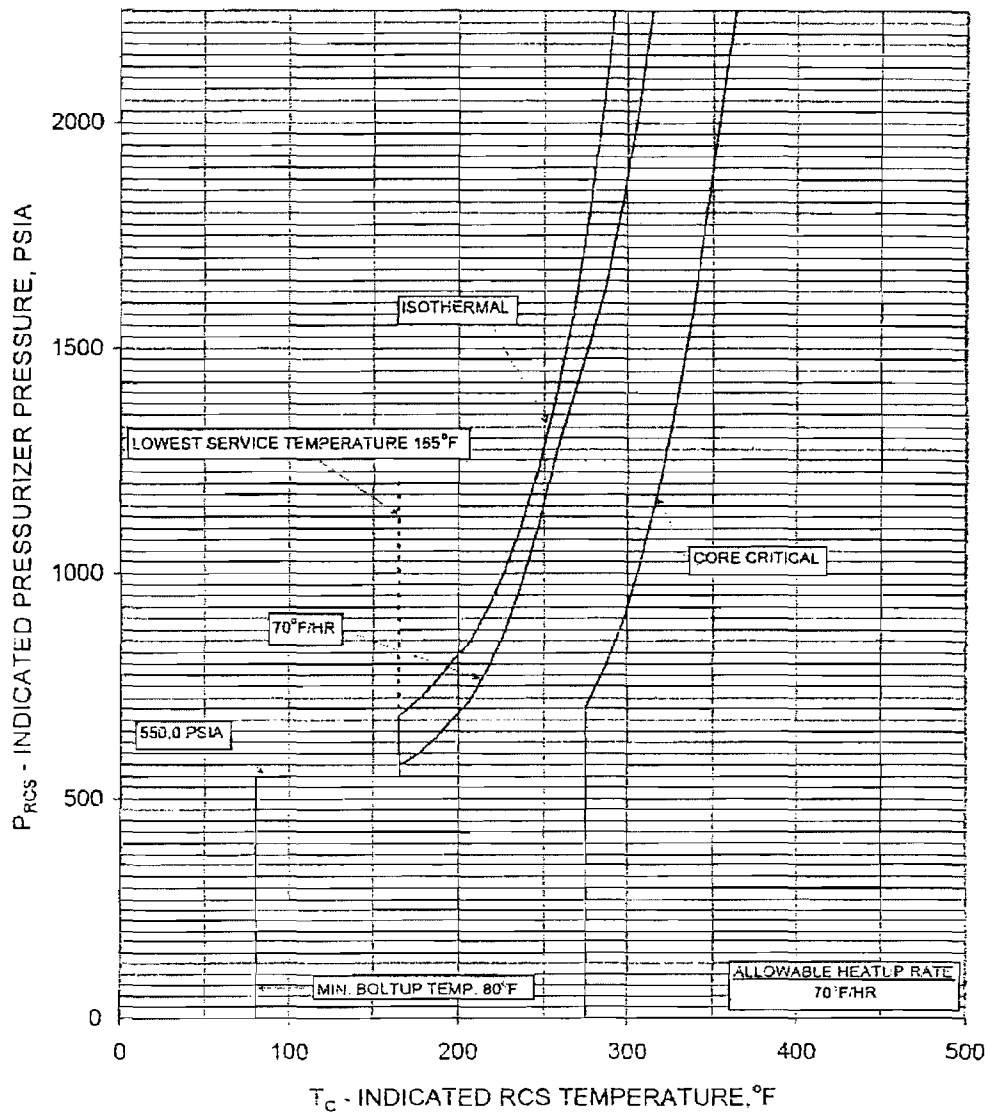
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#### 4.4.9.1

- a. The Reactor Coolant System temperature and pressure shall be determined to be within the limits at least once per 30 minutes during system heatup, cooldown, and inservice leak and hydrostatic testing operations.
- b. The Reactor Coolant System temperature and pressure conditions shall be determined to be to the right of the criticality limit line within 15 minutes prior to achieving reactor criticality.
- c. The reactor vessel material irradiation surveillance specimens shall be removed and examined, to determine changes in material properties as required by 10 CFR 50 Appendix H. The results of these examinations shall be used to update Figures 3.4-2a and 3.4-2b.

FIGURE 3.4-2a

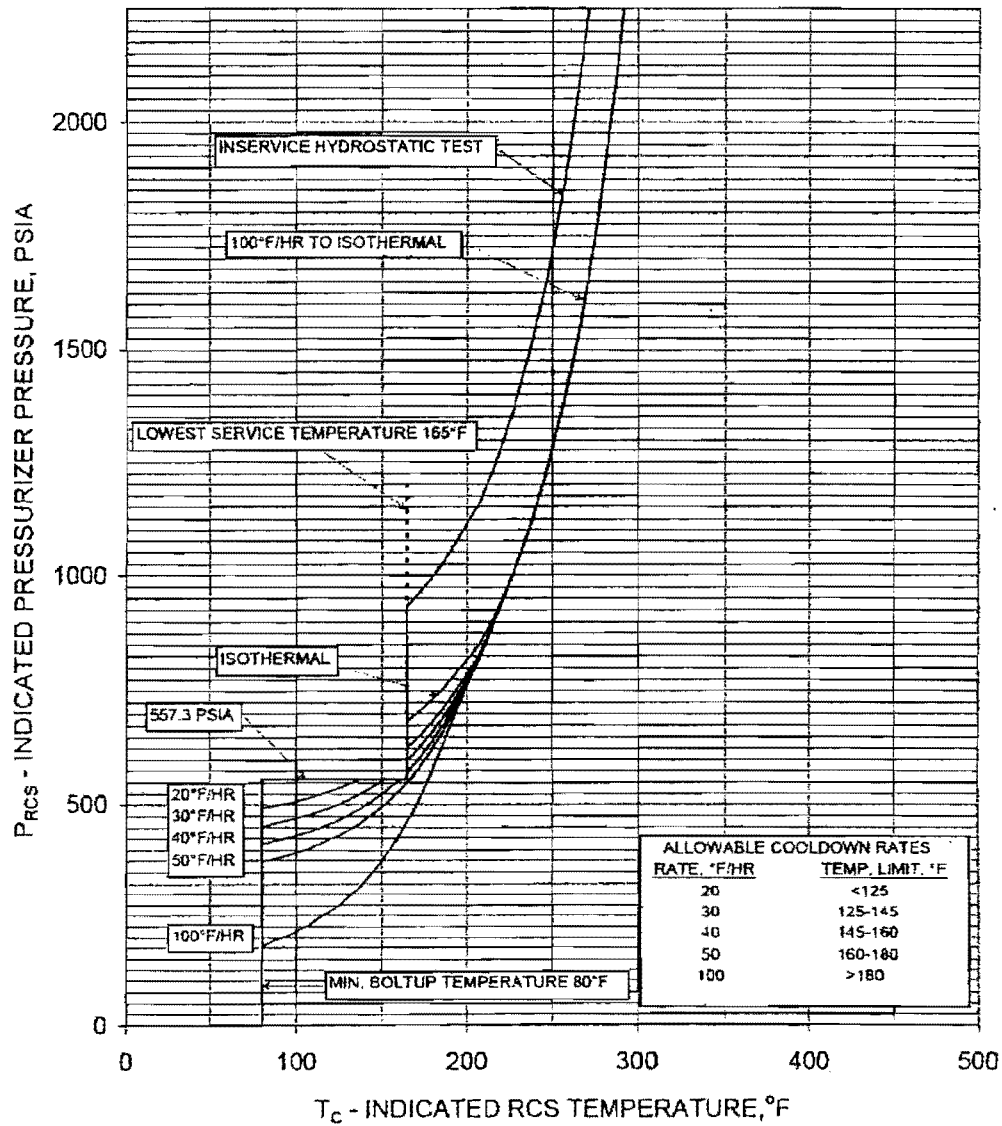
ST. LUCIE UNIT 1 P/T LIMITS, 54 EFPY  
HEATUP AND CORE CRITICAL



Limiting Material: Lower Shell Axial Welds (Ht. #305424)  
Limiting ART Values at 54 EFPY: 1/4T, 210°F  
3/4T, 156°F

FIGURE 3.4-2b

ST. LUCIE UNIT 1 P/T LIMITS, 54 EFY  
COOLDOWN AND INSERVICE TEST



Limiting Material: Lower Shell Axial Welds (Ht. #305424)

Limiting ART Values at 54 EFY:  
1/4T, 210°F  
3/4T, 156°F

DELETED

|

## REACTOR COOLANT SYSTEM

### POWER OPERATED RELIEF VALVES

#### LIMITING CONDITION FOR OPERATION

---

3.4.13 Two power operated relief valves (PORVs) shall be OPERABLE, with their setpoints selected to the low temperature mode of operation as follows:

- a. A setpoint of less than or equal to 350 psia shall be selected during heatup, cooldown and isothermal conditions when the temperature of any RCS cold leg is less than or equal to 200°F.
- b. A setpoint of less than or equal to 530 psia shall be selected during heatup, cooldown and isothermal conditions when the temperature of any RCS cold leg is greater than 200°F and less than or equal to 300°F.

**APPLICABILITY:** MODE 4 when the temperature of any RCS cold leg is less than or equal to 300°F, MODE 5, and MODE 6 when the head is on the reactor vessel; and the RCS is not vented through greater than a 1.75 square inch vent.

#### ACTION:

- a. With one PORV inoperable in MODE 4, restore the inoperable PORV to OPERABLE status within 7 days; or depressurize and vent the RCS through greater than a 1.75 square inch vent within the next 8 hours.
- b. With one PORV inoperable in MODES 5 or 6, either (1) restore the inoperable PORV to OPERABLE status within 24 hours, or (2) complete depressurization and venting of the RCS through greater than a 1.75 square inch vent within a total of 32 hours.
- c. With both PORVs inoperable, restore at least one PORV to operable status or complete depressurization and venting of the RCS through greater than a 1.75 square inch vent within 24 hours.
- d. With the RCS vented per ACTIONS a, b, or c, verify the vent pathway at least once per 31 days when the pathway is provided by a valve(s) that is locked, sealed, or otherwise secured in the open position; otherwise, verify the vent pathway every 12 hours.
- e. In the event either the PORVs or the RCS vent(s) are used to mitigate an RCS pressure transient, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 30 days. The report shall describe the circumstances initiating the transient, the effect of the PORVs or RCS vent(s) on the transient, and any corrective action necessary to prevent recurrence.
- f. The provisions of Specification 3.0.4 are not applicable.

#### SURVEILLANCE REQUIREMENTS

---

4.4.13 Each PORV shall be demonstrated OPERABLE by:

- a. Verifying the PORV isolation valve is open at least once per 72 hours; and
- b. Performance of a CHANNEL FUNCTION TEST, but excluding valve operation, at least once per 31 days; and
- c. Performance of a CHANNEL CALIBRATION at least once per 18 months.



## REACTOR COOLANT SYSTEM

### REACTOR COOLANT PUMP - STARTING

#### LIMITING CONDITION FOR OPERATION

---

3.4.14 If the steam generator temperature exceeds the primary temperature by more than 30°F, the first idle reactor coolant pump shall not be started.

APPLICABILITY: MODES 4<sup>#</sup> and 5.

#### ACTION:

If a reactor coolant pump is started when the steam generator temperature exceeds primary temperature by more than 30°F, evaluate the subsequent transient to determine compliance with Specification 3.4.9.1.

#### SURVEILLANCE REQUIREMENTS

---

4.4.14 Prior to starting a reactor coolant pump, verify that the steam generator temperature does not exceed primary temperature by more than 30°F.

---

# Reactor Coolant System Cold Leg Temperature is less than 300°F.

### 3/4.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

#### SAFETY INJECTION TANKS (SIT)

##### LIMITING CONDITION FOR OPERATION

---

3.5.1 Each reactor coolant system safety injection tank shall be OPERABLE with:

- a. The isolation valve open,
- b. Between 1090 and 1170 cubic feet of borated water,
- c. A minimum boron concentration of 1900 ppm, and
- d. A nitrogen cover-pressure of between 230 and 280 psig.

**APPLICABILITY:** MODES 1, 2 and 3.\*

##### **ACTION:**

- a. With one SIT inoperable due to boron concentration not within limits, or due to an inability to verify the required water volume or nitrogen cover-pressure, restore the inoperable SIT to OPERABLE status with 72 hours; otherwise, be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.
- b. With one SIT inoperable due to reasons other than those stated in ACTION-a, restore the inoperable SIT to OPERABLE status within 24 hours; otherwise, be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

##### **SURVEILLANCE REQUIREMENTS**

---

4.5.1 Each safety injection tank shall be demonstrated OPERABLE:

- a. At least once per 12 hours by:
  1. Verifying that the borated water volume and nitrogen cover-pressure in the tanks are within their limits, and
  2. Verifying that each safety injection tank isolation valve is open.

---

\* With pressurizer pressure  $\geq$  1750 psia.

## EMERGENCY CORE COOLING SYSTEMS

### ECCS SUBSYSTEMS - OPERATING

#### LIMITING CONDITION FOR OPERATION

- 3.5.2 Two independent ECCS subsystems shall be OPERABLE with each subsystem comprised of:
- One OPERABLE high-pressure safety injection (HPSI) pump,
  - One OPERABLE low-pressure safety injection pump,
  - 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
  - One OPERABLE charging pump\*.

APPLICABILITY: MODES 1, 2 and 3\*\*.

#### ACTION:

- 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.
  - 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.
- 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.

\* One ECCS subsystem charging pump shall satisfy the flow path requirements of Specification 3.1.2.2.a or 3.1.2.2.d. The second ECCS subsystem charging pump shall satisfy the flow path requirements of Specification 3.1.2.2.b or 3.1.2.2.e.

\*\* 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 paths 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 Pumps.
    - b. Low-Pressure Safety Injection Pumps.
    - c. Charging Pumps.
  - 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 when tested pursuant to the Inservice Testing Program.
  - 1. High-Pressure Safety Injection pumps.
  - 2. Low-Pressure Safety Injection pumps.

## EMERGENCY CORE COOLING SYSTEMS

### REFUELING WATER TANK

#### LIMITING CONDITION FOR OPERATION

---

- 3.5.4 The refueling water tank shall be OPERABLE with:
- a. A minimum contained volume 477,360 gallons of borated water,
  - b. A minimum boron concentration of 1900 ppm,
  - c. A maximum water temperature of 100°F,
  - d. A minimum water temperature of 55°F when in MODES 1 and 2, and
  - e. A minimum water temperature of 40°F when in MODES 3 and 4

APPLICABILITY: MODES 1, 2, 3 and 4.

#### ACTION:

With the refueling water tank inoperable, restore the tank to OPERABLE status within 1 hour or be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

#### SURVEILLANCE REQUIREMENTS

---

- 4.5.4 The RWT shall be demonstrated OPERABLE:
- a. At least once per 7 days by:
    - 1. Verifying the water level in the tank, and
    - 2. Verifying the boron concentration of the water.
  - b. At least once per 24 hours by verifying the RWT temperature.

## CONTAINMENT SYSTEMS

### INTERNAL PRESSURE

#### LIMITING CONDITION FOR OPERATION

---

3.6.1.4 Primary containment internal pressure shall be maintained between -0.7 and +0.5 psig.

APPLICABILITY: MODES 1, 2, 3 and 4.

#### ACTION:

With the containment internal pressure outside of the limits above, restore the internal pressure to within the limits within 1 hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

#### SURVEILLANCE REQUIREMENTS

---

4.6.1.4 The primary containment internal pressure shall be determined to be within the limits at least once per 12 hours.

**TABLE 3.7-1**

**MAXIMUM ALLOWABLE POWER LEVEL-HIGH TRIP SETPOINT WITH INOPERABLE  
STEAM LINE SAFETY VALVES DURING OPERATION WITH BOTH STEAM GENERATORS**

<b><u>Maximum Number of Inoperable Safety Valves on Any Operating Steam Generator</u></b>	<b><u>Maximum Allowable Power Level-High Trip Setpoint (Percent of RATED THERMAL POWER)</u></b>
1	88.5
2	79.8
3	66.5

**TABLE 4.7-1**  
**STEAM LINE SAFETY VALVES PER LOOP**

	<b><u>VALVE NUMBER</u></b>		<b><u>LIFT SETTING*</u></b>
	<b><u>Header A</u></b>	<b><u>Header B</u></b>	
a.	8201	8205	$\geq 955.3$ psig and $\leq 1015.3$ psig
b.	8202	8206	$\geq 955.3$ psig and $\leq 1015.3$ psig
c.	8203	8207	$\geq 955.3$ psig and $\leq 1015.3$ psig
d.	8204	8208	$\geq 955.3$ psig and $\leq 1015.3$ psig
e.	8209	8213	$\geq 994.1$ psig and $\leq 1046.1$ psig
f.	8210	8214	$\geq 994.1$ psig and $\leq 1046.1$ psig
g.	8211	8215	$\geq 994.1$ psig and $\leq 1046.1$ psig
h.	8212	8216	$\geq 994.1$ psig and $\leq 1046.1$ psig

---

\* +/-3% for valves a through d and +2%/-3% for valves e through h



## PLANT SYSTEMS

### CONDENSATE STORAGE TANK

#### LIMITING CONDITION FOR OPERATION

---

3.7.1.3 The condensate storage tank shall be OPERABLE with a minimum contained volume of 153,400 gallons.

APPLICABILITY: MODES 1, 2 and 3.

#### ACTION:

With the condensate storage tank inoperable, restore the condensate storage tank to OPERABLE status within 4 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

#### SURVEILLANCE REQUIREMENTS

---

4.7.1.3 The condensate storage tank shall be demonstrated OPERABLE at least once per 12 hours by verifying the water level.

### 3/4.8 ELECTRICAL POWER SYSTEMS

#### 3/4.8.1 A.C. SOURCES

##### OPERATING

##### LIMITING CONDITION FOR OPERATION

---

- 3.8.1.1 As a minimum, the following A.C. electrical power sources shall be OPERABLE:
- a. Two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system, and
  - b. Two separate and independent diesel generator sets each with:
    1. Engine-mounted fuel tanks containing a minimum of 152 gallons of fuel,
    2. A separate fuel storage system containing a minimum of 19,000 gallons of fuel, and
    3. A separate fuel transfer pump.

APPLICABILITY: MODES 1, 2, 3 and 4.

##### ACTION:

- a. With one offsite circuit of 3.8.1.1.a inoperable, except as provided in Action f. below, demonstrate the OPERABILITY of the remaining A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter. Restore the offsite circuit to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and COLD SHUTDOWN within the following 30 hours.
- b. With one diesel generator of 3.8.1.1.b inoperable, demonstrate the OPERABILITY of the A.C. sources by performing Surveillance Requirement 4.8.1.1.1.a within 1 hour and at least once per 8 hours thereafter; and if the EDG became inoperable due to any cause other than an inoperable support system, an independently testable component, or preplanned preventative maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE EDG by performing Surveillance Requirement 4.8.1.1.2.a.4 within 8 hours, unless it can be confirmed that the cause of the inoperable EDG does not exist on the remaining EDG\*; restore the diesel generator to OPERABLE status within 14 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. Additionally, within 4 hours from the discovery of concurrent inoperability of required redundant feature(s) (including the steam driven auxiliary feed pump in MODE 1, 2, and 3), declare required feature(s) supported by the inoperable EDG inoperable if its redundant required feature(s) is inoperable.

---

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

## ELECTRICAL POWER SYSTEMS

### SURVEILLANCE REQUIREMENTS (Continued)

- b) Verifying the diesel starts on the auto-start signal\*\*\*\*, energizes the emergency busses with permanently connected loads within 10 seconds, energizes the auto-connected shutdown loads through the load sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the shutdown loads. After energization, the steady-state voltage and frequency of the emergency busses shall be maintained at  $4160 \pm 210$  volts and  $60 \pm 0.6$  Hz during this test.
- 4. Verifying that on an ESF actuation test signal (without loss-of-offsite power) the diesel generator starts\*\*\*\* on the auto-start signal, and:
  - a) Within 10 seconds, generator voltage and frequency shall be  $4160 \pm 420$  volts and  $60 \pm 1.2$  Hz.
  - b) Operates on standby for greater than or equal to 5 minutes.
  - c) Steady-state generator voltage and frequency shall be  $4160 \pm 210$  volts and  $60 \pm 0.6$  Hz and shall be maintained throughout this test.
- 5. Simulating a loss-of-offsite power in conjunction with an ESF actuation test signal, and
  - a) Verifying deenergization of the emergency busses and load shedding from the emergency busses.
  - b) Verifying the diesel starts on the auto-start signal\*\*\*\*, energizes the emergency busses with permanently connected loads within 10 seconds, energizes the auto-connected emergency (accident) loads through the auto-sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the emergency loads. After energization, the steady-state voltage and frequency of the emergency busses shall be maintained at  $4160 \pm 210$  volts and  $60 \pm 0.6$  Hz during this test.
  - c) Verifying that all automatic diesel generator trips, except engine overspeed and generator differential, are automatically bypassed upon loss of voltage on the emergency bus concurrent with a safety injection signal.

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

## ELECTRICAL POWER SYSTEMS

### SHUTDOWN

#### LIMITING CONDITION FOR OPERATION

---

- 3.8.1.2 As a minimum, the following A.C. electrical power sources shall be OPERABLE:
- a. One circuit between the offsite transmission network and the onsite Class 1E distribution system, and
  - b. One diesel generator set with:
    1. Engine-mounted fuel tanks containing a minimum of 152 gallons of fuel,
    2. A fuel storage system containing a minimum of 19,000 gallons of fuel, and
    3. A fuel transfer pump.

APPLICABILITY: MODES 5 and 6.

#### ACTION:

With less than the above minimum required A.C. electrical power sources OPERABLE, immediately suspend all operations involving CORE ALTERATIONS, operations involving positive reactivity additions that could result in loss of required SHUTDOWN MARGIN or boron concentration, movement of irradiated fuel, or crane operation with loads over the fuel storage pool. In addition, when in MODE 5 with the reactor coolant loops not filled, or in MODE 6 with the water level less than 23 feet above the top of irradiated fuel assemblies seated within the reactor vessel, immediately initiate corrective action to restore the required sources to OPERABLE status as soon as possible.

#### SURVEILLANCE REQUIREMENTS

---

- 4.8.1.2.1 The above required A.C. electrical power sources shall be demonstrated OPERABLE by the performance of each of the Surveillance Requirements of 4.8.1.1.1 and 4.8.1.1.2 except for requirement 4.8.1.1.2a.5.

### 3/4.9 REFUELING OPERATIONS

#### BORON CONCENTRATION

#### LIMITING CONDITION FOR OPERATION

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- 3.9.1 With the reactor vessel head unbolted or removed, the boron concentration of all filled portions of the Reactor Coolant System and the refueling cavity shall be maintained within the limit specified in the COLR.

APPLICABILITY: MODE 6\*.

#### ACTION:

With the requirements of the above specification not satisfied, immediately suspend all operations involving CORE ALTERATIONS or positive reactivity changes and initiate and continue boration at  $\geq 40$  gpm of greater than or equal to 1900 ppm boron or its equivalent to restore boron concentration to within limits.

#### SURVEILLANCE REQUIREMENTS

---

- 4.9.1.1 The boron concentration limit shall be determined prior to:
- Removing or unbolting the reactor vessel head, and
  - Withdrawal of any full length CEA in excess of 3 feet from its fully inserted position.
- 4.9.1.2 The boron concentration of the refueling cavity shall be determined by chemical analysis at least 3 times per 7 days with a maximum time interval between samples of 72 hours.

---

\* The reactor shall be maintained in MODE 6 when the reactor vessel head is unbolted or removed.

## REFUELING OPERATIONS

### SPENT FUEL STORAGE POOL

#### LIMITING CONDITION FOR OPERATION

---

3.9.11 The Spent Fuel Pool shall be maintained with:

- a. The fuel storage pool water level greater than or equal to 23 ft over the top of irradiated fuel assemblies seated in the storage racks, and
- b. The fuel storage pool boron concentration greater than or equal to 1900 ppm.

**APPLICABILITY:** Whenever irradiated fuel assemblies are in the spent fuel storage pool.

#### **ACTION:**

- a. With the water level requirement not satisfied, immediately suspend all movement of fuel assemblies and crane operations with loads in the fuel storage areas and restore the water level to within its limit within 4 hours.
- b. With the boron concentration requirement not satisfied, immediately suspend all movement of fuel assemblies in the fuel storage pool and initiate action to restore the fuel storage pool boron concentration to within the required limit.
- c. The provisions of Specification 3.0.3 are not applicable.

#### SURVEILLANCE REQUIREMENTS

---

- 4.9.11 The water level in the spent fuel storage pool shall be determined to be at least its minimum required depth at least once per 7 days when irradiated fuel assemblies are in the fuel storage pool.
- 4.9.11.1 Verify the fuel storage pool boron concentration is within limit at least once per 7 days.

DELETED

|

### 3/4.10 SPECIAL TEST EXCEPTIONS

#### SHUTDOWN MARGIN

#### LIMITING CONDITION FOR OPERATION

---

3.10.1 The SHUTDOWN MARGIN requirement of Specification 3.1.1.1 may be suspended for measurement of CEA worth and shutdown margin provided reactivity equivalent to at least the highest estimated CEA worth is available for trip insertion from OPERABLE CEA(s).

APPLICABILITY: MODE 2.

ACTION:

- a. With any full length CEA not fully inserted and with less than the above reactivity equivalent available for trip insertion, immediately initiate and continue boration at  $\geq 40$  gpm of 1900 ppm boric acid solution or its equivalent until the SHUTDOWN MARGIN required by Specification 3.1.1.1 is restored.
- b. With all full length CEAs inserted and the reactor subcritical by less than the above reactivity equivalent, immediately initiate and continue boration at  $\geq 40$  gpm of 1900 ppm boric acid solution or its equivalent until the SHUTDOWN MARGIN required by Specification 3.1.1.1 is restored.

#### SURVEILLANCE REQUIREMENTS

---

4.10.1.1 The position of each full length CEA required either partially or fully withdrawn shall be determined at least once per 2 hours.

4.10.1.2 Each CEA not fully inserted shall be demonstrated capable of full insertion when tripped from at least the 50% withdrawn position within 7 days prior to reducing the SHUTDOWN MARGIN to less than the limits of Specification 3.1.1.1.



## RADIOACTIVE EFFLUENTS

### GAS STORAGE TANKS

#### LIMITING CONDITION FOR OPERATION

---

- 3.11.2.6 The quantity of radioactivity contained in each gas storage tank shall be limited to less than or equal to 165,000 curies noble gases (considered as Xe-133).

APPLICABILITY: At all times.

ACTION:

- a. With the quantity of radioactive material in any gas storage tank exceeding the above limit, immediately suspend all additions of radioactive material to the tank.
- b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

#### SURVEILLANCE REQUIREMENTS

---

- 4.11.2.6 The quantity of radioactive material contained in each gas storage tank shall be determined to be within the above limit at least once per 24 hours when radioactive materials are being added to the tank when reactor coolant system activity exceeds 518.9  $\mu\text{Ci/gram}$  DOSE EQUIVALENT XE-133.

## DESIGN FEATURES

### 2.1.2 SHIELD BUILDING

- a. Minimum annular space = 4 feet
- b. Annulus nominal volume = 543,000 cubic feet
- c. Nominal outside height (measured from top of foundation base to the top of the dome) = 230.5 feet
- d. Nominal inside diameter = 148 feet
- e. Cylinder wall minimum thickness = 3 feet
- f. Dome minimum thickness = 2.5 feet
- g. Dome inside radius = 112 feet

### DESIGN PRESSURE AND TEMPERATURE

- 5.2.2 The containment vessel is designed and shall be maintained for a maximum internal pressure of 44 psig and a temperature of 264°F.

### PENETRATIONS

- 5.2.3 Penetrations through the containment structure are designed and shall be maintained in accordance with the original design provisions contained in Sections 3.8.2.1.10 and 6.2.4 of the FSAR with allowance for normal degradation pursuant to the applicable Surveillance Requirements.

### 5.3 REACTOR CORE

#### FUEL ASSEMBLIES

- 5.3.1 The reactor core shall contain 217 fuel assemblies. Each assembly shall consist of a matrix of Zircaloy clad fuel rods and/or poison rods, with fuel rods having an initial composition of natural or slightly enriched uranium dioxide (UO<sub>2</sub>) as fuel material. Limited substitutions of zirconium alloy or stainless steel filler rods for fuel rods, in accordance with approved applications of fuel rod configurations, may be used. Fuel assemblies shall be limited to those fuel designs that have been analyzed with applicable NRC staff approved codes and methods and shown by tests or analyses to comply with all fuel safety design bases. A limited number of lead test assemblies that have not completed representative testing may be placed in non-limiting core regions.
- 5.3.1.1 Except for special test as authorized by the NRC, all fuel assemblies under control element assemblies shall be sleeved with a sleeve design previously approved by the NRC.

## **DESIGN FEATURES**

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### **CONTROL ELEMENT ASSEMBLIES**

- 5.3.2 The reactor core shall contain 73 full length and no part length control element assemblies. The control element assemblies shall be designed and maintained in accordance with the original design provisions contained in Section 4.2.3.2 of the FSAR with allowance for normal degradation pursuant to the applicable Surveillance Requirements.

### **5.4 REACTOR COOLANT SYSTEM**

#### **DESIGN PRESSURE AND TEMPERATURE**

- 5.4.1 The reactor coolant system is designed and shall be maintained:
- In accordance with the code requirements specified in Section 5.2 of the FSAR with allowance for normal degradation pursuant to the applicable Surveillance Requirements,
  - For a pressure of 2485 psig, and
  - For a temperature of 650°F, except for the pressurizer which is 700°F.

### **5.5 EMERGENCY CORE COOLING SYSTEMS**

- 5.5.1 The emergency core cooling systems are designed and shall be maintained in accordance with the original design provisions contained in Section 6.3 of the FSAR with allowance for normal degradation pursuant to the applicable Surveillance Requirements.

### **5.6 FUEL STORAGE**

#### **CRITICALITY**

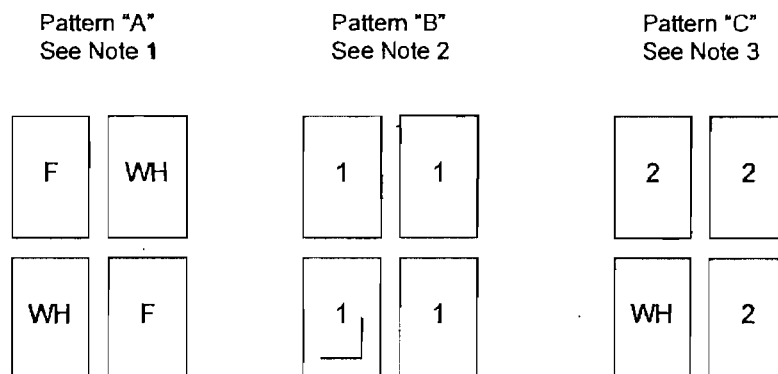
- 5.6.1.a The spent fuel pool and spent fuel storage racks shall be maintained with:
- $k_{eff}$  less than 1.0 when fully flooded with unborated water, which includes an allowance for biases and uncertainties as described in Section 9.1 of the Updated Final Safety Analysis Report.
  - A nominal 10.12 inches center to center distance between fuel assemblies in Region 1 of the spent fuel pool storage racks, a nominal 10.30 inches center to center distance between fuel assemblies in the Region 1 cask pit storage rack, and a nominal 8.86 inches center to center distance between fuel assemblies in Region 2 of the spent fuel pool storage racks.
  - A  $k_{eff}$  less than or equal to 0.95 when flooded with water containing 500 ppm boron, including an allowance for biases and uncertainties as described in Section 9.1 of the Updated Final Safety Analysis Report.

## DESIGN FEATURES

### CRITICALITY (Continued)

4. For storage of enriched fuel assemblies, requirements of Criteria in 5.6.1.a.1 and 5.6.1.a.3 shall be met by positioning fuel in the spent fuel storage racks consistent with the requirements of Specification 5.6.1.c.
  5. Vessel Flux Reduction Assemblies (VFRAs), as defined in Section 9.1 of the Updated Final Safety Analysis Report, may be placed in any allowable fuel storage location.
  6. Fissile material, not contained in a fuel assembly lattice, shall be stored in accordance with the requirements of Criteria in 5.6.1.a.1 and 5.6.1.a.3.
  7. The Metamic neutron absorber inserts shall have a  $^{10}\text{B}$  areal density greater than or equal to 0.015 grams  $^{10}\text{B}/\text{cm}^2$ .
- b. The Region 1 cask pit storage rack shall contain neutron absorbing material (Boral) between stored fuel assemblies when installed in the spent fuel pool.
- c. Loading of spent fuel storage racks shall be controlled as described below. Criteria in 5.6.1.c.2, 5.6.1.c.3, 5.6.1.c.5 and 5.6.1.c.6 do not apply to the Region 1 cask pit storage rack.
1. The maximum initial planar average U-235 enrichment of any fuel assembly inserted in a spent fuel storage rack shall be less than or equal to 4.6 weight percent.
  2. Fuel placed in Region 1 of the spent fuel pool storage racks shall comply with the storage patterns and alignment restrictions of Figure 5.6-1 and the minimum burnup requirements of Table 5.6-1.
  3. Fuel placed in Region 2 of the spent fuel pool storage racks shall comply with the storage patterns or allowed special arrangements of Figure 5.6-2 and the minimum burnup requirements of Table 5.6-1. The allowed special arrangement for fresh fuel may be repeated, provided the applicable interface requirements specified by the safety analysis are met.
  4. Any fuel satisfying criteria 5.6.1.c.1, including fresh fuel, may be placed in the Region 1 cask pit storage rack.
  5. The same directional orientation for Metamic inserts is required for contiguous groups of 2x2 arrays where Metamic inserts are required.
  6. Any 2x2 array of Region 2 storage cells that interface with Region 1 shall comply with the rules of Figure 5.6-3. The allowed special arrangement in Region 2 as shown in Figure 5.6-2 shall not be placed adjacent to Region 1.
- d. The new fuel storage racks are designed for dry storage of unirradiated fuel assemblies having a maximum planar average U-235 enrichment less than or equal to 4.6 weight percent, while maintaining a  $k_{\text{eff}}$  of less than or equal to 0.98 under the most reactive condition.

Allowable Checkerboard Storage Patterns  
(See Notes 4 and 5)



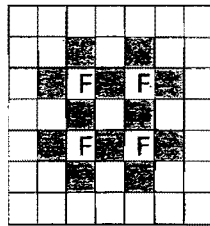
NOTES:

1. F represents Fresh Fuel. WH represents an empty cell. Allowable Pattern is Fresh Fuel checkerboarded with empty cells. Diagram is for illustration only.
2. Numbering denotes fuel assembly type. Minimum burnup for fuel assembly type 1 is defined in Table 5.6-1. Allowable pattern is at least one insert [either Metamic or full-length full-strength-CEA] in any one of the 2x2 array locations. Diagram is for illustration only.
3. Numbering denotes fuel assembly type. WH represents an empty cell. Minimum burnup for fuel assembly type 2 is defined in Table 5.6-1. Allowable pattern is at least one empty cell in any of the 2x2 array locations. Diagram is for illustration only.
4. The storage arrangements of fuel within a rack module may contain more than one pattern. Each cell is a part of up to four 2x2 arrays, and each cell must simultaneously meet the requirements of all those arrays of which it is a part.
5. Empty cells within any pattern are acceptable.

**FIGURE 5.6-1**  
**Allowable Region 1 Storage Patterns and Fuel Arrangements**

# ALLOWED SPECIAL ARRANGEMENT

Fresh Fuel Assemblies in Pattern "C", "D", or "E" Racks

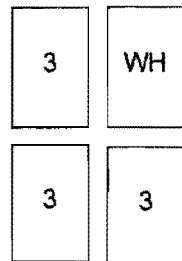


F = FRESH FUEL ASSEMBLY

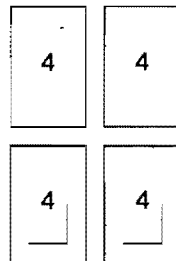
  = EMPTY CELL

## ALLOWABLE CHECKERBOARD STORAGE PATTERNS (See Notes 4 and 5)

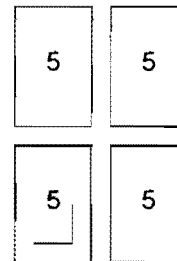
Pattern "C"  
See Note 1



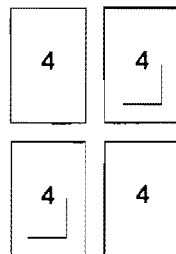
Pattern "D"  
See Note 2



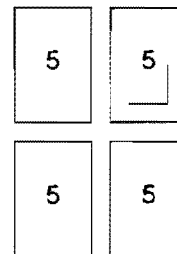
Pattern "E"  
See Note 3



OR



OR



**FIGURE 5.6-2 (Sheet 1 of 2)**  
**Allowable Region 2 Storage Patterns and Fuel Alignments**

## NOTES to Figure 5.6-2

### NOTES:

1. Numbering denotes fuel assembly type. WH represents an empty cell. Minimum burnup for fuel assembly type 3 is defined in Table 5.6-1. Allowable pattern is at least one empty cell in any of the 2x2 array locations. Diagram is for illustration only.
2. Numbering denotes fuel assembly type. Minimum burnup for fuel assembly type 4 is defined in Table 5.6-1. Allowable pattern is at least two inserts, (either Metamic or full-length, full-strength CEA) in the 2x2 array. Diagrams are for illustration only.
3. Numbering denotes fuel assembly type. Minimum burnup for fuel assembly type 5 is defined in Table 5.6-1. Allowable pattern is one insert, (either Metamic or full-length, full-strength CEA) in the 2x2 array. Diagrams are for illustration only.
4. The storage arrangements of fuel within a rack module may contain more than one pattern. Each cell is a part of up to four 2x2 arrays, and each cell must simultaneously meet the requirements of all those arrays of which it is a part.
5. Empty cells within any pattern are acceptable.

**FIGURE 5.6-2 (Sheet 2 of 2)**  
**Allowable Region 2 Storage Patterns and Fuel Arrangements**

(See Notes 4 and 5)



**FIGURE 5.6-3 (Sheet 1 of 2)**



#### NOTES to Figure 5.6-3

##### NOTES:

1. WH represents an empty cell. For the interface of Pattern "C" with Region 1, the empty cell must be on the rack periphery facing Region 1 racks. Diagrams are for illustration only.
2. For the interface of pattern "D" with Region 1, at least one cell on the rack periphery facing Region 1 rack must contain an insert (either Metamic of full-length full-strength CEA) in the 2x2 array. If the insert is Metamic, the insert must be oriented so that the corner of the L-shape is located closest to the Region 1 rack. Diagram is for illustration only.
3. For the interface of Pattern "E" with Region 1, the insert must be on the rack periphery facing the Region 1 rack. The insert may be either a Metamic of full-length full strength CEA. If the insert is Metamic, the insert must be oriented so that the corner of the L-shape is located closest to the Region 1 rack. Diagram is for illustration only.
4. Empty cells with any pattern are acceptable.
5. There are no interface requirements within Region 1. Any Pattern within Region 1 may be used for the interface. Pattern "B" was used only as an illustration.

**FIGURE 5.6-3 (Sheet 2 of 2)**  
**Region 2 Interface requirements with Region 1**

**TABLE 5.6-1**  
**Minimum Burnup as a Function of Enrichment**

Fuel Type	Cooling Time (Years)	Coefficients		
		A	B	C
1	0	-36.6860	22.4942	-1.4413
2	0	-36.1742	16.6000	-0.8958
3	0	-34.7091	23.1361	-1.6204
4	0	-24.5145	21.3404	-1.2444
	2.5	-26.8311	22.5246	-1.5029
	5	-24.7233	20.9763	-1.3246
	10	-23.6285	19.9541	-1.2505
	15	-23.5458	19.9336	-1.3180
	20	-22.4382	19.2460	-1.2629
5	0	-8.1856	14.5275	-0.0719
	2.5	-11.8506	16.1475	-0.3969
	5	-16.5196	18.5309	-0.7837
	10	-13.6831	16.3475	-0.5844
	15	-12.5819	15.6175	-0.5656
	20	-12.6469	16.4575	-0.5906

**NOTES:**

1. To qualify in a "fuel type," the burnup of a fuel assembly must exceed the minimum burnup "BU" calculated by inserting the "coefficients" for the associated "fuel type" and "cooling time" into the polynomial function:

$$BU = A + B \cdot E + C \cdot E^2, \text{ where:}$$

BU = Minimum Burnup (GWD/MTU)

E = Initial Maximum Planar Average Enrichment (weight percent uranium-235)

A, B, C = Coefficients

2. Interpolation between values of cooling time is not permitted.

## ADMINISTRATIVE CONTROLS

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- (2) conform to the guidance of Appendix I to 10 CFR Part 50, and
- (3) include the following:

- 1) Monitoring, sampling, analysis, and reporting of radiation and radionuclides in the environment in accordance with the methodology and parameters in the ODCM.
- 2) A Land Use Census to ensure that changes in the use of areas at and beyond the SITE BOUNDARY are identified and that modifications to the monitoring program are made if required by the results of this census, and
- 3) Participation in a Interlaboratory Comparison Program to ensure that independent checks on the precision and accuracy of the measurements of radioactive materials in environmental sample matrices are performed as part of the quality assurance program for environmental monitoring.

### h. Containment Leakage Rate Testing Program

A program to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50 Appendix J, Option B, as modified by approved exemptions. This program is in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," as modified by the following exception(s):

- a) Bechtel Topical Report, BN-TOP-1 or ANS 56.8-1994 (as recommended by R.G. 1.163) will be used for type A testing.
- b) The first Type A test performed after the May 1993 Type A test shall be no later than May 2008.

The peak calculated containment internal pressure for the design basis loss of coolant accident  $P_a$ , is 42.8 psig. The containment design pressure is 44 psig.

The maximum allowed containment leakage rate,  $L_a$ , at  $P_a$ , shall be 0.50% of containment air weight per day.

Leakage rate acceptance criteria are:

- a. Containment leakage rate acceptance criterion is  $\leq 1.0 L_a$ . During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are  $< 0.60 L_a$  for the Type B and C tests,  $\leq 0.75 L_a$  for Type A tests, and  $\leq 0.096 L_a$  for secondary containment bypass leakage paths.
- b. Air lock testing acceptance criteria are:
  - 1) Overall air lock leakage rate is  $\leq 0.05 L_a$  when tested at  $\geq P_a$ .
  - 2) For the personnel air lock door seal, leakage rate is  $< 0.01 L_a$  when pressurized to  $\geq 1.0 P_a$ .
  - 3) For the emergency air lock door seal, leakage rate is  $< 0.01 L_a$  when pressurized to  $\geq 10$  psig.

## **ADMINISTRATIVE CONTROLS**

### **ANNUAL RADIOLOGICAL ENVIRONMENTAL OPERATING REPORT** (continued)

- 6.9.1.9 At least once every 5 years, an estimate of the actual population within 10 miles of the plant shall be prepared and submitted to the NRC.
- 6.9.1.10 At least once every 10 years, an estimate of the actual population within 50 miles of the plant shall be prepared and submitted to the NRC.

### **6.9.1.11 CORE OPERATING LIMITS REPORT (COLR)**

- a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

Specification 3.1.1.1	Shutdown Margin – $T_{avg}$ Greater Than 200°F
Specification 3.1.1.2	Shutdown Margin – $T_{avg}$ Less Than or Equal to 200°F
Specification 3.1.1.4	Moderator Temperature Coefficient
Specification 3.1.3.1	Full Length CEA Position – Misalignment > 15 inches
Specification 3.1.3.6	Regulating CEA Insertion Limits
Specification 3.2.1	Linear Heat Rate
Specification 3.2.3	Total Integrated Radial Peaking Factor – $F_r^T$
Specification 3.2.5	DNB Parameters
Specification 3.9.1	Refueling Operations – Boron Concentration

- b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, as described in the following documents, approved Revisions and Supplements as specified in the COLR.

1. WCAP-11596-P-A, "Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores," June 1988 (Westinghouse Proprietary)
2. NF-TR-95-01, "Nuclear Physics Methodology for Reload Design of Turkey Point & St. Lucie Nuclear Plants," Florida Power & Light Company, January 1995.
3. XN-75-27(A) [also issued as XN-NF-75-27(A)], "Exxon Nuclear Neutronic(s) Design Methods for Pressurized Water Reactors"
4. DELETED
5. XN-NF-82-21(P)(A), "Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations"

## ADMINISTRATIVE CONTROLS

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### CORE OPERATING LIMITS REPORT (continued)

6. DELETED
7. XN-75-32(P)(A), "Computational Procedure for Evaluating Fuel Rod Bowing"
8. DELETED
9. XN-NF-78-44(NP)(A), "A Generic Analysis of the Control Rod Ejection Transient for Pressurized Water Reactors"
10. XN-NF-621(P)(A), "Exxon Nuclear DNB Correlation for PWR Fuel Designs"
11. DELETED
12. XN-NF-82-06(P)(A), "Qualification of Exxon Nuclear Fuel for Extended Burnup"
13. ANF-88-133(P)(A), "Qualification of Advanced Nuclear Fuels' PWR Design Methodology for Rod Burnups of 62 GWd/MTU"
14. XN-NF-85-92 (P)(A), "Exxon Nuclear Uranium Dioxide/Gadolinia Irradiation Examination and Thermal Conductivity Results"
15. DELETED
16. DELETED
17. EMF-92-116(P)(A), "Generic Mechanical Design Criteria for PWR Fuel Design"
18. EMF-92-153(P)(A), "HTP: Departure from Nucleate Boiling Correlation for High Thermal Performance Fuel"
19. EMF-96-029(P)(A), Volumes 1 and 2, "Reactor Analysis System for PWRs Volume 1 – Methodology Description, Volume 2 – Benchmarking Results"

## ADMINISTRATIVE CONTROLS

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### CORE OPERATING LIMITS REPORT (continued)

20. EMF-1961(P)(A), "Statistical Setpoint/Transient Methodology for Combustion Engineering Type Reactors"
21. EMF-2310(P)(A), "SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors," Revision 1, as supplemented by ANP-3000(P), "St. Lucie Unit 1 EPU - Information to Support License Amendment Request," Revision 0.
22. EMF-2328(P)(A), "PWR Small Break LOCA Evaluation Model, S-RELAP5 Based," Revision 0, as supplemented by ANP-3000(P), "St. Lucie Unit 1 EPU - Information to Support License Amendment Request," Revision 0.
23. EMF-2103(P)(A), "Realistic Large Break LOCA Methodology for Pressurized Water Reactors," Revision 0, as supplemented by ANP-2903(P), "St. Lucie Nuclear Plant Unit 1 EPU Cycle Realistic Large Break LOCA summary Report with Zr-4 Fuel Cladding," Revision 1.

**SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR  
REGULATION RELATED TO AMENDMENT NO. 213  
TO FACILITY OPERATING LICENSE NO. DPR-67  
FLORIDA POWER AND LIGHT COMPANY  
ST. LUCIE PLANT, UNIT NO. 1  
DOCKET NO. 50-335**

# ST. LUCIE PLANT, UNIT NO. 1

## SAFETY EVALUATION FOR EXTENDED POWER UPRATE

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SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO

AMENDMENT NO. 213 TO FACILITY OPERATING LICENSE NO. DPR-67

FLORIDA POWER AND LIGHT COMPANY

ST. LUCIE PLANT, UNIT NO. 1

DOCKET NO. 50-335

1.0 INTRODUCTION

1.1 Application

By application dated November 22, 2010, as supplemented by letters listed in Attachment 1, the Florida Power and Light Company (FPL or the licensee) requested changes to the Facility Operating License and Technical Specifications (TSs) for the St. Lucie Plant, Unit No. 1 (St. Lucie 1). The supplemental letters listed in Attachment 1 provided additional clarifying information that did not expand the scope of the initial application.

The proposed changes would increase the maximum steady-state reactor core power level from 2700 megawatts thermal (MWt) to 3020 MWt, which is an increase of approximately 11.85 percent. The proposed increase in power level is considered an extended power uprate (EPU).

The licensee's application dated November 22, 2010, also requested approval of a revision to TS 3/4.8.1.1 Surveillance Requirements (SRs) associated with emergency diesel generator (EDG) testing. The SR changes address an existing plant condition related to the voltage and frequency tolerances. By letter dated July 5, 2012, the licensee requested to withdraw the TS change related to the 24-hour endurance run of the EDG. Changes to this TS will be addressed in separate correspondence.

1.2 Background

St. Lucie 1 is a pressurized-water reactor (PWR) plant of the Combustion Engineering (CE) design with a containment structure comprised of a steel containment vessel surrounded by a reinforced concrete shield building. St. Lucie 1 is located along with St. Lucie 2 on Hutchinson Island in St. Lucie County about halfway between the cities of Fort Pierce and Stuart on the east coast of Florida. The condenser is cooled by the circulating water system which takes suction from and discharges to the Atlantic Ocean.

The NRC originally licensed St. Lucie 1 on March 1, 1976, for operation at 2560 MWt. By Amendment No. 48 dated November 23, 1981, the NRC granted a power uprate to St. Lucie 1 of approximately 5.5 percent, allowing the plant to be operated at 2700 MWt. Therefore, the proposed EPU would result in an increase of approximately 18 percent over the original licensed power level and 11.85 percent over the current licensed power level for St. Lucie 1.

### 1.3 Licensee's Approach

The licensee's application for the proposed EPU follows the guidance in the Office of Nuclear Reactor Regulation's (NRR's) Review Standard (RS)-001, "Review Standard for Extended Power Uprates" (Reference 1), to the extent that the review standard is consistent with the design basis of the plant. Where differences exist between the plant-specific design basis and RS-001, the licensee described the differences and provided evaluations consistent with the design basis of the plant. Because the proposed EPU also include a measurement uncertainty recapture, the licensee also used Regulatory Issue Summary, (RIS) 2002-03, "Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications."

The licensee has made the modifications necessary to implement the EPU during the refueling outage in spring 2012. Subsequently, the plant will be operated at 2700 MWt. After issuance of this amendment, the licensee will perform a midcycle outage and afterwards the plant will be operated at 3020 MWt.

### 1.4 Plant Modifications

The licensee has determined that several plant modifications are necessary to implement the proposed EPU. The following is a list of these:

- Reactor and Reactor Protection System
  - Implement EPU fuel design
  - Raise reactor protection system steam generator (SG) low-level trip setpoint
- Accident Mitigation Systems
  - Increase safety injection tank design pressure
  - Increase reactor hot leg safety injection flow
  - Add online containment purge capability
- Spent Fuel Storage
  - Add Metamic™ inserts to spent fuel pool (SFP) storage racks
- Steam and Power Conversion System
  - Replace moisture separator reheaters and upgrade level controls
  - Upgrade main steam isolation valves
  - Increase steam bypass control system capacity and upgrade control system
  - Replace high and low pressure turbine steam paths
  - Replace main turbine electro-hydraulic control system
  - Upgrade steam and power conversion system instruments
  - Modify piping supports
- Condensate and Feedwater(FW) System
  - Upgrade main condenser
  - Replace main FW pumps and modify SG flow control valves
  - Replace heater drain pumps
  - Upgrade heater drain valves

- Replace No. 5 FW heaters and upgrade level controls
  - Install leading edge flow meters
  - Upgrade FW controls and instrumentation
  - Modify piping supports
- Alternating Current (AC) Power Block
  - Replace main generator rotor and rewind stator
  - Replace main generator bushings, current transformers, and install power system stabilizer
  - Replace main generator hydrogen cool
  - Replace turbine cooling water heat exchangers
  - Increase main generator hydrogen pressure
  - Replace main generator exciter coolers
  - Increase margin on AC electrical busses
  - Upgrade main transformer cooling systems
  - Upgrade iso-phase bus duct cooling system
  - Modify switchyard components
- Environmental Qualification
  - EQ radiation shielding changes for electrical equipment

The NRC staff's evaluation of the licensee's proposed plant modifications is provided in Section 2.0 of this safety evaluation (SE).

#### 1.5 Method of NRC Staff Review

The NRC staff reviewed the licensee's application to ensure 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) activities proposed 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. The purpose of the NRC staff's review is to evaluate the licensee's assessment of the impact of the proposed EPU on design-basis analyses. The NRC staff evaluated the licensee's application and supplements. The NRC staff also evaluated audits of certain information at the licensee's vendor site, and conducted independent analyses, for areas where such analyses were deemed appropriate by the NRC staff.

In areas where the licensee and its contractors used NRC-approved or widely accepted methods in performing analyses related to the proposed EPU, the NRC staff reviewed relevant material to ensure that the licensee/contractor used the methods consistent with the limitations and restrictions placed on the methods. In addition, the NRC staff considered the affects of the changes in plant operating conditions on the use of these methods to ensure that the methods are appropriate for use at the proposed EPU conditions. Details of the NRC staff's review are provided in Section 2.0 of this SE.

Audits of analyses supporting the EPU were conducted in relation to the reactor systems review, including fuel design. The results of the audits are discussed in section 2.0 of this SE.

Independent NRC staff calculations were performed in relation to the following topics:

- Meteorological data

- Boron precipitation
- Internal cladding pressure
- Power-to-melt
- Peak cladding temperature

The results of the calculations are discussed in section 2.0 of this SE.

## 2.0 EVALUATION

### 2.1 Materials and Chemical Engineering

#### 2.1.1 Reactor Vessel Material Surveillance Program

##### Regulatory Evaluation

The reactor vessel (RV) material surveillance program provides a means for determining and monitoring the fracture toughness of the RV beltline materials to support analyses for ensuring the structural integrity of the ferritic components of the RV. Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix H provides the staff's requirements for the design and implementation of the RV material surveillance program. The NRC staff's review primarily focuses on the effects of the proposed EPU on the licensee's RV surveillance capsule withdrawal schedule. The NRC's acceptance criteria are based on (1) General Design Criterion (GDC) 14, which requires that the reactor coolant pressure boundary (RCPB) be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating failure; (2) GDC 31, which requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a non-brittle manner and the probability of a rapidly propagating fracture is minimized; (3) 10 CFR Part 50, Appendix H, which provides for monitoring changes in the fracture toughness properties of materials in the RV beltline region; and (4) 10 CFR 50.60, which requires compliance with the requirements of 10 CFR Part 50, Appendix H. Specific review criteria are contained in Standard Review Plan (SRP) Section 5.3.1.

Appendix H of 10 CFR Part 50 invokes, by reference, the guidance in American Society for Testing and Materials (ASTM) Standard Practice E185, "Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels." ASTM Standard Practice E185 provides guidelines for designing and implementing the RV materials surveillance programs for operating light-water reactors, including guidelines for determining RV surveillance capsule withdrawal schedules based on the vessel material predicted transition temperature shifts ( $\Delta T_{NDT}$ ).

##### Technical Evaluation

###### Licensee Evaluation

###### *Reactor Vessel Fluence*

In the EPU Licensing Report (Reference 2), Section 2.1.1.2.2, the licensee discussed the RV neutron fluence projections for the EPU. The licensee indicated that although the EPU would normally result in an increase to the neutron fluence on the RV, there was actually a decrease of the neutron fluence because the EPU neutron fluence analysis used a more realistic

approach that removed some of the conservatism from the pre-EPU 60-year neutron fluence analysis. RV neutron fluence projections to 52 effective full-power years (EFPY) (projected neutron fluence for 60-calendar years) that considered the EPU are compared to the previous values in Table 2.1.1-2 of the licensee's application(Reference 2) at the 0 degree and 15 degree azimuthal locations. The 0 degree location corresponds to the peak neutron fluence for the RV plates and circumferential welds. The 15 degree location corresponds to the peak neutron fluence for the RV axial welds.

The licensee further stated that calculated neutron fluence projections used in the EPU evaluation complied with Regulatory Guide (RG) 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," including consideration of dosimetry measurements from the tested surveillance capsules. The end-of-life (EOL) neutron fluence values were used to calculate adjusted reference temperature (ART) values as described in the licensee's application (Reference 2), Section 2.1.2, Pressure-Temperature Limits and Upper-Shelf Energy.

The same neutron fluence projections were used in the upper shelf energy (USE), pressurized thermal shock (PTS), and to determine the ART that is one of the inputs to the development of the pressure-temperature (P-T) limits.

#### *Reactor Vessel Materials Surveillance Program*

The licensee provided a description of the impact of EPU on the RV materials surveillance program in Section 2.1.1 of the licensee's application(Reference 2). The licensee included a surveillance capsule withdrawal schedule that conservatively accounts for the 60-year EPU neutron fluence in Table 2.1.1-1 of (Reference 2). The licensee stated that the effect of the changes in the neutron fluence projections due to EPU on the RV surveillance capsule withdrawal schedule was evaluated, and that both sets of neutron fluence values are judged sufficiently alike to warrant no change to the schedule in Reference 1 Table 2.1.1-1. Therefore, the licensee stated that there is no impact of the proposed EPU on the surveillance capsule withdrawal schedule.

#### *Staff Evaluation*

##### *Reactor Vessel Neutron Fluence*

RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," describes acceptable ways to calculate RV neutron fluence. RG 1.190 states that neutron fluence calculations should adhere to NRC-approved methodology and provides acceptable qualification criteria. In Reference 1 Section 2.1.2.2.2, the licensee stated the NRC-approved methodology of WCAP-16083-NP-A, Revision 0, Benchmark Testing of the FERRET Code for Least Squares Evaluation of Light Water Reactor Dosimetry, S.L. Anderson, May 2006, was used to determine the neutron fluence, which meets the requirements of RG 1.190 including consideration of dosimetry measurements from the tested surveillance capsules. Since the licensee used a methodology to project the EOL neutron fluence that is consistent with the applicable regulatory guidance of RG 1.190 and has been approved by the NRC staff, the staff finds the EOL neutron fluence projections for St. Lucie 1 to be acceptable.

### *Reactor RV Materials Surveillance Program*

ASTM E 185-82 recommends that, for a reactor with a predicted transition temperature shift at the RV inside surface of greater than 200 degrees Fahrenheit (°F), the RV should have a minimum of five surveillance capsules installed. The peak predicted transition temperature shift for St. Lucie 1 is 245 °F for the lower shell axial welds (3-203 A, B, C). St. Lucie 1 actually has six capsules, with one capsule being designated as standby, thus meets this criterion.

ASTM E 185-82 recommends that for a reactor with five surveillance capsules installed, the last capsule should be withdrawn at neutron fluence greater than once but less than twice the peak EOL RV neutron fluence. From Table 2.1.1-2 of Reference 1, the peak RV neutron fluence accounting for EPU at 52 EFPY is  $4.036 \times 10^{19}$  n/cm<sup>2</sup> (E > 1.0 MeV). Per Table 2.1.1-1 of (Reference 2), the fourth capsule is scheduled for withdrawal at approximately 38 EFPY at a neutron fluence of  $3.79 \times 10^{19}$  n/cm<sup>2</sup> (E > 1.0 MeV), which is less than one times the peak RV neutron fluence at EOL. However, the fifth capsule is scheduled to be withdrawn at approximately 45 EFPY with a projected neutron fluence of  $4.60 \times 10^{19}$  n/cm<sup>2</sup> (E > 1.0 MeV). Therefore, since the projected neutron fluence for the fifth capsule is greater than once but less than twice the projected peak RV neutron fluence at EOL, the criterion of ASTM E 185-82 is met. The sixth capsule is designated standby and is not scheduled for withdrawal.

### Conclusion

Since the method of calculating the EOL neutron fluence for the RV, which is used as the basis for the surveillance program, ART, USE, P-T limit, and PTS calculations, meets the applicable regulatory guidance of RG 1.190, the staff finds the licensee's neutron fluence methodology is acceptable.

Since the surveillance capsule withdrawal schedule for St. Lucie 1, modified to account for EPU, meets the ASTM E 185-82 criteria and thus meets 10 CFR Part 50 Appendix H, thereby meeting 10 CFR 50.60, the staff finds the surveillance program is acceptable to support the EPU.

### 2.1.2 Pressure-Temperature Limits and Upper-Shelf Energy

#### Regulatory Evaluation

The NRC's acceptance criteria for P-T limits are based on:

- GDC 14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating failure;
- GDC 31, insofar as it requires that the RCPB be designed with margin sufficient to ensure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized;
- 10 CFR Part 50, Appendix G, which specifies fracture toughness requirements for ferritic components of the reactor coolant pressure boundary;
- 10 CFR 50.60, which requires compliance with the requirements of 10 CFR Part 50, Appendix G.

Specific review criteria are contained in the SRP, Section 5.3.2.

Part 50 of 10 CFR, Appendix G, provides the staff's criteria for maintaining acceptable levels of USE for the RV beltline materials of operating reactors throughout the licensed lives of the

facilities. The rule requires RV beltline materials to have a minimum USE value of 75 ft-lb in the unirradiated condition, and to maintain a minimum USE value above 50 ft-lb throughout the licensed period of operation of the facility, unless it can be demonstrated through analysis that lower values of USE would provide acceptable margins of safety against fracture equivalent to those required by Appendix G of Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (BPV Code). The rule also mandates that the methods used to calculate USE values must account for the effects of neutron irradiation on the USE values for the materials and must incorporate any relevant RV surveillance capsule data that are reported through implementation of a plant's 10 CFR Part 50, Appendix H RV material surveillance program.

### Technical Evaluation

#### *Upper Shelf Energy*

##### Licensee Evaluation

The licensee projected the USE values for 60 years using the neutron fluence values revised for EPU. The quarter thickness (1/4T) neutron fluence values were used and the projection was performed in accordance with RG 1.99, Revision 2, "Radiation Embrittlement of RV Materials." The licensee's projection shows the USE of all the beltline materials remains above 50 ft-lb at 60 years, thus meeting the requirement of 10 CFR Part 50, Appendix G. The licensee's USE projections for 60 years are based on 52 EFPY, which is consistent with the EFPY used for the P-T curves.

##### Staff Evaluation

The staff performed a confirmatory check of the licensee's projected USE values with the neutron fluence values provided by the licensee and using the method of RG 1.99, Revision 2. The staff's check of the USE values verified the licensee's projection, which showed that all USE values will remain above 50 ft-lb at EOL. The staff's projected USE values were very similar to the licensee's values, with the licensee's projected decrease in USE being slightly greater, and the licensee's EOL USE values slightly lower in all cases.

Therefore, since the projected USE values for the St. Lucie 1 RV beltline will remain greater than 50 ft-lb at EOL, the criteria of 10 CFR Part 50, Appendix G with respect to USE are met.

#### *Pressure-Temperature Operating Limits*

##### Licensee Evaluation

The licensee's current P-T operating limits are valid through 35 EFPY. To support the EPU, the licensee prepared new P-T limits good through 54 EFPY. The revised P-T curves are provided in Figures 3.4-2a and 3.4-2b of the proposed revised TS. The basis for the revised P-T limits is documented in Westinghouse Report WCAP-17197-NP, Revision 0, "St. Lucie Unit 1 RCS [reactor coolant system] Pressure and Temperature Limits and Low-Temperature Overpressure Protection [LTOP] Report for 54 Effective Full-Power Years" (Reference 3), provided as Appendix G to Reference 1. The P-T limits are based on the RV neutron fluence and ART values for 54 EFPY that account for the EPU. The revised P-T curves were developed using the methodology of the ASME Code, Section XI, Appendix G, as modified by topical report,



CE-NPSD-683-A, Revision 06, "Development of a RCS Pressure and Temperature Limits Report for the Removal of P-T Limits and LTOP Requirements from the Technical Specifications." (Reference 4) The staff notes that the licensee is not seeking to relocate the P-T limits from the TSs to a P-T limits report. TS Figure 3.4-2a, "St. Lucie Unit 1 P/T Limits, 54 EFPY, Heatup and Core Critical," provides isothermal and 70 °F/hour heatup curves and a core critical curve, as well as incorporating the minimum temperature limits required by 10 CFR Part 50, Appendix G, and the ASME Code Lowest Service Temperature (LST). Figure 3.4-2a also shows the hydrostatic test limits. TS Figure 3.4-2b, "St. Lucie Unit 1 P/T Limits, 54 EFPY, Cooldown and Inservice Test," provides cooldown curves for 20 °F/hour, 30 °F/hour, 40 °F/hour, 50 °F/hour, and 100 °F/hour, as well as the 10 CFR Part 50 Appendix G minimum temperature requirements, and the ASME Code LST. The staff notes that the (Reference 3) provides numerical data for a 50 °F/hour heatup in addition to a 70 °F/hour heatup, and also shows a 10 °F/hour heatup and 10 °F/hour cooldown on the P-T curve figures in the report.

#### Adjusted Reference Temperature and Identification of Limiting Material

The ART values for the beltline materials used as input to the new P-T curves were determined using the revised projected neutron fluence accounting for EPU. In Section 2.1 of (Reference 3), the licensee provided the peak neutron fluence at 54 EFPY for the St. Lucie 1 beltline region as  $4.21 \times 10^{19}$  n/cm<sup>2</sup> (E>1 MeV) for the base metal and the circumferential weld, and  $2.74 \times 10^{19}$  n/cm<sup>2</sup> (E>1 MeV) for the axial welds. These match the 54 EFPY values provided in Table 2.1.2-1 of (Reference 2). The ART values used for the determination of the P-T limits were based on these neutron fluence values.

The method of RG 1.99, Revision 2 was used to determine the ART. The St. Lucie 1 RV beltline has six plate materials and two weld materials (comprised of different heats). Only one plate material (Plate C-8-2) and one weld material (Weld 9-203, heat no. 90136) are included in the surveillance program. The surveillance data has been determined to be credible per the RG 1.99, Revision 2 criteria for both the surveillance plate and weld materials. The best fit chemistry factor (CF) was, therefore, determined from the surveillance data for both the weld and the plate. For Plate C-8-2, the best fit CF is 82.22 °F while for Weld 9-203, the best fit CF is 72.90 °F. Position 2.1 (surveillance data) was used to determine the chemistry factor for plates C-8-1, C-8-2, and C-8-3. The licensee used a ratio procedure in accordance with RG 1.99, Revision 2, Position 2.1 to adjust the CF for Plates C-8-1 and C-8-3, which are from the same heat as Plate C-8-2 but have slightly different copper and nickel values.

The licensee used a similar procedure for Weld 9-203, for which the material heat is in the surveillance program, but the surveillance weld chemistry differs from the RV weld. The RV weld has higher copper than the surveillance weld material (0.27 weight % versus 0.23 weight %). To determine the CF for the ART projections for the RV weld material, the best fit CF for the surveillance weld material was multiplied by the ratio of the CF for the RV weld to the CF for the surveillance weld determined from RG 1.99, Revision 2, Table 1. This heat of weld material is not the limiting material for the St. Lucie 1 RV.

However, the limiting material for St. Lucie 1 with regard to PTS is longitudinal Weld 3-203 A/C (Heat No. 305424), which is in the Beaver Valley, Unit 1 surveillance program but not in the St. Lucie 1 surveillance program. (Reference 2) indicates this material has a CF of 188.8 °F, which was determined using Position 1.1. (Reference 2) stated that a lower CF of 178.4 °F was determined from the Beaver Valley, Unit 1 surveillance data; however, the licensee

conservatively chose to use the Position 1.1 value since it is higher, which is allowed by RG 1.99, Revision 2.

### Lowest Service Temperature

The LST is defined in ASME Section III, NB-3211 as the minimum temperature for piping, pumps, and valves (in a system, for instance, the RCS) to exceed the 20 percent of the preservice hydrostatic test (PSHT) pressure. (Reference 3), Section 2.7 stated that the LST is established as a temperature not less than  $RT_{NDT}$  of the remainder of the RCS plus 100 °F, and that previously, an  $RT_{NDT}$  of 90 °F had been applied in such calculations for St. Lucie 1. (Reference 3) Section 2.7 further stated that it was found that this limitation was associated with an estimate related to the reactor coolant pump (RCP) materials, and that it was determined that the RCP shaft, casing, casing wear ring, hydrostatic bearing, and cover are made of stainless steel and, therefore, do not affect the limiting  $RT_{NDT}$ . Finally, (Reference 3), Section 2.7 stated that the next most limiting  $RT_{NDT}$  documented for the RCS piping was 58 °F; therefore, the LST was 158 °F. When the temperature is adjusted for instrument error, the LST becomes 165 °F.

### 10 CFR Part 50, Appendix G Minimum Temperature Requirements

The licensee indicated the highest  $RT_{NDT}$  for the closure flange region was 50 °F, and that a minimum bolt-up temperature was defined as 80 °F to provide margin over the highest reference temperature (applicable to both hydrostatic and leak test or normal operation). Figure 2-1 and 2-2, "St. Lucie Unit 1 Cooldown P-T Limits 54 EFPY, APCF [actual pressure correction factor] Adjusted to PZR Pressure," and Figure 2-2, "St. Lucie Unit 1 Heatup P-T Limits 54 EFPY, APCF Adjusted to PZR Pressure," of (Reference 3), show that the pressure is limited to 20 percent of the PSHT pressure or below at temperatures below 158 °F (the LST). The minimum temperature for the PSHT with no fuel in the RV is not shown on the curves in (Reference 3) for St. Lucie 1. Figures 2-3, "St. Lucie Unit 1 Cooldown P-T Limits 54 EFPY IPCF [indicated pressure correction factor] Adjusted to Indicated PZR Pressure," and Figure 2-4, "St. Lucie Unit 1 Heatup P-T Limits 54 EFPY, IPCF Adjusted to Indicated PZR Pressure," of (Reference 3) show that the pressures are limited to less than 20 percent PSHT pressure below 165 °F. Section 2.7 of (Reference 3) explained that the P-T curves include a 7 °F margin shift for indicated instrument uncertainty. Therefore, the 165 °F minimum for exceeding 20 percent of PSHT is based on the LST plus the instrument error correction.

For St. Lucie 1, Section 2.7 of the (Reference 3) indicates that the minimum permissible temperature when the core is critical at pressures less than or equal to 20 percent of the PSHT pressure is defined by the inservice hydrotest temperature. The minimum hydrotest temperature is 270.2 °F per (Reference 3) Section 2.7. The inservice hydrotest is performed at 2475 pounds per square inch absolute (psia). Section 2.7 of (Reference 3) stated that the minimum temperature was obtained by interpolating from Table 2-8 of the (Reference 3). However, (Reference 3), Figures 2-1 and 2-2 show the hydrotest temperature (uncorrected for instrument error) as 268.2 °F, and Figures 2-3 and 2-4 of (Reference 3) show the hydrotest temperature as 275.2 °F (accounting for instrument error). The minimum temperature for core critical operation is also given as 268.2 °F on Figures 2-1 and 2.2 of (Reference 3), and 275.2 °F on Figures 2-3 and 2-4 of (Reference 3).

### Calculation of P-T Limits

The licensee's general approach for calculation of the P-T limits is consistent with the approach described in the ASME Code, Section XI, Appendix G. Consistent with paragraph G-2110, the reference stress intensity  $K_{Ic}$ <sup>1</sup> is used.

However, (Reference 3) indicates that to determine the thermal stress intensity factors ( $K_{It}$ ) the membrane stress intensity factors ( $K_{Im}$ ) and the crack tip metal temperatures, the licensee used the method of CE NPSD-683-A (Ref. 3), rather than the method described in the ASME Code, Section XI, Appendix G, Subparagraph G-2214.3.

### Pressure Correction Factors

Since pressure is not measured in the RV, but is only measured in the pressurizer, the licensee applied pressure correction factors to the allowable pressures determined from the ASME Code, Section XI, Appendix G limits. The correction factors account for the pressure difference due to the static head of fluid between the PZR pressure instrument nozzle elevation and RV beltline lowest point, the flow-induced pressure drop between the applicable point in the RV and hot leg surge line nozzle, due to flow resulting from operating RCPs, and the uncertainty associated with the pressure instrumentation, as applicable. Two sets of pressure correction factors were defined. The APCF account for the actual pressure difference between the RV and the pressurizer, while the IPCF add an additional factor to account for instrument uncertainty. The APCF's of 72.8 psid for temperatures above 200 °F, and 59.8 psid for temperatures below 200 °F were subtracted from the licensee's uncorrected allowable pressure values to obtain the APCF values in Table 2-5 of (Reference 3). The licensee provided IPCF's of 92 psid for temperatures above 200 °F and 79 psid for temperatures below 200 °F, for the narrow-range pressure instruments, which were used to adjust the licensee's uncorrected allowable pressure values to obtain the IPCF values in Table 2-6 of (Reference 3). Additionally, in the P-T curves for IPCF, 7 °F was added to the temperature limits to account for instrument uncertainty.

### NRC Staff Evaluation

#### Adjusted Reference Temperature and Identification of Limiting Material

The limiting material with regard to ART and  $RT_{PTS}$  for the St. Lucie 1 RV is Lower Shell Axial Weld 3-203 A/C, Heat Number 305424. This material heat is not contained in the St. Lucie 1 surveillance program but is contained in the Beaver Valley, Unit 1 surveillance program. (Reference 2), Table 2.1.2-4 provides a copper content of 0.27 weight % and a nickel content of 0.63 weight % and a CF of 188.8 °F using RG 1.99 Revision 2 Position 1.1. The reference given for the CF is a letter dated August 28, 1997, forwarding updated information in response to Generic Letter (GL) 92-01, Revision 1 (Reference 5). (Reference 5) references CE NPSD-1039, Revision 2, "Best Estimate Copper and Nickel Values in CE Fabricated Reactor Vessel Welds" (Reference 6). However, Beaver Valley, Unit 1 reported a different best estimate chemistry for Heat Number 305424 in (Reference 7), which included additional

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<sup>1</sup> The 2004 ASME Code Section XI, the most recent edition of the code currently incorporated by reference by 10 CFR 50.55a, allows the use of  $K_{Ic}$  (the material fracture toughness property measured in terms of stress intensity factor,  $K_I$ , which will lead to nonductile crack initiation) rather than  $K_{Ia}$  (the material fracture toughness parameter, which is the critical value of the stress intensity factor,  $K_I$ , for crack arrest as a function of temperature) required by some earlier editions. These terms are defined in Nonmandatory Appendix A to the ASME Code, Section XI.

chemistry measurements from chemical analyses on the surveillance weld material, that altered the best estimate chemistry from (Reference 6). The best estimate chemistry from (Reference 7) is 0.28 weight % Cu and 0.63 weight % Ni (see notes to Table 4-8 of (Reference 7)). Therefore, in RAI CVIB-1 the staff requested that the licensee address whether the CF for weld heat no. 305424 needs to be updated to account for the additional chemistry measurements. In response to request for additional information (RAI) CVIB-1 (Reference 8), the licensee indicated that the (Reference 6) chemistry values were calculated using the coil-weighted average method, which adjusts the average for the volume of weld metal in each unique weld. When the licensee calculated a new coil-weighted average including the additional Beaver Valley, Unit 1, chemistry measurements with all the previous data from (Reference 6), a slightly lower best-estimate copper content was obtained. Therefore, the licensee decided to use the value of 0.27 weight % since it is conservative. The staff reviewed the calculation of the best estimate chemistry of (Reference 7), and determined that a different method was used to calculate the best estimate chemistry (sample-weighted average versus coil-weighted average), which resulted in the higher best estimate copper of 0.28 weight % reported in (Reference 7). However, based on the licensee's response to RAI CVIB-1, the staff agrees that the licensee's best estimate copper content of 0.27 weight % is appropriate and conservative, and thus find that RAI CVIB-1 is resolved.

The staff performed a confirmatory calculation of the ART of all the baseline materials for the St. Lucie 1 RV at 54 EFPY. The staff used the methodology of RG 1.99, Revision 2 to perform the calculation. The staff used the chemistry factors supplied by the licensee. For those chemistry factors for which the ratio procedure was used, the staff independently verified the reduced CF for the materials. The staff used the licensee's projected 54 EFPY neutron fluence at the RV inner diameter (cladding to base metal interface) and used Equation (3) of RG 1.99, Revision 2 to determine the neutron fluence at the 1/4T depth. For the limiting material, the staff calculated ART as 210 °F at 1/4T depth and 156 °F at the three-quarters thickness (3/4T) depth, which match the licensee's values provided in the (Reference 3). The staff therefore finds the licensee's determination of ART to be acceptable.

#### Lowest Service Temperature

The staff reviewed the licensee's revised LST against the ASME Code, Section III, NB-3211 criteria and finds it acceptable.

#### 10 CFR Part 50, Appendix G Minimum Temperature Requirements

The staff reviewed the minimum temperature requirements for the St. Lucie 1 P-T limits against the requirements of 10 CFR Part 50, Appendix G. These requirements cover hydrostatic pressure and leak tests and normal operation (including heatup and cooldown), with both the core critical and core not critical, and are summarized in Table 1 of 10 CFR Part 50, Appendix G. Most of the minimum temperature requirements are derived from the highest reference temperature of the closure flange region of the RV that is highly stressed by bolt preload.

For normal operation, including heatups and cooldowns, including anticipated operational occurrences, 10 CFR Part 50, Appendix G, Table 1, Operating Condition 2.b requires that the RV pressure may not exceed 20 percent of the PSHT pressure until the RV temperature exceeds by 120 °F the highest reference temperature of the material in the closure flange region of the RV that is highly stressed by bolt preload. However, for St. Lucie 1, 20 percent of the

PSHT is 636.25 psia. With the IPCF correction factor applied, this becomes 557.3 psia. Section 2.7 of (Reference 3) states the maximum  $RT_{NDT}$  of the closure flange region is 50 °F, which implies that 557.3 psia should not be exceeded until a temperature of 170 °F is reached. However, TS Figures 3.4-2a and Figure 3.4-2b as well as Figures 2-3 and 2-4 of the (Reference 3) show the heatup curves exceeding the 20 percent PSHT pressure at 165 °F (the LST adjusted for instrument error). The staff requested that the licensee clarify this discrepancy in RAI CVIB-2. In response to RAI CVIB-2 (Reference 8), the licensee stated that after reviewing the documentation associated with the P-T limits of St. Lucie 1, it was determined that the value of the maximum  $RT_{NDT}$  for the closure flange region is 30 °F (rather than 50 °F). The licensee further stated that the sum of the initial  $RT_{NDT}$ , the 120 °F margin, and the instrument uncertainty margin of 7 °F is 157 °F. This value is bounded by the LST (plus instrument error) value of 165 °F, which therefore remains the appropriate limit under which 557.3 psia cannot be exceeded. Based on this response, the NRC staff finds RAI CVIB-2 is resolved.

Part 50 of 10 CFR, Appendix G, Table 1, Operating Condition 2.c requires that when the core is critical at pressures less than or equal to 20 percent of the preservice system hydrostatic test pressure, the minimum temperature is the larger of the minimum permissible temperature for the inservice hydrotest or the highest reference temperature of the material in the closure flange region of the RV that is highly stressed by bolt preload plus 40 °F. However, for St. Lucie 1, Section 2.7 of (Reference 3) indicates that the minimum permissible temperature for the inservice hydrotest is controlling. The inservice hydrotest pressure corresponding to 1.1 times normal operating pressure, in accordance with the ASME Code, Section XI, Article IWB-5000 is 2475 psia. Section 2.7 of (Reference 3) stated that the minimum temperature was obtained by interpolating from Table 2-8 of the (Reference 3). The staff attempted to duplicate the licensee's interpolated value and obtained a hydrotest temperature of 268.2 °F. In response to RAI CVIB-3 (Reference 8), the licensee verified that the correct hydrotest and minimum core critical temperature for St. Lucie 1 is 268.2 °F (uncorrected) and 275.2 °F (corrected for instrument error).

The staff finds the licensee's minimum temperature requirements are acceptable because they meet the requirements of 10 CFR Part 50, Appendix G.

#### Calculation of P-T Limits

The staff previously approved CE NPSD-683-A via a safety evaluation report (included at the beginning of (Reference 4)), which placed conditions on the use of the report. A finite element method (FEM) was used in (Reference 4) to generate the  $K_{Im}$  and  $K_{It}$  factors, which are inputs to the allowable pressure. The method of generating the  $K_{Im}$  and  $K_{It}$  factors was different and could not be shown to be equally conservative as the methods of the ASME Code, Section XI, Appendix G, as required by 10 CFR 50.60 and 10 CFR Part 50, Appendix G. Therefore, the safety evaluation report (SER) requires licensees wishing to use the methods of CE NPSD-683-A to generate P-T limits to submit a plant-specific exemption request in accordance with 10 CFR 50.12. The SER also required a plant-specific exemption request if Code Case N-640, allowing the use of  $K_{Ic}$  instead of  $K_{Ia}$  for the material fracture toughness, was to be used. However, ASME Code editions that are now incorporated by reference in 10 CFR 50.55a, allow a methodology for calculation of the  $K_{It}$  values that is equivalent to the methodology of (Reference 4), and also have incorporated the  $K_{Ic}$  fracture toughness curve, so an exemption is now only required to use the  $K_{Im}$  methodology of (Reference 9).

In (Reference 9), CE documented comparative calculations in which P-T limits were calculated using both the ASME Code, Section XI, Appendix G method and the CE NPSD-683 method for the same plant. The results showed that the P-T limits for cooldown were very similar, but the results for heatup were less conservative, in large part due to lower  $K_{It}$  values at the 3/4T location determined by the CE method. By letter dated March 3, 2011 (Reference 10), the licensee submitted an application for exemption from the requirements of 10 CFR Part 50, Appendix G, to address the use of the CE NPSD-683-A methodology. The staff issued the exemption on December 13, 2011 (76 FR 77563).

The NRC staff performed a comparative calculation of the heatup, cooldown, and hydrostatic test P-T limits for St. Lucie 1 using the methods of the ASME Code, Section XI, Appendix G. The staff compared the ASME allowable pressures to the allowable pressures from Tables 2-4 (cooldown) and 2-7 (heatup) of (Reference 3). Since the 50 °F/hour heatup, 10 °F/hour heatup and 10 °F/hour cooldown, do not appear on TS Figures 3.4-2a and 3.4-2b, these do not appear to be part of the licensing basis for St. Lucie 1. Therefore, the staff did not perform confirmatory calculations for these heatup and cooldown rates.

To assist the staff in evaluating the reasons for the differences in allowable pressure determined by the licensee's method as compared to the ASME method, in an RAI dated January 13, 2011, the staff requested the licensee to provide the  $K_{Im}$  and  $K_{It}$  factors, and the coolant-to crack tip temperature differentials, used as input to their calculation. The licensee provided these values in (Reference 11). The coolant-to-crack tip temperature differential was provided at the 1/4T location for the various cooldown rates, and the 3/4T location for the various heatup rates, as a function of time. The staff observed that the licensee's  $K_{It}$  values, unlike the ASME values, are lower at the beginning of the transient (at lower temperatures for heatup and higher temperatures for cooldown) and ramp up to a steady state value, resulting in lower values than calculated by the ASME method during the low temperature portion of the heatup and lower values than calculated by the ASME method during the high temperature portion of the cooldown transient. The staff also notes that the temperature differential increases for approximately the first 180 minutes of either heatup or cooldown transients, before attaining a steady state value. The staff notes that the licensee's coolant-to-crack tip temperature differentials, once they attain the steady state value, are significantly greater than those that are determined for the same conditions (heatup or cooldown rate and wall thickness) using the ASME Code, Section XI, Appendix G method.

#### Results of the P-T Limit Confirmatory Calculations

Since the allowable pressures for heatup and cooldown are controlled by the 10 CFR Part 50, Appendix G minimum temperature requirement up to a temperature of 165 °F, for heatup and cooldown the staff only compared the licensee's allowable pressures to the ASME allowable pressures at temperatures of 165 °F and greater. For the 70 °F/hour heatup the non-conservative differences in the licensee's P-T limits are minor (only 1 to 3 percent). In addition, for the higher temperature portions of the heatup curve, the ASME allowable pressures are greater than the licensee's allowable pressures (at temperatures greater than 168 °F).

For the cooldown allowable pressures, the staff performed confirmatory calculations for the isothermal and all cooldown rates. The licensee's allowable pressures were generally slightly higher at the lower temperatures, but lower at the higher temperatures. For example, for the 50 °F/hour cooldown, the licensee's allowable pressure is about 6-percent higher than the ASME limits at 160 °F, but 10-percent lower at 280 °F.

For the heatup transients, the licensee's allowable pressures at lower temperatures are probably higher than the ASME values as a result of the licensee's lower  $K_{Ic}$  values at the lower temperatures. However, at higher temperatures, the licensee's higher coolant-to-crack tip differential temperatures result in lower allowable pressures since the corresponding  $K_{Ic}$  values are lower. For the cooldown transients, the licensee's  $K_{Ic}$  values are slightly greater than the ASME value in the temperature range of interest. However, the higher coolant-to-crack tip metal temperature differentials over the entire temperature range results in higher crack tip metal temperatures and thus higher  $K_{Ic}$  values for a given coolant temperature for the licensee in the cooldown case. These two differences appear to offset each other resulting in the licensee's allowable pressures being very close to the ASME allowable pressures in most cases, except at the higher temperature portions of the transient. Since the licensee's method uses the minimum of the finite cooldown rate and the isothermal condition allowable pressure, while the ASME method considers only the finite cooldown rate, at higher temperatures the isothermal condition resulted in lower allowable pressures for the licensee.

Based on the confirmatory calculations, the staff was unable to confirm that the licensee's P-T limits were at least as conservative to those determined using the methods of the ASME Code, Section XI, Appendix G. For the heatup transients and the 100 °F/hour cooldown transient, the licensee's allowable pressures are actually significantly more conservative than those determined using the ASME Code, Section XI, Appendix G, for the higher temperature portion of the heatup transient. For the other cooldown rates and the hydrostatic test, the licensee's allowable pressures are generally within a few percent of the corresponding allowable pressures determined using the method of the ASME Code. These differences were expected based on the differences in methodology as documented in CE NPSD-683-A and (Reference 9). Given the difference in methodology, the staff finds the differences in the licensee's P-T limits from those calculated using the ASME method to be reasonable. Since the licensee requested and the staff has granted a plant-specific exemption to use the CE NPSD-683-A methodology, the staff finds the licensee's proposed P-T limits acceptable.

#### Core Critical P-T Limits

For normal operations with the core critical, 10 CFR Part 50, Appendix G requires that 40 °F be added to the temperature corresponding to the allowable pressure determined using the ASME Code, Section XI, Appendix G, for pressures both less than or greater than the PSHT pressure. The staff verified that the core critical P-T limits for heatup provided on Figures 3.4-2a of the Technical Specifications, and Figures 2-1, 2-2, 2-3, and 2-4 of the (Reference 3), show the core critical P-T curves offset by 40 °F from the ASME Code, Section XI, Appendix G P-T curves.

#### Hydrostatic Test Limits

The CE NPSD-683-A equation for hydrostatic test limits, like the equations for heatup and cooldown during normal operation, uses the  $K_{Im-P}$  influence coefficient for the relationship between  $K_{Im}$  and pressure which was determined by FEM and thus yields less conservative results in some cases.

The staff performed a confirmatory calculation of the hydrostatic test limits using the method of the ASME Code, Section XI, Appendix G, comparing the results to the numerical values from Table 2-8 of (Reference 3). The differential between the licensee's allowable hydrostatic test pressure and the ASME Code allowable hydrostatic test pressure ranges from 2.8 percent

greater at 165 °F to 2 percent greater at 268.2 °F (the hydrostatic test temperature for 1.1 times normal operating pressure). Using the ASME method, the temperature for 1.1 times normal operating pressure is less than 2 °F higher than the licensee's full hydrostatic test temperature. Since the membrane stress intensity factors ( $K_{Im}$ ) are calculated by a different method than the method of the ASME Code, Section XI, Appendix G in the CE NPSD-683-A methodology, the staff finds this difference is expected and is reasonable.

## Conclusion

### *Upper Shelf Energy*

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the USE values for the RV beltline materials at EOL and on the P-T limits for the plants. The staff concludes that the licensee has adequately addressed the changes in neutron fluence and their impacts on the USE values and the P-T limits for the plants. The staff concludes that the St. Lucie 1 RV beltline materials will continue to have acceptable USE values, as mandated by 10 CFR Part 50, Appendix G, through the expiration of the current operating licenses for the facilities.

### *Pressure-Temperature Operating Limits*

With respect to P-T limits, the staff concludes the licensee's P-T limits accounting for EPU are acceptable based on the licensee's request for and the staff's issuance of a plant-specific exemption to use the methodology of CE-NPSD-683-A, which demonstrates that the underlying purpose of 10 CFR Part 50, Appendix G, with respect to P-T limits, is met. In addition, the staff concludes that the licensee appropriately accounted for the effects of the change in neutron fluence due to EPU on the limiting materials with respect to the P-T limits. The staff also concludes, based on our confirmatory calculations, that the revised P-T limits are reasonable considering the differences in methodology from the ASME Code, Section XI, Appendix G.

### 2.1.3 Pressurized Thermal Shock

#### Regulatory Evaluation

The PTS evaluation provides a means for assessing the susceptibility of the RV beltline materials to PTS events to assure that adequate fracture toughness is provided to support reactor operation. The staff's requirements, methods of evaluation, and safety criteria for PTS assessments are given in 10 CFR 50.61. The NRC staff's review covered the PTS methodology and the calculation of the reference temperature,  $RT_{PTS}$ , at the expiration of the license, considering neutron embrittlement effects. The NRC's acceptance criteria for PTS are based on (1) GDC 14, which requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture; (2) GDC 31, which requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; and (3) 10 CFR 50.61, which sets fracture toughness criteria for protection against PTS events. Specific review criteria are contained in SRP Section 5.3.2.

The staff has established requirements in 10 CFR 50.61 that are designed to protect the RVs of PWRs against the consequences of PTS events. The rule requires licensees owning PWR-



designed light-water reactors to calculate a nil-ductility reference temperature at EOL neutron fluence ( $RT_{PTS}$  as defined in 10 CFR 50.61) for each base metal and weld material in the RV made from carbon or low-alloy steel materials. The rule also requires the  $RT_{PTS}$  values to be maintained below the PTS screening criteria throughout the serviceable life of the facilities. The rule sets a maximum limit of 270 °F for  $RT_{PTS}$  values that are calculated for base metals (i.e., forging and plate materials) and axial weld materials and a maximum limit of 300 °F for  $RT_{PTS}$  values that are calculated for circumferential weld materials.

Section 50.61 of 10 CFR provides a required methodology for calculating these  $RT_{PTS}$  values, which are based on the calculation methods in RG 1.99, Revision 2. For materials in the beltline region of the RV, the rule requires that the calculations account for the effects of neutron irradiation on the materials and incorporate any relevant RV surveillance capsule data that are required to be reported as part of the licensee's implementation of its RV material surveillance program.

### Technical Evaluation

#### Licensee Evaluation

Section 2.1.3.2.2 of (Reference 2) discussed the input parameters, assumptions and acceptance criteria for the licensee's PTS evaluation. (Reference 2), Tables 2.1.3-1 through 2.1.3-5, provides the supporting data for the licensee's PTS evaluation. The licensee used the methodology of 10 CFR 50.61 to determine the  $RT_{PTS}$  values for the RV beltline materials at 60 years. The CFs for the beltline materials were determined either using Position 1.1 or 2.1 of RG 1.99, Revision 2. The CFs used to calculate  $RT_{PTS}$  values were determined using identical methods as were used to calculate the CF's for determining the ART used in the P-T limit development. Refer to Section 2.1.2.2 of this Safety Evaluation (SE) for a description of the methods for determining the CFs, and the results obtained, for the St. Lucie 1 beltline materials.

The licensee stated in Section 2.1.3.2.2 of (Reference 2) that the neutron fluence for St. Lucie 1 was determined using NRC approved methodology that follows the guidance and meets the requirements of Regulatory Guide (RG) 1.190. The licensee referenced WCAP-16083-NP-A, Revision 0, "Benchmark Testing of the FERRET Code for Least Squares Evaluation of Light Water Reactor Dosimetry," as the NRC-approved neutron fluence methodology.

#### Staff Evaluation

The licensee referenced RG 1.99, Revision 2 Position 1.1 or 2.1 with respect to the methodology of calculating the CFs. The staff notes that the methods of calculating the CF are identical between RG 1.99, Revision 2, Position 1.1 and 10 CFR 50.61, Paragraph c(1), and RG 1.99, Revision 2, Position 2.1 and 10 CFR 50.61, paragraphs (c)(2) and (c)(3).

The limiting material with regard to ART and  $RT_{PTS}$  for the St. Lucie 1 RV is Lower Shell Axial Weld 3-203 A/C, Heat Number 305424. Refer to Section 2.1.2.2 of this SE for the staff's evaluation of the licensee's calculated CFs for the St. Lucie 1 beltline materials, since the CFs used as input to the calculation of the ART used in the P-T limit development, and  $RT_{PTS}$  were determined identically.

The staff checked the copper, nickel and initial  $RT_{NDT}$  values for the St. Lucie 1 RV provided by the licensee as input to the PTS evaluation against the values for the same material heats from

the NRC's Reactor Vessel Integrity Database (RVID). The staff observed all the licensee's values match those in RVID.

The staff performed a confirmatory calculation of the  $RT_{PTS}$  values for the St. Lucie 1 RV materials using the method of 10 CFR 50.61. The staff's values for  $RT_{PTS}$  at 52 EFPY are identical to the licensee's values for all beltline materials when the inputs from Reference 1, Table 2.1.3-5 are used.

In (Reference 2), Section 2.1.3, the  $RT_{PTS}$  evaluation was based on the neutron fluence for 52 EFPY. Additionally, Reference 1, Table 2.1.1-2, "Comparison of Peak 0° and 15° Azimuth RV ID Neutron fluence Values at 52 EFPY," implies that 52 EFPY is the expected maximum EFPY value for St. Lucie 1 corresponding to 60 calendar years of operation. However, for the ART evaluation supporting the revised P-T limits, ART values were projected for both the 52-EFPY and 54-EFPY neutron fluences. (Reference 2), Section 2.1.2.2 states that new 60-year P-T limits have been generated based on the neutron fluence projected to 54 EFPY to provide margin for fuel management. Therefore, in RAI CVIB-4 the staff requested the licensee clarify which EFPY value should be the basis for the PTS evaluation. The licensee indicated in the response to RAI CVIB-4 (Reference 8) that 52 EFPY corresponds to 60 calendar years of operation for St. Lucie 1. The 54 EFPY value was used for the ART evaluation since it is linked to the P-T curves, which are more difficult to change since a TS change and operator retraining is required, hence the desire for some margin. However, a change to the PTS or USE evaluation would require only a submittal to the NRC. The licensee further indicated that they would review and update the PTS and USE evaluations as necessary if changes in operational conditions result in an increase in the EFPY projection at EOL. The staff therefore finds RAI CVIB-4 is resolved. The staff calculated  $RT_{PTS}$  values using the 54 EFPY neutron fluence values from (Reference 2), Table 2.1.2-1 and all other inputs from (Reference 2), Table 2.1.3-5 and found that all  $RT_{PTS}$  values meet the PTS screening criteria.

### Conclusion

The staff has reviewed the licensee's projected values of  $RT_{PTS}$  for EOL considering EPU, and concludes based on our confirmatory calculation that all beltline materials will meet the PTS screening criteria required by 10 CFR 50.61 through the EOL. Therefore, the staff concludes that the evaluation of PTS for St. Lucie 1 considering EPU is acceptable.

### 2.1.4 Reactor Internal and Core Support Materials

#### Regulatory Evaluation

The reactor vessel internals (RVI) components include structures, systems, and components (SSCs) that perform safety functions or whose failure could affect safety functions performed by other SSCs. These safety functions include reactivity monitoring and control, core cooling, and fission product confinement (within both the fuel cladding and the RCS. The NRC staff's review assessed the impact of the EPU on the margins of safety for maintaining the structural integrity of the RVI components. The NRC's acceptance criteria for RVI materials are based on GDC 1 and 10 CFR 50.55a for inspecting and evaluating the structural integrity of RVI components. Section 50.55a of 10 CFR specifies the ASME Code editions and addenda that are approved for use by the NRC. The ASME Code, Section II contains the allowable materials. Specific review criteria are contained in SRP Section 4.5.2 and other review criteria and guidance are provided in Matrix 1 of NRC Review Standard, RS-001, Revision 0. For PWRs, Matrix 1 of RS-001,

Revision 0, "Review Standard for Extended Power Uprates," provides references to the NRC's approval of the recommended guidelines for RVI components in Topical Report WCAP-14577, Revision 1-A, "License Renewal Evaluation: Aging Management for Reactor Internals (March 2001)." The staff also observes that under "Other Guidance," Matrix 1 of RS-001 refers to Note 1, which states, in part, that "[f]or thermal and neutron embrittlement of cast austenitic stainless steel, stress-corrosion cracking, and void swelling, licensees will need to provide plant-specific degradation management programs or participate in industry programs to investigate degradation effects and determine appropriate management programs."

### Technical Evaluation

#### Licensee Evaluation

In (Reference 2), Section 2.1.4.1, the licensee included their regulatory evaluation and a discussion of the current licensing basis of St. Lucie 1 with respect to RVI components. The licensee's regulatory evaluation is consistent with the staff's regulatory evaluation. Additionally, the licensee noted that WCAP-14577 does not apply in its entirety to CE-designed RVI components, therefore only the applicable criteria are applied to St. Lucie 1. In their discussion of the current licensing basis, the applicant noted that St. Lucie 1, was designed and constructed based on the 1967 draft Atomic Energy Commission (AEC) GDC. In preparation for issuance of the St. Lucie 1 Final Safety Analysis Report (FSAR), an effort was made to comply with the newer (1971) final GDC. The licensee also indicated that the materials of construction of the RVI components meet 10 CFR 50.55a as documented in FSAR Table 5.2.1.

In its discussion of the current license basis, the licensee also noted that the RVI materials were evaluated for St. Lucie 1 License Renewal. The applicant indicated that Section 2.3.1.4 of the SE for license renewal (NUREG-1779, (Reference 12)) identifies that components of the RVI materials are within the scope of License Renewal, and that programs used to manage the aging effects associated with the RVI and core support materials are discussed in SE Sections 3.1.0.7 and 3.1.4 and Chapter 18 of the updated FSAR.

In (Reference 2), Section 2.1.4.2, the licensee described the materials of construction of the RVI components as primarily Type 304 stainless steel, with limited use of high-strength precipitation hardening austenitic stainless steel and solution-annealed Type 316 stainless steel in some fastener applications. The applicant indicated that there are a limited number of fasteners because welded construction was used wherever possible. Other materials include stellite hardfacing at potential wear points such as the snubber spacer blocks on the core support barrel outside surface and Type 403 stainless steel for the upper internals hold down ring. The licensee stated in this section that there are no applications of nickel-based Alloy 600 or weld metals Alloys 82 or 182 in the RVI components and that there are no applications of high-strength, precipitation-hardening nickel-base alloys in the RVI components.

(Reference 2), Section 2.1.4.2 states that the primary objective of the RVI materials assessment was to ensure that the EPU conditions (primary coolant chemical conditions, temperature and neutron fluence) will not result in any new aging effects for the RVI materials through the end of the current 60-year license period nor change the manner in which component aging will be managed by the aging management programs.

The licensee listed the relevant degradation (aging) mechanisms for the RVI components that were evaluated to assess the effects of the EPU as:

- A. Integrity of RV fuel cladding,
- B. Intergranular and transgranular stress corrosion cracking (IGSCC and TGSCC) of austenitic stainless steel,
- C. Irradiation-enhanced embrittlement,
- D. Irradiation-assisted stress corrosion cracking (IASCC) of austenitic stainless steel,
- E. Irradiation-induced void swelling of austenitic stainless steel,
- F. Thermal aging (embrittlement) of cast austenitic stainless steel (CASS), and
- G. Irradiation-enhanced stress relaxation of threaded structural fasteners (TSFs).

In (Reference 2), Section 2.1.4.2.2, the licensee described the service conditions of the RVI components that will result from EPU. The water chemistry conditions are bounded by the current water chemistry conditions, with respect to boron, lithium, pH and impurities. The core outlet temperature will increase from 594 °F to 608.2 °F and the core inlet temperature will increase from 548.5 °F to 551 °F. With respect to internal temperature of the RVI components, the licensee indicated that the maximum value of the long-term steady-state temperature in the RVI components as the result of gamma heating is 784.5 °F, which will be at a subsurface location in the former plates of the core shroud near the mid-section of the core. The licensee provided the maximum neutron fluence after 60 years (52 EFPY) at the inner surface of the core shroud as  $6.586 \times 10^{22}$  n/cm<sup>2</sup> (E>1MeV), and stated that the areas of maximum neutron fluence are at the core shroud inner surfaces opposite the center regions of the reactor core. In terms of displacements per atom (dpa), the projected neutron fluence at the end of 60-year license (52 EFPY) will be 96.03 dpa.

In (Reference 2), Section 2.1.4.2.3, the licensee evaluated the changes expected due to EPU for each aging mechanism listed above. The licensee identified no significant changes to the severity of the aging mechanisms due to EPU. For both IGSCC and TGSCC, the licensee concluded no significant changes would occur in these mechanisms because the temperature increases are minor and because the reactor coolant chemistry will not change.

With respect to irradiation embrittlement, the licensee identified the core shroud as the limiting component and listed several other components that are potentially affected by this mechanism. The licensee indicated that the increase in neutron fluence due to EPU would not cause significant additional decreases in fracture toughness to these RVI components.

With respect to IASCC, the licensee listed RVI components that are potentially susceptible. The licensee concluded that operating experience did not indicate IASCC will become a major problem for PWR RVI components, including those at St. Lucie 1, either with or without EPU, but could not be completely ruled out. The licensee provided a threshold neutron fluence of  $1 \times 10^{21}$  n/cm<sup>2</sup> (E > 1 MeV) for IASCC. The licensee indicated that additional industry data is needed to assess this mechanism, and until that data is available, IASCC will be managed through inservice inspections conducted in accordance with Section XI of the ASME Code, Subsections IWB, IWC and IWD Program, and the RVI Inspection Program. The licensee additionally credited the Chemistry Control Program for management of IASCC of RVI components.

The licensee concluded the total amount and severity of void swelling in the RVI will be minor at the end of the 60-year license period and will be managed through inservice inspections conducted in accordance with Section XI of the ASME Code, Subsections IWB, IWC and IWD

Program, and the RVI Inspection Program. The licensee also listed the Chemistry Control program as a program that manages void swelling of RVI components.

For thermal aging embrittlement of CASS components, the licensee identified the susceptible components as the core support columns, which operate at the core inlet temperature of 551 °F, and the control element assembly (CEA) shroud tubes, which operate at the core outlet temperature of 608.2 °F. The licensee indicated that there would be no change in the lower-bound fracture toughness of these components, although the components could reach the lower-bound fracture toughness in a shorter period of time. The licensee stated that the CEA shroud tubes are centrifugally cast. Therefore, the CEA shroud tubes, according to the criteria in NUREG-1801 (the General Aging Lessons Learned (GALL) report), are not susceptible to thermal aging embrittlement provided the delta ferrite content is 20 percent or less. However, the core support columns are susceptible to thermal aging, which is managed by the RVI inspection program and the Thermal Aging Embrittlement of CASS Program.

The licensee's evaluation of irradiation-induced stress relaxation of RVI components concluded that the small increases in neutron fluence and temperature due to EPU would not adversely affect stress relaxation of RVI components. Only TSFs are considered susceptible to stress relaxation by the licensee.

The licensee concluded that there are no new degradation mechanisms for the RVI resulting from EPU, the program identified to manage these aging mechanisms are appropriate, and no changes are needed to the programs that manage these degradation mechanisms. With respect to the degradation assessment of the RVI components conducted under license renewal, there are no changes to the materials included, component or system functions, system boundaries, and aging management programs identified. The licensee also concluded the RVI would continue to meet the regulatory requirements after EPU, including GDC 1 and 10 CFR 50.55a.

#### Staff Evaluation

Matrix 1 of RS-001 provides the NRC staff's basis for evaluating the potential for EPU to induce these aging effects. In RS-001, Matrix-1, the staff states that, in addition to the SRP, guidance on the neutron irradiation-related threshold levels inducing IASCC in RVI components are given in WCAP-14577.

The staff compared the licensee's evaluation of the aging effects and mechanisms of the RVI components for EPU to the licensee's evaluation of the aging effects and mechanisms for license renewal. The staff notes that in the license renewal application for St. Lucie 1 and 2 (Reference 13), the aging mechanisms identified for the RVI components are consistent with those identified for EPU with the exception of mechanical wear. The staff also notes that the licensee addressed the effects of EPU on the aging mechanisms, but did not specifically address the impact of EPU on the aging effects (for example, loss of fracture toughness).

In (Reference 2), the effects of EPU are evaluated for the following aging mechanisms of the RVI components: fuel cladding corrosion, IASCC, stress corrosion cracking (SCC), irradiation embrittlement, thermal embrittlement, void swelling, and irradiation-enhanced stress relaxation.

The susceptibility of the St. Lucie 1 RVI components to these mechanisms (with the exception of fuel cladding corrosion) was assessed for license renewal as documented in the St. Lucie 1

and 2 License Renewal Application (LRA, (Reference 13)) and the associated SE (Reference 12). (Reference 13) identified the following aging effects and the mechanisms that cause the aging effect: (1) cracking due to SCC and IASCC, (2) reduction in fracture toughness due to irradiation embrittlement and thermal embrittlement (TE), (3) loss of material due to wear, (4) loss of mechanical closure integrity due to cracking (SCC and IASCC) and stress relaxation, (5) loss of preload due to stress relaxation, and (6) dimensional change due to void swelling. No additional components were identified in Reference 1 as susceptible to these effects due to EPU, compared to those components previously identified as susceptible to these effects.

Neutron fluence and temperature are important parameters with respect to assessing the susceptibility of RVI components to many of these aging mechanisms. In particular, threshold neutron fluence levels are identified for certain aging mechanisms in industry guidance documents and topical reports such as WCAP-14577, Revision 1, "License Renewal Evaluation: Aging Management for Reactor Internals," and similar threshold neutron fluence values are also identified in Reference 1 for several of the aging mechanisms evaluated, including IASCC, irradiation embrittlement, void swelling, and stress relaxation. WCAP-14577 establishes a threshold of  $1 \times 10^{21} \text{ n/cm}^2$  ( $E > 1.0 \text{ MeV}$ ) for the initiation of IASCC, loss of fracture toughness, and/or void swelling in PWR RVI components made from stainless steel (including cast austenitic stainless steels) or Alloy 600/82/182 materials. Section 2.1.4.2.2 of Reference 1 provides the post-EPU values of the EOL neutron fluence, the core inlet and outlet temperatures, and the peak metal temperature due to gamma heating. However, with the exception of the core inlet and outlet temperatures, the pre-EPU values of these parameters were not provided for comparison.

It was not clear to the staff how it was determined that no additional components are susceptible to the aging effects listed above as a result of EPU, compared to those identified in the LRA. For example, (Reference 2), Section 2.1.4.2.3.D lists components that are susceptible to irradiation embrittlement. This list does not exactly match the components listed as susceptible to irradiation embrittlement in Section 3.1.4.2.2 of the LRA. Since (Reference 2) does not explain how the screening for susceptibility to these mechanisms was accomplished, in RAI CVIB-5 the staff requested additional information on how this screening was performed and the results of the screening, with respect to the identification of additional components susceptible to particular mechanism. In response to RAI CVIB-5 (Reference 8), the licensee indicated that their screening criteria for the various degradation mechanisms were based on MRP-175, "Materials Reliability Program: PWR Internals Material Aging Degradation Mechanism Screening and Threshold Values." To support the evaluation of those degradation mechanisms that depend on neutron fluence, the licensee developed a detailed neutron fluence map. The licensee stated that beyond the core shroud area, the neutron fluence was extrapolated from the core shroud model (using the decreasing neutron fluence values at increasing distances from the mid-plane core shroud plate interior surface).

The following summarizes the licensee's response regarding the method of evaluation and results for the six aging effects:

- Cracking due to SCC, IASCC:
  - SCC - comparison of the chemistry and temperatures were made to determine susceptibility. Credit for positive changes was also given, such as implementation of zinc injection. All RVI components were already identified as requiring aging management for SCC, and the increases in temperature or stress

for EPU conditions would not increase the susceptibility to SCC for the extended license period.

- IASCC - comparison of plant conditions were made, especially with regard to the neutron fluence threshold values. The licensee considered neutron fluence and stress but not temperature since temperature is not among the MRP-175 screening criteria for IASCC.
- Reduction of fracture toughness due to thermal embrittlement, irradiation embrittlement:
  - Thermal embrittlement - austenitic stainless steel materials with high delta ferrite were considered potentially susceptible. The licensee used the guidance of NUREG-1801 to evaluate the potential susceptibility of cast stainless steel components.
  - Irradiation embrittlement – the screening criteria included neutron fluence, but stress and temperature were not considered.
- Loss of mechanical closure integrity due to IASCC, irradiation embrittlement, irradiation creep, or stress relaxation. This aging effect applies to core support threaded structural fasteners (bolting). A calculation was performed for remaining preload. The licensee stated that calculations were performed for stress relaxation, based on the neutron fluence screening criteria of MRP-175, that showed that no specific threaded structural fastener will lose enough preload to potentially lose mechanical closure integrity. The licensee noted that all RVI threaded structural fasteners have already been identified as susceptible to loss of mechanical closure integrity in the LRA, and that changes in stress or temperature due to EPU are not expected to change how bolting is managed during the license extension period.
- Loss of material due to wear – The licensee stated that wear occurs due to reduced preload and changing flow patterns. As mentioned in the discussion of loss of mechanical closure integrity, the licensee's calculations did not indicate a significant loss of preload. The staff notes that per MRP-175, wear is only significant for those bolted connections that are above the neutron fluence screening threshold for loss of preload. The licensee's evaluations determined EPU will not increase flow rates in the RCS so wear will not increase.
- Dimensional change due to void swelling – Void swelling was assessed using the screening criteria of MRP-175 (608 °F and  $1.3 \times 10^{22}$  n/cm<sup>2</sup> (E > 1.0 MeV)). The highest temperature of any RVI component and the highest neutron fluence on the core shroud plates were assumed to occur at the same location and the potential void swelling calculated using the equation provided by MRP-175.

Based on the screening and evaluation described above, the licensee determined that certain components may be susceptible to additional degradation mechanisms, compared to the degradation mechanisms identified in the LRA for those components, under EPU conditions. Specifically, the fuel alignment plate, CEA shroud assemblies, and the upper guide structure support plate may be susceptible to irradiation embrittlement. Cracking of these components was previously identified in the LRA. The licensee stated that the license renewal documentation would be updated to reflect this change. However, the response does not indicate specifically which aging management programs (AMPs) will manage the additional aging effects, or whether changes to the existing identified AMPs will be necessary. Therefore, in RAI CVIB-7 the staff requested that (1) the licensee identify the AMP(s) that will manage the aging effects associated with the additional aging mechanisms discussed above, and (2) to

discuss the adequacy of the existing AMP(s) to manage the aging effects associated with the additional aging mechanisms, and describe any changes that are necessary to the existing identified AMP.

In the response to RAI CVIB-7, via letter dated July 8, 2011, the licensee stated that the additional RVI components determined to be susceptible to age-related degradation resulting from the EPU will be included in the St. Lucie 1 RVI Inspection Program. With respect to the adequacy of the AMP to manage the additional aging effects, the licensee stated that they plan to modify the RVI Inspection Program to align with MRP-227-A, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines." The licensee further stated that the adequacy of MRP-227-A for management of aging effects associated with the RVI has been evaluated by the NRC as documented in the final SE of MRP-227, Revision 0. The licensee additionally indicated that they have evaluated the changes in operating parameters associated with EPU and determined they do not change the bounding assumptions of MRP-227-A. The staff notes that the licensee evaluation of the changes in operating parameters is consistent with the requirement of Applicant/Licensee Action Item 1 of the final SE of MRP-227, which requires that each licensee perform an evaluation of its plant's operating history (including the effects of any power uprate) demonstrating the applicability of MRP-227, Revision 0 to the facility. Based on the foregoing, the staff finds that the licensee has assigned an appropriate AMP to manage the effects of aging on the RVI considering EPU, since the NRC staff approved MRP-227 for referencing in licensing applications and as an acceptable AMP for RVI components, subject to the conditions and limitations and applicant/licensee action items contained in the final SE of MRP-227. The staff finds that RAI CVIB-7 is resolved.

Some of the aging effects identified in the LRA for St. Lucie 1 and 2, were not discussed in the licensee's evaluation of the RVI for EPU. Specifically, the effects of EPU on the aging effects loss of mechanical closure integrity and loss of material were not discussed in (Reference 2). Loss of material due to wear was not evaluated for EPU. The SE related to the St. Lucie LRA, NUREG-1779, indicated that loss of material from wear of RVI components can occur due to relative motion between the interfaces and mating surfaces of components caused by flow-induced vibration during plant operation, differential thermal expansion and contraction movements during plant heat up and cool down, and changes in power operating cycles. NUREG-1779, Section 3.1.4.2.1 also indicated that, for the St. Lucie 1 RVI components, loss of mechanical closure integrity of fuel alignment plate guide lug bolts, fuel alignment plate guide lug insert bolts, and CEA shroud bolts can occur due to cracking and stress relaxation, and that loss of mechanical closure integrity associated with the core shroud tie rods and snubber bolts can occur due to cracking, reduction in fracture toughness (irradiation embrittlement), and stress relaxation. The staff requested that the licensee address the aging effects loss of material and loss of mechanical closure integrity in the EPU evaluation of the RVI (RAI CVIB-6). The licensee's responses to RAI CVIB-6 (Reference 8) for loss of mechanical closure integrity and wear are similar to the responses for the same aging effects in RAI CVIB-5, therefore will not be repeated here. Since the licensee has evaluated the aging effects loss of mechanical closure integrity and wear for EPU, the staff considers RAI CVIB-6 to be resolved.

Section 4.6.3 of the LRA describes time-limited aging analyses (TLAAs) related to a plug repair of the core support barrel (CSB). As part of the LRA, FPL determined that two specific elements of the CSB repair qualify as TLAAs: (1) the fatigue analysis of the core support barrel (CSB) middle cylinder and (2) the acceptance criteria for the CSB expandable plugs' preload based on irradiation-induced stress relaxation. In the LRA, the CSB fatigue analysis was determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i), while the analysis of irradiation induced stress relaxation of the plug



preload was revised to project the analysis to 60 years in accordance with 10 CFR 54.21(c)(1)(ii). (Reference 2), Section 2.14, states that the CSB fatigue TLAA was reevaluated for EPU and continues to remain valid for the period of extended operation. (Reference 2), Section 2.14 also indicates the TLAA for the expandable plugs loss of preload was reevaluated considering the increased neutron fluence (54 EFPY) due to EPU, and was found to be acceptable. Refer to Section 2.2.3 of this SE for the staff's evaluation of the TLAA related to fatigue of the CSB. Since the licensee has reevaluated the two TLAAs related to the RVI considering EPU conditions, the staff finds that the effect of EPU on the RVI-related TLAAs has been appropriately considered.

With respect to adequacy of the licensee's existing aging management programs to manage the aging of the RVI, considering the components with additional aging mechanisms resulting from EPU, the staff observes that FPL committed in LRA to "submit a report summarizing the aging effects applicable to RVIs, including a description of the inspection plan," prior to the end of the current 40-year operating term for St. Lucie 1 (See NUREG-1779 Section 3.1.0.7 and Updated FSAR Supplement Section 18.1.4 (Appendix A of LRA). FPL also committed to perform a one-time inspection of the RVI components (to implement the enhanced inspections of the RVI Inspection Program). NUREG-1779 (Reference 12) also documents that St. Lucie 1 and 2 are participating in the Electric Power Research Institute (EPRI) Materials Reliability Program (MRP) effort related to RVI, which would provide additional bases for inspections under the RVI program. The licensee did not specifically commit during the license renewal process to implement an RVI inspection program consistent with the guidance of the standard industry program as did most of the later license renewal applicants. The topical report "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227, Revision 0)" (Reference 14), provides the industry's recommendations for plant-specific PWR RVI inspection and evaluation programs. In RAI CVIB-8, the staff requested that the licensee discuss their plans to implement the industry's recommended inspection and evaluation guidelines for RVI components as documented in topical report MRP-227, Revision 0, as modified by the staff's final SE of MRP-227, Revision 0 (Reference 15), or the approved version of the topical report (MRP-227-A), for St. Lucie 1. In the response to RAI CVIB-8, via letter dated July 8, 2011, the licensee stated that it hereby revises its current commitments associated with the aging management of RVI components during the period of extended operation to adopt MRP-227-A in place of the existing RVI Inspection Program. The staff notes that the licensee will submit a plant-specific integrated report for St. Lucie 1 and 2, conforming to MRP-227-A, which will summarize the understanding of the aging effects applicable to the RVI and will contain a description of the St. Lucie 1 and 2 inspection plans including methods for detection and sizing of cracks and acceptance criteria. The staff will review the program to ensure that it includes an evaluation confirming that the operating conditions for St. Lucie 1, are bounded by the operating conditions (neutron fluence, temperature, etc.) assumed as the basis for the development of the generic inspection and evaluation guidelines for RVI components in MRP-227. The NRC staff finds RAI CVIB-8 is closed because the licensee has committed to modify their RVI AMP to conform to the NRC-approved version of the industry RVI inspection and evaluation program described in topical report MRP-227, Revision 0.

The staff notes that the licensee listed the Chemistry Control Program among the programs credited for managing void swelling. No inspections are conducted under the Chemistry Control Program and the Chemistry Control Program would not provide any means of prevention of void swelling since it is not influenced by water chemistry. However, the staff finds the other program credited for managing void swelling (RVI Inspection Program and ASME Section XI,

Subsections IWB, IWC and IWD Program) would effectively manage change in dimensions of RVI components due to void swelling.

RS-001, in Note 1 to Matrix 1, states that for thermal and neutron embrittlement of CASS, SCC, and void swelling, licensees will need to provide plant-specific degradation management programs or participate in industry programs to investigate degradation effects and determine appropriate management programs. As noted above, the licensee has an existing commitment to provide a plant-specific program, and has stated their program will be consistent with the industry generic RVI component inspection program guidance, which takes into account the industry findings on void swelling, SCC, and thermal and neutron embrittlement of CASS, the staff finds that the recommendation in Note 1 of Matrix 1 of RS-001 is met.

### Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the susceptibility of RVI to known degradation mechanisms and concludes that the licensee has identified appropriate degradation management programs to address the effects of changes in operating temperature and neutron fluence on the integrity of these components.

The staff finds that the licensee has appropriately evaluated the potential for age-related degradation of the RVI components because they considered the changes in neutron fluence, temperature, and water chemistry in their evaluation. The staff agrees with the applicants conclusion that the RVI components will experience no new aging mechanisms or effects due to EPU, and that the previously identified aging mechanisms and effects (identified through the aging management review process conducted for license renewal) will continue to be adequately managed by the programs identified (RVI Inspection Program; ASME Section XI IWB, IWC, and IWD Program; and the Water Chemistry Program).

Consistent with Matrix 1 of RS-001, the staff further concludes that the licensee has committed to an augmented inspection program for the RVI and core support components to ensure that the components will continue to meet the requirements of GDC 1 and 10 CFR 50.55a following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to maintaining the structural integrity of the RVI components.

## 2.1.5 Reactor Coolant Pressure Boundary Materials

### Regulatory Evaluation

The RCPB defines the boundary of systems and components containing the high-pressure fluids produced in the reactor. The NRC staff's review of RCPB materials covered their specifications, compatibility with the reactor coolant, fabrication and processing, susceptibility to degradation, and degradation management programs. The NRC's acceptance criteria for RCPB materials are based on (1) 10 CFR 50.55a and GDC 1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (3) GDC 14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; (4) GDC 31, insofar as it requires that the RCPB be

designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; and (5) 10 CFR Part 50, Appendix G, which specifies fracture toughness requirements for ferritic components of the RCPB. Specific review criteria are contained in SRP Section 5.2.3 and other guidance provided in Matrix 1 of RS-001. Additional review guidance for primary water stress-corrosion cracking (PWSCC) of dissimilar metal welds and associated inspection programs is contained in GL 97-01, Information Notice (IN) 00-17, Bulletin (BL) 01-01, BL 02-01, and BL 02-02. Additional review guidance for thermal embrittlement of cast austenitic stainless steel components is contained in a letter from C. Grimes, NRC, to D. Walters, Nuclear Energy Institute (NEI), dated May 19, 2000.

The staff notes that in its application the licensee states that St. Lucie 1 was designed and constructed based on the 1967 draft AEC GDC. The staff also notes that the adequacy of the plant's design relative to the GDC as found in 10 CFR Part 50, Appendix A as amended through February 20, 1971, is discussed in section 3.1 of the plant FSAR. Any issues arising from differences between plant design bases and the GDC acceptance criteria described above will be discussed in the technical evaluation section, below.

#### Technical Evaluation

The licensee indicated that the RCPB defines the boundary of systems and components containing the high-pressure fluids produced in the reactor. The licensee's evaluation of RCPB materials covered the design specification, compatibility with the reactor coolant, fabrication and processing, susceptibility to degradation, and degradation management programs. The staff notes that the licensee did not change any of the materials of construction in the RCPB as a result of this power uprate. As a result, the licensee applied less emphasis on the issues of design specifications and fabrication and processing and more emphasis on the issues of compatibility with the reactor coolant, susceptibility to degradation, and degradation management programs. The staff concurs with this approach because the issues of design specification and fabrication and processing are primarily issues associated with new materials or components and the remaining issues related to material degradation associated with changes in the RCPB environment.

In its application the licensee stated that the principle materials from which the RCPB is constructed include: (a) carbon and low alloy steel; (b) wrought and cast austenitic stainless steel; (c) alloy 600/82/182; and, (d) alloy 690/52/152. In its application the licensee also stated that the primary environmental changes within the RCPB as a result of the EPU will include: (a) an increase in RCS hot leg temperature of 12 °F and RCS cold leg temperature of 2.5 °F; and (b) potential changes in water chemistry including lithium, boron and pH but not zinc, hydrogen, dissolved oxygen, chlorides, sulfates or other contaminants. The pH values of the RCS water will remain between 6.9 and 7.4. The staff notes that the principal modes of material degradation in the RCS system are: (a) loss of material due to various forms of corrosion including corrosion due to boric acid; (b) transgranular cracking; (c) PWSCC; and, (d) thermal aging. While the potential exists that the severity of the previously mentioned degradation mechanisms may increase, no additional degradation mechanisms are foreseen.

The paragraphs that follow will consider the effect of the projected environmental changes on each combination of material and degradation effect.

### Carbon and Low Alloy Steel / Loss of Material

In its application the licensee stated that due to the replacement of the 19 alloy 600 instrument and sampling nozzles in the hot leg by the half nozzle repair process, a small amount of carbon steel hot leg piping is permanently exposed to reactor coolant. The staff notes that some corrosion of carbon steel components can be expected in hot, dilute boric acid solutions such as occur in the reactor coolant. The staff also notes that WCAP-15973-P-A, Low-Alloy Steel Component Corrosion Analysis Supporting Small-Diameter Alloy 600/690 Nozzle Repair/Replacement Program, addresses this corrosion issue. The staff further notes that the licensee utilized this reference at the time the repairs were made to determine that sufficient corrosion allowances prior to meeting minimum code criteria were available. The staff finally notes that the EPU environmental conditions are bounded by those used in WCAP-15973-P-A. This indicates to the staff that the original analysis conducted by the licensee remains valid and that additional actions regarding the corrosion of carbon steel exposed to the RCS environment following the uprate are not necessary.

In its application the licensee also addressed the concept of leakage of reactor coolant onto the external surfaces of RCS components. The staff notes that while the corrosivity of the leaking fluid is very low, rapid evaporation of water causes the formation of solid boric acid in conjunction with a highly concentrated boric acid solution on the external surfaces of RCSB components. This concentrated solution of boric acid corrodes carbon steel at an appreciable rate. The staff also notes that the rate of corrosion of steel exposed to concentrated boric acid is primarily a function of the solution concentration and to a lesser extent on the absolute temperature of the solution. The staff finds that the change in chemistry of the reactor coolant will have no effect on corrosion of the external surfaces of RCS components since the concentration of boric acid in the reactor coolant is essentially unrelated to the concentration following evaporation on the external surface of the components. The staff also finds that the change in corrosion rate on the external surfaces of steel components due to the EPU temperature rise will be insignificant due to the small change in temperature (1054 degrees Rankine (°R) to 1066 °R, which is a change of 1.1 percent). The staff further notes that the licensee stated that it manages potential corrosion on the external surfaces of carbon and low alloy steel components due to reactor coolant leakage through the use of AMP XI.M10, Boric Acid Corrosion, as contained in revision 1 of the Generic Aging Lessons Learned Report (NUREG 1801). The staff identified this approach to corrosion management as being acceptable for the current operating conditions while evaluating the licensee's application for license renewal. Based on the fact that the AMP does not recommend additional actions on the part of the licensee as a result of a small increase in operating temperature, the staff finds that the AMP will remain an effective tool to mitigate corrosion of the external surfaces of carbon and low alloy steel components under the extended power uprate conditions.

### Carbon and Low Alloy Steel / Transgranular Cracking, PWSCC, Thermal Aging

The degradation mechanisms, transgranular cracking, PWSCC, and thermal aging have never been observed by the staff under environmental conditions resembling either the current operating conditions or those for the extended power uprate for carbon or low alloy steels. Additionally, based on material characteristics such as chemical composition, crystal structure, and active/passive behavior, the staff finds no basis to expect these degradation mechanisms in carbon or low alloy steels exposed to either the current or EPU operating conditions. The staff, therefore, finds that these issues do not need to be addressed in this application.

### Austenitic Stainless Steel / Loss of Material

In its discussion of carbon and low alloy steel components, the licensee states that the internal surfaces of most carbon and low alloy steel components are clad with austenitic stainless steel. The licensee also states that the Electric Power Research Institute (EPRI) Pressurized-Water Reactor (PWR) Water Chemistry Guidelines indicate that increasing initial lithium concentrations up to 3.5 parts per million (ppm) with controlled boron concentrations to maintain pH values between 6.9 and 7.4 does not produce undesirable material integrity issues. The staff concurs with the licensee's interpretation of the EPRI guidelines. The staff also notes that due to its passive condition, stainless steel is highly resistant to corrosion in near neutral pH solutions, as maintained by the proposed lithium and boric acid additions to the coolant. The staff therefore, concurs with the licensee's assessment that the loss of material due to corrosion of stainless steel by reactor coolant is not an issue of concern at either the existing or the proposed EPU environmental conditions.

### Austenitic Stainless Steel / Transgranular Cracking

In its discussion of stress corrosion cracking of austenitic stainless steels, the licensee identifies transgranular cracking as a possible degradation mechanism for austenitic stainless steels. The licensee also states that transgranular cracking of austenitic stainless steels occurs only in the presence of halogens such as chlorides and dissolved oxygen. The licensee further states that its current water chemistry is within EPRI recommended guidelines and that, relative to halogens and oxygen, the water chemistry will not change under EPU conditions. The staff notes that one of the objectives of the EPRI water chemistry guidelines is the prevention of transgranular cracking. The licensee finally states that, in the absence of an increase in chlorides or oxygen, the slight increase in temperature under the EPU conditions will not result in the occurrence of transgranular cracking of stainless steel. Based on its knowledge of the extensive body of literature associated with transgranular cracking of stainless steels, the staff finds that: (a) the licensee has correctly identified the conditions which may lead to transgranular cracking; and, (b) the licensee has correctly concluded that transgranular cracking is not expected under current operating conditions. Based on the absence of changes in critical contaminants (i.e., chlorides and oxygen) between current and EPU conditions, the staff also concurs with the licensee's assessment that transgranular cracking of stainless steel is not expected under EPU conditions. The staff, therefore, finds that additional precautions on the part of the licensee for the prevention of transgranular cracking under EPU conditions are not required.

### Austenitic Stainless Steel / PWSCC

PWSCC does not generally occur in stainless steels, however, some instances of intergranular cracking have occurred in sensitized stainless steel under dead leg conditions (see NRC Information Notice 2006-27). While these instances technically meet the definition of PWSCC (i.e., intergranular cracking of material exposed to primary water), they are generally called IGSCC and are thought to be caused by issues such as crevices, high halogens, and/or high oxygen concentrations. Given the absence of operating experience of PWSCC in stainless steels exposed to reactor coolant meeting the EPRI water chemistry guidelines, the staff concurs with the licensee's statement that, in the absence of additional contaminants, the slight increase in temperature expected at EPU conditions would not lead to PWSCC in stainless steel materials.

### Austenitic Stainless Steel / Thermal Aging

The staff notes that some CASSs are subject to thermal aging. Thermal aging manifests itself as an increase in hardness and yield strength and a decrease in ductility and toughness. The staff also notes that the degree of aging is a function of the chemistry of the steel and the process by which it was cast. The rate of degradation is a function of the operating temperature of the material.

In its discussion of thermal aging of CASSs, the licensee indicated that it has evaluated its cast stainless steel components against the standards established in NUREG-1801 (GALL Report AMP XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)). Based on that evaluation the licensee stated that some, but not all of its CASS material met the AMP criteria for exclusion from aging management. The licensee also stated that the aging of the remaining material was being managed through the use of the AMP. The licensee further stated that the increase in temperature between the current and EPU conditions would not cause an increase in the number of components for which aging management was required. The licensee finally stated that while the components subject to aging management may reach their minimum toughness values more quickly due to the slight increase in temperature under the EPU operating conditions, the AMP does not require any modification to the program as result. The staff finds that the licensee has accurately assessed the pertinent technical aspects of thermal aging of austenitic stainless steel (i.e., an increase in temperature will affect the rate but not the extent of toughness reductions for a CASS component). The staff also finds that the licensee has correctly interpreted the information regarding the management of aging of CASS components contained within the AMP. The staff, therefore, concurs with the licensee's assessment that no further action is required on the part of the licensee relative to thermal aging of CASS as a result of the EPU temperature change. The staff also notes that the water chemistry change associated with the EPU will not affect thermal aging of CASS because thermal aging of CASS is a thermal rather than chemically driven process.

### Alloy 600/82/182 / Loss of Material

The staff notes that in its application the licensee does not specifically address the susceptibility to loss of material of alloy 600/82/182 components or welds. The staff also notes that based on the chemical composition of these materials, high nickel and chromium contents that lead to passive behavior, these materials, when exposed to reactor coolant, are expected to be highly resistant to corrosion. The staff further notes an absence of operating experience indicating that these alloys are susceptible to loss of material. An examination of revision 2 to the GALL report reveals that there are no entries for loss of material due to any form of corrosion for nickel alloys exposed to reactor coolant. Alternatively, the GALL report does contain entries for loss of material due to mechanisms such as wear or fretting for nickel alloy components exposed to reactor coolant. The staff additionally notes that, as part of its license renewal process, the licensee has aging management programs for the affected components which are designed to detect and manage loss of material. The staff finally notes that while increases in flow velocity which are likely to be associated with EPU conditions may accelerate this type of wear, the aging management programs in use by the licensee are not specific to any given flow rate. Due to the presence of these programs and to the fact that they are not specific to the existing plant conditions, the staff finds that the licensee's approach for addressing loss of material of alloy 600/82/182 components and welds under EPU conditions is acceptable.

### Alloy 600/82/182 / Transgranular Cracking

In its application, the licensee fails to address transgranular cracking of alloy 600/82/182 (i.e., cracking of austenitic materials due to the presence of oxygen and halides). The staff notes, however, that materials with high nickel contents such as alloys 600/82/182 are essentially immune to this form of degradation (Fontana, M.G., Corrosion Engineering 1986, p. 124). The staff finds that this degradation mechanism for these alloys exposed to reactor coolant need not be considered for either the current or EPU conditions.

### Alloy 600/82/182 / PWSCC

In its application the licensee acknowledges that the primary mode of degradation of alloy 600/82/182 components is PWSCC. To mitigate this mode of degradation, the licensee has replaced most of the alloy 600/82/182 components and welds in the RCSB. Despite this replacement program, some alloy 600/82/182 components/welds remain. One location that has not been replaced or mitigated, the drain nozzle safe end weld, is in a hot leg location. A second location in which alloy 600/82/182 remains is the cladding on the primary faces of the replacement steam generator (RSG) tube sheets. The remaining alloy 600/82/182 components/welds are in cold leg locations. These components/welds are subject to PWSCC under current operating conditions, and, because time for PWSCC crack initiation is reduced as temperature is increased, they are subject to a more rapid onset of PWSCC under EPU conditions. The licensee has calculated that the time required for initiation of PWSCC cracks will decrease approximately 38 percent in hot leg locations as a result of the 12 °F temperature increase anticipated as a result of the EPU. The staff notes that a much smaller decrease in time to PWSCC initiation will occur for cold leg locations. The licensee proposes to address the issue of PWSCC through the use of its alloy 600 management plan. The licensee stated that this plan follows industry experience, identifies and ranks alloy 600/82/182 locations, develops and maintains inspection plans and develops mitigation/repair replacement strategies for remaining alloy 600/82/182 components.

The staff finds that the licensee's approach to managing PWSCC in the remaining hot leg location is acceptable because the licensee has been and will continue to inspect this weld during each refueling outage and plans to replace or mitigate this weld. This inspection frequency is in accordance with ASME code case N-770-1 for both current and EPU hot leg temperatures. Code case N-770-1 is being considered for incorporation into 10 CFR 50.55a under current rulemaking efforts.

The staff finds that the licensee's approach to managing PWSCC in the tube sheet cladding acceptable because any cracking that occurs in the cladding will terminate in the carbon/low alloy steel beneath the cladding. While some corrosion may occur in the substrate, the rate will be sufficiently low under both current and EPU conditions so as not to affect the structural integrity of the tube sheet (see discussion of Carbon and Low Alloy Steel / Loss of Material above).

The staff finds that the licensee's approach to managing PWSCC in the cold leg locations containing alloy 600/82/182 is acceptable because: (a) the licensee has a comprehensive alloy 600 management plan; (b) the plan has been effective in managing hot leg components under current operating conditions; (c) the cold leg conditions under power uprate conditions are cooler than the hot leg conditions under current operating conditions indicating that the program has been demonstrated to be sufficiently robust to address cracking under the cold leg EPU

conditions; (d) the alloy 600 management plan was examined as part of the license renewal process and found to be acceptable; and, (e) the NRC staff is currently engaged in rulemaking to include additional inspection requirements in 10 CFR 50.55a for the examination of alloy 82/182 piping butt welds. Once finalized, these requirements will need to be incorporated into the licensee's alloy 600 management plan.

#### Alloy 600/82/182 / Thermal Aging

In its application, the licensee fails to address thermal aging of alloy 600/82/182. The staff notes, however, that thermal aging of alloy 600/82/182 has never been observed by the staff under environmental conditions resembling either the current operating conditions or those for the extended power uprate. The staff also notes that thermal aging has been observed only in cast austenitic stainless steels. Thermal aging in these steels is a function of casting method, molybdenum content and delta ferrite content. The staff further notes that cast alloy 600/82/182 is not used in nuclear power plants. The staff additionally notes that the nickel and chromium equivalents in alloys 600/82/182 are such that no delta ferrite is expected. The staff finally notes that alloy 600 contains no more than trace level of molybdenum. The staff, therefore, finds that thermal aging of alloy 600/82/182 does not need to be addressed in this application.

#### Alloy 690/52/152 / Loss of Material

The staff notes that in its application the licensee does not specifically address the susceptibility to loss of material of alloy 690/52/152 components or welds. The staff also notes that based on the chemical composition of these materials, high nickel and chromium contents that lead to passive behavior, these materials, when exposed to reactor coolant, are expected to be highly resistant to corrosion. The staff further notes an absence of operating experience indicating that these alloys are susceptible to loss of material. An examination of revision 2 to the GALL Report reveals that there are no entries for loss of material due to any form of corrosion for nickel alloys exposed to reactor coolant. Alternatively, the GALL Report does contain entries for loss of material due to mechanisms such as wear or fretting for nickel alloy components exposed to reactor coolant. The staff additionally notes that, as part of its license renewal process, the licensee has aging management programs for the affected components that are designed to detect and manage loss of material. The staff finally notes that while increases in flow velocity that are likely to be associated with EPU conditions may accelerate this type of wear, the aging management programs in use by the licensee are not specific to any given flow rate. Due to the presence of these programs and to the fact that they are not specific to the existing plant conditions, the staff finds that the licensee's approach for addressing loss of material of alloy 690/52/152 components and welds under EPU conditions is acceptable.

#### Alloy 690/52/152 / Transgranular Cracking

In its application, the licensee fails to address transgranular cracking of alloy 690/52/152 (i.e., cracking of austenitic materials due to the presence of oxygen and halides). The staff notes, however, that materials with a high nickel contents such as alloys 690/52/152 are essentially immune to this form of degradation (Fontana, M.G., Corrosion Engineering 1986, p. 124). The staff finds that this degradation mechanism for these alloys exposed to reactor coolant need not be considered for either the current or EPU conditions.



### Alloy 690/52/152 / PWSCC

In its application the licensee states that, based on substantial laboratory data, alloy 690/52/152 is significantly more resistant to PWSCC than alloy 600. The licensee also states that, based on 20 years of field experience for alloy 690 and 15 years of field experience for alloy 52/152, there have been no reports of PWSCC up to temperatures of 653 °F. The staff concurs with the licensee's interpretation of these data. Based on this combination of field and laboratory data, the staff has incorporated the use of ASME code case N-729-1 in 10 CFR 50.55a and is considering the incorporation of ASME code case N-770-1 in 10 CFR 50.55a. These code cases address examination requirements for PWR reactor vessel upper heads and examination requirements for class 1 PWR piping and vessel nozzle welds fabricated from alloy 82/182 with or without mitigation activities (including weld overlays with alloy 52/152). The staff finds that compliance with these code cases as incorporated in 10 CFR 50.55a is sufficient to address concerns of PWSCC in alloy 690/52/152 components and welds.

### Alloy 690/52/152 / Thermal Aging

In its application, the licensee fails to address thermal aging of alloy 690/52/152. The staff notes, however, that thermal aging of alloy 690/52/152 has never been observed by the staff under environmental conditions resembling either the current operating conditions or those for the EPU. The staff also notes that thermal aging has been observed only in CASS. Thermal aging in these steels is a function of casting method, molybdenum content and delta ferrite content. The staff further notes that cast alloy 690/52/152 is not used in nuclear power plants. The staff additionally notes that the nickel and chromium equivalents in alloys 690/52/152 are such that no delta ferrite is expected. The staff finally notes that alloy 690 contains no more than trace levels of molybdenum. The staff, therefore, finds that thermal aging of alloy 690/52/152 does not need to be addressed in this application.

### Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the susceptibility of RCPB materials to known degradation mechanisms and concludes that the licensee has identified appropriate degradation management programs to address the effects of changes in system operating temperature on the integrity of RCPB materials. The NRC staff further concludes that the licensee has demonstrated that the RCPB materials will continue to be acceptable following implementation of the proposed EPU and will continue to meet the requirements of GDC 1, GDC 4, GDC 14, GDC 31, 10 CFR Part 50, Appendix G, and 10 CFR 50.55a. Therefore, the NRC staff finds the proposed EPU acceptable with respect to RCPB materials.

#### 2.1.6 Leak-Before-Break

### Regulatory Evaluation

Leak before break (LBB) analyses provide a means for eliminating from the design basis the dynamic effects of postulated pipe ruptures. NRC approval of LBB for a plant permits the licensee to (1) remove protective hardware along the piping system (e.g., pipe whip restraints and jet impingement barriers) and (2) redesign pipe connected components, their supports, and their internals. The NRC staff's review for LBB covered (a) direct pipe failure mechanisms (e.g., water hammer, creep damage, erosion, corrosion, fatigue, and environmental conditions);

(b) indirect pipe failure mechanisms (e.g., seismic events, system overpressurizations, fires, flooding, missiles, and failures of SSCs in close proximity to the piping); and (c) deterministic fracture mechanics and leak detection methods. The NRC's acceptance criteria for LBB are based on GDC 4, insofar as it allows for exclusion of dynamic effects of postulated pipe ruptures from the design basis. Specific review criteria are contained in SRP Section 3.6.3 and other guidance provided in Matrix 1 of RS-001.

The staff notes that while St. Lucie 1 was designed and constructed based on the 1967 draft AEC GDC, GDC 4 as contained in FSAR Section 3.1.4 Criterion 4 is identical to GDC 4 as contained in the current edition of 10 CFR Part 50 appendix A.

### Technical Evaluation

#### St. Lucie 1 LBB Technical Evaluation

In section 2.1.6.2 of its application, the licensee states that the current structural design basis for the plant includes the application of LBB methodology to eliminate consideration of the dynamic effects resulting from pipe breaks in the RCS primary loop piping. The licensee also stated that the original LBB analysis was conducted in accordance with CE Owners Group (CEOG) Report CEN-367-A Rev. 000, "Leak Before Break Evaluation of Primary Coolant Loop Piping in Combustion Engineering Designed Nuclear Steam Supply Systems," February 1991. As denoted by the "-A" in the report designation, the approach for the analysis of LBB that is described in the report has been accepted by the staff. The staff's safety evaluation is included in the report. The licensee further stated that, as part of its license renewal it requested Westinghouse to conduct a plant-specific reevaluation of the original LBB analysis for the EPU conditions.

Staff guidance for LBB analyses is contained in SRP Section 3.6.3 and NUREG-1601 Volume 3. This guidance states that LBB analyses should: (a) demonstrate that margin exists between the "critical" flaw size and a postulated flaw that yields a detectable leak rate; (b) demonstrate that there is sufficient margin between the leakage through a postulated flaw and the leak detection capability; (c) demonstrate margin on the applied load; and, (d) demonstrate that fatigue crack growth is negligible. Acceptance criteria for LBB analyses include: (a) margin of 10 on detectable leak rate; (b) margin of 2 on flaw size; and, (c) Margin of  $\sqrt{2}$  on loads for leakage flaw size. The staff notes that the primary inputs to LBB analyses are material properties (which are functions of the materials used and temperature), internal pressure, normal operating loads, safe shutdown earthquake loads, and certain plant transients (for fatigue calculations).

In its review of the licensee's application, the staff reviewed the original analysis (i.e., CEOG Report CEN-367-A). The staff notes that, with one potential exception, discussed below, this evaluation successfully addressed all the issues included in the staff's LBB guidance. This review will, therefore, only consider potential changes to the LBB analysis that may be necessitated by the change from current to EPU conditions. The staff notes that the principal changes associated with EPU conditions are: (a) a change in RCS flow rate; (b) an increase in both RCS hot and cold leg temperatures; and, (c) changes in water chemistry.

In considering the effects of the changes to the RCS system environment caused by the EPU which may affect the LBB analysis, the staff finds that: (a) water chemistry changes will not affect the LBB analysis and need not be considered; (b) changes in hot and cold leg temperatures may affect material properties; (c) changes in fluid flow and changes in hot and

cold leg temperature may change normal operating loads; (d) internal pressure for the LBB analysis will not change because system pressure does not change as a result of the EPU; and, (e) safe shutdown earthquake loads will not change as the characteristics of the safe shutdown earthquake are not affected by the EPU.

Based on the above the staff finds it necessary for the licensee to address changes in material properties with temperature and changes in normal operating loads in its demonstration that its LBB analysis remains valid for EPU conditions.

The staff notes that the licensee is silent in its application concerning the effects of temperature on material properties. The staff also notes, however, that the original analysis conservatively utilizes stress strain properties for 650 °F and fracture toughness properties for 550 °F. Since the change in temperature as a result of the EPU remains within these bounds, the staff finds that the actual changes in material properties resulting from the EPU need not be considered in the analysis.

In its application the licensee states that changes in normal operating loads do occur as a result of EPU conditions. However, the licensee also states that changes in normal operating loads resulting from the EPU are bounded by the normal operating loads used in the original analysis because the normal operating loads originally used were selected to bound the normal operating loads at several plants. The staff concurs with this analysis.

Based on the above analysis, the staff concurs with the licensee's assertion that the LBB analysis for the EPU conditions is bounded by the original analysis and that the acceptance criteria as set forth above are not affected by the EPU.

The staff notes, however, that one aspect of the original LBB analysis, the existence of components and welds that are susceptible to PWSCC and have not been mitigated, is contrary to guidance found in SRP Section 3.6.3. The staff has established precedent for accepting LBB analyses for conditions in which nonmitigated, PWSCC susceptible, welds or components are present based on increased inspections performed under MRP-139. In this instance, the staff chooses to remain consistent with this precedent and accepts the licensee's LBB analysis despite its deviation from SRP Section 3.6.3. The staff is, however, reviewing the PWSCC issue with respect to LBB evaluations. If necessary, changes in the staff policy on this issue will be generically addressed for all plants.

### Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the LBB analysis for the plant and concludes that the licensee has adequately addressed changes in primary system pressure and temperature and their effects on the LBB analyses. The NRC staff further concludes that the licensee has demonstrated that the LBB analyses will continue to be valid following implementation of the proposed EPU and that lines for which the licensee credits LBB will continue to meet the requirements of GDC 4. Therefore, the NRC staff finds the proposed EPU acceptable with respect to LBB.

## 2.1.7 Protective Coating Systems (Paints) - Organic Materials

### Regulatory Evaluation

Protective coating systems (paints) provide a means for protecting the surfaces of facilities and equipment from corrosion and contamination from radionuclides and also provide wear protection during plant operation and maintenance activities. The NRC staff's review covered protective coating systems used inside the containment for their suitability for and stability under design basis loss-of-coolant accident (DBLOCA) conditions, considering radiation and chemical effects. The NRC's acceptance criteria for protective coating systems are based on (1) 10 CFR Part 50, Appendix B, which states quality assurance requirements for the design, fabrication, and construction of safety-related SSCs and (2) RG 1.54, Revision 2, for guidance on application and performance monitoring of coatings in nuclear power plants. Specific review criteria are contained in SRP Section 6.1.2.

St. Lucie 1 was designed and constructed based on the 1967 draft AEC GDC. In preparation for issuance of the St. Lucie 1 FSAR, an effort was made to comply with the newer (1971) final GDC. As noted in FSAR Section 3.1, the design bases of St. Lucie 1 are measured against the NRC "General Design Criteria for Nuclear Power Plants," 10 CFR Part 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie 1 design relative to the GDC is discussed in FSAR Section 3.1. The licensee stated that the application of protective coating systems inside the containment pre-dated RG 1.54, Rev. 0, and American National Standards Institute (ANSI) Standard N101.4.

FSAR Section 3.8.3.6.1 states that coatings located within the reactor containment building (RCB), which could potentially be subjected to design basis accident (DBA) conditions, are referred to as Service Level I coatings. The primary purposes of Service Level I protective coatings are to provide corrosion protection and a suitable surface with regard to radioactive decontamination. Since Service Level I protective coatings are located within the RCB, failure to adhere to the surfaces to which they are applied could hypothetically result in a larger than anticipated build-up of coating material debris at the containment sump strainers. Conceivably, such a build-up could adversely impact the flow of water through the nuclear safety-related containment sump strainers and, correspondingly, the flow of water available for the safety-related function of the containment spray (CS) pumps for containment cooling.

FSAR Section 6.3.6 provides the summary of the response to NRC GL 98-04, regarding potential degradation of emergency core cooling system (ECCS) and CS system due to protective coatings failure and foreign material accumulation in containment recirculation sumps after a LOCA. The licensee's response to GL 98-04 is documented in a letter from J.A. Stall (FPL), *Generic Letter 98-04 Initial Response*, to NRC Document Control Desk; dated November 4, 1998 as summarized below. The NRC closed this issue for St. Lucie 1 via letter from K.N. Jabbour (NRC), *Completion of Licensing Action for Generic Letter 98-04, Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System after a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment*, to T.F. Plunkett (FPL) dated December 9, 1999.

The licensee stated work on Service Level I protective coatings is controlled as a "Special Process" in accordance with requirements of ASME NQA-1-1994, *Quality Assurance Requirements for Nuclear Applications*, and 10 CFR Part 50, Appendix B. Technical and quality requirements for procurement, surface preparation, application, surveillance, and maintenance

of Service Level I protective coatings in containment are derived from an engineering specification. The licensee does not use commercial grade dedication for Service Level I protective coatings in containment. Additionally, the following inspections are discussed in the licensee's response:

1. Inspection of safeguards sump is performed every refueling outage;
2. Inspection of containment for loose debris at the end of each outage prior to restart;
3. Inspection of containment coatings at the end of each refueling outage to ensure that quantities of unqualified coatings are below acceptable limits.

### Technical Evaluation

The licensee stated that the protective coating system (paints) provide a means for protecting the surfaces of facilities and equipment from corrosion and contamination from radionuclides, as well as provide wear protection during plant operation and maintenance activities. The licensee additionally stated that although coatings typically do not perform a nuclear safety function, detachment from protected surfaces is an especially important consideration inside containment. Qualified containment coatings are required to remain intact after a DBLOCA to avoid compromising the ECCS or safety-related CS system by plugging containment sump screens with debris.

In a letter dated November 22, 2011, the licensee stated that the Service Level I coatings are required to prevent corrosion and facilitate decontamination of structures and equipment as well as remain intact under postulated accident conditions involving elevated levels of temperature, pressure, radiation, and chemical spray. In a response to an RAI dated May 19, 2011, the licensee stated that the Service Level I coatings were specifically qualified for and tested to withstand the worst case accident conditions analyzed for the containment environment. Additionally, the licensee stated that the Protective Coatings Program is limited to the qualification criteria of Service Level I coatings to withstand DBLOCA, the evaluation of other service level classifications for coatings is excluded, and only Service Level I protective coatings are permitted inside containment. The current Service Level I coatings were qualified by laboratory testing and certified by the manufacturer. For the purposes of this review, the staff evaluated the results of the DBA qualification testing of the Service Level I coatings currently used in containment to ensure that the current DBA testing bound the anticipated conditions inside containment following a DBLOCA, post-EPU implementation.

As a result of implementing the EPU, the minimum boric acid concentration of the refueling water tank (RWT) and safety injection tanks (SITs) will be increased by 180 ppm, which will result in slightly reducing the anticipated maximum sump pH. No modifications to the CS system or the associated iodine removal system will be made as a result of the EPU. The maximum boric acid concentration in the RWT and the SITs is not changing as a result of the EPU; therefore, the minimum containment sump pH will remain approximately 7. Based on the planned changes to the CS system, the licensee stated that the chemical effects of the EPU will have a negligible impact on the Service Level I coatings inside containment.

The Service Level I coatings were qualified to a temperature of 286 °F from zero to 2.8 hours and 219 °F from 2.8 to 23.9 hours during DBA qualification testing. The anticipated temperature in containment following a DB LOCA at EPU conditions is 265.57 °F from zero to 2.8 hours, and

approximately 215 °F from 2.8 to 23.9 hours. The maximum pressure during the DBA qualification testing of the Service Level I coatings was 54 pounds per square inch gauge (psig), while the anticipated pressure in containment following a DBLOCA at EPU conditions is 42.77 psig. The maximum radiation level during the DBA qualification testing of the Service Level I coatings was  $3 \times 10^8$  rads, while the anticipated radiation level in containment following a DBLOCA at EPU conditions is  $1.48 \times 10^8$  rads. In all the above cases, the staff agrees that the DBA qualification testing bounds the anticipated changes in the chemical effects, temperature, pressure, and radiation in containment, following a DBLOCA at EPU conditions.

### Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on protective coating systems and concludes that the licensee has appropriately addressed the impact of changes in conditions following a DBLOCA and their effects on the protective coatings. The NRC staff further concludes that the licensee has demonstrated that the protective coatings will continue to be acceptable following implementation of the proposed EPU and will continue to meet the requirements of 10 CFR Part 50, Appendix B. Therefore, the NRC staff finds the proposed EPU acceptable with respect to protective coatings systems.

### 2.1.8 Flow-Accelerated Corrosion

#### Regulatory Evaluation

Flow accelerated corrosion (FAC) is a corrosion mechanism occurring in carbon steel components exposed to single-phase or two-phase water flow. Components made from stainless steel are immune to FAC, and FAC is significantly reduced in components containing even small amounts of chromium or molybdenum. The rates of material loss due to FAC depend on flow velocity, fluid temperature, steam quality, oxygen content, and pH. During plant operation, it is not normally possible to maintain these parameters in a regime that minimizes FAC; therefore, loss of material by FAC can occur. The NRC staff reviewed the effects of the proposed EPU on FAC and the adequacy of the licensee's FAC program to predict the rate of material loss so that repair or replacement of damaged components could be made before reaching a critical thickness.

The licensee's FAC program is based on NUREG-1344, NRC GL 89-08, and the guidelines in EPRI Report NSAC-202L-R2 & R3 "Recommendations for an Effective Flow-Accelerated Corrosion Program" dated April 1999 and August 2007 respectively. The FAC program predicts loss of material using the CHECWORKS™ computer code, as well as visual inspection and volumetric examination of the affected components. The NRC's acceptance criteria are based on the structural evaluation of the minimum acceptable wall thickness for the components undergoing degradation by FAC.

#### Technical Evaluation

The licensee stated that the FAC program predicts, detects, monitors, and mitigates FAC in high energy carbon steel piping associated with the main steam, extraction steam, main FW, heater drains and blowdown systems, and is based on industry guidelines and experience. The licensee also stated that the FAC program addresses internal loss of material of drain lines and selected steam trap lines due to flow accelerated corrosion.

Additionally, the licensee stated that large bore piping systems that are susceptible to FAC and meet the minimum criteria for effective modeling are analyzed using the EPRI computer code CHECWORKS™ SFA. Inputs to the CHECWORKS™ SFA code include heat balance information (steam cycle data), water chemistry data, piping line data, and pipe material and component data. Wear rates of piping components are obtained using the wear calculation feature of CHECWORKS™ SFA. The FAC computer program also utilizes CHECWORKS™ SFA for determination of minimum wall thickness. The licensee went on to state that piping component structural calculations, where required to satisfy code requirements, are performed by site engineering.

Certain systems and pipe segments have usage and flow rates that cannot be accurately quantified because demand and operating conditions vary greatly or are controlled by a remote level, pressure, or temperature signal. These systems cannot be effectively modeled using CHECWORKS™ SFA and are categorized as Susceptible-Non-Modeled systems. For determination of wear rates in Susceptible-Non-Modeled lines, the licensee stated that ultrasonic testing (UT) or radiography techniques (RT) inspections are performed at selected locations, usually immediately downstream of flow orifices, steam traps, control valves, etc. The five methods commonly used for determining the wear of piping components from inspection data are: (1) Band Method, (2) Averaged Band Method, (3) Area Method, (4) Moving Blanket Method, and (5) Point-to-Point Method. Although methods (1) through (4) use different approaches, the total wear is the difference between an initial/baseline thickness and the minimum measured thickness. This value is divided by the inservice life of the component to determine the wear rate. In method (5), the difference between two sets of thickness data from two different examination dates are used to determine the wear rate over the component inservice life between the dates of examination.

The licensee additionally stated that radiography is used normally in the Long-Term Flow Accelerated Corrosion Monitoring Program for small bore components and may be used on large bore components that are 8 inches in diameter or less and Schedule 40; computed radiography is not used where wear rate trending is required. For determination of wear rates in large bore Susceptible-Non-Modeled piping and components in the FAC program, the licensee stated that UT measurements are taken at selected locations. The licensee's FAC engineer then determines the wear rate and predicts the wall thickness at the next outage, and the time to the next inspection.

In its letter dated November 22, 2011, the licensee provided Tables 2.1.8-1 and 2.1.8-2, which compare the current wear rates, of a sampling of high-risk lines, with post-EPU wear rates. The tables also compare predicted wall thickness with measured wall thickness at the pre-EPU wear rate. On April 27, 2011, the staff issued a request for additional information, to obtain amplifying information regarding the information provided in Tables 2.1.8-1 and 2.1.8-2. In its response, dated May 19, 2011, the licensee provided tables listing additional inspected components to supplement Tables 2.1.8-1 and 2.1.8-2, as well as amplifying information on the maturity of the CHECWORKS™ model used by the licensee. Overall, the tables provided by the licensee showed both increases and decreases in predicted FAC wear rates; however, the staff finds the corrosion rate changes reasonable for the corresponding changes in operating conditions. Additionally, of the 31 lines provided, 30 lines (97 percent) showed that the predicted wall thickness was more conservative than the measured wall thickness, measured by UT or RT, at the current wear rate. The staff finds that the current FAC program incorporates adequate conservatism to ensure that components susceptible to FAC will be managed appropriately prior to exceeding minimum wall thickness after implementation of the proposed EPU. The licensee

also stated that, prior to the implementation of the EPU, the CHECWORKS™ SFA program will be updated to reflect the EPU heat balances and the new thermodynamic flow conditions and that an enhanced monitoring program will be implemented to develop baseline EPU erosion rates, to define inspection periodicity, to predict long-term degradation rates, and to perform maintenance as required.

### Conclusions

The NRC staff has reviewed the licensee's evaluation of the proposed EPU on the FAC analysis for the plant and concludes that the licensee has adequately addressed the impact of changes in plant operating conditions on the FAC analysis. Additionally, the NRC staff concludes that the licensee has demonstrated the updated analyses will predict the loss of material by FAC and will ensure timely repair or replacement of degraded components following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to FAC.

#### 2.1.9 Steam Generator Tube Inservice Inspection

##### Regulatory Evaluation

SG tubes constitute a large part of the reactor coolant pressure boundary (RCPB). SG tube inservice inspection (ISI) provides a means for assessing the structural and leak tight integrity of the SG tubes through periodic inspection and testing of critical areas and features of the tubes. The NRC staff's review in this area covered the effects of changes in differential pressure, temperature, and flow rates resulting from the proposed EPU on plugging limits, potential degradation mechanisms (e.g., flow-induced vibration), plant-specific alternate repair criteria, and redefined inspection boundaries. The NRC's acceptance criteria for SG tube ISI are based on 10 CFR 50.55a requirements for periodic inspection and testing of the RCPB. Specific review criteria are contained in SRP Section 5.4.2.2 and other guidance provided in Matrix 1 of RS-001. Additional review guidance is contained in St. Lucie 1 TS 3.4.5, Steam Generator Tube Integrity for SG surveillance, NRC RG 1.121 for SG tube plugging limits, NRC GL 95-03 and NRC BL 88-02 for degradation mechanisms; and NEI 97-06 for structural and leakage performance criteria.

##### Technical Evaluation

St. Lucie 1 has two recirculating SGs designed and fabricated by Babcock & Wilcox (B&W) International. Each SG has 8523 thermally-treated Alloy 690 tubes that have an outside diameter of 0.75 inch and a nominal wall thickness of 0.045 inch.

While the process parameters of the St. Lucie 1 SGs will change as a result of the EPU (e.g., temperature, steam pressure, steam and FW flow rate), the process of SG tube ISI and integrity assessment will not change as a result of the EPU. The licensee has evaluated the effects of the proposed EPU on SG tube integrity and concluded that the evaluation has adequately assessed the continued acceptability of the plant's technical specifications under the proposed EPU conditions and has identified appropriate degradation management inspections to address the effects of changes in temperature, differential pressure, and flow rates on SG tube integrity. Additionally, the licensee concluded that SG tube integrity will continue to be maintained and will continue to meet its current licensing basis with respect to the performance



criteria in NEI 97-06 and the requirements of 10 CFR 50.55a following implementation of the proposed EPU.

The licensee determined that, over a 40-year operating life, the EPU did not significantly increase the maximum calculated wear as compared to the benchmark case prior to the EPU. Additionally, the licensee stated that there remains a significant margin in the inspection interval beyond the end-of-cycle 21 operational assessment that would compensate for an unexpected change in wear rate after the EPU is implemented. The licensee further stated that there are 29 tubes (.17 percent) with identified tube support wear and that the existing SG Program would detect large changes easily, while more subtle changes would be detected by the evaluation of wear rates of each inspection. Based on the end-of-cycle 21 inspection, no actively tracked foreign objects remain in the SG's and secondary inspections are routinely performed in both SGs during plant outages to evaluate the effectiveness of sludge lancing and detect and investigate any potential foreign objects.

Finally, the licensee stated that their SG tubing has not experienced any corrosion related degradation. The expected impact on the initiation of corrosion degradation, due to an increase in  $T_{hot}$ , is negligible based on current operating experience with other Alloy 690 Thermally Treated plants operating at higher  $T_{hot}$  conditions and for longer operating periods in terms of effective full power hours. Additionally, the pressure differential of 1417 psi used in the current assessment, across the tube wall, bounds the projected pressure differential of 1410 psi at EPU conditions.

### Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on SG tube integrity and concludes that the licensee has adequately assessed the continued acceptability of the plant's TSs under the proposed EPU conditions and has identified appropriate degradation management inspections to address the effects of changes in temperature, differential pressure, and flow rates on SG tube integrity. The NRC staff further concludes that the licensee has demonstrated that SG tube integrity will continue to be maintained and will continue to meet the performance criteria in NEI 97-06 and the requirements of 10 CFR 50.55a following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to SG tube ISI.

### 2.1.10 Steam Generator Blowdown System

#### Regulatory Evaluation

Control of secondary side water chemistry is important for preventing degradation of SG tubes. The SG blowdown system (SGBS) provides a means for removing SG secondary side impurities and thus, assists in maintaining acceptable secondary side water chemistry in the SGs. The design basis of the SGBS includes consideration of expected and design flows for all modes of operation. The NRC staff's review covered the ability of the SGBS to remove particulate and dissolved impurities from the SG secondary side during normal operation, including anticipated operational occurrences (main condenser in-leakage and primary-to-secondary leakage). The NRC's acceptance criteria for the SGBS are based on GDC 14, insofar as it requires that the RCPB be designed so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture.

St. Lucie 1 was designed and constructed based on the 1967 draft AEC GDC. In preparation for issuance of the St. Lucie 1 FSAR, an effort was made to comply with the newer (1971) final GDC. As noted in FSAR Section 3.1, the design bases of St. Lucie 1 are measured against the NRC "General Design Criteria for Nuclear Power Plants," 10 CFR 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie 1 design relative to the GDC is discussed in FSAR Section 3.1.

The specific GDC for the SGBS is described in FSAR Section 3.1.14 Criterion 14 - Reactor Coolant Pressure Boundary, which states, "The reactor coolant pressure boundary shall be designed, fabricated, erected and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure and of gross rupture." Specific review criteria are contained in SRP Section 10.4.8.

### Technical Evaluation

The SGBS provides for continuous blowdown between 19,799 lb/hr and 118,787 lb/hr from above the SG tube sheet from two 2-inch blowdown nozzles that are piped into a single blowdown header per SG. This continuous blowdown prevents the concentration of soluble and insoluble impurities in the SGs, thus preventing or minimizing the degradation of the RCPB SG tubes from the secondary side. The blowdown pipe lines from each SG pass through the containment penetrations and containment isolation valves to either a blowdown tank or to the SG blowdown treatment facility where the blowdown is cooled, filtered, purified by ion exchange and sent to monitoring storage tanks prior to recycling back to the condenser or to the discharge canal. The blowdown is cooled using a closed cycle cooling system to 139 °F, which is cooled by the open cycle cooling system. The intake cooling water system provides the cooling for the open cycle heat exchangers.

The licensee indicated that the increased steam and FW flow rates at EPU conditions do not significantly affect the concentration of impurities throughout the turbine cycle or increase the affect of the impurities in the SGs. Because the blowdown flow rates required during operation are based on chemistry control and tubesheet sweep requirements to control the buildup of solids, and the increased steam and FW flow rates will have a negligible effect on the concentration of impurities in the SGs, the licensee stated that the blowdown rates will remain unchanged at EPU conditions. The licensee also stated that the SG vendor confirmed that the EPU will have a negligible impact on SG water chemistry and accordingly, the blowdown requirements for maintaining chemistry will be unchanged at EPU conditions. Additionally, the existing design pressure and temperature of the SG blowdown piping (985 psig and 550 °F) remain bounding for the EPU since the conditions these values are based upon do not change at EPU conditions. The licensee stated that the SGBS piping, including the pumps, valves, tanks, vessels, and heat exchangers remain unchanged by the proposed EPU.

### Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the SGBS and concludes that the licensee has adequately addressed changes in system flow and impurity levels and their effects on the SGBS. The NRC staff further concludes that the licensee has demonstrated that the SGBS will continue to be acceptable and will continue to meet the requirements of FSAR Section 3.1.14 Criterion 14 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the SGBS.

## 2.1.11 Chemical and Volume Control System

### Regulatory Evaluation

The chemical and volume control system (CVCS) and boron recovery system (BRS) provide means for (a) maintaining water inventory and quality in the RCS, (b) supplying seal water flow to the reactor coolant pumps (RCP) and pressurizer auxiliary spray, (c) controlling the boron neutron absorber concentration in the RCS, (d) controlling the primary water chemistry and reducing coolant radioactivity level, and (e) supplying recycled coolant for demineralized water makeup for normal operation and high-pressure injection flow to the ECCS in the event of postulated accidents.

The NRC staff reviewed the safety related functional performance characteristics of CVCS components. The NRC's acceptance criteria are based on (1) GDC 14, insofar as it requires that the RCPB be designed so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture, and (2) GDC 29, insofar as it requires that the reactivity control systems be designed to assure an extremely high probability of accomplishing their safety functions in the event of anticipated operational occurrences.

St. Lucie 1 was designed and constructed based on the 1967 draft AEC GDC. In preparation for issuance of the St. Lucie 1 FSAR, an effort was made to comply with the newer (1971) final GDC. As noted in FSAR Section 3.1, the design bases of St. Lucie 1 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR Part 50, Appendix A, as amended through February 20, 1971. The adequacy of the St. Lucie 1 design relative to the GDC is discussed in FSAR Section 3.1.

The specific GDC for the CVCS are described in FSAR Section 3.1.14 Criterion 14 - Reactor Coolant Pressure Boundary, which states, "The reactor coolant pressure boundary shall be designed, fabricated, erected and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure and of gross rupture," and FSAR Section 3.1.29 Criterion 29 - Protection Against Anticipated Operational Occurrences, which states, "The protection and reactivity control systems shall be designed to assure an extremely high probability of accomplishing their safety functions in the event of anticipated operational occurrences." Specific review criteria are contained in SRP Section 9.3.4.

### Technical Evaluation

The CVCS is described in FSAR, Section 9.3.4. The system is designed to perform the following functions:

- Control the reactor coolant inventory, chemistry conditions, activity level, and boron concentration.
- Automatically divert letdown flow to the waste management system when the highest permissible water level is reached in the volume control tank (VCT).

- Provide pressurizer auxiliary spray.
- Support containment isolation.

To perform these functions, continuous feed and bleed is maintained between the RCS and the CVCS. Water is let down from the RCS, through a regenerative heat exchanger (HX), to minimize thermal loss from the RCS. The pressure is reduced through letdown control valves and further cooling occurs in the letdown HX followed by a second pressure reduction. Water is returned to the RCS by the charging system.

The chemistry of the letdown flow may be altered by passing the flow through ion exchangers that remove ionic impurities. A filter removes solids, and the gases dissolved in the coolant are removed, added, or maintained in the VCT, as applicable. The boric acid concentration in the coolant is changed by the reactor makeup portion of the CVCS as required for reactivity control. The boric acid and charging portions of the CVCS perform safety-related functions for injecting boric acid into the RCS following a SIAS during accident conditions or for safe shutdown of the plant. Excess coolant may be diverted into the waste management system.

In its letter dated November 22, 2011, the licensee stated that changes in Nuclear Steam Supply system (NSSS) design parameters that could potentially affect the CVCS design bases functions, as a result of implementing the EPU, include the increase in core power and the allowable range of RCS full-load design temperatures. The increase in core power and the allowable range of RCS full-load design temperatures may also affect the CVCS design bases requirements related to the core re-load boron requirements. Additionally, increasing the allowable range of RCS full load design temperatures may affect the heat loads that the CVCS HXs must transfer to the component cooling water (CCW) system; and in the case of the regenerative HX, to the charging flow.

The regenerative HX cools the normal letdown flow from the RCS, which is at the RCS  $T_{cold}$  temperature, and the design inlet (RCS  $T_{cold}$ ) temperature of the regenerative HX is 550 °F. The licensee stated that design inlet temperature of 550 °F bounds the highest RCS  $T_{cold}$  temperature associated with the RCS no-load temperature of 532 °F. Additionally, the licensee stated that the no-load RCS temperature, letdown flow, and charging flow do not change for the EPU. The licensee further stated that although the full-load EPU  $T_{cold}$  temperature of 551 °F will increase above the current value of 548.5 °F, it is within 1°F of the design inlet  $T_{cold}$  value and that the regenerative HX materials were evaluated and determined to be acceptable for a range of temperatures which bound the maximum EPU operating temperatures. On April 27, 2011, the staff issued a request for additional information, to obtain amplifying information on the evaluation done on the regenerative HX materials.

In its response dated May 19, 2011, the licensee stated that the design temperature of the regenerative HX is 650 °F and that this temperature was the bounding value for the material properties of the HX. The licensee further stated that since the design temperature was higher than the maximum expected transient temperature through the HX of 551 °F, the regenerative HX materials were determined to be acceptable at EPU conditions. The staff evaluated the licensee's response and finds that the regenerative HX materials are adequate to handle the increased temperature at full load EPU conditions.

Since the change in performance of the regenerative HX is unchanged at EPU conditions, as discussed in the previous section, there is no effect on the performance of the letdown HX. The licensee stated that the 1 °F difference in the letdown temperature can easily be accommodated within the capability of the letdown HX cooling water temperature control valve. Therefore, the licensee concluded that acceptable letdown HX performance will be provided at the EPU conditions.

The licensee stated there are no effects on the charging and letdown flows at EPU conditions due to the temperature change. The minimum and maximum charging and letdown flows are the same as those for current operation. With no change in letdown and charging flows, the CVCS functions of maintaining the RCS inventory, supplying pressurizer auxiliary spray, and RCS chemistry control are not impacted by EPU.

The makeup system relies on the storage capacity of various sources of water, including primary makeup water and boric acid solutions from both the boric acid makeup (BAM) tanks and the RWT. Primary makeup water is used to dilute the RCS boron concentration, to provide positive reactivity control, or to blend concentrated boric acid to match the RCS boron concentration during RCS inventory makeup operations. Since the flow capacity performance of the RCS makeup system is not impacted by the change in RCS conditions resulting from the EPU conditions as discussed above, the licensee stated that the EPU does not affect the capability of the makeup system to perform these system functions.

The BAM tanks and RWT provide the sources of boric acid for providing negative reactivity control to supplement the reactor control rods. The EPU is expected to have an effect on the boration requirements that must be provided by the CVCS boration capabilities. The licensee stated that the EPU analysis has determined that the increases in the BAM tank and RWT minimum concentration requirements are within the CVCS capability. The reload safety analysis checklist (RSAC) is designed to address the boration capability for routine plant changes, such as core reloads, and infrequent plant changes such as a plant uprating that result in a change to core operating conditions and initial core reactivity. The licensee stated that the RSAC process will ensure the boration requirements are within the boration capability.

CVCS letdown flow and charging flow are varied to control pressurizer water level and RCS inventory. The pressurizer water level is programmed as a function of power level to assist in compensating for RCS coolant contraction and expansion. The licensee indicated that this programmed level will remain as currently installed with the revised average temperature program endpoints. The licensee stated that the current setpoints for charging and letdown control remain appropriate for EPU conditions.

The portion of the expansion/contraction volume not accounted for by the pressurizer programmed level is made up by inventory from the VCT and if necessary, from safety-related boric acid water sources. Safety-related makeup will always be available even when the VCT is drawn down below the low-low-level setpoint. The licensee stated that the additional expansion/contraction at the EPU temperature will result in acceptable system response. Furthermore, the licensee stated that there will be a slight increase in nominal letdown temperatures that will impact the letdown flow control valve limit setpoints that maintain minimum and maximum letdown flows; however, this impact is within the design capability of the valves.

There is the potential for an increase in crud buildup due to the EPU. The licensee indicated that 40 gallons per minute (gpm) purification flow is sufficient at the current power level and that maximum purification flow is 128 gpm, which leaves adequate margin is available at EPU conditions.

### Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the CVCS and BRS and concludes that the licensee has adequately addressed changes in the temperature of the reactor coolant and their effects on the CVCS and BRS. The NRC staff further concludes that the licensee has demonstrated that the CVCS and BRS will continue to be acceptable and will continue to meet the requirements of GDC 14 and GDC 29 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CVCS.

#### 2.1.12 Metamic™ Surveillance Program

In the license amendment request (LAR) (Reference 2), the licensee included a Metamic™ insert surveillance program to monitor the material condition of the Metamic™ inserts proposed to be installed in the unit's SFP to support the SFP criticality analysis. The staff required additional information and issued an RAI dated October 28, 2011 (ADAMS Accession No. ML112990830) and February 16, 2012 (ADAMS Accession No. ML12048A277). The licensee's responses to those RAIs are dated December 27, 2011 and March 8, 2012.

### Regulatory Evaluation

The following is the regulatory basis for the use of Metamic™:

GDC 62, "Preventing of criticality in fuel storage and handling," states that, "criticality in the fuel storage and handling system shall be prevented by physical systems or processes, preferably by use of geometrically safe configurations."

The Construction Permit for St. Lucie Unit 1 was issued on July 1, 1970, which preceded the publication of the AEC "General Design Criteria for Nuclear Power Plants" (10 CFR Part 50, Appendix A, February 20, 1971). As such, the FSAR lists criteria reflecting the design intent for this nuclear power plant in consideration of the GDC for Nuclear Power Plants. GDC 62, "Prevention of Criticality in Fuel Storage and handling", states:

Criticality in the fuel storage and handling system shall be prevented by physical systems or processes, preferably by use of geometrically safe configurations.

According to SRP, Section 9.1.2, "Spent Fuel Storage," the staff's review should ensure the compatibility and chemical stability of the materials wetted by the water in the SFP and, if applicable, in the new fuel vault and evaluate potential mechanisms that alter the dispersion of any strong fixed neutron absorbers:

A. Compatibility and chemical stability of the materials in the components wetted by water in the spent fuel pool and in the new fuel vault. If the possibility for corrosion mechanisms is detected, the existing programs for preventing or minimizing corrosion are reviewed for their applicability to control corrosion.

B. The reactivity of fuel in the spent fuel pool is controlled by plates or inserts attached to spent fuel racks containing neutron poison dispersed in a matrix. In some environments, the matrix may degrade and release the neutron poison, resulting in some reduction of neutron absorbing properties of the panels. The licensee should have a program for monitoring the effectiveness of the neutron poison present in the neutron absorbing panels.

### Technical Evaluation

#### 2.1.12.1 Metamic™ Insert Description

Metamic™ is composed primarily of Boron Carbide and Aluminum (Al 6061). Boron Carbide is the main constituent in materials known to perform effectively as neutron absorbers and Al 6061 is a marine-qualified material known for its resistance to corrosion. The licensee provided the following description of the proposed Metamic™ inserts to be used:

- The Metamic™ used for the inserts shall have a boron carbide weight percentage of 24.5 percent minimum. Alloy 6061 aluminum powder is used in the manufacture of Metamic™. The areal density of B<sup>10</sup> in the inserts shall be 0.0160 gm/cm<sup>2</sup> nominal and 0.0150 gm/cm<sup>2</sup> minimum.
- The overall length of the inserts will be approximately 156.5 inches. The cross section width of the inserts will be approximately 8.3 inches square. The Metamic™ panel thickness is nominally 0.070 inches thick.
- The landing element material will be constructed from 6061-series aluminum.
- The formed Metamic™ panel will be attached to the head piece (landing element) using a pinned connection. The top flange of the formed Metamic™ panel will be sandwiched between upper and lower aluminum pieces. There are four aluminum pins, passing through holes in the top flange of the Metamic™ panel, which will be welded to the upper and lower aluminum pieces. There will be no welding of or to Metamic™.

The staff reviewed the licensee's description of the inserts to be used in the SFP and requested clarification concerning the upper limit on the boron carbide weight percentage planned on being used for the inserts in the SFP. The licensee stated in its response (ADAMS Accession No. ML11326A109) that the coupons used in the Metamic™ Surveillance Program are identical in composition and manufacturing process as the inserts. Additionally, the licensee stated that the twenty Metamic™ coupons to be installed in the spent fuel pools (ten per unit) have been received and that the Certificate of Compliance provided with the coupons stated that the boron carbide content for each of the twenty coupons have a weight percent that ranges from 25.07 to 25.98.

The staff has reviewed the licensee's response and has determined that because the coupons used in licensee's surveillance program are identical in composition and manufacturing process as the inserts installed in the licensee's SFP, then the maximum boron carbide weight percent of the inserts is bounded by the maximum upper bound of the boron carbide weight percent of the coupons, which is 25.98 percent. An insert that has a boron carbide weight percent greater

than the maximum upper bound of the coupons will not be properly modeled by the coupons during the surveillance testing as described in the licensee's Metamic<sup>TM</sup> surveillance program; therefore, it would not be appropriate for installation in the SFP. Ensuring that the boron carbide weight percent of the inserts falls within the range of the boron carbide weight percent of the coupons provides reasonable assurance that the Metamic<sup>TM</sup> inserts will perform as designed in the SFP. The staff's concern on the upper limit of the boron carbide content of the inserts is resolved. The licensee stated that the current analysis of the structural integrity of the spent fuel pool and its contents bounds the use of the inserts. Therefore, a review of the effect on the structural integrity of the spent fuel pool is not included in this SE.

#### 2.1.12.2 CEA or Equivalent Discussion

In the LAR, the licensee stated that the new criticality analysis in the proposed EPU also considers the inclusion of rack enhancements that equip the storage cells with a full-length full-strength CEA or equivalent. The staff required additional information on what the licensee means by "equivalent", as well as what materials were proposed to be used in the SFP with the associated "equivalent" hardware. The staff issued an RAI dated February 16, 2012.

In the response dated March 8, 2012, the licensee stated the CEAs credited in the SFP criticality analysis are the St. Lucie Unit 1 five-finger CEAs which have five absorber rods. The licensee stated that to allow the option of using only the absorber rods (5), without the CEA hardware, the wording "or equivalent (5 absorber rods)" was included in the updated Technical Specifications. The licensee stated that the absorber rods will be of the same design and material as that of the CEA absorber rods and that there will not be any other material/hardware associated with this option.

The staff has reviewed the licensee's response and has determined that it is acceptable based on the assertion that the CEA or equivalent used in the SFP contains hardware that is designed to be subjected to primary coolant boric acid conditions in core. Because the CEA or equivalent is designed for use in core, no degradation is expected from its use in the less harsh SFP environment. The staff's concerns regarding the use of a CEA or equivalent assembly and the hardware associated with an equivalent option are resolved.

#### 2.1.12.3 Metamic<sup>TM</sup> Program Description

The licensee stated that the purpose of the Metamic<sup>TM</sup> insert surveillance program is to ensure Metamic<sup>TM</sup> panels continue to meet the licensing bases requirements. This will be done by confirming that physical and chemical properties of Metamic<sup>TM</sup> perform in the SFP as in the pre-installation qualification data. The surveillance program will monitor how Metamic<sup>TM</sup> absorber material properties perform over time as a result of radiation, chemical, and thermal environment found in the spent fuel pool. The specific details of the surveillance program, including the test sample size, will be incorporated into the UFSAR, based on the general elements provided below:

- Visual inspection of the Metamic<sup>TM</sup> inserts.
- Physical measurement of Metamic<sup>TM</sup> coupons.
- Neutron attenuation testing of Metamic<sup>TM</sup> coupons.



#### 2.1.12.4 Initial and Follow on Surveillance Selection

The licensee stated that the Metamic™ inserts inspected as part of the initial surveillance campaign will be selected by considering the following criteria and generally selecting the most challenging conditions:

- Results of pre-installation inspections (e.g., select inserts that have pre-existing conditions),
- Experience gained during installation (e.g., select inserts that required higher insertion or removal forces),
- Spatial variations in cooling water flow within the pool, specifically considering effects of the fuel pool cooling system suction and discharge piping,
- Storage arrangements and the characteristics of fuel assemblies adjacent to each insert, especially heat generation rates,
- Noteworthy or unique aspects of St. Lucie fuel pool-related operating experience during the inservice interval, such as atypical water chemistry or impact by a foreign object, and
- Relevant operating experience from other plants.

Development of follow-on inspection campaigns will be determined by results from this initial inservice inspection. Some of the same sample of inserts/coupons may be included in future inservice inspections.

The staff has reviewed the surveillance criteria and has determined that they are acceptable. The incorporation of operational experience from the licensee's spent fuel pool and relevant operating experience from other plants provides reasonable assurance that the inserts exposed to the most challenging conditions will be selected for inspection.

#### 2.1.12.5 Coupons and Coupon Tree in the SFP

A coupon tree will be installed in the SFP that holds ten coupons. The coupons are identical in composition and manufacturing process as the Metamic™ inserts. The coupon tree will be placed in a SFP cell in a location that will ensure a representative dose to the coupons, in addition to simulating the flow characteristics and pool chemistry. The cell location will be in Region 2 of the SFP which typically has highly burned permanently discharged fuel. Tested coupons will not be returned to the SFP.

The licensee stated that should the Metamic™ inserts no longer be required for control of neutron multiplication within the spent fuel pool (e.g., as a result of vacating the fuel pool to dry storage), insert surveillance and inspections may be terminated.

The staff reviewed the licensee's submittal concerning the placement of the coupon tree and requested additional information regarding what the licensee meant by "representative dose"

and whether the placement of the coupon tree was such that the coupons experienced an environment that bounds the SFP conditions for the inserts to be used. The staff issued an RAI dated February 16, 2012.

In the response dated March 8, 2012, the licensee stated that the most important factors of consideration for deciding on the location of the coupon tree, and the characteristics of fuel assemblies in cells surrounding the cell containing the coupon tree, are the accumulated dose and the neutron flux. The licensee additionally stated that proximity to higher burned fuel will yield a higher dose, whereas positioning near higher reactivity fuel will increase the localized flux. The licensee stated that this combined effect will be achieved by placing most recent discharged assemblies in at least two of the four cells, face-adjacent to the Region 2 cell containing the coupon tree. Additionally, other cells, face-adjacent to the coupon tree, will be loaded with discharged fuel assemblies cooled for no more than 5 years with an expected burnup in excess of 35,000 megawatt days per metric ton uranium (MWd/MTU).

The licensee stated that this configuration of the coupon tree surrounded by recently discharged assemblies, including freshly discharged assemblies in two adjacent cells without a CEA or Metamic™ insert, will create an environment that is expected to bound all inserts. The licensee stated that the environment established around the coupons would provide reasonable assurance that, if the monitoring program were to detect degradation in the coupons, proper corrective actions can be taken to mitigate the degradation of the inserts prior to any insert falling below the design requirements.

The licensee stated that Region 1 of the SFP is mostly empty and typically these racks are only used during refueling evolutions to accommodate assemblies temporarily offloaded from the core; therefore, the typical fuel bundle resides in Region 1 only for a short period of time. Because of this, the licensee stated that Region 1 is considered inappropriate for placement of the coupon tree. The licensee stated that Region 2 of the SFP, where most of the Metamic™ inserts will be placed, is used for the storage of permanently discharged fuel assemblies with typical burnups in excess of 35,000 MWd/MTU. The licensee further stated that the assemblies in Region 2, including the assemblies placed in cells with inserts, typically remain in the same location for a period of greater than 5 years, until removed to dry cask storage. Therefore, inserts are not exposed to freshly discharged assemblies in an as severe configuration as the coupons, described above.

The staff has reviewed the licensee's response and has determined that the placement of the coupon tree bounds the environmental conditions seen by the inserts in the SFP based on the anticipated amount of burnup and storage time of fuel assemblies planned to be stored around the coupon tree. Placing the coupon tree in an environment that bounds the environmental conditions seen by the inserts in the SFP will provide reasonable assurance that any degradation experienced by the coupons will preclude possible degradation experienced by the inserts and allow the licensee enough time to take corrective actions. The staff's concerns about the coupon tree placement have been resolved.

The staff also requested additional information concerning the physical dimensions of the coupons to be used in the SFP. Specifically, the staff requested if there would be any coupons that had a formed chevron cross-section similar to the inserts used in the pool. The staff also requested if there would be coupons that simulate the potential galvanic coupling that may be seen by the inserts in the SFP. The staff issued an RAI dated February 16, 2012.

In the response dated March 8, 2012, the licensee stated that the Metamic™ coupons have a height of 8 inches by 6 inches wide, and a thickness of 0.070 inches. This is the same thickness as the Metamic™ inserts. The licensee stated that the Metamic™ coupons do not include a formed chevron cross-section; the coupons are a flat, rectangular panel. The licensee stated that because the most important physical measurement parameter is material thickness to monitor for potential swelling, and the thickness of the Metamic™ coupon is the same thickness as the Metamic™ inserts, the coupons are representative of the inserts for this critical dimensional check. The licensee further stated that the remaining coupon measurement parameters (height, width, and weight) serve a supporting role and are utilized to identify early indications of the potential onset of neutron absorber degradation; these parameters will be measured before the coupons are installed in the spent fuel pool, and subsequently checked during future coupon inspections. The licensee stated that because relative change in these measured parameters will be evaluated as part of the surveillance program, the coupons do not have to replicate the exact geometry of the inserts.

The licensee additionally stated that the visual inspections of the Metamic™ inserts will be sufficient to detect evidence of galvanic coupling. Additionally, the licensee stated that visual inspection of the actual inserts rather than the coupons is the preferred method to detect any potential for galvanic coupling as they eliminate the need to simulate area ratio and proximity effects to other dissimilar materials in the SFP (fuel assemblies, spent fuel pool racks, etc.). For these reasons, the licensee stated that the Metamic™ coupons will not be used as a means to detect galvanic coupling.

The staff has reviewed the licensee's response and has determined that based on swelling being the most significant physical characteristic of concern, the chosen coupon dimensions are representative of the inserts used in the SFP, because the coupons are the same thickness and of the same material as the inserts. Additionally, the staff has determined that the licensee's method for detecting galvanic coupling is acceptable based on using the visual examination of the inserts in the SFP, rather than relying on simulating area ratio and proximity effects to other dissimilar materials in the SFP with the coupons, because the visual examination will represent actual insert conditions. The staff's concerns with the coupon physical dimensions and galvanic coupling have been resolved.

#### 2.1.12.6 Inspections

##### 2.1.12.6.1 Visual Inspection of the Metamic™ inserts

The licensee stated five inserts will be selected as described in section 3.4 for visual examination at 4, 8, 12, 20, and 30 years after the initial installation and physical measurement. The licensee additionally stated that the surveillance campaigns will be scheduled to avoid refueling intervals and periods when fresh fuel is stored in fuel pool racks in preparation for refueling.

The licensee stated that the visual inservice inspection method will be a camera-aided visual examination of the insert base material, its edges, regions of the insert where base material has been formed (i.e., bent to shape), as well as any connection to the base metal. Non-welded connections will also be examined. Interior and exterior bend radii and front and back faces of the insert will be inspected. The licensee stated that the visual examination is sufficient to detect evidence of cracking, corrosion pitting or other gross damage. Inspections may be performed on inserts underwater, after they have been removed from their storage rack cell

location, or inserts may be temporarily removed from the fuel pool water, if radiation and surface contamination levels permit.

The licensee stated that should insert anomalies be noted on the visual inspections, then an additional set of five inserts will be inspected. Issues identified during the visual inspections will be included in the licensee's corrective action program for investigation and resolution.

#### 2.1.12.6.2 Physical Inspection of the Metamic™ Coupons

In accordance with manufacturer's recommendations, the licensee stated that two coupons will be selected for physical measurement inspection at 4, 12, 20 and 30 years following initial installation of Metamic™. Measurements will include weight and physical dimensional measurements (length, width and thickness) of the coupons to confirm the absence of swelling and shrinkage.

The licensee stated that should physical inspections of the coupons result in a failure to meet acceptance criteria for thickness, then an additional two coupons will be inspected. Issues identified during physical measurements inspection will be included in the licensee's corrective action program for investigation and resolution.

#### 2.1.12.6.3 Neutron Attenuation Testing of the Metamic™ Coupons

The licensee stated that two coupons will be selected for neutron attenuation inspection 4, 12, 20, and 30 years following initial installation of Metamic™. Neutron attenuation testing is required to prove a periodic validation of certain assumptions embedded in the fuel pool rack's criticality analysis, and to also confirm that the neutron absorption capability of the Metamic™ would remain unchanged throughout its service lifetime.

The licensee stated that should a coupon fail to meet acceptance criteria during neutron attenuation testing, then an additional two coupons will be tested. Issues identified during neutron attenuation testing will be included in the licensee's corrective action program for investigation and resolution.

#### 2.1.12.6.4 Staff Summary of the Proposed Inspections

The staff has reviewed the three elements of the proposed Metamic™ surveillance program. The licensee's proposed visual examinations of the Metamic™ inserts are acceptable because they will provide an insitu indication of any material degradation happening to the inserts while in the SFP environment. The use of Metamic™ coupons for physical measurements and neutron attenuation testing is also acceptable because the results of these examinations will also give an early indication of neutron absorber degradation, as well as a loss of neutron attenuation, given that the placement of the coupons in the SFP will be bounding of the environment experienced by the Metamic™ inserts. The interval chosen by the licensee for the inspections is acceptable because earlier inspections intervals are spaced closer together, allowing the licensee to catch the onset of any degradation and take timely corrective actions sooner in the life of the inserts. In addition, the inspections performed at earlier intervals will inform later inspections providing reasonable assurance that later inspections will be more effective at detecting degradation. The staff finds that the three elements of the Metamic™ Surveillance Program are acceptable.

#### 2.1.12.7 Acceptance Criteria

The licensee's acceptance criteria for each inspection are as follows:

- Visual Inspection:

Any surfaced-based abnormalities, such as, through-wall corrosion/damage, bubbling, blistering, corrosion pitting, cracking, or flaking.

- Physical Measurement Inspection:

The licensee stated that based on the manufacturer's recommendations, an increase in thickness at any point should not exceed 25 percent of the initial thickness at that point. This acceptance criterion is to monitor for swelling. The remaining measurement parameters (length, width, and weight) serve a supporting role and should be examined for early indications of potential onset of neutron absorber degradation, if any, that would suggest the need for further attention and possibly a change in the measurement schedule.

The licensee stated that baseline inspections will be performed at the fabrication facility and will include determination of Boron Carbide weight percentage, dimensional measurements, weight measurement, visual examination for any Metamic™ panel defects (inclusions, cracks, etc.), and operability checks (interface with handling tool). A panel map will be made to document any observed panel defects. The results of baseline examinations will be recorded in the inserts documentation package for future availability. The licensee additionally stated that the following dimensional measurements will be made:

Dimensional Measurement	Information Recorded
Insert Length	As-Found Values
Metamic™ panel width	As-Found Values
Metamic™ thickness	As-Found Values
Metamic™ panel longitudinal bond radius	Pass/Fail
Metamic™ panel bend angle	Pass/Fail

- Neutron Attenuation Testing:

B<sup>10</sup> areal density is to be greater than or equal to 0.015 grams of B<sup>10</sup> per square centimeter. The licensee stated that the revised Technical Specification 5.6.1.a.7 will contain the acceptance criteria for neutron attenuation testing (ML11291A035). The staff has reviewed the licensee's technical specification submittal and finds that it adequately reflects the required B<sup>10</sup> areal density stated above.

The licensee stated that the failure to meet the acceptance criteria for either physical measurement or neutron attenuation testing requires investigation and engineering evaluation, along with early retrieval and measurement of two additional coupons, to provide corroborative

evidence that the indicated change(s) is real. If the deviation is determined to be real, an engineering evaluation shall be performed to identify further testing or any corrective action that may be necessary.

The staff has reviewed the acceptance criteria for the three elements of the licensee's Metamic<sup>TM</sup> surveillance program and finds them acceptable. The acceptance criteria for the visual inspection will provide adequate assurance that the onset of any potential degradation will be detected so that the appropriate corrective actions can be initiated by the licensee. The physical measurement inspection of the coupons, which are representative of the inserts in the SFP, will provide adequate assurance that any swelling in the coupons will be detected early enough for the licensee to take corrective actions to prevent the adverse effects of swelling in the inserts. Furthermore, the baseline inspection of the inserts will facilitate documentation of the initial conditions of the inserts, which can be used as a reference point for later inspections. The neutron attenuation testing of the coupons, which are representative of the inserts in the SFP, will provide reasonable assurance that the inserts will continue to meet the Technical Specification requirement for B<sup>10</sup> areal density.

## Conclusion

Based on a review of the licensee's Metamic<sup>TM</sup> surveillance program, the staff concludes that the Metamic<sup>TM</sup> inserts proposed for use by the licensee are compatible with the environment in the SFPs. Additionally, the staff finds the proposed surveillance program, which includes visual, physical and confirmatory tests, capable of detecting potential degradation of the Metamic<sup>TM</sup> material that could impair its neutron absorption capability. The implementation of the Metamic<sup>TM</sup> surveillance program provides reasonable assurance that the Metamic<sup>TM</sup> inserts will be able to perform their intended function and if degradation were to occur it would be detected, monitored and mitigated to maintain subcriticality in the SFP. The staff finds that the licensee's program meets the requirements of criterion 62 of the licensee's Technical Specifications, as well as Standard Review Plan Section 9.1.2, and concludes that the use of Metamic<sup>TM</sup> as a neutron absorber insert for the SFP post EPU implementation is acceptable.

## 2.2 Mechanical and Civil Engineering

### 2.2.1 Pipe Rupture Locations and Associated Dynamic Effects

#### Regulatory Evaluation

SSCs important to safety could be impacted by the pipe-whip dynamic effects of a pipe rupture. The NRC staff conducted a review of pipe rupture analyses to ensure that SSCs important to safety are adequately protected from the effects of pipe ruptures. The NRC staff's review covered (1) the implementation of criteria for defining pipe break and crack locations and configurations, (2) the implementation of criteria dealing with special features, such as augmented ISI programs or the use of special protective devices such as pipe-whip restraints, (3) pipe-whip dynamic analyses and results, including the jet thrust and impingement forcing functions and pipe-whip dynamic effects, and (4) the design adequacy of supports for SSCs provided to ensure that the intended design functions of the SSCs will not be impaired to an unacceptable level as a result of pipe-whip or jet impingement loadings. The NRC staff's review focused on the effects that the proposed EPU may have on items (1) through (4) above. The NRC's acceptance criteria are based on GDC 4, which requires SSCs important to safety to be

designed to accommodate the dynamic effects of a postulated pipe rupture. Specific review criteria are contained in SRP Section 3.6.2.

### Technical Evaluation

According to the plant's current licensing basis (CLB), St. Lucie 1 postulates high energy pipe failures inside and outside containment. The St. Lucie 1 CLB acceptance criteria for postulated pipe break and crack locations and the dynamic effects associated with postulated pipe breaks and cracks are contained in the plant's FSAR Section 3.6.

According to the LAR and the licensee's response to staff's RAI, for postulating pipe failures inside containment for EPU, the licensee used guidance provided in RG 1.46, which is part of St. Lucie 1 CLB, except for RCS loop branch piping, which in accordance with FSAR Section 3.6.4.1, considered the approach of a break anywhere. For postulating pipe failures outside containment for EPU, the licensee used guidance and pipe break stress equations provided in the A. Giambusso Letter (December 1972), which the licensee has stated that is part of the St. Lucie 1 CLB. Review of the EPU pipe stress evaluations (for other than pipe break postulation) is performed in SER Section 2.2. The staff finds the EPU criteria used for postulating pipe failures acceptable because they are contained in the CLB.

The current structural design basis of St. Lucie 1 implements the guidance of GDC 4 to include the application of LBB methodology described in NUREG-1061 Volume 3 and eliminate consideration of the dynamic effects associated with circumferential (guillotine) and longitudinal (slot) breaks in the RCS primary loop piping. The validity of LBB methodology under the proposed EPU conditions is contained in LAR Attachment 5, Section 2.1.6. The staff's evaluation of LBB is documented in Section 2.1.6.

The licensee considered EPU operating parameters of temperatures, pressures and flow rates in performing piping evaluations that did not result in any new or revised postulated pipe failure locations. The licensee also considered design features that protect essential equipment from the dynamic effects of pipe whip and jet impingement of postulated pipe failures and stated that operating parameters associated with EPU did not result in any load increases that would adversely impact existing pipe whip and jet impingement assessments. In addition, the licensee in its response to staff's RAI demonstrated that the containment with its subcompartment walls and plant SSCs important to safety, including containment penetrations, are structurally capable to withstand the effects due to postulated pipe failures at EPU conditions.

The licensee, using methods and criteria from the existing licensing basis and design basis analysis of record (AOR), found that the pipe break evaluations for EPU conditions of applicable piping systems did not result in new or revised break/crack locations, and the existing design basis for pipe break, jet impingement, pipe whip and environmental considerations remain valid for EPU. The staff finds the licensee's pipe break evaluations adequate and acceptable as they meet the licensing and design basis acceptance criteria found in its FSAR.

### Conclusion

The NRC staff has reviewed the licensee's evaluations related to determinations of rupture locations and associated dynamic effects and concludes that the licensee has adequately addressed the effects of the proposed EPU on them. The NRC staff further concludes that the licensee has demonstrated that SSCs important to safety will continue to meet the requirements

of GDC 4 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the determination of rupture locations and dynamic effects associated with the postulated rupture of piping.

## 2.2.2 Pressure-Retaining Components and Component Supports

### Regulatory Evaluation

The NRC staff has reviewed the structural integrity of pressure-retaining components (and their supports) designed in accordance with the ASME *Boiler and Pressure Vessel Code* (B&PV Code), Section III, Division 1, ASME/ANSI B31.1, ANSI B31.7, and GDC 1, 2, 4, 14, and 15. The NRC staff's review focused on the effects of the proposed EPU on the design input parameters and the design-basis loads and load combinations for normal operating, upset, emergency, and faulted conditions. The NRC staff's review covered (1) the analyses of flow-induced vibration and (2) the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. The NRC staff's review also included a comparison of the resulting stresses and cumulative fatigue usage factors (CUFs) against the code-allowable limits. The NRC's acceptance criteria are based on (1) 10 CFR 50.55a and GDC 1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (3) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (4) GDC 14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; and (5) GDC 15, insofar as it requires that the RCS be designed with margin sufficient to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation. Specific review criteria are contained in SRP Sections 3.9.1, 3.9.2, 3.9.3, and 5.2.1.1; and other guidance provided in Matrix 2 of RS-001.

In addition to their GDC compliance described above, St. Lucie 1 pressure-retaining components and supports were evaluated for plant license renewal. The evaluations are documented in NUREG-1779, "Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2," dated September 2003 (Reference 8).

### Technical Evaluation

#### *Nuclear Steam Supply System Piping, Components, and Supports*

The primary systems of St. Lucie 1 is the NSSS piping, which is the RCS piping and it consists of two heat transfer piping loops connected in parallel to the reactor pressure vessel (RPV). Each loop contains one SG, two RCPs, carbon steel piping with stainless steel cladding and instrumentation. The major function of the RCS is to transport heated coolant from the RPV through the SGs and back to the RPV for reheating. The primary system also contains an electrically heated pressurizer connected to the hot leg of one of the reactor coolant loops via a stainless steel surge line. The St. Lucie 1 current design bases for NSSS piping, components and supports is contained in FSAR Sections 5.5.6, Reactor Coolant Piping; 5.5, Component and Subsystem Design; 5.2.1.2, Transients Used in Design and Fatigue Analyses; 3.9, Mechanical



System and Components; 3.7, Seismic Design and Section 3.2, Classification of SSCs. In addition, the current design basis also includes the pressurizer surge line thermal stratification, requested by NRC BL 88-11, "Pressurizer Surge Line Thermal Stratification."

According to the St. Lucie 1 CLB (FSAR Sect 3), Class I piping systems have been designed in accordance with the 1969 ANSI B31.7. Based on the licensee's responses to staff RAI, the St. Lucie 1 RCS EPU piping evaluations utilized the original code of construction ANSI B31.7, which, therefore is acceptable. The surge line was reevaluated to include the effects of thermal stratification on fatigue and stress in accordance with the ASME Code, Section III, 1986 Edition as required by NRC BL 88-11. The licensee in its response to staff's RAI also stated that evaluations of class 1 branch lines connected to the RCS primary loop utilized the ASME Code, Section III 1971, 1986, or 1989 editions. According to the licensee, code reconciliation has been performed in accordance with ASME Section XI to document acceptance for use of these later ASME III codes for the subject RCS branch piping. Therefore, use of the reconciled codes for EPU evaluations is acceptable. The LAR Attachment 5 shows that the EPU structural evaluation criteria for the NSSS primary equipment supports are based on the ASME Code as used in the current design basis, and, therefore acceptable. These include Section III, 1965 Edition through Winter 1967 Addenda and Section III, Subsection NF, 1971 Edition through Winter 1973 Addenda.

The licensee evaluated the existing design basis analyses for RCS loop piping and associated branch piping, RCS loop primary equipment nozzles and supports and the pressurizer surge line to assess the impact associated with the EPU implementation. In its EPU evaluations the licensee specifically considered the NSSS design parameters shown in LAR Attachment 5, Table 1.1-1; EPU NSSS design transients identified in LAR Attachment 5, Section 2.2.6; Loop LOCA hydraulic forces and the associated Loop LOCA RPV motions. For the EPU program the licensee specifically evaluated:

- RCS piping system stresses
- RCS piping system LBB loads for LBB evaluation
- RCS piping system displacements at the junction of the centerline of the RCS piping and the branch nozzle connections of the branch line piping systems to the RCS, and their impact on the branch line piping systems
- Primary equipment nozzle loads
- Pressurizer surge line piping analysis, including the effects of thermal stratification
- Primary equipment support loads (RV, SGs, and RCPs)

LAR Attachment 5. Tables 2.2.2.1-1 and 2.2.2.1-2 provide RCS maximum stress and fatigue usage summaries for current licensed thermal power (CLTP) and EPU with comparisons to code allowable values. The licensee, in its response to staff's RAI, revised and resubmitted Table 2.2.2.1-1 to correct allowable values. The licensee also verified that structural evaluations of SSCs performed for EPU have used allowable stress values contained in the existing design basis analyses that utilized original code of construction allowable values. Thus, assurance is provided that the original code of construction allowable values will not be exceeded. The licensee has also demonstrated in its response to staff's RAI that cumulative fatigue usage factors contained in the LAR Attachment 5, Section 2.2, Mechanical and Civil Engineering, have been derived for the 60-year renewed operating license of the plant. The

licensee's tables show that existing AOR for the pressurizer surge line remain bounding for EPU, majority of the RCS piping AOR are also bounding for EPU with two RCS piping locations experiencing approximately 11 and 14 percent increases in stress due to EPU. The staff notes that all calculated stresses and fatigue usage values are within code allowable values, and, therefore are acceptable.

The licensee also evaluated the effect of the EPU temperatures and the design transients on the pressurizer surge line design basis analysis, including the effects of thermal stratification and determined that there is no significant impact and the analysis on record remains valid for EPU. Therefore, the pressurizer surge line thermal stratification remains in compliance with the NRC BL 88-11.

The licensee also evaluated primary equipment nozzles. LAR Attachment 5, Table 2.2.2.1-1, shows that EPU stresses and CUF values for RCS nozzles are within code of record allowable limits, and therefore are acceptable. The primary equipment support loads (RPV supports, SG supports, RCP supports and pressurizer supports) were also evaluated by the licensee for EPU conditions and the licensee indicated that they met the required design basis criteria for equipment support stresses.

Fatigue evaluations are required for class 1 SSCs. Metal fatigue is a time-limited aging analysis (TLAA) identified in the renewed plant operating license evaluations and license renewal programs and is discussed in plant licensing renewal NUREG-1779, SER Section 4.3 and Chapter 18 of the FSAR. The licensee evaluated the EPU impact on the licensing renewal TLAA's and determined that the EPU has not resulted in any change to the plant fatigue monitoring program (FMP) commitments to track, monitor and review the affect of fatigue upon impacted components. Therefore, the TLAA related to metal fatigue of ASME Section III, Class 1 components will continue to be valid following implementation of the EPU.

NRC Regulatory Issue Summary (RIS) 2008-30, "Fatigue Analysis of Nuclear Power Plant Components", identified a concern with the simplified single-stress methodology used by some license renewal applicants to perform fatigue calculations, and as input for on-line fatigue monitoring programs, in lieu of the ASME Code, Section III, Subsection NB, Subarticle NB-3200 method which requires it to consider all six stress components. For stress based fatigue monitoring, the St. Lucie 1 licensee, FPL, in its response to staff's RAI confirmed that St. Lucie 1 does not rely on the simplified single-stress methodology described in RIS 2008-30 and that fatigue analyses for St. Lucie 1 license renewal were performed in accordance with the rules of ASME Section III, Subsection NB-3200 which considers the six stress components. For cycle monitoring, the licensee stated in its response to staff's RAI that the St. Lucie 1 fatigue monitoring program does not rely on an online fatigue monitoring system. Instead, it is based on the manual logging of design cycles throughout the life of the plant. The staff finds the licensee's response acceptable, as fatigue monitoring at St. Lucie 1 follows acceptable ASME Section III and industry methods.

The licensee in its response to staff's RAI (Reference 16) had stated that design and analysis for the auxiliary spray path modification, required to meet EPU hot leg injection flow requirements, had not been completed. This was identified as open item 2.2.2-1 during the issuance of the EMCBSER input with open item (ADAMS accession No. ML12046A890). By letter dated February 21, 2012 (Reference 17), the licensee submitted supplemental response to staff to resolve open item 2.2.2-1. The licensee's response shows that the design modification to the hot leg injection auxiliary spray flow path has been completed. The licensee's

response provided tabulated pipe stress summaries that show that calculated pipe stresses meet ASME code equation allowable stress limits with maximum EPU stress ratio (calculated over allowable) of 0.536. The staff from its review finds that the licensee has provided sufficient information to successfully close OI 2.2.2-1 by demonstrating that the hot leg injection auxiliary spray flow path planned modification is structurally adequate at EPU conditions.

The licensee, using the current plant design basis methodology and acceptance criteria, has evaluated the structural integrity of the NSSS piping and supports, the primary equipment nozzles, and the primary equipment supports. Therefore, based on its review as summarized above, the staff concurs with the licensee that the NSSS piping, components and supports are structurally adequate for the proposed power uprate.

#### *Balance-of-Plant Piping, Components, and Supports*

The licensee evaluated the balance of plant (BOP) piping, components and supports inside and outside containment to assess the impact of temperature, pressure and flow rate changes that will result due to the implementation of EPU, in accordance with the current licensing and design basis criteria. According to the St. Lucie 1 CLB (FSAR Section 3), the piping code for Class II and III piping systems is identified as the 1969 ANSI B31.7. In response to staff's RAI, the licensee stated that for EPU, class II and class III piping evaluations were performed utilizing ASME Section III, 1971 edition through Summer 1973 Addenda for which a code reconciliation was performed in accordance with ASME Section XI. In addition, the licensee via its response to staff's RAI provided assurance that original code of construction allowable values have been utilized for comparison and acceptance of SSC structural evaluations performed for EPU. Based on the above, the staff finds the ASME Code edition used for EPU structural evaluations acceptable because the original code of construction requirements and intent has been satisfied. In its LAR and in its response to staff's RAI, the licensee stated that the 7<sup>th</sup> Edition of the AISC Steel Manual was utilized for EPU pipe support evaluations and assessments, which is consistent with the CLB. The staff notes that for the design of structural steel, the FSAR makes reference to the American Institute of Steel Construction (AISC) "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings," dated February 12, 1969. This specification has been incorporated in to the AISC 7<sup>th</sup> edition, and, therefore makes utilization of the 7<sup>th</sup> edition acceptable (as the revision of the AISC specification is the main difference of the 6<sup>th</sup> to the 7<sup>th</sup> edition). Therefore, the staff agrees with the licensee that use of the 7<sup>th</sup> Edition of the AISC Steel Manual is consistent with the CLB.

The LAR states that the BOP piping and support systems that were evaluated for EPU conditions included the following systems: main steam, auxiliary steam, auxiliary FW, FW, condensate, heater drains, extraction steam, circulating water, intake cooling water, CCW, spent fuel pool cooling, SG blowdown, safety injection, containment spray, chemical and volume control, shutdown cooling and turbine cooling water.

The staff's review of the LAR identified that the structural design and analysis of BOP components, piping and supports at EPU conditions had not been completed. The staff's RAIs requested that the licensee identify all systems (inside and outside containment) that experience an increase in temperature, pressure and/or flow rate due to EPU; complete the required structural design evaluations and provide summaries of the results for EPU affected piping, pipe supports, penetrations and equipment nozzles, which show that these SSCs are capable of maintaining their designed structural integrity for EPU conditions in accordance with the current plant design basis. The licensee completed these structural evaluations and in its response to

the staff's RAIs, in (Reference 18) and (Reference 19), submitted summaries of the results as requested by the staff. The staff's review of the licensee's responses to staff's RAI and LAR with regard to the balance of plant piping, components and supports is summarized below.

In (Reference 19), the licensee identified that systems which will experience an increase in temperature, pressure and/or flow rate due to EPU include reactor coolant (see staff's review of RCS in Section 2.2.2.2.1), main steam, FW, condensate, extraction steam, heater drains, CCW, intake cooling water, chemical and volume control, pressurizer spray, safety injection, shutdown cooling, SG blowdown and containment hydrogen purge. For these systems the licensee performed pipe stress and pipe support evaluations using the current plant design basis and utilizing computer analysis and scaling factors. The two piping systems that are mainly affected by the EPU due to operation at increased flow rates are the main steam and FW. According to licensee's responses to staff's RAIs, the licensee's structural evaluations for main steam included loads from the turbine stop valve closure and the main steam isolation valve closure transient events for the higher EPU flow rates. Structural evaluations for the FW also included fluid transient loads associated with FW regulating valve and FW isolation valve closure events due to higher EPU flow rates. Force time histories from the main steam and FW transients were utilized to generate pipe loads and stresses which were then combined with loads and stresses from other pipe loadings (due to pressure, deadweight and seismic) to produce stresses for code equations and pipe reaction loads for pipe support evaluations. The licensee, in its response to staff's RAI, described six piping modifications that are required for EPU. Review of the licensee's summaries as submitted in the LAR and in (Reference 18) and (Reference 19), show that the revised stress levels at EPU conditions are within the code of record allowable stress levels and, therefore, are acceptable. The maximum EPU stress ratio (calculated over allowable) for the main steam is 0.874 and for the FW is 0.789, both less than the allowable stress ratio of one.

The licensee also evaluated the pipe supports of the affected systems due to the EPU increased loads using current plant design basis. The licensee found that, mainly for the main steam, FW, condensate and heater drains, additional supports were required and several of the existing supports needed various modifications, ranging from support replacement and/or relocation to weld modifications and structural reinforcements. The licensee's LAR Table 2.2.2.2-2 contains a list of 81 pipe support modifications with description summaries. In response to staff's RAI, the licensee stated that the new and replacement snubbers shown in Table 2.2.2.2-2 were required to accommodate revised fluid transients and vibration levels at EPU conditions on the main steam FW and condensate piping. The licensee found that pipe supports of the above EPU affected systems, including new and modified supports, meet the current plant design basis requirements at EPU conditions and, therefore, are acceptable.

The licensee evaluated loads for equipment nozzles and containment penetrations that are affected by the EPU and found that they are within the design basis allowable values, and, therefore acceptable. The maximum EPU stress ratio (calculated over allowable) for the main steam penetrations is 0.79 and for the FW penetrations is 0.65, both less than the allowable stress ratio of one. With regard to FW pump nozzles for the replacement FW pumps and their acceptability for the higher EPU fluid transient loads, the licensee's response shows that the calculated pump nozzle loads for EPU are within the allowable nozzle loads contained in the FW pump specification, and, therefore acceptable.

With respect to flow-induced vibration (FIV) at the higher EPU flow rates for affected piping systems, the staff, as a result of its review of the licensee's LAR and its responses to staff's RAI, concludes the following:

For piping affected by the proposed power uprate, St. Lucie 1 has developed a plan to address FIV. The plan began with the development of a program to address scope, method, evaluation and acceptance criteria. The scope includes all piping with increased flow rates resulting from the power uprate including main steam, extraction steam, condensate, FW and FW heater vents and drains. The method is to perform a series of pre-EPU full power level walkdowns to collect data and establish the baseline pipe vibrations. This, the licensee calls pre-baseline walkdowns. Several pre-Baseline piping vibration walkdowns that were performed in 2008, 2009, and 2010 identified vibration levels at piping locations that required further evaluation. Detailed structural analyses of piping configurations that included these locations were performed. Resulting pipe stresses from these analyses were compared with the acceptance limits (of permitted endurance limit) recommended by the ASME Operation and Maintenance (OM) Code Part 3, guidance of which is recommended by SRP 3.9.2, Dynamic Testing and Analysis of Systems, Structures and Components. Based on the results of these analyses the licensee identified six piping modifications and nine pipe support installations/modifications that are required to be implemented prior to EPU implementation. During EPU power ascension testing, observation will take place at various power level test plateaus from 25 percent to 100 percent power, to identify increased pipe vibrations and the need for additional evaluations will be determined. Acceptance criteria for all piping vibration evaluations shall be in accordance with ASME OM S/G-2007, Part 3. The staff finds the licensee's plan to monitor FIV for this piping adequate and acceptable. This is based on the fact that the licensee has verified that the methodology for evaluation and acceptance criteria for all in-scope piping (see above) for vibration issues will be in accordance with ASME OM Part 3.

With regard to thermal expansion on the issue that piping could potentially expand due to higher EPU temperatures in affected systems and impose an unanalyzed condition that could potentially overstress piping and supports or otherwise damage SSCs, the LAR identifies that during the planned baseline walkdowns to be performed for piping vibration, piping systems subjected to a temperature increase associated with EPU (such as main steam, condensate, FW, extraction steam, and heater drains), will be inspected to identify any locations where there is a potential for unacceptable thermal expansion interaction. The licensee estimated that the increases in thermal expansion displacements associated with the proposed EPU are less than 1/16 of an inch and, therefore, of no significant concern. In addition, the licensee stated that during startup of the EPU, piping systems subjected to a temperature increase will be observed to identify any unacceptable conditions. Piping that is potentially affected by vibration and thermal expansion will be included as part of the start-up testing program related to the overall implementation of EPU. The staff finds that the licensee has adequately addressed the issue that piping thermal expansion at higher EPU temperatures will not impose an unanalyzed condition that could potentially overstress the piping and supports or otherwise damage SSCs.

With regard to the proposed addition of Metamic™ neutron-absorbing inserts to fuel assemblies located within the SFP, the licensee has reviewed the structural integrity of the SFP under its existing design review and 10 CFR 50.59 evaluation programs, which are both subject to inspection by the NRC staff.

Based on the staff's review of St. Lucie 1 evaluations for BOP piping, components and supports for EPU as summarized above, the staff finds the licensee's methodology acceptable as it

conforms to the codes of record and the plant design basis requirements. Therefore, the staff concurs with the licensee's conclusion that the BOP piping, components and supports with the planned modifications and additions will maintain their structural integrity for EPU conditions.

### *Reactor Vessel and Supports*

The RPV is the principal component of the RCS. It forms a pressure boundary to contain the reactor coolant and the heat-generating core, core support structures, control rods, and other components directly associated with the core. The RPV primary outlet and inlet nozzles provide for the exit of the heated coolant and its return to the RPV for recirculation through the core.

The St. Lucie 1 RPV is cylindrical, with a welded hemispherical bottom head and a removable hemispherical, flanged and gasketed, upper head. The head flange is drilled to match the 54 vessel flange stud bolt locations. The head studs are hydraulically bolt-tensioned to ensure uniform loading of the closure seal. According to the FSAR, a detailed analysis has been performed which shows that 36 evenly distributed studs can fail before the remaining stud stresses reach yield and the closure separates at design pressure, and that 16 adjacent studs can fail before the closure will fail by "zippering." The RPV is described in St. Lucie 1 FSAR Chapter 5, Section 5.4, Reactor Vessel and Appurtenances. The original code of construction for the RPV is the ASME Section III, 1965 Edition through Winter 1967 Addenda. The RV closure head (RVCH) was replaced in 2005 in accordance with the ASME B&PV Code 1989 Edition, No Addenda.

The staff reviewed the licensee's evaluation methodology and evaluations for the RPV and its supports presented in the LAR and in the licensee's responses to the staff's RAIs. The licensee performed its evaluations for the St. Lucie 1 RPV at EPU conditions in accordance with the current plant codes of record using the current design basis reactor vessel stress report. For EPU, the licensee determined new loads throughout the RCS either by analysis or where bounding used existing design basis RCS loads. The resulting loads were then used to reconcile the individual subcomponents for the EPU conditions. Stress intensity (SI) ranges and CUFs due to changes in design transients were evaluated and compared to the acceptance criteria of the current code of record, ASME, Section III, Class 1 requirements. LAR Attachment 5, Table 2.2.2.3-1 through Table 2.2.2.3-3 provide summaries of the maximum ranges of SI and maximum CUFs at critical location (including RPV nozzles and RPV integral support feet) from the reactor vessel evaluations at EPU and pre-EPU conditions. For the majority of the locations, the stress and CUF values remained unchanged, while at some locations maximum calculated stresses increased slightly (by less than 3 percent). All of the regions of the reactor vessel are shown to meet the primary plus secondary SI allowable of  $3S_m$ , as required by ASME Section III, NB-3222.2.

The licensee also evaluated the RPV structural steel supports for EPU conditions. For the RPV structural steel supports, the LAR makes the statement that the deadweight (DWT) plus thermal load combination is bounded by the original design and provided in LAR Attachment 5, Table 2.2.2.3-4 a load comparison of EPU to original design for the vessel support loads. The staff, in a RAI to the licensee, noted errors in the LAR Attachment 5 provided Table 2.2.2.3-4, which invalidated the licensee's statement that the original DWT plus thermal load combination is bounding. The staff reviewed the licensee's response to staff's RAI, which also revised and corrected LAR Attachment 5, Table 2.2.2.3-4, and found that although the reaction loads at the RPV structural steel supports at EPU conditions are not bounded by the original design loads (the maximum vertical load under EPU increased by 6.7 percent and the friction force increased

by 5.7 percent), they are still within current design basis allowable values, and, therefore are acceptable.

As shown in SER Section 2.2.2.2.1, the licensee has also evaluated the EPU impact on the St. Lucie 1 plant licensing renewal aging evaluations approved by the NRC in NUREG-1779 and found it acceptable.

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the structural integrity of the St. Lucie 1 RPV and supports and concludes that the licensee has demonstrated that the St. Lucie 1 RPV and supports will remain structurally adequate to perform their function at EPU conditions and will continue to meet the requirements of 10 CFR 50.55a; GDC 1, GDC 2, GDC 4, GDC 14, and GDC 15; and the code of record ASME Section III Division 1 following implementation of the proposed EPU.

#### *Control Rod Drive Mechanism*

The control rod drive mechanisms, which St. Lucie 1 refers to as the as the control element drive mechanisms (CEDM), are located on top of the RPV head and are coupled to the control element assemblies (CEAs) via extension shafts. Each CEDM is capable of withdrawing, inserting, holding or tripping the CEA from any point within its travel in response to operating signals to control reactivity. The CEDMs were replaced in 2005 as part of the RVCH replacement program. The replacement CEDMs were designed and fabricated in accordance with the requirements of the ASME Code Section III, Class 1, 1998 Edition through 2000 Addenda.

The staff reviewed the licensee's evaluation of the CEDM and its components summarized in LAR Attachment 5, Section 2.2.2.4 and in the licensee's responses to the staff's RAI. The licensee evaluated the St. Lucie 1 structural integrity of the CEDM considering the current design analysis on record evaluations and the NSSS operating parameters of EPU (LAR Attachment 5 Section 1.1) and the EPU NSSS design transients (LAR Attachment 5, Section 2.2.6). Applicable loadings include pressure, deadweight, seismic, thermal and transient loads. Pressure, deadweight and seismic loads are unaffected by the EPU. LAR Attachment 5, Section 2.2.2.4, Control Rod Drive mechanisms, shows that the NSSS parameters and NSSS design transients for EPU are bounded by the parameters and transients used the current design AOR evaluations. Therefore, the staff agrees with the licensee's response to staff's RAI that reanalysis of the CEDMs for EPU conditions is not required because design conditions for the current CEDM analysis bound the EPU conditions. The staff reviewed the stress summaries presented in the LAR, which show that CUFs and stress values remain unchanged for EPU and meet the ASME Code of record allowable values, and, therefore are acceptable.

The licensee, using the current plant design basis methodology to evaluate the pressure boundary components of the CEDMs, has demonstrated that these components meet the code of record criteria requirements for structural integrity. Therefore, the staff, based on its review as summarized above, concurs with the licensee that the St. Lucie 1 pressure boundary components of the CRDMs are structurally adequate for continuous operation under the proposed power uprate.

### *Steam Generators and Supports*

The St. Lucie 1 SGs were replaced in 1998 by B&W SGs. The SGs are vertical shell and inverted U-tube type heat exchangers. The RSGs were designed and manufactured in accordance with ASME Section III, 1986 Edition, no Addenda.

The staff reviewed the licensee's SG and support evaluations presented in the LAR and in the licensee's responses to the staff's RAIs. The licensee used the current design basis codes of record to evaluate the structural adequacy of the SGs' pressure boundary and the internal components and SG supports for EPU conditions. Review of the licensee's presented stress and CUF summaries shows the maximum EPU stress ratio (calculated over allowable) on the primary side of the pressure boundary occurred at the [ ] at a stress ratio value of [ ], which is still less than the allowable ratio value of one. For the primary manway studs the licensee's summary shows calculated CUF equal to the ASME allowable of one. This is a pre-EPU existing condition at CLTP. As mentioned, the RSGs were installed in 1998. At CLTP conditions the studs require replacement prior to [ ] loading and unloading transient cycles (normally [ ] years of operation). For EPU, the licensee determined that the number of allowable cycles needs to be reduced to [ ] cycles (normally [ ] years of operation) at which point the studs are required to be replaced. The staff finds the licensee's determination acceptable, as it assures that the studs will be replaced prior to reaching their acceptable fatigue limit. Review of the stress and fatigue evaluation summaries for the remainder of the primary and secondary boundary pressure components, presented in the LAR Attachment 5, Section 2.2.2.5, shows that stress ranges and CUFs are within the ASME Section III, Subsection NB allowable limits, and, therefore are acceptable. The licensee also evaluated the SG supports for EPU conditions and indicated that they meet the required design basis criteria for equipment support stresses, and, therefore are acceptable.

The licensee's evaluations of the SG tubes for FIV and tube wear due to higher EPU flow rates are summarized in LAR Attachment 5, Section 2.2.2.5 and in the licensee's responses to the staff's RAIs. Evaluations of FIV and tube wear were performed for fluid-elastic stability and amplitudes of tube vibration due to turbulences. The staff's review of the licensee's summary evaluations finds that for EPU the fluid-elastic stability ratio increased to [ ] over the [ ] pre-EPU benchmark case but is still less than the acceptance limit of 1.0 identified in NRC BL 88-02, and, therefore acceptable. The licensee, in its staff's RAI response, showed that stresses due to FIV remain well below the material endurance limit, and, therefore are acceptable. The licensee also evaluated the EPU expected tube wear. Review of the licensee's tube wear evaluations shows that the maximum expected tube wear at EPU conditions is much less than the ASME Section XI driven St. Lucie 1 Technical Specification requirement of 40 percent tube wall wear prior to tube plugging, and, therefore acceptable. With regard to the steam separators in the steam drum of the St. Lucie RSGs, the licensee reviewed operating experience from 11 PWR plants that use B&W RSGs. In its response to staff's RAI, the licensee stated that at steam flows greater than the steam flow expected at EPU conditions confirms that the steam separators used in the St. Lucie 1 RSGs are not likely to suffer any degradation due to acoustic or flow induced vibration following the EPU power uprate. In addition, the licensee stated that no station with B&W RSGs has ever observed any degradation of the steam separators that could be attributed to flow induced vibration or acoustic pressure fluctuations in the steam space. The licensee also plans to perform a baseline visual inspection of the steam separators prior to the implementation of the EPU. During the refueling outage, following the first operating cycle under EPU conditions, a visual inspection of the steam separators will be performed. Subsequent visual inspections of the steam separators will be



based upon the results of the refueling outage inspection. The staff finds the licensee's response acceptable because operating experience has shown that there is little potential for acoustic or FIV related degradation of the steam drum components in the St. Lucie RSGs and if any occurs it will be identified and corrected via planned inspections and the plant's corrective action program.

The staff also notes, from its review of the LAR and from the licensee's responses to the staff's RAIs, that the St. Lucie 1 has an extensive loose parts monitoring system (LPMS) with procedures in place and a system of transducers and preamplifiers that could detect debris and loose parts and initiate actions to assess the condition. The sensor outputs are monitored automatically via a computer and the LPMS is permanently installed to provide inservice monitoring function during plant operation. Loose parts can potentially damage the safety related tubes of the SGs. The licensee stated that the risk of a primary to secondary tube leak due to loose part damage is managed through regularly scheduled inspection and maintenance activities, including eddy current inspections, tubesheet flushing, and foreign object search and retrieval (FOSAR). Eddy current testing inspections will detect tube wear due to loose parts so that the affected tubes can be plugged and/or the objects can be removed. Tubesheet flushing and FOSAR will identify parts on the top of tubesheet region so the parts can be removed and/or the affected tubes plugged if required.

The staff, based on its review, finds that the licensee has adequately addressed the EPU flow induced effects on the SG internals. The staff also finds that the licensee has adequately addressed the potential of loose parts generation due to EPU flow conditions on the SG internals.

The licensee, using the current plant design basis methodology has evaluated the SGs and their supports for EPU and has demonstrated that these components meet the codes of record and design basis criteria requirements. Therefore, the staff, based on its review as summarized above, concludes that the effects of the proposed EPU at St. Lucie 1 do not adversely affect the structural integrity of the SGs and their supports.

#### *Reactor Coolant Pumps and Supports*

There are two RCPs per each RCS loops. The RCPs are installed in the RCS cold legs between the SG outlet and the reactor vessel inlet and circulate the reactor coolant through the RCS. The RCPs and their motors are supported on snubbers and springs. The current licensing and design basis for the RCPs are contained in FSAR, Chapter 5. The RCPs are designed to the requirements of ASME Section III, Nuclear vessels, Class A, 1965 Edition through the Winter of 1967 Addenda as supplemented by the requirements given in the FSAR Table 5.2-2A for load combinations and primary stress limits.

The staff reviewed the licensee's evaluations for RCP and supports presented in the LAR and in the licensee's responses to staff's RAIs. The licensee evaluated the RCS piping and supports (RPV supports, SG supports, RCP supports and the pressurizer supports) for EPU parameters and EPU NSSS design transients. The staff's review of the RCS piping and supports is presented in Section 2.2.2.2.1 of this SE. NSSS performance parameters for EPU and CLTP are provided in LAR Attachment 5, Table 1-1. The licensee compared and reconciled the design loads developed from EPU conditions to those used in the existing design basis analysis on record and demonstrated in its LAR and in its responses to staff's RAIs that no increases in the existing set of design basis loads were required. Therefore, the staff agrees with the

licensee that the design basis stresses in the analysis on record remain bounding for EPU conditions. The licensee also evaluated the RCP supports for EPU and indicated that they meet the required design basis criteria for equipment support stresses.

The licensee, using the current design basis and code of record, has adequately addressed the EPU effects on the RCPs and supports. The staff, based on its review as summarized above, concludes that the EPU does not adversely affect the structural integrity of the RCPs and their supports.

### *Pressurizer and Supports*

The St. Lucie 1 has a replacement pressurizer. The current licensing and design basis for the pressurizer and its supports is contained in FSAR, Chapter 5 and 15. The replacement pressurizer was designed and fabricated in accordance with the ASME Section III, 1998 Edition through 2000 Addenda. In considering only the effects of thermal stratification for the pressurizer surge line, the original code of record is the ASME Code, Section III, 1986 Edition.

The licensee evaluated the pressurizer and its supports for EPU conditions summarized in LAR Attachment 5, Section 1.1. For the EPU NSSS design transients, the licensee's summary is provided in Section 2.2.6 of the LAR Attachment 5. The licensee reviewed and compared the design loads developed from EPU conditions to those used in the existing design basis analyses of record and determined that the design loads from the existing analyses bound the EPU design loads. The licensee also reviewed the NSSS EPU design transients and noted that the primary side transients were either unaffected or not significantly affected, and, therefore concluded that existing pressurizer stress and fatigue analyses remain valid. The licensee also evaluated the pressurizer safety relief valve and power operated relief valve (PORV) piping for EPU conditions. Based on its evaluation the licensee determined that the maximum loads in the piping segments connected to the PORV and safety relief valve nozzles are bounded by the original design. Therefore, the staff agrees with the licensee that the nozzle loads are also bounded by the original design. The licensee also evaluated the pressurizer supports and determined that they are acceptable for EPU conditions. The licensee evaluated the RCS piping and supports (RPV supports, SG supports, RCP supports and the pressurizer supports) for EPU parameters and EPU NSSS design transients. The staff's review of the RCS piping and component supports is presented in Section 2.2.2.2.1 of this SER.

The licensee also evaluated the pressurizer surge line thermal stratification due to EPU changes to temperature and design transients. The staff's review of the pressurizer surge line thermal stratification is presented in Section 2.2.2.2.1 of this SE. The staff's review found that the proposed EPU has no significant structural impact on the surge line stratification and found it to be in compliance with NRC BL 88-11.

The licensee, using the current plant design basis methodology and acceptance criteria, has evaluated the structural integrity of the pressurizer and its supports under EPU conditions. The staff, based on its review as summarized above, concurs with the licensee that the St. Lucie 1 pressurizer and its supports are structurally adequate for continued operation under the proposed power uprate.

## Conclusion

The NRC staff has reviewed the licensee's evaluations related to the structural integrity of pressure-retaining components and their supports. For the reasons set forth above, the NRC staff concludes that the licensee has adequately addressed the effects of the proposed EPU on these components and their supports. Based on the above, the NRC staff further concludes that the licensee has demonstrated that pressure-retaining components and their supports will continue to meet the requirements of 10 CFR 50.55a, GDC 1, GDC 2, GDC 4, GDC 14, and GDC 15 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the structural integrity of the pressure-retaining components and their supports.

### 2.2.3 Reactor Pressure Vessel Internals and Core Supports

#### Regulatory Evaluation

Reactor pressure vessel internals consist of all the structural and mechanical elements inside the RV, including core support structures. The NRC staff reviewed the effects of the proposed EPU on the design input parameters and the design-basis loads and load combinations for the reactor internals for normal operation, upset, emergency, and faulted conditions. These include pressure differences and thermal effects for normal operation, transient pressure loads associated with LOCAs, and the identification of design transient occurrences. The NRC staff's review covered (1) the analyses of flow-induced vibration for safety-related and nonsafety-related reactor internal components and (2) the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. The NRC staff's review also included a comparison of the resulting stresses and CUFs against the corresponding Code-allowable limits. The NRC's acceptance criteria are based on (1) 10 CFR 50.55a and GDC 1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (3) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; and (4) GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to assure that specified acceptable fuel design limits (SAFDLs) are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences. Specific review criteria are contained in SRP Sections 3.9.1, 3.9.2, 3.9.3, and 3.9.5; and other guidance provided in Matrix 2 of RS-001.

In addition to their GDC compliance described above, St. Lucie 1 reactor internals components were evaluated for plant license renewal. The evaluations are documented in NUREG-1779 (Reference 12).

#### Technical Evaluation

The St. Lucie 1 evaluations of RPV core support structures (CSS) and non-CSS (all internal structures that are not CSS) for the effects of the proposed power uprate are summarized in Section 2.2.3 of the LAR. The current licensing and design basis for the RPV internals is contained in FSAR Section 4.2.2 Reactor Vessel Internals. FSAR Table 4.2.2 contains the

ASME stress limits for the reactor vessel internal structures. According to the FSAR, the code of record for the RPV internals is the May 1972 draft of Section III of the ASME Boiler and Pressure Vessel Code, Subsection NG.

The staff reviewed the licensee's evaluations for the RPV internals and core support structures presented in the LAR and in the licensee's responses to the staff's RAIs. The licensee, using the code of record, evaluated critical St. Lucie 1 RPV internal components for EPU RCS conditions and revised NSSS design transients. The licensee also evaluated the RPV internal components for FIV effects due to EPU increased hydraulic loads and indicated that the dynamic hydraulic loads that cause flow-induced vibration are included in the revised hydraulic loads and are accounted for in the stress evaluations. Specifically, the following most critical reactor internal components were evaluated: core support barrel, core support plate, lower support structure beams and columns, core shroud, upper guide structure, fuel alignment plate, control element assembly shrouds, instrument tube supports, reactor vessel level monitoring system support tube and thimble support plate. Summaries of results of these evaluations at EPU conditions showing maximum stress intensity ranges and CUFs are presented in LAR Attachment 5, Table 2.2.3-1. Loads that were impacted by the EPU conditions and were incorporated in the EPU stress analyses and evaluations are the hydraulic loads for the thimble support plate that increased by 2.4 percent and for all other components subjected to core exit temperatures the hydraulic loads increased by 3.4 percent. According to the licensee's response to staff's RAI, the core shroud was the only component that at EPU conditions exceeded the primary plus secondary stress intensity allowable limit of  $3 S_m$ , specified by ASME Section III, NG-3222.2. The licensee has shown acceptability of the core shroud by elastic-plastic analysis in accordance with Subparagraph NG-3228.3, and, therefore is acceptable. Review of the licensee's presented stress and CUF summaries shows that the maximum EPU stress ratio (calculated over allowable) occurred on the reactor vessel level monitoring system support tube for the faulted condition which reached a stress ratio value of 0.979, which is still less than the allowable stress ratio value of one. The summaries also show that the maximum EPU CUF occurs on the core shroud at a calculated value of 0.721, which is less than the allowable of one. The summaries show that all stresses and CUFs meet code allowable values and, therefore, are acceptable.

The RPV internals and core supports are within the scope of License Renewal. The licensee evaluated the EPU impact on the licensing renewal TLAA's and determined that the EPU has not resulted in any change to the plant fatigue monitoring program (FMP) commitments to track, monitor and review the affect of fatigue upon impacted components. Therefore, the TLAA related to metal fatigue of ASME Section III, Class 1 components will continue to be valid following implementation of the EPU.

The licensee has demonstrated that overall, the maximum stress intensity ranges and cumulative fatigue usage factors for the RPV internals continue to meet ASME acceptable limits. Therefore, based on its review as summarized above, the staff concludes that the effects of EPU do not adversely affect the structural integrity of the RPV internal components and core support structures.

### Conclusion

The NRC staff has reviewed the licensee's evaluations related to the structural integrity of reactor internals and core supports and concludes that the licensee has adequately addressed the effects of the proposed EPU on the structural integrity of the reactor internals and core

supports. The NRC staff further concludes that the licensee has demonstrated that the reactor internals and core supports will continue to meet the requirements of 10 CFR 50.55a, GDC 1, GDC 2, GDC 4, and GDC 10 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the design of the reactor internal and core support structures.

#### 2.2.4 Safety-Related Valves and Pumps

##### Regulatory Evaluation

The NRC's staff's review included certain safety-related pumps and valves typically designated as Class 1, 2, or 3 under Section III of the ASME B&PV Code and within the scope of Section XI of the ASME B&PV Code and the ASME Operations and Maintenance (O&M) Code, as applicable. The NRC staff's review focused on the effects of the proposed EPU on the required functional performance of the valves and pumps. The review also covered any impacts that the proposed EPU may have on the licensee's motor-operated valve (MOV) programs related to GL 89-10, GL 96-05, and GL 95-07. The NRC staff also evaluated the licensee's consideration of lessons learned from the MOV program and the application of those lessons learned to other safety-related power-operated valves. The NRC's acceptance criteria are based on (1) GDC 1, insofar as it requires that SSCs important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 37, GDC 40, GDC 43, and GDC 46, insofar as they require that the ECCS, the containment heat removal system, the containment atmospheric cleanup systems, and the cooling water system, respectively, be designed to permit appropriate periodic testing to ensure the leak-tight integrity and performance of their active components; (3) GDC 54, insofar as it requires that piping systems penetrating containment be designed with the capability to periodically test the operability of the isolation valves to determine if valve leakage is within acceptable limits; and (4) 10 CFR 50.55a(f), insofar as it requires that pumps and valves subject to that section must meet the inservice testing program requirements identified in that section. Specific review criteria are contained in SRP Sections 3.9.3 and 3.9.6; and other guidance provided in Matrix 2 of RS-001.

##### Technical Evaluation

In its submittal dated November 22, 2010, requesting a license amendment to operate St. Lucie 1 at EPU conditions, the licensee discussed its evaluation of safety-related valves and pumps to perform their intended functions under EPU conditions. By letter dated March 14, 2011, the licensee submitted additional information related to the LAR. The NRC staff has reviewed the licensee's evaluation of the impact of EPU conditions on safety-related valves and pumps at St. Lucie 1. This review is summarized in the following paragraphs:

In response to GL 89-10 and GL 96-05, St. Lucie 1 established a testing and surveillance program for MOVs. The NRC acceptance of the MOV program for St. Lucie 1 was documented in a letter dated July 13, 1995. In a letter dated June 30, 2000, the NRC attached the SE (ADAMS Accession No. ML003728144) for St. Lucie 1's response to GL 96-05, and stated that St. Lucie 1 had established an acceptable program to periodically verify the design-basis capability of the safety-related MOVs through its commitments to the Joint Owners Group Program on MOV Periodic Verification.

In its request for the EPU license amendment, the licensee described its evaluation of the MOVs within the scope of GL 89-10 at St. Lucie 1 for the effects of the proposed EPU on the following systems: Main Steam, Main FW, Auxiliary FW (AFW), Containment Spray, Intake Cooling Water, Instrument Air, Primary Makeup Water, Reactor Coolant, Chemical and Volume Control, and Emergency Core Cooling. The licensee's review of the affected systems indicates that the MOVs will not be outside their original design specifications under EPU conditions and the EPU conditions will have a negligible effect on the differential pressures/line pressures determined during the GL 89-10 review. Additionally, the licensee stated that the EPU will not affect MOV motor terminal voltages or MOV performance due to higher ambient temperatures. Therefore, no changes were identified to the design functional requirements for all GL 89-10 MOVs. Based on the information provided by the licensee, the NRC staff determined that all MOVs will perform their safety-related function under EPU conditions.

In response to GL 95-07, St. Lucie 1 modified the Shutdown Cooling System gate valves by installing bypass lines around the RCS side of the valve seats to prevent pressure locking and thermal binding. This modification was reviewed and accepted by the NRC in a letter dated July 15, 1999. In its request for the EPU license amendment, the licensee stated that the EPU does not increase the chance of pressure locking or thermal binding because susceptibility was due to the gage valve design or piping configurations and not based on any system process conditions. No previous responses or conclusions with respect to GL 95-07 were changed for the EPU; therefore, the NRC staff determined that the licensee continues to abide by the GL 95-07 requirements.

St. Lucie 1 has in place a program to ensure that safety-related air-operated valves (AOVs) are selected, set, tested and maintained so that the AOVs will operate under normal, abnormal, or emergency operating design basis conditions. Furthermore, the AOV Program ensures continued AOV reliability for the life of the plant. The AOV program includes the following categorization of AOVs:

Category 1 – AOVs that are safety-related, active, and have high safety significance

Category 2 – AOVs that are active and have safety-related or have a quality-related function, but do not have a high safety significance

Category 3 – All remaining AOVs that are deemed to have significance at St. Lucie 1 with respect to operation/generation impact, plant performance, unit efficiency, etc.

The licensee evaluated AOVs in the following systems for EPU conditions: Main Steam, Containment Purge, Containment Spray, Steam Generator Blowdown, Component Cooling Water, Intake Cooling Water, Waste Management, Containment Vacuum Relief, Reactor Coolant, Chemical and Volume Control, Low Pressure Safety Injection (LPSI), High Pressure Safety Injection (HPSI), Shutdown Cooling. The results of the evaluation showed that the following AOVs require modifications for EPU conditions:

Main Steam Isolation Valves – The licensee stated that the safety-related close stroke has an increasing maximum expected differential pressure (MEDP) beyond the current analysis. The licensee stated that the closing margin remains adequate for the safety-related close stroke. This closing margin is calculated to be 22.3 percent for EPU conditions, reduced from 23.2 percent at current conditions, a 4 percent margin reduction. The NRC staff determined that this margin reduction is acceptable because the MSIVs use steam flow to assist in closure.

Containment Purge System – a modification to the exhaust isolation valves will be added to allow remote-manual control of the valves. The licensee stated that the AOV program will be modified to account for these modifications.

Steam Generator Blowdown Containment Isolation Valve – The licensee stated that the safety-related close stroke has an increasing MEDP beyond the current analysis. The licensee stated that the closing margin remains adequate for the safety-related close stroke. This closing margin is calculated to be 5.0 percent at EPU conditions, reduced from 5.9 percent at current conditions, a 15 percent margin reduction. The NRC staff determined that this margin reduction is acceptable because the overall closing margin was reduced by less than 1 percent, the static tests performed by the licensee demonstrated an 8 percent margin, and the seating load is accounted for in the margin calculation, resulting in a conservative calculation.

The EPU does not affect any other AOV program valves since the current MEDP/line pressures are bounded under EPU conditions. Additionally, the results of an updated Probabilistic Risk Assessment will be used to determine any needed changes to either the risk category of AOVs or periodic verification requirements as a result of the EPU. The licensee noted that as a result of the increased flows at EPU conditions, the following additional valve changes need to be made:

The MSIV valves will be modified by redesigning the valve internal parts to increase the structural strength and fatigue life. The valve actuators will be replaced to meet EPU design basis accident conditions and will contain at least a 15 percent thrust margin.

The Safety Injection Tank relief valve setpoint will be changed from 250 psig to 280 psig. The licensee stated that this modification will be performed as part of the plant change/modification process.

The Main Steam Safety Valves (MSSVs) as-found setpoint tolerances, currently +1/-3 percent, will be changed to  $\pm 3$  percent for MSSVs with a nominal setpoint of 1000 psia and +2/-3 percent for MSSVs with a nominal setpoint of 1040 psia. The current MSSV nominal setpoints, 1000 psia and 1040 psia, will remain unchanged for the EPU. This tolerance change is acceptable because the MSSVs were designed to hold a  $\pm 3$  percent tolerance. The +2 percent limit for the 1040 psia setpoint MSSVs is due to the overpressure analysis.

The minimum accident condition flow rates for the HPSI System check valves will be increased at EPU conditions. An update of the inservice testing (IST) program will document the revised flow rates during the EPU implementation phase.

The EPU does not affect any check valves in the following systems: chemical and volume control, LPSI, containment spray, AFW, component cooling water, intake cooling water, and steam supply to the steam-driven AFW pump.

Additionally, the containment leakage rate testing program (Appendix J) will be revised due to the increase of the peak calculated containment internal pressure for the DBLOCA from 39.6 psig to 42.8 psig. The impact of the peak containment pressure increase on the stroke times was evaluated for following containment isolation valves communicating with the containment atmosphere: containment purge supply and exhaust, nitrogen supply to containment, RCP cooling water supply and return, containment vent header, reactor cavity

sump pump discharge, reactor drain tank pump suction, hydrogen sampling and return, containment atmosphere radiation monitoring, and containment vacuum. The St. Lucie 1 containment design pressure of 44 psig is greater than the DBLOCA pressure of 42.8 psig; therefore, the increased pressure will not affect these containment isolation valves.

The licensee evaluated the following safety-related pumps: boric acid makeup, charging, high pressure injection, low pressure injection, AFW, component cooling water, intake cooling water, containment spray, diesel fuel oil transfer, diesel fuel electric priming, diesel soak back lube oil AC, and diesel soak back lube oil direct current (DC). The licensee determined that no changes in pump designs or pump head performance are required at the EPU conditions. Based on the licensee's evaluations, the NRC staff determined that the IST program requirements for these pumps will not be affected by the EPU.

In its submittal, the licensee described its review of the IST Program for safety-related pumps and valves at St. Lucie 1 for EPU operations. The Code of Record for St. Lucie 1 is the 2001 Edition through 2003 Addenda of the ASME OM Code and its fourth 10-year IST interval began on February 11, 2009, and ends on February 10, 2018. The scope of and the testing frequencies for components in the IST program at St. Lucie 1 will not be affected by the EPU, and the St. Lucie 1 IST program will be updated to account for the EPU modifications, setpoint changes, and component upgrades. The licensee stated that the safety-related valves and pumps in the IST Program, with the modifications described above, will continue to meet the current licensing basis with respect to the requirements of 10 CFR Part 50, Appendix A Criterion: GDC 1, GDC 37, GDC 40, GDC 43, GDC 46, GDC 54, and 10 CFR 50.55a(f) following implementation of the proposed EPU.

The NRC staff reviewed the impact of EPU on safety-related pumps and valves, the IST program, associated testing requirements, and acceptance criteria, and has concluded that the modifications and additions described above are acceptable for the normal, transient, and accident EPU operating conditions.

### Conclusion

The NRC staff has reviewed the licensee's assessments related to the functional performance of safety-related valves and pumps and concludes that the licensee has adequately addressed the effects of the proposed EPU on safety-related pumps and valves. The NRC staff further concludes that the licensee has adequately evaluated the effects of the proposed EPU on its MOV programs related to GL 89-10, GL 96-05, and GL 95-07, and the lessons learned from those programs to other safety-related power-operated valves. Based on this, the NRC staff concludes that the licensee has demonstrated that safety-related valves and pumps will continue to meet the requirements of GDC 1, GDC 37, GDC 40, GDC 43, GDC 46, GDC 54, and 10 CFR 50.55a(f) following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to safety-related valves and pumps.

### 2.2.5 Seismic and Dynamic Qualification of Mechanical and Electrical Equipment

#### Regulatory Evaluation

Mechanical and electrical equipment covered by this section includes equipment associated with systems that are essential to emergency reactor shutdown, containment isolation,



reactor core cooling, and containment and reactor heat removal. Equipment associated with systems essential to preventing significant releases of radioactive materials to the environment are also covered by this section. The NRC staff's review focused on the effects of the proposed EPU on the qualification of the equipment to withstand seismic events and the dynamic effects associated pipe-whip and jet impingement forces. The primary input motions due to the safe-shutdown earthquake (SSE) are not affected by an EPU. The NRC's acceptance criteria are based on (1) GDC 1, insofar as it requires that SSCs important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 30, insofar as it requires that components that are part of the RCPB be designed, fabricated, erected, and tested to the highest quality standards practical; (3) GDC 2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (4) 10 CFR Part 100, Appendix A, which sets forth the principal seismic and geologic considerations for the evaluation of the suitability of plant design bases established in consideration of the seismic and geologic characteristics of the plant site; (5) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (6) GDC 14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; and (7) 10 CFR Part 50, Appendix B, which sets quality assurance requirements for safety-related equipment. Specific review criteria are contained in SRP Section 3.10.

In addition to their GDC compliance described above, the seismic and dynamic qualification of mechanical and electrical equipment was evaluated for St. Lucie 1 License Renewal to identify which components required an aging management review. NUREG-1779 contains the staff's SE related to the license renewal of St. Lucie 1 (Reference 12).

### Technical Evaluation

The staff has reviewed the licensee's evaluations for the seismic and dynamic evaluation of the mechanical and electrical equipment presented in LAR Attachment 5, Section 2.2.5. At EPU conditions, the seismic design inputs remain unchanged. Therefore, the staff concurs with the licensee that the proposed power uprate does not affect the seismic qualification of essential equipment. The current structural design basis of St. Lucie 1 implements the guidance of GDC 4 to include the application of LBB methodology to eliminate consideration of the dynamic effects resulting from pipe breaks in the RCS primary loop piping. The staff's review of LBB is documented in Section 2.1.6 of this SE. The staff's review of the St. Lucie pipe break evaluation for the proposed EPU is contained in Section 2.2.1 of this SE, where it is shown that pipe break evaluations at EPU conditions of applicable piping systems did not result in new or revised break/crack locations, and the existing design basis for pipe break, jet impingement and pipe whip remain valid for the proposed EPU. Therefore, the staff concurs with the licensee that the EPU will have no adverse impact on essential equipment as a result of pipe whip and jet impingement. In Section 2.2.2.1 of this SE, the staff's review shows that there is no adverse impact in the structural integrity of NSSS piping, components and supports due to the dynamic effects of the EPU. Also, the staff's review in Section 2.2.2.2 shows that there is no adverse impact in the structural integrity of balance of plant piping, components and supports due to the dynamic effects of the EPU.

Seismic and dynamic qualification of mechanical and electrical equipment is within the scope of License Renewal. The licensee's evaluation of the EPU effect on the seismic and dynamic qualification of mechanical and electrical equipment determined that no new aging effects requiring management are identified due to EPU and no changes are necessary to any existing aging management programs due to EPU. In addition, the licensee determined that the proposed EPU does not introduce any new system or component functions nor does it change the functions of existing components such that License Renewal system boundaries are affected. Furthermore, the licensee determined that the EPU has not resulted in any change to the plant FMP commitments to track, monitor and review the affect of fatigue upon impacted components. Therefore, the TLAA related to metal fatigue of ASME Section III, Class 1 components will continue to be valid following implementation of the EPU.

The licensee has also evaluated the plant changes proposed for the EPU and ensured that there are no additions to the scope of non-safety-related SSCs, whose failure could prevent the satisfactory accomplishment of a function required by 10 CFR 54.4(a)(1) and (a)(3).

### Conclusion

The NRC staff has reviewed the licensee's evaluations of the effects of the proposed EPU on the qualification of mechanical and electrical equipment and concludes that the licensee has (1) adequately addressed the effects of the proposed EPU on this equipment and (2) demonstrated that the equipment will continue to meet the requirements of GDC 1, 2, 4, 14, and 30; 10 CFR Part 100, Appendix A; and 10 CFR Part 50, Appendix B, following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the qualification of the mechanical and electrical equipment.

## 2.3 Electrical Engineering

### 2.3.1 Environmental Qualification of Electrical Equipment

#### Regulatory Evaluation

Environmental qualification (EQ) is required for certain electrical equipment to demonstrate that the equipment is capable of performing its safety function under significant environmental stresses during and following design basis events. Electrical equipment important to safety is described in 10 CFR 50.49(b), which includes: (1) safety-related electrical equipment, (2) nonsafety-related electrical equipment whose failure under postulated environmental conditions could prevent satisfactory accomplishment of safety functions, and (3) certain post-accident monitoring equipment. The NRC staff's review focused on the effects of the proposed EPU on the environmental conditions that the electrical equipment will be exposed to during normal operation, anticipated operational occurrences, DBAs. The NRC staff's review was conducted to ensure that the electrical equipment will continue to be capable of performing its safety functions following implementation of the proposed EPU. The NRC's acceptance criteria for EQ of electrical equipment are based on 10 CFR 50.49, which sets forth requirements for the qualification of electrical equipment important to safety that is located in a harsh environment. Specific review criteria are contained in SRP Section 3.11.

#### Technical Evaluation

##### Inside Reactor Containment Building (RCB) Environmental Parameters and Evaluation

EQ of electrical equipment located inside RCB is based on main steam line break (MSLB), LOCA and normal plant operation conditions and evaluation of resultant peak temperature, peak pressure, humidity, radiation, and submergence consequences. The peak temperature values for the DBAs bound the temperature transients of the anticipated operational occurrences. In the LAR, the licensee stated that St. Lucie 1 was originally required to meet the Institute of Electrical and Electronics Engineers (IEEE) Standard 323-1971 for the EQ of equipment. In February 1983, the requirements for the EQ of electrical equipment were codified in 10 CFR 50.49. This section required all holders of an operating license issued prior to February 22, 1983, to develop and complete a program for the qualification of equipment subject to 10 CFR 50.49 by the end of the second refueling outage after March 31, 1982, or by March 31, 1985, whichever came first. Pursuant to the requirements of 10 CFR 50.49, the licensee established a program for qualifying the electrical equipment defined in paragraph (b) of 50.49. Based on the information provided in the LAR, the staff verified that the normal operating conditions such as temperatures, pressure, humidity, and radiation will continue to be bounded by the pre-EPU parameters used in the licensee's EQ analyses. The accident temperature, pressure, submergence, and radiation are discussed as follows.

The staff noted that the containment LOCA and MSLB accident temperature and pressure profiles do not appear to have adequate EQ margins recommended by IEEE 323-1974. In response to the staff's RAI on required EQ margins per IEEE 323-1974, the licensee stated in letter dated June 16, 2011, that St. Lucie 1 licensing basis was originally required to meet IEEE 323-1971 for EQ of electrical equipment that does not require EQ margins. On this basis, the EQ margin recommendations of IEEE 323-1974 are not applicable to St. Lucie 1. However, the licensee confirmed in its response to the staff's RAI that each environmental parameter value with the potential of being impacted by EPU, specially, temperature, pressure, and radiation were evaluated to ensure the recommended requirements of IEEE 323-1974 have been met. Whenever, the margin recommendations were not met for the peak accident values under the initial EPU screen for a specific piece of equipment, that piece of equipment was considered an outlier. If the IEEE 323-1974 margin recommendations could not be met, then alternative solutions (e.g., operating time duration, relocation, replacement, or modification) were considered.

In response to the staff's RAI on the apparent lack of required EQ margin for the LOCA/MSLB peak accident temperatures shown in Figure 2.3.1-1 of Attachment 5 of LAR, the licensee stated in letter dated June 16, 2011, that the margin and qualification were accomplished by a thermal lag analysis that demonstrated (analytically) that the internal temperature of the equipment never exceeds the EQ temperature of record for the MSLB analysis. The licensee, furthermore, confirmed in its response that for EPU, the LOCA curves are bounded by the EQ profile and satisfies the current licensing basis. Since the original EQ program licensing basis for St. Lucie 1 is based on IEEE 323-1971, margin requirements of IEEE 323-1974 are not applicable. The staff verified that IEEE 323-1971 does not contain any specific margin requirements for temperature and pressure. Based on the above, the staff considers the available EQ margins acceptable for the equipment qualified in accordance with plant's current licensing basis IEEE 323-1971.

In its responses dated June 16 and September 8, 2011, to the staff's RAI on EQ submergence issue, the licensee stated that based on the review of component evaluation sheets for equipment inside containment below the current conservatively established 26-foot maximum flood elevation, no additional equipment was identified below the flood level as a result of

implementation of EPU. Based on the above clarification, the staff has no concerns regarding the submergence of EQ equipment under EPU conditions.

The staff reviewed the licensee's evaluation in the LAR and its supplemental response on EQ for safety-related electrical equipment inside RCB based on the radiation environment expected to exist during normal operations, post-LOCA conditions, and the resultant cumulative radiation doses. The licensee stated that the normal operation and accident radiation doses inside reactor containment building will increase due to the EPU. However, based on the results of radiation comparisons between EPU radiation values against the qualification values of record, all equipment in the EQ Program will continue to be qualified at the EPU conditions and, thus, continue to meet the current licensing basis with respect to the requirements of 10 CFR 50.49. Based on the above review, the staff finds that the total integrated radiation doses (normal plus accident) for EPU conditions would not adversely affect the qualification of equipment inside RCB.

The licensee provided a comparison of the current RCB EQ profiles with the EPU accident profiles for LOCA and MSLB peak temperature and pressure and the transient at 24 hours and subsequent temperature and pressure profiles leading to the long term Post-Accident Operability Time (PAOT) in Attachment 5 of LAR. Based on this comparison, the licensee determined that the EPU LOCA and MSLB remained bounded by the EQ envelope following the peak temperature and pressure plateaus during and following the onset of PAOT period. The EPU accident does not impact the required PAOT of 180 days. Based on the above, the staff finds that the PAOT of the EQ components remain valid for EPU conditions and therefore, acceptable.

Based on the review of the LAR and licensee's supplemental information, the staff finds that the EQ of electrical equipment will remain bounding under EPU conditions inside containment.

#### Outside Containment in Reactor Auxiliary Building (RAB) Environmental Parameters and Evaluation

EQ of electrical equipment located outside containment in RAB is based on design basis high-energy line break (HELB) and normal plant operation conditions and the resultant peak temperature, peak pressure, radiation, humidity, flooding, and pH consequences. The staff reviewed the licensee's evaluation of normal service conditions and verified that the normal operating temperatures pressure, humidity, and radiation will continue to be bounded by the pre-EPU parameters used in the licensee's EQ analyses. In Attachment 5, Section 2.3.1.2.2.3 of LAR, the licensee's evaluation determined that the HELB, which are the bases for EQ outside containment, do not change as a result of EPU operation and all equipment outside containment remain qualified for the appropriate EPU accident conditions. The staff finds that the post-accident peak temperature and pressure will continue to be bounded by the peak temperature and pressure conditions used in the licensee's EQ analyses.

In the LAR, the licensee noted that certain localized areas, previously designated as mild areas on the 43-foot elevation of the RAB in the vicinity of the shield building ventilation system, the high-efficiency particulate air (HEPA) and charcoal filters could receive a total integrated dose greater than permissive total integrated dose (TID) of  $1.0\text{E}+5$  Rads as a result of EPU. As a result, the licensee initially identified in the LAR four equipment that were credited for post-accident mitigation in the RAB HVAC area receiving TIDs greater than the harsh radiological environment threshold of  $1.0\text{E}+05$  Rads. In a response to the staff's RAI, the licensee stated in

letter dated September 8, 2011, that eight components required additional radiation evaluation. The licensee performed more refined radiation analyses subsequent to the submittal of the LAR for six of the eight affected equipment and concluded that EPU TID values were reduced below the EQ threshold dose of  $1.0\text{E}+5$  Rads. However, the TID values for the two remaining components (two damper motors (D-23 and D-24)) remained above  $1.0\text{E}+5$  Rads dose threshold. To resolve this issue, the licensee stated that they will install metal shielding for the two damper motors to reduce TIDs below  $1.0\text{E}+5$  Rads without affecting structural integrity, equipment operation and maintenance. The licensee included above modifications to install metal shielding as a Regulatory Commitment No. 3 in Attachment 7 Summary of Regulatory Commitments of the LAR.

Based on the above and review of the LAR and the supplemental responses, the staff finds that the licensee has adequately evaluated the effect of EPU on EQ of electrical equipment and that the EQ of electric equipment will remain bounding under EPU conditions outside containment in RAB.

#### Outside Containment Trestle Area Environmental Parameters and Evaluation

The staff reviewed the licensee's evaluation in the LAR that the steam trestle area is essentially an open structure and not an enclosed space, which reduces the challenges of temperature, pressure and radiation to equipment. At normal service conditions, the temperature, pressure, humidity, and radiation in this area do not change following implementation of the EPU. In response to the staff's RAI, the licensee stated in letter dated June 16, 2011, that the limiting main steam line break locations potentially affect two EQ components – valve MV-09-11 and push button station for valve MV-09-12 (B1507). The valve MV-09-11 is EQ qualified to inside containment criteria and the temperature profile conservatively bounds any postulated profile from outside containment steam line break. The push button station B1507 is not EQ qualified. However, it is unlikely to be adversely impacted by the postulated break due to the following conditions: (a) Distance from break approximately 21 feet, (b) Push button enclosure construction is an electrical box installed within a NEMA- 4 (weather-tight) box, (c) the line sight to break location is limited due to several obstructions, (d) Push button B1507 was evaluated to withstand exposure to 300 °F for one year as part of FPL's response to NRC IEB 79-01B, and (e) the distance to the critical component exceeds the area of influence.

In response dated September 8, 2011, to the staff's RAI to clarify "several obstructions" in the line of sight, the licensee stated that these obstructions are structural steel, deck plating, piping, valves and hand rails in the line of sight of B1507. Regarding staff's RAI on how the licensee concluded that the distance to the critical component exceeded the area of influence, the licensee clarified that it was based on a calculation which demonstrated that the component B1507 will be outside of the influence of the pipe break. Based on above, the staff finds the licensee response acceptable.

Based on the above review, the staff concluded that EPU will not adversely affect current EQ of the electrical equipment in this area.

#### Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The licensee evaluation of the operation of the electrical components under EPU conditions to determine if there are any new aging effects requiring aging management or if any existing aging management programs are affected, concluded that the EPU conditions do not result in

the addition of any new or previously unevaluated materials to the system nor does it result in exceeding any operating or environmental parameters previously evaluated for components included within the scope of License Renewal. Thus, no new aging effects requiring management are identified and no changes are necessary to any existing aging management programs.

### Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the EQ of electrical equipment and concludes that the licensee has adequately addressed the effects of the proposed EPU on the environmental conditions inside and outside containment and the qualification of electrical equipment. The licensee will install metal shielding by a plant modification to maintain radiological exposures below the threshold EQ radiation value of  $1.0E+5$  Rads on two affected damper motors D-23 and D-24 identified in Attachment 1 of letter dated September 8, 2011. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the EQ of electrical equipment and consistent with 10 CFR 50.49 requirements.

### 2.3.2 Offsite Power System

#### Regulatory Evaluation

The St. Lucie 1 offsite power system includes two or more physically independent circuits capable of operating independently of the onsite standby power sources. The NRC staff's review covered the descriptive information, analyses, and referenced documents for the offsite power system; and the stability studies for the electrical transmission grid. The NRC staff's review focused on whether the loss of the nuclear unit, the largest operating unit on the grid, or the most critical transmission line will result in the loss of offsite power (LOOP) to the plant following implementation of the proposed EPU. The NRC's acceptance criteria for offsite power systems are based on GDC 17. Specific review criteria are contained in SRP Sections 8.1 and 8.2, Appendix A to SRP Section 8.2, and Branch Technical Positions (BTPs) PSB-1 and ICSB-11. St. Lucie 1 was designed and constructed based on the 1967 draft AEC GDC. As noted in FSAR Section 3.1, the design bases of St. Lucie 1 are compared against GDC in 10 CFR Part 50, Appendix A, as amended through February 20, 1971. For the Offsite Power System, Criterion 17 – Electrical Power Systems, discussed in FSAR Section 3.1.17 is applicable.

Offsite power is transmitted to the plant Switchyard by three physically independent 230 kilo-Volt (kV) transmission lines. During normal plant operation, the station auxiliary power is normally supplied from the main generator through the plant auxiliary transformers. Upon loss of power from the auxiliary transformers, there will be a "fast dead bus" automatic transfer to the startup transformers thus providing continuity of power. Section 8.2.2.2 of the FSAR identifies reliability considerations that satisfy the requirements of AEC GDC 17 and Safety Guide 32 for offsite power systems and minimize the probability of power failure due to faults in the network interconnections and associated switching.

#### Technical Evaluation

The St. Lucie 1 offsite transmission system is designed to provide reliable facilities to:  
(1) Accept the electrical output of the plant, and (2) Supply the plant auxiliary power system for

station startup, shutdown, or at any time that auxiliary power is unavailable from the unit auxiliary transformers.

The transmission system design consists of three separate circuits connected to the plant Switchyard. One of the three 230 kV transmission lines can supply all of the plant auxiliary power. The five bay 230 kV (nominal) Switchyard that is arranged in a breaker-and-a-half configuration provides switching capability for two main generator outputs, four startup transformers (SUTs), three outgoing transmission lines, and the Hutchinson Island distribution substation.

The main generator is directly connected through a 22 kV, isolated phase bus to the main transformers (MTs) 1A and 1B, where it is stepped up to 230 kV nominal and enters the 230 kV Switchyard through the overhead tie-lines. SUTs, 1A and 2A or 1B and 2B, can be fed from any one of the incoming transmission lines that serve as both incoming and outgoing lines depending on plant status. The SUTs are sized to accommodate the auxiliary loads of the unit under operating or accident conditions and power to step down the offsite voltage from 230 kV to 6.9 kV and 4.16 kV.

#### Grid Stability Study

The System Impact Study evaluated the impact on the FPL Transmission System due to an increase in existing capacity of the St. Lucie 1 from 905 megawatt-electric (MWe) to the maximum potential cold winter output of 1052 MWe, and St. Lucie 2 from 905 MWe to the maximum potential cold winter output of 1072 MWe. The System Impact Study included reactive power capability analyses, short circuit analyses, and dynamic stability analyses. The results of the System Impact Study are as follows.

- The fault levels at the Switchyard 230 kV did not exceed the ratings of any of the Switchyard breakers as a result of EPU.
- As result of both St. Lucie 1 and 2 planned uprates, the integration of the EPU as an FPL transmission network resource will require an increase in the thermal rating of the existing three St. Lucie-Midway 230 kV lines from 2380 A to 2790 A. However, if only St. Lucie 1 is to be uprated, then upgrading of the existing facility is not required.
- Results of the dynamic simulations indicate acceptable performance for the most extreme North America Electric Reliability Corporation category D fault at Midway substation; the transmission system remained stable.
- The EPU meets the reactive capability requirements of FPL system.

#### Offsite Power System Components

Transmission Lines – The licensee's evaluation determined that the 230 kV transmission lines connected to the St. Lucie Switchyard require to be upgraded due to EPU by installing spacers between the existing bundled phase conductors, fiber optic overhead ground wire on all three lines, and replacement of associated disconnect switches. The proposed modifications will insure that the transmission lines' design functions will be maintained following implementation of the EPU.

Switchyard Connections – The licensee’s evaluation of the Switchyard equipment determined replacement of wavetraps with overhead fiber optic protection schemes, replacement of 230 kV Switchyard disconnect switches and upgrading or replacement of associated jumpers, busses and equipment connections. The proposed modifications will insure that the design functions of the Switchyard equipment will be maintained following implementation of the EPU.

Main Transformers Tie-Line – The licensee’s evaluation determined that the existing tie lines between the 230 kV Switchyard and the main transformers and the associated differential protection scheme are adequate and acceptable for use under EPU conditions.

Startup Transformers Tie-Lines - The licensee’s evaluation determined that the existing tie lines between 230 kV Switchyard and startup transformers high voltage side and the associated differential protection scheme are adequate and acceptable for use under EPU conditions.

Based on the review of the System Impact study and Grid stability study the staff finds that with a combination of system upgrades and proposed modifications, offsite power system will not be degraded by implementation of the EPU. The staff finds that the studies bound the proposed St. Lucie power uprate.

#### Impact on Renewed Plant Operating License Evaluations and License Renewal Program

The licensee evaluated the St. Lucie 1 offsite power systems that are within the scope of license renewal. The licensee’s evaluation determined that the changes associated with operating the offsite system at EPU conditions do not add any new or previously unevaluated materials to the system, nor require any changes to the Aging Management Program. No new aging effects requiring management are identified. Based on the review of the licensee’s evaluation, the staff finds that there is no impact on renewed plant operating license due to EPU for the offsite power system.

#### Conclusion

The NRC staff reviewed the licensee’s assessment of the effects of the proposed EPU on the offsite power system and concludes that offsite power system will continue to meet its current licensing basis with respect to the requirements of GDC 17 as described in St. Lucie FSAR Section 3.1.17, following implementation of the modifications required to support EPU. Adequate physical and electrical separation exists and the offsite power system has the capacity and capability to supply power to all safety loads and other required equipment. The licensee has committed to implement all modifications described in Section 2.3.2 (AC Offsite Power System) in its letter dated October 20, 2011. The staff further concludes that the proposed EPU does not degrade the grid stability. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the offsite power system.

#### 2.3.3 AC Onsite Power System

##### Regulatory Evaluation

The AC onsite power system includes those standby power sources, distribution systems, and auxiliary supporting systems provided to supply power to safety-related equipment. The NRC staff’s review covered the descriptive information, analyses, and referenced documents for the



AC onsite power system. The NRC's acceptance criteria for the AC onsite power system are based on GDC 17, insofar as it requires the system to have the capacity and capability to perform its intended functions during anticipated operational occurrences and accident conditions. The specific review criteria are contained in SRP Sections 8.1 and 8.3.1. St. Lucie 1 was designed and constructed based on the 1967 draft AEC GDC. As noted in FSAR Section 3.1, the design bases of St. Lucie 1 are compared against GDC in 10 CFR Part 50, Appendix A, as amended through February 20, 1971. For the Onsite Power System, Criterion 17 – Electrical Power Systems, discussed in FSAR Section 3.1.17 is applicable.

### Technical Evaluation

St. Lucie 1 AC onsite power system consists of station service transformers (SST), 6900 Volt (V), 4160 V, 480 V, 120 V systems, EDGs, associated busses, non-segregated phase bus ducts, cables, electrical penetrations (where applicable), circuit breakers and protective relays. In addition, the main generator, isolated phase bus (IPB) ducts, MTs, unit auxiliary transformers (UATs) and SUTs are also part of AC onsite power system.

Main Generator –The licensee's evaluation of the main generator rating for the St. Lucie 1 EPU condition indicated that the existing main generator must be modified to increase its rating to support EPU conditions. The revised generator nameplate rating will be 1200 megavolt amperes (MVA), 22 kV, 1080 megawatts (MW), 0.90 power factor (pf), 60 Hz, 1800 rotation per minute at 75 psig hydrogen pressure. The maximum generator output at EPU conditions is 1052.1 MW at 0.89 pf lagging. The required generator changes include rewinding of the rotor and stator and modifying the associated hydrogen cooling system. The generator capability curves show that the modified main generator will be capable of continuous operation at this level and adequate to support unit operation at EPU conditions including machine leading and lagging reactive power requirements. The licensee's evaluation of the main generator protection for operation at EPU conditions reveals that the existing generator protection current transformers (35,000:5 A rating) require replacement with new current transformers (40,000:5 A rating) to interface with the existing electrical protection system, and the existing main generator protection relays require revised setpoints to support operation at EPU conditions. Improved generator cooling is required and will be accomplished with the hydrogen cooler modifications.

The staff finds that the increased rating of the main generator will be adequate corresponding to EPU conditions.

IPB Duct – In the LAR, the licensee stated that the existing IPB duct main bus and main transformer tap bus will be upgraded to 33.2 kiloamperes (kA) and 16.6 kA (by upgrading the existing isolated phase coolers), respectively, which bounds unit operations at EPU loading conditions and based on the upgraded MW rating of the main generator. The existing IPB duct tap busses to UAT and potential transformer (PT) are rated 2.5 kA self-cooled, which bound the loading at EPU conditions. The licensee's evaluation demonstrated that IPB Main Transformers (MT), Unit Auxiliary Transformer (UAT) and PT tap busses short circuit design ratings are less than the anticipated worst-case fault current levels (i.e., over-duty condition) for both pre-EPU and EPU conditions. The licensee stated in the LAR that the over-duty condition on IPB tap busses will be further analyzed, modifications and corrective action, as appropriate, will be completed prior to EPU. In response dated June 16, 2011, to the NRC staff RAI

regarding the proposed modifications, the licensee provided the result of further evaluations of IPB taps as follows.

**Main IPB and MT Taps:**

The main bus and MT bus taps are adequate to operate during and after the short circuit fault. The short circuit forces on the conductor and the insulators are below the design limits. The temperature rise during the short circuit fault is small and is within the limits.

**PT Taps:**

The PTs are located in individual compartments and are isolated from each other. It is unlikely to have a phase to phase fault in the PT cubicle or in the PT bus. The PTs have fuses in their primary windings (IPB side). The net length of the conductor is only 32 inches. This will limit amount of force to which the insulator will be subjected. The insulator has adequate cantilever strength to withstand DC, 60 Hz, and 120 Hz forces produced on the conductor. The temperature rise during short circuit condition is within the limits.

**UAT Taps:**

Three phase windings in the MT and UAT could cause phase to phase or three phase fault currents in the UAT tap. The conductor in each phase is 50 inches long and has one insulator support. Under short circuit conditions, this conductor will be subjected to high DC and 60 Hz forces. Both forces will cause movement in the conductor. The resulting cantilever force will be higher than cantilever strength of the insulator. Conductor cross section area is 2.9 square inches. The small cross section or mass will cause temperature to reach 247 °C [Celsius]. This is close to, but less than the acceptable limit.

To address concerns in the UAT taps, the licensee proposed to weld a stiffener plate to the existing U-shaped conductor channel. This will add an additional conductor area of 2.3 square inches. Additionally, a second insulator will be added to increase the resistance to the cantilever forces.

Based on the above modifications to the IPB, the staff finds that the modified IPB will be adequate corresponding to EPU conditions.

Main Transformers (MTs) 1A and 1B – The licensee's EPU evaluation determined that the existing generator step up transformer design rating at 65 °C is inadequate to support unit operation at EPU conditions. As a result, the licensee determined to upgrade the MT rating from 475 MVA to 635 MVA at 65 °C, with additional coolers to support generator output at EPU conditions. The existing MT 1A will have its cooling unit upgraded. The existing MT 1B is to be swapped with existing spare transformer. The existing spare transformer is to be relocated as new MT 1B and have its associated coolers upgraded. The existing MT protection requires revised relay setpoints to support operation at EPU conditions.

The staff finds that with the above upgrading of the main transformer cooling systems, the main transformer rating will be adequate to support safe operation of the plant under EPU conditions.

Unit Auxiliary Transformers (UATs) 1A and 1B – The licensee's evaluation determined that the existing UAT 65 °C design ratings for the high voltage and both low voltage windings envelope

the anticipated worst-case loading on the UATs at EPU conditions. The existing UAT protection relay setpoints are not affected and are adequate at EPU conditions.

The staff finds that UAT ratings are adequate corresponding to EPU conditions.

Startup Transformers (SUTs) 1A and 1B - The licensee's evaluation determined that the existing SUT 65 °C design ratings for the high voltage and both low voltage windings envelope the anticipated worst-case loading on the SUTs at EPU conditions. The existing SUT protection relay setpoints are not affected and are adequate at EPU conditions.

The staff finds that SUT ratings are adequate corresponding to EPU conditions.

6.9 kV AC System – The staff reviewed the licensee's evaluation of the 6.9 kV system, switchgear busses, circuit breakers, non-segregated phase bus ducts and affected motors at EPU conditions. The licensee's evaluation determined the following:

- The calculated worst-case continuous current for each affected 6.9 kV switchgear bus and circuit breaker during maximum full load at EPU conditions, is less than the equipment design ratings. The evaluation of the non-segregated phase bus duct indicates that the maximum full load at EPU conditions is less than the equipment design ratings. Therefore, the EPU loading requirements of switchgear busses, circuit breakers and non-segregated phase bus ducts are within the equipment design ratings based on the LAR Tables 2.3.3-2 and 2.3.3-3.
- The 6.9 kV FW pump motors are affected by operation at EPU conditions. However, the calculated worst-case full load current for the FW pump motors during operation at EPU conditions are less than the motor rated maximum full load current and 6.9 kV switchgear feeder circuit breaker rating. Therefore, the motor loading, motor feeder breakers are bounded by equipment design ratings.
- The short circuit ratings of 6.9 kV system switchgear busses, circuit breakers, and non-segregated phase bus ducts remain adequate to support operation at EPU conditions based on the LAR Tables 2.3.3-4 and 2.3.3-5.

The staff finds that 6.9 kV AC system is adequately sized corresponding to EPU conditions.

4.16 kV AC System – The staff reviewed the licensee's evaluation of the 4.16 kV system, switchgear busses, circuit breakers, non-segregated phase bus ducts and affected motors at EPU conditions. The licensee's evaluation determined the following:

- Calculated worst case continuous current for each affected 4.16 kV switchgear bus and circuit breaker during maximum full load at EPU conditions, is less than the equipment design ratings. The evaluation of the non-segregated phase bus duct indicates that the maximum full load at EPU conditions is less than the equipment design ratings. Therefore, the EPU loading requirements of switchgear busses, circuit breakers and non-segregated phase bus ducts are within the equipment design ratings.

- The short circuit ratings of 4.16 kV system switchgear busses, circuit breakers, and non-segregated phase bus ducts remain adequately sized to support operation at EPU conditions based on LAR Tables 2.3.3-6 and 2.3.3-8.

The staff finds that 4.16 kV AC system is adequately sized corresponding to EPU conditions.

480 V AC System – The 480 V AC System is comprised of seven 480 V load center busses 1A1, 1B1, 1A2, 1B2, and 1AB supplied from the 4.16 kV system through 4160 V/480 V station service transformers (SSTs) which are normally powered from the UATs or SUTs. The licensee's evaluation determined the following changes under EPU conditions:

- The 60 horse power (hp) supply fan motors 4A and 4B will be removed from MCCs [motor control centers] 1A5(SA), 1B5(SB), and repowered from 480 V load centers 1A2 and 1B2 which are safety related. However there is no load increase in load center bus load because associated MCCs are in the same load group.
- The 25 hp IPB duct cooler fan motors will be replaced by 100 hp fan motors and will be removed from MCCs 1A1 and 1B1 and re-powered from 480 V load centers busses 1A1 and 1B1.
- The existing current limiting reactors (CLRs) in 480 V load centers (1A2 and 1B2) will be replaced with new CLRs having lower impedances. In a response dated June 16, 2011, to the staff RAI regarding changes in fault current due to the replacement of CLRs, the licensee provided a table showing calculated fault current under EPU conditions is bounded by the existing breaker ratings.
- The horsepower of the high pressure oil seal backup pump motor on non-safety-related MCC 1A1, powered from load center 1A1, will increase from 20 hp to 40 hp.

The licensee's evaluation also included the following 480 V system:

4160-480 V AC SSTs – There is no increase in load on the safety-related 480 V systems under EPU conditions. The load changes related to operation under EPU conditions downstream of the SSTs are limited to the IPB duct cooler fan motor and high pressure oil seal back-up pump motor modifications. The affected SST design ratings envelope the load requirements under EPU conditions.

480 V AC Load Center Busses and Breakers - The calculated worst-case steady-state continuous current and short circuit momentary and interrupting duties at the 480 V load center busses are enveloped by the equipment design ratings under existing and EPU conditions.

480 V AC Motor Control Centers - Licensee's load flow calculations determined that the load current requirements are enveloped by the MCC bus design rating. However, the 480 V MCC circuit breakers rated 14 kilo Ampere (kA) on the busses 1A5, 1A6, 1B5 and 1B6 are over-duty and are scheduled for replacement with a 25 kA rated circuit breakers prior to EPU by the MCC bus design ratings. Based on the short circuit calculations, the remaining 480 V MCC circuit breakers have adequate interrupting current ratings.

480 V AC System Voltage Level - There are no adverse voltage effects on the safety-related 480 V load center busses protected by degraded voltage relays. Therefore the degraded

voltage relay settings are not affected by operation at EPU conditions. The load flow calculations determined that the minimum steady-state voltages on the safety-related 480 V load centers and MCCs are above the allowable minimum design values. The maximum steady-state voltage on 480 V load centers and MCCs also do not exceed the maximum allowable design values.

480 V AC Motor Load Changes - The new IPB duct cooler fan motors rated 100 hp will be powered from the 480 V load centers 1A1 and 1B1. The supply fan motors 4A and 4B will be powered from 480 V load centers 1A2 and 1B2. The high pressure AC seal oil backup pump motors rated 20 hp will be replaced by new 40 hp motors on MCC 1A1. The licensee included this modification in Regulatory Commitment No. 7 in Attachment 7 Summary of Regulatory Commitments of the LAR.

The staff finds that the licensee has adequately evaluated the impact of EPU conditions on the 480 V system.

#### Emergency Diesel Generators (EDGs)

The staff reviewed the St. Lucie 1 FSAR Section 8.3.1.1.7 and licensee's evaluation in the LAR for the St. Lucie 1 EDG design, ratings, worst-case loading, related TS Surveillance Requirements (SR) 4.8.1.1.2.e voltage and frequency limits. In the LAR, the licensee stated that the continuous rating of the EDGs is 3500 kilo Watts (kW) with additional short term ratings of 3730 kW (2000 hour) and 3960 kW (30 minutes). Licensee's calculations and evaluation to assess the impact of the EPU loads on the EDGs indicated that EDG ratings are not exceeded by the cumulative loads applied, either as part of the load blocks or individually. No modification of the EDGs is required to accommodate the increased loads. Since the EDG loading is bounded by the EDG rating, the existing protective relay settings are not impacted by EPU.

In its response dated September 8, 2011, to the staff's RAI regarding transient capability of the diesel generator engine and generator verses maximum starting (transient) loads on the EDGs, the licensee stated that the starting (transient) loads remain within the vendor's transient capability of the engine/generator set, and therefore, the EDG frequency (engine speed) remains within the specified limit. Similarly, starting loads remain within the transient capability of the generator, and therefore, the EDG voltage remains within the specified limit.

Based on the above, the staff finds that EDG will continue to have the capability and capacity to operate under EPU conditions.

#### EDG Technical Specifications (TS), Surveillance Requirements (SR) Changes Relating to Steady State Voltage and Frequency Limits

In the LAR, Attachment 1, the licensee proposed to revise TS, SR 4.8.1.1.2.e.3.b, SR 4.8.1.1.2.e.4, and SR 4.8.1.1.2.e.5.b.

Currently, according to the above SRs, when started from standby conditions, each EDG is required to have steady state voltage  $4160 \pm 420$  V ( $\pm 10$  percent) and frequency  $60 \pm 1.2$  Hz ( $\pm 2$  percent) during this test. The licensee has proposed to revise TS SR 4.8.1.1.2.e.3.b, SR 4.8.1.1.2.e.4, and SR 4.8.1.1.2.e.5.b to require each EDG to achieve a steady state voltage  $4160 \pm 210$  V ( $\pm 5$  percent), and frequency  $60 \pm 0.6$  Hz ( $\pm 1$  percent).

The proposed changes to steady state frequency and steady state voltage limits are conservative. In the LAR Attachment 1, the licensee stated that the revised steady state frequency,  $60 \pm 0.6\text{Hz}$  ( $\pm 1$  percent), and revised steady state voltage,  $4160 \pm 210\text{V}$  ( $\pm 5$  percent), reflect worst case values used in determining MOV and pump loads connected to an EDG. The accident analyses considered the over and under frequency and voltage uncertainty tolerance of the EDGs. The change in frequency tolerance has been evaluated for changes in MOV stroke times and pump flow rates. The IST program acceptance criteria will be verified for MOVs and pump flows during the EPU Implementation Phase. For MOVs with AC motors powered from the EDGs, the voltage tolerance of  $\pm 5$  percent will not affect the motor speed, and therefore the stroke time of these MOVs will not be affected. Evaluation shows that the voltage tolerance of  $\pm 5$  percent will not affect the minimum motor terminal voltage values used in determining MOV motor torque values under degraded voltage conditions.

In response to the staff's RAI, to confirm that all safety-related loads powered by the EDGs with the proposed voltage and frequency limits would start and run without any damage, the licensee stated in response letter dated September 8, 2011, that there are EDG frequency and voltage sensing relays that have their contacts wired in series that serve as permissives to the EDG output breaker automatic close circuit. These permissives operate in conjunction with engineered safety features (ESFs) bus voltage relaying permissives. Once these permissive relays are actuated, the EDG output breaker is automatically closed. The TS allowable time duration from the initiation of the EDG start sequence to the EDG output breaker closure cannot exceed 10 seconds. The EDG voltage and frequency must be in an acceptable range within 10 seconds for its associated output breaker to close in order to satisfy TS requirements. Therefore, for the event described, the EDG would be expected to achieve acceptable voltage and frequency values within 10 seconds, but the output breaker would not automatically close. The EDG supplied motor loads are not subjected to EDG induced voltage and frequency deviations that would inhibit their ability to perform their designed safety function for this event. The proposed change tightens the steady state frequency and voltage tolerances, and is conservative.

Based on the above explanation by the licensee, the staff finds the EDG TS changes are conservative and acceptable.

120 V AC Instrument Power and 120/208 V AC Power Systems – The 120 V AC instrument power system and 120V/208V AC Power System are described in FSAR Sections 8.3.1.1.6 and 8.3.1.1.5. In the LAR, the licensee stated that anticipated modifications as required due to EPU conditions that may affect the 120 V AC non-Class 1E and 120 V/208 V AC non-Class 1E Power Systems will be implemented as part of the plant modification process. The new load additions from these modifications are expected to be minor, and the effect on the 120 V AC non-Class 1E and 120 V/208 V non-Class 1E power systems is expected to be small.

The staff finds the licensee's assessment acceptable that the minor load additions will have minimal impact on the 120 V AC power systems.

### Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the AC onsite power system and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the AC Onsite Power System design. The licensee has committed to implement all modifications described in Section 2.3.3 (AC Onsite Power System)

as Regulatory Commitment No. 7 in Attachment 7 of the LAR. The NRC staff concludes that the AC onsite power system will continue to meet the GDC 17 requirements as described in FSAR Section 3.1.17 Criterion-17 – Electrical Power Systems following implementation of the proposed modifications required to support the EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the AC onsite power system.

#### 2.3.4 DC Onsite Power System

##### Regulatory Evaluation

The St. Lucie 1 safety-related DC onsite power system includes the DC power sources and their distribution and auxiliary supporting systems that are provided to supply motive or control power to safety-related equipment. The NRC staff's review covered the information, analyses, and referenced documents for the DC onsite power system. The NRC's acceptance criterion for this review is based on 10 CFR 50 Appendix A, GDC 17, insofar as it requires the system to have the capacity and capability to perform its intended functions during anticipated operational occurrences and accident conditions. Specific review criteria are contained in NRC SRP Sections 8.1 and 8.3.2.

St. Lucie 1 was designed and constructed based on the 1967 draft AEC GDC. In preparation for issuance of the St. Lucie 1 FSAR, an effort was made to comply with the newer (1971) final GDC. FSAR Section 3.1 states that the design bases of St. Lucie 1 are compared against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR Part 50, Appendix A, as amended through February 20, 1971. Specifically, the adequacy of the onsite DC power system design relative to GDC 17, Electrical Power Systems, is described in FSAR Section 3.1.17 Criterion 17 - Electrical Power Systems.

With respect to electrical separation relative to the DC onsite power system, as stated in part in FSAR Section 8.3.2.2.2, the licensee stated in the LAR that there are no direct connections between parts of the system which serve load group A and those parts which serve load group B. There are no automatic transfers of loads between load groups A and B. Busses serving load group AB can be manually connected with either of the busses serving load groups A or B. Ties from the AB busses to the A or B busses have a breaker at each end of the tie. Interlock is provided to prevent closing both ties at the same time. Physical separation as a protection against common failure of DC power to both redundant DC load groups has been achieved by spatial separation and/or erection of physical barriers between redundant portions of the DC system.

##### Technical Evaluation

The DC power system is discussed in FSAR Section 8.3.2. The staff reviewed the licensee's evaluation of the safety-related portions of the 125 V DC Systems to determine whether the DC system and its components would remain capable of performing their intended design functions at EPU conditions. The evaluation is based on the system's required design functions and upon a comparison between existing and the anticipated operating requirements at EPU conditions. The licensee stated in the LAR that there are two plant modifications that are planned to be implemented for St. Lucie 1 that will affect the safety-related portions of the 125 V DC System as follows:

1. The first modification changes the power sources for isolated phase bus duct cooling fans from 480 V AC MCCs to 480 V AC load centers. The circuit breakers for the 480 V AC load centers utilize dc control power, which will increase the loading of the 1A and 1B Batteries.
2. The second modification changes the power sources of vent fans 1HVS-4A and 1HVS-4B from 480 V AC MCCs to 480 V AC load centers. The circuit breakers for the 480 V AC load centers utilize DC control power, which will increase the loading of the 1A and 1B Batteries.

In the LAR, the licensee stated that EPU load increases on the safety-related batteries 1A and 1B were compared with the first minute's loading (most conservative approach) under the station blackout (SBO) coping and SIAS scenarios and a percent increase was calculated. The most limiting case (i.e., the case with least amount of available margin) was the SBO coping case. For Battery 1A, the additional first minute loading associated with EPU (20A) represents an 8.0 percent load increase, with a pre-EPU margin of 44.1 percent. For Battery 1B, the additional first minute loading associated with EPU (20A) represents a 4.6 percent load increase, with a pre-EPU margin of 34.5 percent. In addition, the licensee stated that SBO and 10 CFR Part 50, Appendix R program evaluations did not result in any 125 V DC System load changes due to EPU conditions.

In response dated September 8, 2011, to the staff's RAI, the licensee confirmed that the worst case battery loading is on battery 1B for the SBO event. The service test profile envelopes the increase in safety-related dc loads due to EPU conditions and a 1-hour SBO DC loading.

Based on the battery load review, the staff finds that the 125 V DC System continues to have the capacity and capability to perform its function and remains within equipment ratings while maintaining adequate margin for battery capacity. Separate and independent station battery systems are maintained to supply power to all safety loads in accordance with the current licensing basis with respect to GDC 17.

#### Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

The staff reviewed the licensee's evaluation of impact on renewed plant operating license and license renewal programs. In the LAR, the licensee stated that DC onsite power system is within the scope of License Renewal programs. The licensee evaluated DC onsite power system under EPU conditions to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. The licensee's evaluation determined that the EPU does not result in the addition of any new or previously unevaluated materials to the system nor does it result in exceeding any operating or environmental parameters previously evaluated for components included within the scope of License Renewal. Thus, no new aging effects requiring management are identified and no changes are necessary to any existing aging management programs.

#### Conclusion

The Staff has reviewed the licensee's assessment of the effects of the proposed EPU on DC onsite power system and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system's functional design. The NRC staff further concludes that the DC onsite power system will continue to meet its current licensing basis with respect to



GDC 17 as described in St. Lucie 1 FSAR Section 3.1.17 Criterion 17 - Electrical Power Systems, following implementation of the proposed EPU. Adequate physical and electrical separation exists and the system has the capacity and capability to supply power to all safety loads and other required equipment. Therefore, the staff finds the proposed EPU acceptable with respect to the DC onsite power system.

### 2.3.5 Station Blackout

#### Regulatory Evaluation

SBO refers to a complete loss of AC electric power to the essential and nonessential switchgear busses in a nuclear power plant. SBO involves the LOOP concurrent with a turbine trip and failure of the onsite emergency AC power system. SBO does not include the loss of available AC power to busses fed by station batteries through inverters or the loss of power from "Alternate AC sources" (AACs). The NRC staff's review focused on the impact of the proposed EPU on the plant's ability to cope with and recover from an SBO event for the period of time established in the plant's licensing basis. The NRC's acceptance criteria for SBO are based on 10 CFR 50.63, guidance provided in RG 1.155 Station Blackout, and NUMARC 8700, Revision 0. Specific review criteria are contained in SRP Sections 8.1 and Appendix B to SRP Section 8.2, and other guidance provided in Matrix 3 of RS-001.

#### Technical Evaluation

The licensee evaluated the impact of the proposed EPU on the plant's ability to cope with and recover from 4-hour SBO duration established in the plant's licensing basis. The 4-hour coping time consisted of the proposed 1 hour DC coping time (revision from the 25 minutes in the current licensing basis) and subsequent three hours by a St. Lucie 2 EDG as an AAC source, as discussed in Attachment 8 of the LAR.

The staff reviewed the licensee's evaluation of the impacts of the proposed EPU on the following SBO-related plant functions and programs:

SBO Coping Duration – In the LAR, the licensee stated that St. Lucie 1 SBO duration is 4-hours based on guidance of RG 1.155 and the methodology of NUMARC 8700, Rev. 0, Guidelines. No AC power is assumed available for the first hour of the SBO event; the AAC source is assumed to be available for the subsequent 3 hours of the event. In Attachment 5, Section 2.3.2 of the LAR, the licensee evaluated EPU grid stability studies and planned modifications to maintain necessary transmission lines stability. The licensee's evaluation indicated that the proposed modifications of the transmission system will successfully maintain required grid stability and not increase the likelihood of an SBO event. Therefore, the licensee's evaluation concluded that the EPU does not affect the current 4-hour SBO duration.

Condensate Inventory for Decay Heat Removal and Plant Cooldown – The condensate inventory required for decay heat removal for the four hour SBO duration at EPU conditions to be bounded by 130,500 gallons, the volume required for plant cool down at a rate of 75 °F/hr. The current TS Section 3.7.1.3 states that condensate storage tank (CST) shall be operable with a minimum usable volume of 116,000 gallons. In the LAR, Attachment 5, Section 2.5.4.5, the licensee proposed a revision to TS 3.7.1.3 to increase the minimum total contained volume to 153,400 gallons to provide sufficient cooling water for the EPU

operating condition. According to Table 2.5.4.5-1 in Attachment 5 of the LAR, CST has low level alarm volume of 185,000 gallons. Since the CST will have sufficient capacity to provide 130,500 gallons, the EPU will not impact the ability to cope with the SBO event.

Class 1E Battery Capacity – In the LAR, the licensee stated that its evaluation of the 125 V DC system concluded that EPU conditions do not increase loads on the station batteries during SBO event, thus the ability of the DC system to perform its design function while maintaining adequate margin will be maintained for EPU conditions.

In Attachment 8 of the LAR, the licensee provided analytical evaluation to demonstrate that the existing safety-related batteries are capable of providing sufficient power to the SBO DC loads for the first one hour from the onset of SBO. The licensee concluded that changing coping duration from 25 minutes to 1-hour does not adversely impact voltage and capacity of batteries since the batteries were originally sized for a 4-hour SBO. After 1-hour DC coping duration, power is restored to the battery chargers via the AAC cross-tie from St. Lucie 2 EDG. Other SBO topics such as total SBO event duration, EDG reliability, AAC source criteria, procedures, and training are not adversely affected by the proposed change in DC coping duration from 25 minutes to 1-hour. The staff finds that the safety-related battery capacity and capability are adequate to power the necessary loads for the proposed 1-hour DC coping period of SBO.

Compressed Air - In the LAR, the licensee stated that the compressed air system is unchanged due to EPU conditions during the SBO event.

Effects of Loss of Ventilation - During the SBO event, ventilation systems inside and outside of the reactor containment building are assumed not to function during the 1-hour DC coping period. Upon restoration of the AAC power source, ventilation systems will be available. The impact of SBO event on EPU conditions is described in the following paragraphs.

Reactor Containment Building - Inside containment, the primary impacts of loss of ventilation during the SBO event are the increases in pressure and temperature caused by assumed RCS leakage and an increase in EPU decay heat. Since safe shutdown equipment is qualified for the accident environments under the plant's electrical equipment qualification (EEQ) program, operation during the less severe EPU SBO event is assured. Therefore, the operability of equipment needed for safe shutdown inside containment is acceptable for the SBO event under EPU conditions.

Areas outside Containment Containing SBO Equipment - The control room, the electrical equipment areas (switchgear, static inverter, and battery rooms), the charging pump cubicle, and the AFW pump area were determined to contain equipment needed to achieve safe shutdown during the SBO event. The licensee's evaluations in Attachment 8 of the LAR determined calculated temperatures to be acceptable. The EPU does not impact the consequences of loss of ventilation in areas housing equipment required to achieve hot shutdown conditions during the SBO event.

Containment Isolation - During a SBO event, it is important to maintain appropriate containment integrity, which includes the capability for valve position indications and closure of certain containment isolation valves independent of Class 1E power supplies. In Attachment 8 of LAR, the licensee discussed the containment isolation valves reviews and justification for their exclusion from consideration based on NUMARC 8700 criteria. The

conclusions reached in Attachment 8 of the LAR do not change as a result of EPU conditions. Therefore, containment integrity remains unchanged during the SBO event under EPU conditions.

Reactor Coolant Inventory –In the LAR, the licensee stated that the results of their analysis as described in the FSAR Section 15.2.13 demonstrated that St. Lucie 1 can successfully withstand the SBO event for at least 4 hours assuming a total leakage of 120 gpm at EPU conditions. The licensee's evaluation indicates that, at the end of a 4-hour SBO event, core cooling is maintained, sufficient liquid inventory remains in the vessel to ensure that the core does not uncover, and no fuel failure is imminent.

AFW Flow – During the SBO event, it is essential to maintain SG FW inventory to remove sensible and decay heat from the reactor core. The Turbine Driven AFW (TDAFW) pump is credited with supporting the decay and sensible heat removal from the core during the SBO event. At inception of the SBO event, the TDAFW pump receives an actuation signal on low level and is credited with delivering 600 gpm to two SGs within 330 seconds and FW continues throughout the coping period of four hours. With respect to maintaining SG inventory, an operator action has been credited for the SBO event as a result of the EPU. Operator action is credited with ensuring that SG blowdown is isolated on loss of instrument air pressure. Steam turbine controls will remain unchanged due to EPU conditions. Therefore, the TDAFW pump will deliver adequate AFW and will remain successfully controlled throughout the four-hour coping period for SBO during EPU conditions.

Plant Procedures and Training - There are no changes to procedures or training as a result of the EPU.

Modifications Required to Cope with SBO - No modifications are necessary for St. Lucie 1 to cope with the SBO event under EPU conditions.

EDG Reliability Program - The licensee stated in the LAR that this program is unaffected by the EPU. The EDGs are not included among planned EPU modifications; therefore, the EDG Reliability Program remains unchanged by the EPU.

Impact on License Renewal Program –The systems required to mitigate the SBO event are within the scope of license renewal. The EPU does not result in the addition of any new or previously unevaluated materials to the system nor does it result in exceeding any operating or environmental parameters previously evaluated for components included within the scope of license renewal. Thus, no new aging effects requiring management are identified and no changes are necessary to any existing aging management programs.

## Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the plant's ability to cope with and recover from an SBO event for the period of 4 hour established in the plant's licensing basis. The NRC staff concludes that the licensee has adequately evaluated the effects of the proposed EPU on SBO and demonstrated that the plant will continue to meet the requirements of 10 CFR 50.63, the guidance provided in RG 1.155, and NUMARC 8700, following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to SBO.

## 2.4 Instrumentation and Controls

### 2.4.1 Reactor Protection, Safety Features Actuation, and Control Systems

#### Regulatory Evaluation

Instrumentation and control systems are provided (1) to control plant processes having a significant impact on plant safety, (2) to initiate the reactivity control system (including control rods), (3) to initiate the engineered safety features (ESF) systems and essential auxiliary supporting systems, and (4) for use to achieve and maintain a safe shutdown condition of the plant. Diverse instrumentation and control systems and equipment are provided for the express purpose of protecting against potential common-mode failures of instrumentation and control protection systems. The NRC staff conducted a review of the reactor trip system, engineered safety feature actuation system (ESFAS), safe shutdown systems, control systems, and diverse instrumentation and control systems for the proposed EPU to ensure that the systems and any changes necessary for the proposed EPU are adequately designed such that the systems continue to meet their safety functions. The NRC staff's review was also conducted to ensure that failures of the systems do not affect safety functions. The NRC's acceptance criteria related to the quality of design of protection and control systems are based on 10 CFR 50.55a(a)(1), 10 CFR 50.55a(h), and GDC 1, 4, 13, 19, 20, 21, 22, 23, and 24. Specific review criteria are contained in SRP Sections 7.0, 7.2, 7.3, 7.4, 7.7, and 7.8.

#### Technical Evaluation

##### *Instrument Setpoint Methodology*

Per the licensee, there are two uncertainty calculations pertaining to the establishment and maintenance of each TS setpoint value, an instrument uncertainty calculation and a setpoint uncertainty calculation.

The instrument uncertainty calculation exists for each safety system input parameter. These calculations determine the various elements of uncertainty applicable to each component within that instrument channel from the sensor/transmitter up to the protection system cabinet input. These calculations for the SG level instrument uncertainties have been prepared by FPL in accordance with FPL standards. FPL states that this instrument uncertainty calculation standard (not submitted as part of the LAR) is based on Instrument Society of America (ISA) 67.04, Setpoints for Nuclear Safety Related Instrumentation, and NRC RG 1.105, Instrument Setpoints for Safety Related Systems (ADAMS Accession No. ML003740318). Elements of uncertainty for individual components, such as setting tolerance, measuring & test equipment, and drift are specifically based on associated surveillance procedure requirements and test frequencies. Environmental effects for both normal and harsh conditions are determined for each loop component as applicable. The loop setpoint uncertainty calculation combines the instrument accuracy with the rack accuracy terms and establishes the setpoint uncertainty for the loop. For SG level setpoint uncertainty this calculation has been prepared by Westinghouse.

The full range of uncertainty effects are considered including instrument performance specifications, calibration effects, environmental effects, process effects and electrical circuit effects. Manufacturer's specification sheets and qualification reports are used as the basis for determining applicable instrument uncertainty effects, magnitudes and statistical confidence,

and the extent to which each effect is random and independent. Calibration uncertainty effects, such as setting tolerance and measuring & test equipment are specifically based on associated surveillance procedure requirements. Environmental effects for both normal and harsh conditions are determined for each loop component as applicable. The maximum variation range of each applicable environmental parameter is based on the limiting analysis for which that protection function is credited.

The random uncertainty terms were based on  $2\sigma$  confidence interval values (ADAMS Accession No. ML11242A150). The licensee states that the uncertainties came from manufacturer inputs and the industry practice is to operate with the assumption of  $2\sigma$  values unless the specifications state it otherwise or a knowledge base exists to the contrary. These terms were combined without scaling to calculate the total loop uncertainty (TLU). Uncertainty effects that are determined to be random and independent are combined using square root of the sum of the squares method. All other non-random/non-independent uncertainty effects are algebraically included as bias terms. No credit is taken for bias terms that are conservative with respect to the protection function. Total loop uncertainty is determined as the square root of the sum of square of random terms plus any non-conservative bias terms. This described overall calculation method is acceptable to staff based on the guidance contained in RG 1.105.

The licensee states that they maintain a separate document for the safety analysis plant parameters (SAPP) (ADAMS Accession No. ML11242A150). The SAPP serves as a bridge between the instrument channel setpoint calculations and the safety analysis. The bounding uncertainty allowance applicable to each protection system function is documented and managed in the SAPP. Where applicable, the SAPP includes individual bounding uncertainty allowances for both normal and harsh conditions.

The non-rack component uncertainties (from the corresponding instrument uncertainty calculations) are combined with the protection system cabinet uncertainties to determine an overall TLU. These setpoint uncertainty calculations also verify that the uncertainty allowances defined in the SAPP are bounding. Further, these setpoint uncertainty calculations determine operability limits (OL) for the related actuation functions.

The instrument setpoint uncertainties are based on using random and bias errors commensurate with the guidance contained in RG 1.105. Process errors have been considered and included when non-negligible or non-conservative. Margin is provided between the calculated error (TLU + setting tolerance) and the SAPP uncertainty allowance. Appropriate controls are provided to maintain the variables within prescribed limits per GDC 13 and RG 1.105. The staff has determined that the setpoint method described in the licensing request meets the requirements of GDC 13 and the regulatory guidance in RG 1.105.

#### Compliance with RIS 2006-17

Conformance with the key issues in RIS 2006-17 is summarized in the following paragraphs:

RIS 2006-17 clarified the application of the setting tolerances and the need to assure that the as-left tolerance (ALT) and the as-found tolerance (AFT) is controlled such that the analyzed limits are not violated. NRC clarifications provided in RIS 2006-17 stipulate that as-left setting tolerance should be explicitly accounted for in the setpoint determination. More specifically, since the walk-away equipment setpoint may be left anywhere within the as-left band, this allowed setting tolerance should be treated as a bias in the setpoint determination.

RIS 2006-17 further stipulates that the surveillance procedures must ensure that the trip setpoint is restored to within the as-left band before the channel is returned to service. To comply with this NRC guidance, the verification that the SAPP-defined uncertainty allowance is bounding (as performed in the setpoint calculations per above discussion) has been structured to ensure that TLU plus setting tolerance (ST) is less than or equal to SAPP allowance. To clarify, the ST is algebraically added to TLU (for SAPP allowance verification) and is also included as a random/independent term in the square root of the sum of the squares TLU calculation. In addition, St. Lucie protection system surveillance procedures require that trip setpoints are restored to within the as-left band before the channel is returned to service. Using this methodology, the SAPP uncertainty allowances are verified to be bounding for protection system functions at EPU conditions. The safety analysis Analytical Limits are based on the algebraic combination of the TS setpoint and the SAPP uncertainty allowance to ascertain that all TS setpoints are sufficiently conservative at EPU conditions to ensure that applicable safety limits will not be exceeded if a design basis event occurs before the next periodic surveillance.

Additional NRC guidance provided in RIS 2006-17 stipulates use of an as-found acceptance criteria band centered about the field trip setpoint or FTSP (FTSP is same as nominal trip setpoint (NTSP) as used in RIS 2006-17) as a measure of instrument channel operability. To comply with this NRC guidance, the setpoint calculations have been structured to include determination of an OL band. For St. Lucie, the OL band is synonymous with the as-found acceptance criteria band. The operability determination for St. Lucie 1 protection system monthly functional surveillance tests is explained in Notes 6 and 7 of Table 4.3-1, Reactor Protective Instrumentation Surveillance Requirements of the Technical Specifications as stated later in this section (ADAMS Accession No. ML11242A150).

Historically, St. Lucie has used an AFT band width equal to 2 times the procedure ST as the basis for initiation of corrective action under the corrective action program. This ST used for periodic surveillance is for the rack accuracy components. This ST value is 0.25 percent of span for St. Lucie 1. The stated AFT band width meets the intent of the NRC guidance since the previous as-left setting may be anywhere within one ST band width, leaving just one ST band width for accommodation of drift and other periodic test uncertainties. As-found readings within the allowed ST are not typically optimized in the monthly functional surveillance procedures. Therefore the ALT is treated as a bias. The licensee considered other methodologies for calculation of an OL band width based on a statistical combination of drift and other periodic test uncertainty effects, but rejected them since the resultant OL bands were either larger or smaller than reasonable. Therefore, the OL band (synonymous with the as-found acceptance criteria) is based on 2 times the ST and is normally centered about the nominal equipment setting. It should be noted that for St. Lucie 1, the OL band is synonymous with the as-found acceptance criteria and is normally centered about the nominal equipment setting (clarified as the FTSP or NTSP). FPL originally proposed to use different setting tolerances (ALT and AFT) around the FTSP, which was not acceptable to the Staff as there was insufficient justification for using unequal tolerances around the FTSP. Staff maintained that unless there is evidence to the contrary, the instrument deviations are considered to be random and hence must be centered around the FTSP. In their November 1, 2011, response to the Staff request for further clarifications (ADAMS Accession No. ML11308B353), the licensee agreed to use equal setting tolerances around the FTSP.

The licensee proposed to add the following two notes to TS Table 4.3-1, Reactor Protective Instrumentation Surveillance Requirements pertaining to Functional Unit 7, Steam Generator Water Level – Low under Channel Functional Test with frequency M (monthly):

(6) "If the as-found setpoint is either outside its predefined as-found acceptance criteria band or is not conservative with respect to the Allowable Value, then the channel shall be declared inoperable and shall be evaluated to verify that it is functioning as required before returning the channel to service."

(7) "The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the Field Trip Setpoint, otherwise that channel shall not be returned to OPERABLE status. The Field Trip Setpoint and the methodology used to determine the Field Trip Setpoint, the as-found acceptance criteria band, and the as-left acceptance criteria are specified in the FSAR Section 7.2".

The ALT is considered both as a random and a bias term and this is a conservative assumption per the clarifications in RIS 2006-17. The licensee's revised ALT and the AFT tolerances, which are centered around the NTSP (FTSP), are acceptable to the NRC Staff. The notes clarify the actions required if the ALT or the AFT is found to exceed the specified tolerances. Therefore, the staff has determined that the application of the clarifications of RG 1.105 in RIS 2006-17 are acceptable.

#### *Summary of Low SG Level Setpoint/Uncertainty Calculations*

This summary uses the following terms and acronyms:

A	Device reference accuracy
BTU	Bistable trip unit
D	Drift
FTSP	Field trip setpoint
IR	Insulation Resistance
LT	Level transmitter
M	Measuring and test equipment (M&TE)
OL+	Upper operability limit
OL-	Lower operability limit
PS	Power Supply
R	Radiation effects (Ra and Rn for accident and normal)
RLE	Reference leg effect (RLEa and RLEn for accident and normal)
S	Seismic Effect
SAPP	Safety analysis plant parameters
SPE	Static pressure effect
SQRT	Square root
ST	Setting tolerance
T	Temperature Effect (Ta and Tn for accident and normal)
TLU	Total loop uncertainty (TLUa and TLUn for accident and normal)

For the reactor protection system (RPS) Low SG Level trip function, the channel consists of a Rosemount Model 1154DP transmitter and the RPS bistable trip unit (BTU). Device uncertainties that were determined to be both applicable and non-negligible are summarized in the table below. Although not referenced herein, other effects, including dynamic effects, were also evaluated.

Several process effects, specifically the downcomer velocity effect, the void fraction effect, etc., have not been included in the low SG level protection functions since they produce conservative biases.

The reference leg effect analysis incorporates both the hydrostatic pressure and FW subcooling effects and has been included in the TLU for the normal as well as the accident case conditions because they produce non-conservative biases. The reference leg effects for both normal and accident cases have been included as bias terms to account for this non-conservative effect.

The magnitude of the non-conservative acceleration effect through the SG frustum (frustum) is small in relation to the conservative downcomer velocity effect. Since FPL does not credit the downcomer velocity term, the acceleration effect does not have to be included in the reference leg effect (RLE) error calculation.

Effects other than those specifically addressed above are either very small or conservative and have not been included in the calculations. Seismic uncertainties were not initially included in the calculations because the plant requires a manual plant shut down for earthquakes greater than the operating basis earthquake and for smaller confirmed earthquakes below operating basis earthquake all instrument loops would be monitored to check the drift due to seismic event. The staff sought clarification because the equipment would have to perform its safety function subsequent to an earthquake and prior to checking out the calibration drift and the need for recalibration. In the January 14, 2012, response the licensee included the error due to seismic events and revised the setpoint calculation to include the seismic error component.

Radiation effects under normal conditions were neither included nor an explanation provided as to why they have not been included. Staff requested a clarification for not addressing the radiation effects under normal conditions. In its January 14, 2012, response the licensee explained that the radiation dose under normal conditions is very low. The level transmitters are located outside the bioshield wall and the normal dose without fuel failure for 22.5 months is less than 250 rads for 22.5 months, this represents a mild environment and any minor calibration errors are calibrated out during refueling outage (every 18 months). With 1 percent fuel failure rate the 22.5 month radiation dose is less than 1410 rads (this dose is based on Unit 2 radiation dosage, which is higher than the radiation dose for Unit 1). This radiation dose does not represent a harsh environment per the Rosemount 1154DP transmitter performance specification and, hence, not accounted for in the calculation. The level transmitters are qualified to an integrated dose of over  $10^6$  ( $10 \times 10^6$ ). Equipment other than the level transmitters is located in the control room, which is a mild environment (integrated 60 year dose rate less than 300 Rads). Based on this explanation the staff finds the rationale acceptable for not including radiation error under normal conditions.

Per the licensee, insulation resistance (IR) effects are not included in the RPS low level trip function because no credit is taken for this function for actuation under long term accident conditions. Therefore, the IR error due to high radiation for normal and accident conditions is negligible (ADAMS Accession No. ML12019A067).

The Total Loop Uncertainty with normal environmental conditions (TLUn) for the RPS Low SG Level trip function is calculated as follows:

$$\text{TLUn} = \text{SQRT} (A_{\text{LT}}^2 + A_{\text{BTU}}^2 + M_{\text{LT}}^2 + ST_{\text{LT}}^2 + D_{\text{LT}}^2 + SPE_{\text{LT}}^2 + Tn_{\text{LT}}^2 + S_{\text{LT}}^2 + D_{\text{BTU}}^2 + M_{\text{BTU}}^2 + ST_{\text{BTU}}^2 + Tn_{\text{BTU}}^2) + \text{RLEn}_{\text{LT}}$$



TLUn = 1.18+0.89=2.07 % span  
TLUn + ST = 2.32 % span (using 0.25 % as ST)  
SAPP normal uncertainty allowance = 5 % span  
Net margin for normal case is 2.68 % (5.0 %-2.32 %)

The Total Loop Uncertainty with accident environmental conditions (TLUa) for the RPS Low Steam Generator Level trip function is calculated as follows:  
$$TLUa = \text{SQRT} (A\_LT^2 + A\_BTU^2 + M\_LT^2 + ST\_LT^2 + D\_LT^2 + SPE\_LT^2 + Ta\_LT^2 + S\_LT^2 + D\_BTU^2 + M\_BTU^2 + ST\_BTU^2 + Tn\_BTU^2 + Ra\_LT^2) + RLEa\_LT$$
  
TLUa = 4.60+7.93=12.53 % span  
TLUa + ST = 12.78 % span (using 0.25 % as ST)  
SAPP accident uncertainty allowance = 14 % span  
Net margin for accident conditions is 1.22 % (14.0 %-12.78 %)

#### Operability Limit Calculations

RPS Low S/G Level BTU Signal Range = -1 Vdc to -5 Vdc for 0 % to 100 %  
RPS Low S/G Level BTU FTSP = -2.420 Vdc or 35.5 % span  
RPS Low S/G Level BTU ST = -2.410 Vdc to -2.430 Vdc  
RPS Low S/G Level BTU ST Band Width = 20 mV=0.5 % span  
RPS Low S/G Level BTU OL+ = -2.440 Vdc or 36.00 % span  
RPS Low S/G Level BTU OL- = -2.400 Vdc or 35.00 % span  
RPS Low S/G Level BTU OL Band Width = 40 mV=1.0 % span

### RPS Low SG Level Instrument Loop Device Uncertainties

	Level Transmitter (LT)	RPS BTU
Reference accuracy (A)	±0.25% span	±0.125% span
M&TE (M)	±0.35% span	±0.125% span
Setting tolerance (ST)	±0.25% span	±0.25% span
Drift (D)	±0.32% span	±0.25% span
Temperature effect (Tn)	±0.70% span	±0.25% span
Temperature effect (Ta)	±4.20% span	N/A
Static pressure effect (SPE)	±0.43% span	N/A
Power Supply Effect	N/A	N/A
Seismic effect (S)	±0.40% span	N/A
Radiation effect (Ra)	±1.61% span	N/A
Reference leg effect (RLEn)	±0.89% span	N/A
Reference leg effect (RLEa)	±7.93% span	N/A

Circuit loading error for the BTU due to indicating lamp is -0.75 percent of span. Since this error is in the conservative direction it has not been accounted for in the calculation.

The calculated setpoints are based on the guidance of RG 1.105 and RIS 2006-17 and have sufficient margin between the calculated setpoint with uncertainty and the safety analysis value to provide reasonable assurance that the analytical limits will not be exceeded and that the instruments will be operable. Therefore, the staff has determined that the proposed changes meet the TS requirements of 10 CFR 50.36 and the guidance in RG 1.105.

#### *Technical Specifications changes related to the power uprate*

The following TS changes have been proposed by the licensee:

TS Table 2.2-1, Function 3, Reactor Coolant Flow – Low (1), Four Reactor Coolant Pumps Operating

With regard to the current trip setpoint and the allowable values the note states, “Design reactor coolant flow with 4 pumps operating is 365,000 gpm.” The revised TS note states, “For minimum reactor coolant flow with 4 pumps operating, refer to Technical Specification LCO 3.2.5.”

One of the inputs and assumptions used in the calculation of the NSSS design parameters established an increased minimum RCS total flow requirement of 375,000 gpm to ensure that the reactor core thermal margin safety limit is not exceeded. FPL letter L-2011-423, dated October 10, 2011 (ADAMS Accession No. ML11285A045), clarified that the LCO 3.2.5 will be revised from “c. Reactor Coolant System Total Flow Rate” to “c. Reactor Coolant System Total Flow Rate – greater than or equal to 375,000 gpm....” This change is consistent with the new analyzed reactor coolant flow rate needed to support EPU conditions.

TS Table 2.2-1, Function 7, Steam Generator Water Level – Low

The licensee has proposed to increase the trip setpoint for SG water low setpoint from  $\geq 20.5$  percent water level – each SG to  $\geq 35.0$  percent water level – each SG. In addition, the licensee has proposed to change the corresponding allowable values from  $\geq 19.5$  percent to  $\geq 35.00$  percent, which is the same as low operability limit. The corresponding NTSP (FTSP) is 35.50 percent.

In support of this change the licensee has proposed to add the following two notes:

If the as-found setpoint is either outside its predefined as-found acceptance criteria band or is not conservative with respect to the Allowable Value, then the channel shall be declared inoperable and shall be evaluated to verify that it is functioning as required before returning the channel to service.

The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the Field Trip Setpoint, otherwise that channel shall not be returned to OPERABLE status. The Field Trip Setpoint and the methodology used to determine the Field Trip Setpoint, the as-found acceptance criteria band, and the as-left acceptance criteria are specified in the FSAR Section 7.2.

The licensee has determined that with the EPU, the accident and transient analysis results show that the existing setpoint of  $\geq 20.5$  percent water level with all RCPs operating is satisfactory. The licensee states that the revised trip setpoint of  $\geq 35.0$  percent water level provides for greater operator response time for restoration of FW following a total loss of FW event, thereby resulting in an overall risk reduction. Based on the accident and transient analysis and the greater operator response time, the staff has determined that this setpoint change is acceptable.

TS Table 4.3-1, Reactor Protective Instrumentation Surveillance Requirements, Function 7, Steam Generator Water Level – Low

The licensee has proposed to add notes 6 and 7 (as enumerated in section 1.0 of this safety evaluation) to meet the guidance of RG 1.105 and the clarifications provided in RIS 2006-17. The staff has determined that the new Notes 6 and 7 meet the staff guidance and are acceptable.

*Control Systems*

The following changes are related to control systems. The purpose of review is to evaluate that there will be no adverse affect on safety due to these changes.

Turbine first stage pressure instrumentation

Turbine first stage pressure increases essentially linearly from 0 percent to 100 percent turbine load and provides a close correlation of secondary power to reactor power. The current 0 percent–100 percent turbine load turbine first stage pressure correlates to 0 to 521.4 psig. The current high pressure (HP) turbine has a governing stage and the governing stage exit pressure (impulse pressure) is used as the reference value for the first stage pressure. For EPU, a new HP turbine is being installed that does not have a governing stage. Therefore, the

first stage pressure is the HP control valve exit pressure. The new HP turbine currently is expected to generate a 0 percent–100 percent power with nominal first stage turbine pressure of 0 to 736.7 psig. The significant increase in first stage pressure is because of no governing stage in the new HP turbine. Actual full power turbine first stage pressure may change slightly as the HP turbine design is refined and instrument calibrations will be revised accordingly. The change in the first stage pressure is needed due to change in the HP turbine design. For EPU conditions the analyzed main steam design pressure is 985 psig remains unchanged and the pressure at the common header to HP turbine throttle valves for EPU conditions is 815.6 psia compared with the current HP turbine throttle valve pressure of 824.3 psia (ADAMS Accession No. ML103560429). This pressure setting envelopes the new turbine first stage pressure and therefore, this change does not adversely affect any safety system.

### Reactor Regulating System

The reactor regulating system responds to changes in RCS temperature and secondary load as sensed by the RCS measured  $T_{avg}$  (average temperature) instrumentation and turbine first stage pressure instrumentation. The reactor regulating system is designed to calculate the 0 percent–100 percent  $T_{avg}$  program reference value ( $T_{ref}$ ) derived from 0–100 percent power turbine first stage pressure. The reactor regulating system calculates the pressurizer water level setpoint based upon  $T_{avg}$ . In addition, the reactor regulating system provides deviation alarms for  $(T_{avg} - T_{ref})$ .

For EPU, the  $T_{ref}$  temperature program must be rescaled such that the new 0 to 100 percent power turbine first stage pressure range of 0 to 736.7 psig corresponds to the new  $T_{avg}$  range of 532 °F to 577 °F. For EPU, the low limit  $T_{avg}$  setpoint is at 15 percent power for  $T_{avg}$  of 538.7 °F. The high limit  $T_{avg}$  setpoint is at 90 percent power for  $T_{avg}$  of 572 °F. The  $T_{avg}$  for power below 15 percent is the same as at 15 percent power and the  $T_{avg}$  for power greater than 90 percent is the same as the  $T_{avg}$  at 90 percent power. The current  $T_{ref}$  varies linearly with power from a nominal temperature of 532 °F at a hot standby to an adjustable limit of 520 °F to 580 °F at 100 percent power. Even though the  $T_{ref}$  program has been changed, the  $T_{avg}$  temperature control limits are enveloped within the existing limits). There is no safety function associated with this change. Based on the foregoing discussion, the changes in the scaling for the reactor regulating system are needed due to change in the turbine first stage pressure (described above) and do not adversely affect operation of any safety system.

### Pressurizer Level Control System

The pressurizer level control system maintains the pressurizer level within a programmed band consistent with measured  $T_{avg}$ . The programmed level is designed to maintain a sufficient margin above the low level alarm where the heaters turn off while maintaining the level low enough that a sufficient steam volume is maintained to ensure the pressurizer does not go solid during accidents and transient conditions. Since  $T_{avg}$  temperature program has changed for EPU, the nominal pressurizer level program temperatures for the low and high level limits have changed for EPU. The low limit  $T_{avg}$  setpoint is at 15 percent power temperature of  $T_{avg}$  538.7 °F. The high limit  $T_{avg}$  setpoint is at a temperature between 90 percent power  $T_{avg}$  temperature of 572 °F. The level control program is linear between 15 percent power  $T_{avg}$  and the high limit  $T_{avg}$ . For measured  $T_{avg}$  below 15 percent load, the level program is constant at the low limit. For measured  $T_{avg}$  above the high limit  $T_{avg}$  setpoint, the level program is constant at the high limit. Since the low and the high level limits have not changed due to EPU, the

changes in the pressurizer level control needed for EPU do not adversely affect any safety system.

### Feedwater Regulating System

The FW regulating system, which is a subsystem of the distributed control system (DCS), maintains steam SG water level within acceptable limits by positioning the main FW regulating valves and FW bypass valves. In addition, in the event of a reactor trip or turbine trip, the FW regulating valves are closed and the DCS controls SG level via the FW bypass valves. For the EPU, the FW pumps have been changed and the regulating valves are being modified and will be rescaled as necessary for the new FW flow range. Therefore, changes to the FW regulating and FW bypass valve demand programs within the DCS software are required. In addition, changes were made to the post trip (turbine trip override) control setpoints to improve level response following a reactor trip.

FW isolation is required for a variety of postulated transients and accident events. The current plant design provides for FW isolation using the FW isolation valves, with the FW pump trip providing backup. The main FW isolation valves (MFIVs) and main FW pump discharge isolation valves have been evaluated for the increased flow rates, differential pressures, and temperatures at EPU. Isolation of these valves is classified as a safety function. The licensee confirms that the MFIV and FW isolation valves will continue to meet the existing required valve closure response times at the EPU conditions (ADAMS Accession No. ML103560429). Containment isolation is accomplished by the provision of MFIVs and the check valves on the FW headers outside containment. The containment isolation requirements are unaffected by EPU and the current plant design features remain acceptable.

The safety function of FW isolation is not affected by EPU and other changes to the non-safety part of the control systems do not affect plant safety. Therefore the changes described above do not adversely affect safety systems.

### Steam Bypass Control System (SBCS)

The SBCS is comprised of five valves, one bypass valve and four dump valves, which dump steam to the condenser. For EPU, the capacity of the steam dump and bypass valves is being increased. Therefore, changes to the valve demand programs within the SBCS control logic are required. In addition, the setpoint for the large load rejection permissive signal was reduced, which allows the system to respond in a valve quick open mode of operation (rather than valve modulation mode) to improve the overall transient response. Minor changes were also made to the master valve controller output signal tracking logic to provide a smoother transition back to steam pressure modulation control following an initial SBCS quick open response to a large load rejection event.

The current SBCS load rejection capacity of 29 percent remains unchanged. However, to maintain the load rejection capability at higher steam flow the SBCS flow capacity will be increased and valve response time decreased to maintain operating margin under EPU conditions, and to decrease challenges to the reactor protection system by increasing the size of the step load reduction that can be mitigated by the control systems without a reactor trip. The analysis used increased SBCS valve capacities with linear trim and a 2 second quick open stroke time due to the EPU (ADAMS Accession No. ML103560429).

Based on the increased steam bypass capability to handle loss of load at the 29 percent capacity, the probability of challenges to the reactor protection system remains unchanged. There is no safety function for this system and the proposed changes do not adversely affect safety systems.

#### Containment Venting

The existing containment hydrogen purge system manual containment isolation exhaust valves will be upgraded to provide remote-manual control capability, and they will automatically close on a containment isolation signal. Open/close valve position indication will be provided in the control room. This change provides more operational flexibility and does not adversely affect the safety systems.

#### Moisture Separator Reheater (MSR) and FW Heaters 5A/B Level Controls

The existing pneumatic controls for MSR and high pressure FW heater 5 level control are being replaced with electronic instruments. The existing backup level switch control functions will not be changing. This controls upgrade does not adversely affect the safety systems.

#### Condensate and FW System

To regain operating margin when the EPU occurs, the following setpoints will be changed for the main FW system:

FW pump suction – Low suction pressure alarm and pump trip setpoints will be revised as necessary to reflect EPU operating conditions and requirements for the replacement main FW pumps; and

FW flow – The FW pumps will be replaced with higher capacity pumps to accommodate the increase in FW flow due to EPU. The range of the various FW flow channels will be increased to accommodate the higher EPU flow rates. Those instrument channels with an upper range of 7E6 ( $7 \times 10^6$ ) pound-mass per hour (lbm/hr) will be revised for an expanded upper range of 8E6 lbm/hr. Associated indicators, recorders, computer points, and alarm setpoints will be rescaled as necessary.

There is no safety function associated with these changes. These controls changes are needed for EPU and they do not adversely affect the safety systems.

#### Main Steam System

The range of the various main steam flow channels will be increased to accommodate the higher EPU flow rates. Those instrument channels with an upper range of 7E6 lbm/hr will be revised for an expanded upper range of 8E6 lbm/hr. Associated indicators, recorders, computer points, and alarm setpoints will be rescaled as necessary.

Due to EPU conditions, the main steam flow rate from each SG will increase from the normal operation pre-EPU total flow rate of approximately 5,892,295 lbm/hr to a post-EPU total normal flow rate of approximately 6,657,560 lbm/hr. Due to this increase in main steam flow rate, the capability of the MSIVs required evaluation, which confirmed satisfactory EPU performance,

including the ability to meet the safety-related isolation function to prevent uncontrolled blowdown of both SGs in the event of a steam line rupture accident.

These controls changes are needed for EPU and they do not adversely affect the safety systems.

#### Condensate and Circulating Water System

The condenser low vacuum turbine trip setpoint will be adjusted for the EPU conditions. There is no safety function associated with change and the change does not adversely affect the safety systems.

#### Turbine Cooling Water System

As a result of EPU the isolated phase bus air coolers flow indicating switches will be replaced. There is no safety function associated with this change and the change does not adversely affect the safety systems.

#### Turbine Generator Control

As part of EPU, a new HP turbine rotor is being installed. With the new turbine, the control valve program will be changed from partial arc emission admission control (load change controlled by sequential valve opening) to full arc emission admission control (load change controlled by all valves moving together). Additionally, a new digital turbine control system is being installed resulting in the modification to the existing turbine controls and the turbine overspeed protection system. This change will also include new control room displays and controls to provide operator interfaces with the digital turbine control system.

A reactor trip is initiated on a turbine trip. The signal for this trip comes from 4 hydraulic oil pressure switches and is not dependent on the digital control system. In addition, a turbine trip event is bounded by the loss of external load event. Thus, this change will not result in an adverse affect to the safety systems.

The control system changes described above are needed to support the EPU implementation due to larger flows, pressures, etc. Since these changes pertain to non-safety systems and do not affect safety adversely, staff determined that these changes are acceptable.

#### Conclusion

The NRC staff has reviewed the licensee's application related to the effects of the proposed EPU on the functional design of the reactor trip system, ESFAS, safe shutdown system, and control systems. The NRC staff concludes that the licensee has adequately addressed the effects of the proposed EPU on these systems and that the changes that are necessary to achieve the proposed EPU are consistent with the plant's design basis. The NRC staff further concludes that the systems will continue to meet the requirements of 10 CFR 50.55a(a)(1), 10 CFR 50.55(a)(h), and GDC 1, 4, 13, 19, 20, 21, 22, 23, and 24. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to instrumentation and controls.

## 2.4.2 Measurement Uncertainty Recapture

### Regulatory Evaluation

Nuclear power plants are licensed to operate at a specified core thermal power. Appendix K, "ECCS Evaluation Models," to 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," requires LOCA and emergency core cooling system (ECCS) analyses to assume "that the reactor has been operating continuously at a power level at least 102 percent of the licensed thermal power level to allow for instrumentation uncertainties." Alternatively, Appendix K allows such analyses to assume a value lower than the specified 102 percent, but not less than the licensed thermal power level, "provided the proposed alternative value has been demonstrated to account for uncertainties due to power level instrumentation error." This allowance gives licensees the option of justifying a power uprate with reduced margin between the licensed power level and the power level assumed in the ECCS analysis by using more accurate instrumentation to calculate the reactor thermal power.

Because the maximum power level of a nuclear plant is a licensed limit, the NRC must review and approve a proposal to raise the licensed power level under the license amendment process. The LAR should include a justification for the reduced power measurement uncertainty to support the proposed power uprate.

Topical Report ER-80P and its supplement, Topical Report ER-157P, describe the Caldon LEFM (Leading Edge Flow Meter) CheckPlus™ System for the measurement of FW flow and provide a generic basis for the proposed uprate. The staff also considered the guidance of RIS 2002-03 (Reference 20), in its review of the licensee's submittals for the proposed power uprate request. By following the regulatory summary guidance provided in RIS 2002-03, the requirements of 10 CFR Part 50, Appendix K are satisfied.

### Technical Evaluation

Neutron flux instrumentation is calibrated to the core thermal power, which is determined by an automatic or manual calculation of the energy balance around the plant nuclear steam supply system. The accuracy of this calculation depends primarily on the accuracy of FW flow and FW net enthalpy measurements. FW flow is the most significant contributor to the core thermal power uncertainty. A more accurate measurement of this parameter will result in a more accurate determination of core thermal power.

FW flow rate is typically measured using a venturi. This device generates a differential pressure proportional to the FW velocity in the pipe. Due to the need to improve flow instrumentation measurement uncertainty, the industry evaluated other flow measurement techniques and found the Caldon LEFM Check™ and LEFM CheckPlus™ ultrasonic flow meters to be a viable alternative.

Staff in the Office of Nuclear Reactor Regulation's Instrumentation and Controls Branch reviewed this measurement uncertainty recapture (MUR) power uprate based on the LEFM CheckPlus™ technology and the issued RIS 2002-03, as described below.



## LEFM Technology and Measurement

Both the Caldon LEFM Check™ and LEFM CheckPlus™ Systems use transit time methodology to measure fluid velocity. The basis of the transit time methodology for measuring fluid velocity and temperature is that ultrasonic pulses transmitted through a fluid stream travel faster in the direction of the fluid flow than through the opposite flow. The difference in the upstream and downstream traversing times of the ultrasonic pulse is proportional to the fluid velocity in the pipe. The temperature is determined using a correlation between the mean propagation velocity of the ultrasound pulses in the fluid and the fluid pressure.

Both systems use multiple diagonal acoustic paths instead of a single diagonal path, allowing velocities measured along each path to be numerically integrated over the pipe cross-section to determine the average fluid velocity in the pipe. This fluid velocity is multiplied by a velocity profile correction factor, the pipe cross-section area, and the fluid density to determine the FW mass flow rate in the piping. The mean fluid density may be obtained using the measured pressure and the derived mean fluid temperature as an input to a table of thermodynamic properties of water. The velocity profile correction factor is derived from calibration testing of the LEFM in a plant-specific piping model at a calibration laboratory.

The Caldon LEFM Check™ System consists of a spool piece with eight transducers, two on each of the four acoustic paths in a single plane of the spool piece. The velocity measured by any one of the four acoustic paths is the vector sum of the axial and the transverse components of fluid velocity as projected onto the path. The Caldon LEFM CheckPlus™ System uses 16 transducers, 8 each in two orthogonal planes of the spool piece. In the Caldon LEFM CheckPlus™ System, when the fluid velocity measured by an acoustic path in one plane is averaged with the fluid velocity measured by its companion path in the second plane, the transverse components of the two velocities are canceled and the result reflects only the axial velocity of the fluid. This makes the numerical integration of four pairs of averaged axial velocities and the computation of volumetric flow inherently more accurate than a result obtained using four acoustic paths in a single plane. Also, since there are twice as many acoustic paths and there are two independent clocks to measure the transit times, errors associated with uncertainties in path length and transit time measurements are reduced.

The NRC staff's review in the area of instrumentation and controls (I&C) covers the proposed plant-specific implementation of the FW flow measurement technique and the power increase gained as a result of implementing this technique, in accordance with the guidelines (A through H) provided in Section I of Attachment 1 to RIS 2002-03 which relates to 10 CFR Part 50, Appendix K. The staff conducted its review to confirm that the licensee's implementation of the proposed FW flow measurement device is consistent with staff-approved Topical Reports ER-80P and ER-157P and that the licensee adequately addressed the four additional requirements listed in the staff's SE (Section 3.2, Item D, discusses these four requirements in more detail). The NRC staff also reviewed the power measurement uncertainty calculations to ensure that (1) the conservatively proposed uncertainty value of 0.3 percent correctly accounts for all uncertainties associated with power level instrumentation errors and (2) the uncertainty calculations meet the relevant requirements of 10 CFR Part 50, Appendix K, as described in Section 2 of this SE.

The licensee provided the information described below regarding the Caldon LEFM CheckPlus™ System FW flow measurement technique and its implementation at St. Lucie 1.

The LEFM systems of St. Lucie 1 contain an individual LEFM metering spool piece on each of the two FW flow headers. Each of the LEFM meters functions independently to calculate a FW mass flow rate. FPL plans to permanently install the LEFM CheckPlus™ System in accordance with the requirements of Topical Reports ER-80P and ER-157P and FPL procedures. The system will provide FW mass flow and FW temperature input data to the distributed control system (DCS), which is the computer system that automatically performs continuous calorimetric power calculations.

The LEFM CheckPlus™ System incorporates self-verification features to ensure that hydraulic profile and signal processing requirements are met within the site-specific design-basis uncertainty analysis. Critical performance parameters, including signal-to-noise ratio, are continually monitored for every individual meter path, and alarm setpoints are established to ensure that the corresponding assumptions in the uncertainty analysis remain bounding. Signal noise will be minimized via strict adherence to Cameron design requirements. Cameron has provided transducer signal cables that meet the design requirements. Processed transducer data from the LEFM transmitters are sent to the LEFM central processing units (CPUs) via communication cables.

The LEFM CheckPlus™ System communicates with the DCS via a digital communications interface. Dual data outputs provide redundant information sources for the DCS. The LEFM data sent to the DCS is limited to values actually used in the calorimetric calculations (i.e., FW mass flow rate and FW temperature for each header) and the associated data quality status. The LEFM-based mass flow rate and FW temperature data is to be integrated into appropriate DCS calorimetric display screens. Alarms to the main control room annunciator panels will notify operators of degraded system performance or system failure.

License Amendment Request Compliance with RIS 2002-03, Attachment 1, Section I, Guidance A through H:

Items A through C

Items A, B, and C in Section I of Attachment 1 to RIS 2002-03 guide licensees in identifying the approved topical reports, providing references to the NRC's approval of the measurement technique, and discussing the plant-specific implementation of the guidelines in the topical report and the NRC staff's approval of the FW flow measurement technique, respectively.

In its LAR, the licensee identified Topical Reports ER-80P and ER-157P as applicable to the Caldon LEFM CheckPlus™ System. The licensee also referenced NRC SE dated March 8, 1999, for Topical Report ER-80P, and SE dated December 20, 2001, for Topical Report ER-157P.

Based on its review of the licensee's submittals as discussed above, the staff finds that the licensee has sufficiently addressed the plant-specific implementation of the Caldon LEFM CheckPlus™ System using proper topical report guidelines. Therefore, the licensee's description of the FW flow measurement technique and implementation of the power uprate using this technique follows the guidance in Items A through C of Section I of Attachment 1 to RIS 2002-03.

#### Item D

Item D in Section I of Attachment 1 to RIS 2002-03 guides licensees in addressing four criteria, which the NRC staff stated in its SEs on Topical Reports ER-80P and ER-157P, when implementing the FW flow measurement uncertainty technique. The staff's SEs on Topical Reports ER-80P and ER-157P both include these four plant-specific criteria to be addressed by a licensee referencing these topical reports for power uprate. The licensee's submittals address each of the four criteria as follows:

- (1) The licensee should discuss the maintenance and calibration procedures that will be implemented with the incorporation of the LEFM. These procedures should include processes and contingencies for an inoperable LEFM and the effect on thermal power measurement and plant operation.

The licensee states that implementation of the power uprate license amendment will include developing the necessary procedures and documents required for operation, maintenance, calibration, testing, and training at the uprated power level with the new LEFM system. Plant maintenance and calibration procedures will be revised to incorporate Cameron's maintenance and calibration requirements prior to declaring the LEFM system OPERABLE and raising power above 2,968 MWt.<sup>2</sup> Items G and H of this safety evaluation discuss LEFM system maintenance and calibration procedures and contingency plans for operation of the plant with the LEFM CheckPlus™ System out of service (OOS).

Based on its review of the licensee submittals, the staff concludes that the licensee adequately addressed Criterion 1.

- (2) For plants that currently have LEFMs installed, provide an evaluation of the operational and maintenance history of the installed installation and confirmation that the installed instrumentation is representative of the LEFM system and bounds the analysis and assumptions set forth in Topical Report ER-80P.

This Criterion is not applicable to St. Lucie 1 since the LEFMs are not yet installed.

- (3) The licensee should confirm that the methodology used to calculate the uncertainty of the LEFM in comparison to the current FW instrumentation is based on accepted plant setpoint methodology (with regard to the development of instrument uncertainty). If an alternative approach is used, the application should be justified and applied to both Venturi and ultrasonic flow measurement instrumentation installations for comparison.

The licensee provided core thermal power measurement uncertainty for the LEFM system at St. Lucie 1. Those uncertainty calculations are based on proprietary Cameron Engineering Report ER-740. The licensee stated that calculation methods are based on FPL Nuclear Engineering Department Discipline Standard IC-3.17, Revision 7, "Instrument Setpoint Methodology for Nuclear Power Plants." Both the Cameron method

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<sup>2</sup> The value of 2,968 MWt is based on operation at the requested EPU power level, but without the MUR power uprate provided by the LEFM. Note: Operation at the EPU power level must be specifically approved.

and FPL standard are in turn based on ISA RP67.04.02 (Reference 21), which is consistent with the guidelines in RG 1.105 (Reference 22).

In addition, the licensee needs to perform the postmodification test, which includes verifying LEFM calorimetric calculations using LEFM mass flow and temperatures to ensure LEFM is within established limits (Item 6 in Regulatory Commitments of Attachment 7 to the LAR (Reference 2)).

Based on the above discussion and its review of licensee's setpoint methodology and calculation, the NRC staff concludes that the licensee adequately addressed Criterion 3.

- (4) For plant installation where the ultrasonic meter (including LEFM) was not installed with flow elements calibrated to a site-specific piping configuration (flow profiles and meter factors are not representative of the plant-specific installation), licensees should provide additional justification for its use. The justification should show that the meter installation is either independent of the plant-specific flow profile for the stated accuracy, or that the installation can be shown to be equivalent to known calibrations and plant configurations for the specific installation, including the propagation of flow profile effects at higher Reynolds numbers. Additionally, for previously installed calibrated elements, licensees should confirm that the piping configuration remains bounding for the original LEFM installation and calibration assumptions.

The calibration factor (also known as the meter factor) for the St. Lucie 1 flow elements has been established by tests of these spools at Alden Research Laboratory in February 2009. These tests included a full-scale model of the St. Lucie 1 hydraulic geometry and piping arrangement. Cameron Engineering Report ER-733, "Meter Factor Calculation and Accuracy Assessment for St. Lucie Unit 1" documents test data and results for the flow elements.

Final verification of the site-specific uncertainty analyses occurs as part of the LEFM CheckPlus™ system commissioning process. The commissioning process provides final positive confirmation that actual performance in the field meets the uncertainty bounds established for the instrumentation as described in Cameron engineering report ER-733 and ER-740.

Based on the information given above and the staff's review of the licensee's submitted calibration data in Cameron Engineering Reports ER-733 and ER-740, the NRC staff concludes that the licensee adequately addressed Criterion 4.

#### Item E

Item E in Section I of Attachment 1 to RIS 2002-03 guides licensees in the submittal of a plant-specific total power measurement uncertainty calculation, explicitly identifying all parameters and their individual contribution to the power uncertainty.

To address Item E of RIS 2002-03, the licensee provided Cameron Engineering Reports ER-740, Revision 0, "Bounding Uncertainty Analysis for Thermal Power Determination at St. Lucie 1 & 2 Using the LEFM Checkplus System." The licensee lists each contribution parameters and values for the overall thermal power calorimetric uncertainty in Table 2.4.4-1 of

Attachment 5 of the LAR. The uncertainties documented in this table are based on Cameron engineering reports ER-733 and ER-740.

The staff reviewed the uncertainty calculations and issued a request for additional information (ADAMS Accession No. ML110550011) regarding the steam moisture carryover assumption and the steam enthalpy uncertainty calculation. In its responses (ADAMS Accession No. ML110840043), the licensee provided its expected (actual) moisture carryover percentage at the St. Lucie 1 SG with adequate justification that its assumption is conservative. Therefore, the NRC staff determined that the licensee properly identified all the parameters associated with the thermal power measurement uncertainty, provided individual measurement uncertainties, and calculated the overall thermal power uncertainty.

The licensee's calculations arithmetically summed uncertainties for parameters that are not statistically independent and that are statistically combined with other parameters. The licensee combined random uncertainties using the square-root-sum-of-squares approach and added systematic biases to the result to determine the overall uncertainty. This methodology is consistent with the vendor's determination of the uncertainty of the Caldon LEFM CheckPlus™ System, as described in the referenced topical reports, and is consistent with the guidelines in RG 1.105, Revision 3.

As a result, the NRC staff finds that the licensee has provided calculations of the total power measurement uncertainty at the plant, explicitly identifying all parameters and their individual contributions to the overall thermal power uncertainty. Therefore, the licensee has adequately addressed the guidance in Item E of Section I of Attachment 1 to RIS 2002-03.

#### Item F

Item F in Section I of Attachment 1 to RIS 2002-03 guides licensees in providing information to address the specified aspects of the calibration and maintenance procedures related to all instruments that affect the power calorimetric.

In the LAR, the licensee addressed each of the five aspects of the calibration and maintenance procedures listed in Item F of RIS 2002-03 related to all instruments that affect the power calorimetric as follows:

##### (1) Maintaining Calibration

The licensee stated that the Calibration and maintenance is performed by I&C maintenance department personnel working under the site work control processes, using site-specific procedures. The site-specific procedures are to be developed using Cameron technical manuals. Selected I&C personnel will be trained and qualified per the St. Lucie Station Institute for Nuclear Power Operations (INPO) accredited training program before maintenance or calibration is performed and prior to increasing power above 2,968 MWt (approval to operate at this power level is contingent on the approval of the EPU).

##### (2) Controlling Hardware and Software Configuration

The Cameron LEFM CheckPlus™ system is designed and manufactured in accordance with the vendor's quality assurance program, which meets the requirements of

Appendix B to 10 CFR Part 50. The licensee stated that the LEFM software is controlled on site by FPL's software quality assurance program, which includes configuration control via the Master Software Index, Software Classification Determination, Software Quality Assurance Plan, Software Requirements Specification, Software Design Description, Software Verification and Validation Plan, Backup / Recovery Contingency Planning and QA Record Storage. The LEFM hardware changes are controlled by a design change program.

(3) Performing Corrective Actions

Corrective action involving maintenance is to be performed by maintenance department I&C personnel, qualified in accordance with St. Lucie I&C Training Program, and formally trained on the LEFM CheckPlus™ system. The licensee documents and evaluates any conditions that are adverse to quality under the site corrective action program.

(4) Reporting Deficiencies to the Manufacturer

Equipment problems for all plant systems, including the LEFM equipment, fall under the site work control process or the corrective action process. The licensee documents and evaluates conditions adverse to quality under the corrective action program and subsequently transmits them to the vendor as appropriate.

(5) Receiving and Addressing Manufacturer Deficiency Reports

The St. Lucie 1 LEFM CheckPlus™ system will be included in Cameron's Verification and Validation program and procedures are maintained for user notification of important deficiencies. The LEFM CheckPlus™ system purchase agreement with FPL included requirements that Cameron informs FPL of any deficiencies in accordance with Cameron's maintenance agreement and/or 10 CFR Part 21 reporting requirements.

The NRC staff's review of the above information found that the licensee addressed the calibration and maintenance aspects of the Caldon LEFM CheckPlus™ System and all other instruments affecting the power calorimetric. Thus, the licensee meets the guidance in Item F of Section I of Attachment 1 to RIS 2002-03.

Items G and H

Items G and H in Section I of Attachment 1 to RIS 2002-03 guide licensees to provide a proposed allowed outage time (AOT) for the instrument and to propose actions to reduce power if the AOT is exceeded.

The licensee discussed the proposed AOT and various LEFM operating modes as described below.

FPL proposed the AOT for operation at any power level in excess of 2,968 MWt with the Cameron LEFM CheckPlus™ system out of service, is 48 hours, provided steady-state conditions persist (i.e., no power changes in excess of 10 percent) throughout the 48-hour period. The 48-hour "clock" starts at the time of the LEFM CheckPlus™ system failure.

Since the licensee proposed various maximum power levels with three LEFM maintenance modes, the staff issued an RAI to request a list of the maximum power levels for all LEFM maintenance modes and other OOS conditions after the AOT expires. In response, the licensee provided a table (ADAMS Accession No. ML110840043) that outlines the maximum MWt for all LEFM operating conditions when the 48-hour AOT expires. The NRC staff verified each value of those maximum allowable power levels in the following table provided by the licensee:

<b>Maximum MWt</b>	<b>Total Power Uncertainty %</b>	<b>LEFM Operating Condition</b>
3020	0.30%	System Fully Functional
3015	0.46%	One Section (Plane) of One LEFM in Maintenance
3013	0.50%	One Section (Plane) of Both LEFMs in Maintenance

Additionally, with any one of the two LEFM meters OOS, the maximum MWt is limited to 2968 MWt following the 48-hour AOT.

Licensee provides the following bases for the AOT and the proposed power reduction following the 48-hour AOT:

- The mass flow rate data (based on the venturis, differential pressure (DP) transmitters, and RTDs) is normalized to the Cameron LEFM CheckPlus™ system mass flow rate on a periodic basis. This periodic normalization provides a seamless transition at the time of a LEFM out of service condition. Over a 48 hour time period, with the plant at stable full power conditions, the errors due to venturi fouling and transmitter drift are not significant by the review of plant calibration records.
- The LEFM system, including the interface to DCS, has been designed to be fault tolerant. The active CPU data source for the DCS calorimetric calculations will be automatically swapped by the DCS when necessary based on quality status flags of LEFM and the Ethernet interface module between LEFM and DCS. Redundant processors are used within DCS with automatic fail-over logic. In the unlikely event that the automated DCS based calorimetric power calculation was not available, manual calorimetric calculations would be performed in accordance with existing plant procedures.
- As a conservative measure, licensee's FSAR Section 13.8, Licensee-Controlled Technical Specification Requirements, will restrict plant power to less than or equal to 2,968 MWt if the automated calorimetric portion of DCS cannot be restored within 48 hours.
- If the plant experiences a power change of greater than 10 percent during the 48-hour period, then power level will be restricted to less than or equal to 2,968 MWt until the LEFM CheckPlus™ system is fully functional.
- As described above, the St. Lucie 1 configuration will include separate LEFM flow elements (spool pieces), one for each of the two FW headers. These LEFM subsystems (meters) function independently of each other to calculate a mass flow rate for each of

the two FW headers. Each LEFM CheckPlus™ meter consists of two meter sections of transducers. Each LEFM meter section includes four signal paths arranged in a plane that is orthogonal to the four signal paths of the other meter section. In effect, each LEFM CheckPlus™ meter section is functionally equivalent to the previous generation LEFM Check™ meter. In accordance with the site-specific uncertainty analysis (Cameron ER-740), a loss of one section of one meter results in 0.46 percent uncertainty vs. 0.30 percent uncertainty with both sections of both meters operable. FSAR Section 13.8 will include an Action Statement to specify that if either LEFM meter has experienced a failure of only one section (four paths) of the system then plant power will be limited based on a total calorimetric uncertainty of 0.46 percent.

- The site-specific uncertainty analysis (Cameron ER-740) also documents a system level uncertainty of 0.50 percent for a postulated failure of one section in both LEFM CheckPlus™ meters. FSAR Section 13.8 will include an Action Statement to specify that if both LEFM subsystems (meters) have experienced a failure of only one section (four paths) then plant power will be limited based on a total calorimetric uncertainty of 0.50 percent.
- Unavailability of certain LEFM system redundant subcomponents (including a single CPU), a single FW pressure transmitter and a single steam header pressure transmitter) is already considered in the site-specific uncertainty analysis. Since unavailability of these subcomponents has no adverse affect on the bounding calorimetric uncertainty, FSAR Section 13.8 will specify those components that may be removed from service without any corresponding reduction in plant power.
- If the 48-hour outage period is exceeded, then the plant will operate at a power level consistent with the accuracy of the alternate plant instruments. The Action Statement requirements for power reduction are to be in accordance with current operating procedures, such that the plant will be operating at or below the specified power limit by the time the 48 hours has elapsed.

The staff reviewed Cameron engineering reports ER-733 and ER-740, which list the meter factors of flow calibration for LEFM CheckPlus™ normal, plane A, and plane B (i.e. maintenance mode - LEFM CheckPlus™ with only one transducer plane failed) separately for each flow calibration test at Alden Research Laboratory. The staff found that in effect, each LEFM CheckPlus™ System meter section is functionally equivalent to the previous generation LEFM Check™ meter with the proper meter factor. In accordance with the site-specific uncertainty analysis (Cameron Engineering Report ER-740), failures of one plane of one meter, and two meters result in total calorimetric uncertainties of 0.46 percent, and 0.50 percent, respectively, as shown in the table above. However, based on the principles of simple decision making and conservative plant operation, the staff determines that only one maintenance mode is acceptable, that is, the plant will be operated as follows:



<b>Maximum MWt</b>	<b>Total Power Uncertainty %</b>	<b>LEFM Operating Condition</b>
3020	0.30%	System Fully Functional
3015	0.46%	One Section (Plane) of Any One LEFMs in Maintenance
2968	2.0%	Dual Section (Plane) Failure of any LEFM meters or any other OOS

The licensee will establish plant procedures based on these calculated uncertainties to set power limitations for maintenance conditions.

Based on the above discussion and the staff's review of the licensee's LAR, RAI responses, and Cameron engineering reports, the NRC staff found that the licensee provided sufficient justifications for the proposed AOT and the proposed power reduction actions if the AOT is exceeded. Therefore, the licensee has followed the guidance in Items G and H of Section I of Attachment 1 to RIS 2002-03.

#### Conclusion

The NRC staff reviewed the licensee's proposed plant-specific implementation of the FW flow measurement device and the power uncertainty calculations. Based on its review of the licensee's LAR, RAI responses, uncertainty calculations, and referenced topical reports, the NRC staff finds that the licensee's proposed amendment is consistent with the approved Caldon Topical Report ER-80P and its supplement Topical Report ER-157P. The staff also finds that the licensee adequately accounted for all instrumentation uncertainties in the total thermal power measurement uncertainty calculations and demonstrated that the calculations meet the relevant requirements of 10 CFR Part 50, Appendix K, and NRC RIS 2002-03, as described above. The licensee has committed to the following action:

Final verification of the site-specific uncertainty analyses occurs as part of the LEFM CheckPlus™ system commissioning process. The commissioning process provides final positive confirmation that actual performance in the field meets the uncertainty bounds established for the instrumentation as described in Cameron engineering report ER-733 (page 2.4.4-5, paragraph 2 of Attachment 5 to the LAR, Reference 1).

Therefore, the staff concludes that the I&C aspect of the proposed MUR thermal power uprate of 1.7 percent is acceptable.

## 2.5 Plant Systems

### 2.5.1 Internal Hazards

#### 2.5.1.1 Flooding

##### 2.5.1.1.1 Flood Protection

#### Regulatory Evaluation

The NRC staff conducted a review in the area of flood protection to ensure that SSCs important to safety are protected from flooding. The NRC staff's review covered flooding of SSCs important to safety from internal sources, such as those caused by failures of tanks and vessels. The NRC staff's review focused on increases of fluid volumes in tanks and vessels assumed in flooding analyses to assess the impact of any additional fluid on the flooding protection that is provided. The NRC's acceptance criteria for flood protection are based on GDC 2. Specific review criteria are contained in SRP Section 3.4.1.

#### Technical Evaluation

In Section 2.5.1.1.1 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on flood protection analysis in comparison to its current design basis described in the FSAR for St. Lucie 1. Specific FSAR sections evaluated by the licensee were Sections 3.1.2, Criterion 2 – Design Bases for Protection Against Natural Phenomena, Section 3.4.4, Flood Protection, and Chapter 9.5A Subsection 3.1.3, ECCS Pump Room Flooding Analysis. The licensee indicated that the design basis external flooding event outside containment is the postulated rupture of a fire main pipe, in which the proposed EPU will not impact the potential for internal flooding from a postulated rupture of a fire main pipe not impact the fire protection system. This is due to no physical changes requiring to be made to the fire protection system flow, pressure or piping to support EPU conditions.

The licensee further stated in the EPU licensing report that "St. Lucie Units 1 and 2, Individual Plant Examination (IPE) Submittal" was submitted in response to NRC GL 88-20, Individual Plant Examination for Severe Accident Vulnerabilities – 10 CFR 50.54(f). Section 3.6 specifically addressed an internal flooding analysis for structures outside containment. The IPE submittal was evaluated according to the proposed EPU. The licensee identified several flood zones in the IPE submittal that were determined to be vulnerable to the effects of floods, and found to have the potential for contributing to the overall core damage frequency.

The flood zones identified were:

- Steam trestle/auxiliary FW pumps
- Intake cooling water
- Component cooling
- Condensate pump and condenser area/condensate pump pit
- FW pumps 1A and 1B
- Aerated waste storage tank and main hallway east (El. 19.5 feet)
- Shutdown heat exchangers 1A and 1B
- Pipe tunnel
- 1A and 1B emergency core cooling system

- Holdup tank enclosure
- “AB” switchgear room
- “B” switchgear room
- Cable spreading room
- “A” switchgear room
- Resin addition tank
- Control room
- Component cooling water surge tank

These flood zones were defined by the licensee as identical to the fire zones described in the fire protection analysis in FSAR Chapter 9.5A. The licensee also performed a zone-by-zone screening by utilizing plant drawing reviews, plant walkdowns, and review of previous internal flooding analyses. Consequently, the licensee determined that the proposed EPU will not introduce any new internal flood/spray scenario that could provide a significant contribution to the overall risk of the plant. The licensee also indicated that the proposed EPU will not impact the above flood zones identified in the St. Lucie 1 IPE submittal due to no increase in fluid volumes contained in tanks within the flood zones as a result of the EPU.

The staff evaluated the licensee’s FSAR references along with the GDC 2 criteria for flood protection. The staff found that the licensee did not provide additional justification to make its determination on how the proposed EPU would not impact the flood zones as described in the IPE submittal. The staff issued RAI 2.5.1.1.1-01, dated May 27, 2011, to the licensee seeking additional justification regarding these flood zones. The licensee provided its RAI response by letter, dated June 22, 2011, extensive details on the proposed EPU impacts on the above flood zones. In each area, the licensee described why the proposed EPU would not introduce any new initiating events that would impact the internal flooding analysis at St. Lucie 1. The staff determined that the licensee’s assessment of flood protection at St. Lucie 1 during EPU conditions is acceptable because no changes are being made to the physical components that are included in the flood zones and the evaluations of the flood zones during EPU conditions will continue to be met as described in the St. Lucie 1 IPE submittal. Therefore, the staff concluded that protection against external and internal flooding remains consistent with the St. Lucie licensing basis and acceptable for proposed EPU operation.

### Conclusion

The NRC staff has reviewed the proposed changes in fluid volumes in tanks and vessels for the proposed EPU. The NRC staff concludes that SSCs important to safety will continue to be protected from flooding and will continue to meet the requirements of GDC 2 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to flood protection.

#### 2.5.1.1.2 Equipment and Floor Drains

### Regulatory Evaluation

The function of the equipment and floor drainage system (EFDS) is to assure that waste liquids, valve and pump leakoffs, and tank drains are directed to the proper area for processing or disposal. The EFDS is designed to handle the volume of leakage expected, prevent a backflow of water that might result from maximum flood levels to areas of the plant containing safety-related equipment, and protect against the potential for inadvertent transfer of

contaminated fluids to an uncontaminated drainage system. The NRC staff's review of the EFDS included the collection and disposal of liquid effluents outside containment.

The NRC staff's review focused on any changes in fluid volumes or pump capacities that are necessary for the proposed EPU and are not consistent with previous assumptions with respect to floor drainage considerations. The NRC's acceptance criteria for the EFDS are based on GDC 2 and 4 insofar as they require the EFDS to be designed to withstand the effects of earthquakes and to be compatible with the environmental conditions (flooding) associated with normal operation, maintenance, testing, and postulated accidents (pipe failures and tank ruptures). Specific review criteria are contained in SRP Section 9.3.3.

#### Technical Evaluation

In Section 2.5.1.1.2 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the EFDS in comparison to its current design basis described in the St. Lucie 1 FSAR. The specific FSAR section evaluated by the licensee was Section 9.3.3, Equipment and Floor Drainage System. The licensee also evaluated IE Notice 83-044, "Potential Damage to Redundant Safety Equipment as a Result of Backflow Through the Equipment and Floor Drain System," for any impacts of the proposed EPU on the evaluation performed for potential backflow through the EFDS. The licensee determined through its assessment that the proposed EPU would not impact the seismic design of components in the EFDS nor add or modify equipment in the St. Lucie 1 reactor building, reactor auxiliary building, or fuel handling building that would result in increasing the quantities of liquids currently entering the EFDS. The licensee also determined that there are no changes to the EFDS that would allow contaminated fluids to be inadvertently transferred to an uncontaminated drainage system. The licensee further determined that its assessment of IE Notice 83-044 remains valid for EPU conditions, in which the licensee previously assessed that the scenario of flooding damage into safety-related equipment caused by backflow through the EFDS could not occur at St. Lucie 1.

The staff evaluated the licensee's assessment of the proposed EPU effects on the EFDS according to GDC 2 and GDC 4. The staff found that the licensee did not provide further information regarding how the internal flooding assessments were performed for the EFDS. The staff issued RAI 2.5.1.1.2-01, by letter dated May 27, 2011, to the licensee for further information on the internal flooding assessment for the EFDS. The licensee provided in its RAI response by letter, dated June 22, 2011, "...that the regulatory requirement for the internal flooding review for St. Lucie Unit 1 was limited to the effects of a postulated fire main pipe rupture, as provided in FSAR Appendix 9.5A, Section 3.1.3. Water from a ruptured fire line could eventually drain toward the emergency core cooling system (ECCS) pump room sumps located at elevation -10 ft. The ECCS Pump Room Flooding Analysis presented in FSAR Appendix 9.5A, Section 3.1.3, demonstrates that flooding will not result in a loss of ECCS function." The licensee provided additional details regarding the design of the ECCS pump room to discuss how flooding would not impact the ECCS function during EPU conditions. The licensee further iterated in its RAI response that no additional or modified equipment would be required for the EFDS for EPU conditions and the licensee would maintain its current ability to limit flooding in the ECCS pump rooms. The staff evaluated the licensee's RAI response and determined that its assessment of the EFDS is acceptable due to no physical or design changes being made to the EFDS to support EPU conditions. The staff also finds the licensee's assessment of internal flooding effects on the EFDS acceptable. Therefore, the staff concluded that the EFDS remains consistent with the St. Lucie licensing basis and acceptable for proposed EPU operation.

## Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the EFDS and concludes that the licensee has adequately accounted for the plant changes resulting in increased water volumes and larger capacity pumps or piping systems. The NRC staff concludes that the EFDS has sufficient capacity to (1) handle the additional expected leakage resulting from the plant changes, (2) prevent the backflow of water to areas with safety-related equipment, and (3) ensure that contaminated fluids are not transferred to noncontaminated drainage systems. Based on this, the NRC staff concludes that the EFDS will continue to meet the requirements of GDC 2 and 4 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the EFDS.

### 2.5.1.1.3 Circulating Water System

The circulating water system (CWS) provides a continuous supply of cooling water to the main condenser to remove excess heat from the turbine cycle and auxiliary systems. For proposed power uprates, the staff's review of the CWS includes evaluating the impact that the proposed uprate will have on existing flooding analyses due to any increases that may be necessary in fluid volumes or flow rates that could result from installation of larger capacity CWS pumps or piping. There are no modifications to the circulating water pumps or system that would increase the maximum flow from a rupture in the system. Accordingly, the analyses and design features related to internal flooding due to leakage or a break in the circulating water system for current plant conditions are unaffected by the EPU.

### 2.5.1.2 Missile Protection

#### 2.5.1.2.1 Internally Generated Missiles

## Regulatory Evaluation

The NRC staff's review concerns missiles that could result from in-plant component overspeed failures and high-pressure system ruptures. The NRC staff's review of potential missile sources covered pressurized components and systems, and high-speed rotating machinery. The NRC staff's review was conducted to ensure that safety-related SSCs are adequately protected from internally generated missiles. In addition, for cases where safety-related SSCs are located in areas containing non-safety-related SSCs, the NRC staff reviewed the non-safety-related SSCs to ensure that their failure will not preclude the intended safety function of the safety-related SSCs. The NRC staff's review focused on any increases in system pressures or component overspeed conditions that could result during plant operation, anticipated operational occurrences, or changes in existing system configurations such that missile barrier considerations could be affected. The NRC's acceptance criteria for the protection SSCs important to safety against the effects of internally generated missiles that may result from equipment failures are based on GDC 4. Specific review criteria are contained in SRP Sections 3.5.1.1 and 3.5.1.2.

### Technical Evaluation

In Section 2.5.1.2.1 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the internally generated missiles analysis in comparison to its current design basis described in the St. Lucie 1 FSAR. Specific FSAR sections evaluated by the licensee were FSAR Section 3.5.2.1 and Section 3.5.3.2.b. The licensee's assessment of internally generated missiles focused on any increase in system pressure or component overspeed conditions due to implementation of EPU that could result during plant operation, anticipated operational occurrences, or changes in existing system configurations such that missile barriers could be affected. The licensee concluded that the proposed EPU would not affect the existing missile barrier protection measures due to no system or equipment changes being made. The licensee also determined that the existing missile analysis for St. Lucie 1 will remain valid for EPU conditions due to no operating pressures not increasing for the reactor coolant and main steam systems.

The staff reviewed the licensee's assessment of internally generated missiles for the proposed EPU according to GDC 4. The staff finds the licensee's assessment acceptable due to no changes being made to any systems and components that are currently part of the existing missile analysis for St. Lucie 1 and the current analysis remains valid for EPU conditions. The staff identified no other modifications with the potential to affect missile protection of safety-related components outside containment. Therefore, the staff concluded that the licensee's internally generated missiles analysis remains consistent with the St. Lucie licensing basis and acceptable for proposed EPU operation.

### Conclusion

The NRC staff has reviewed the changes in system pressures and configurations that are required for the proposed EPU and concludes that SSCs important to safety will continue to be protected from internally generated missiles and will continue to meet the requirements of GDC 4 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to internally generated missiles.

#### 2.5.1.2.2 Turbine Generator

### Regulatory Evaluation

The turbine control system, steam inlet stop and control valves, low pressure turbine steam intercept and inlet control valves, and extraction steam control valves control the speed of the turbine under normal and abnormal conditions, and are thus related to the overall safe operation of the plant. The NRC staff's review of the turbine generator focused on the effects of the proposed EPU on the turbine overspeed protection features to ensure that a turbine overspeed condition above the design overspeed is very unlikely. The NRC's acceptance criteria for the turbine generator are based on GDC 4, and relates to protection of SSCs important to safety from the effects of turbine missiles by providing a turbine overspeed protection system (with suitable redundancy) to minimize the probability of generating turbine missiles. Specific review criteria are contained in SRP Section 10.2.

### Technical Evaluation

In Section 2.5.1.2.2 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the turbine generator with regards to missile protection analysis in comparison to its current design basis as described in the St. Lucie 1 FSAR. Specific FSAR sections evaluated by the licensee were Section 3.5, Missile Protection; Section 7.7, Control Systems Not required for Safety; and Section 10.2, Turbine Generator. The licensee provided a detailed description of the turbine generator and control systems as well as the overspeed protection. The licensee also described its missile generation analysis used for St. Lucie 1 and the impact of the proposed EPU. The licensee made the following conclusions in regards to effects of the EPU on turbine generator under EPU conditions:

- The normal operating turbine running speed of 1800 rpm [revolutions per minute] will not change as a result of the power uprate and its associated modifications.
- The design overspeed limit of 120-percent will not change as a result of the power uprate.
- Maintenance, inspection and testing associated with the turbine rotors and the turbine overspeed control system, including frequencies of these activities, will not change as a result of the EPU.
- The existing 18 month fuel cycle conditional probability of destructive overspeed value of  $2.58\text{E-}6$  per year will remain unchanged after EPU and its associated modifications. This conditional probability assumes system separation as a precursor event and is based on a 6 month turbine valve test interval.
- The probability value of the precursor system separation event of  $5.40\text{E-}02$  is unchanged by the EPU. Therefore, the probability of generating a destructive overspeed missile, which is taken as the product of the system separation and above conditional probability values, remains at a value of  $1.39\text{E-}07/\text{year}$  under EPU conditions.
- Material properties of the replacement rotors along with their physical properties will be considered in the generation and growth of disk cracks and the potential generation and ejection of missiles originating from the failure of these new turbine disks in the evaluation of the EPU design condition.
- The normal operating turbine running speed of 1800 rpm will not change as a result of the power uprate and its associated modifications.
- The design overspeed limit of 120 percent will not change as a result of the power uprate.

The licensee also stated that the two existing low pressure (LP) turbines will be replaced with new Siemens-supplied replacement turbines prior to the implementation of the EPU. In addition, the high pressure (HP) rotor will be replaced due to the increased volumetric flow requirements under the proposed uprate condition. The licensee indicated that these modifications to the turbine generator will result in a significant overall increase in the compound

turbines moment of inertia as compared to the existing unit. However, the licensee stated that the effects will be "...somewhat offset by the operational changes of higher pressure and power output, as well as, by the increased efficiency of the replacement rotors."

In addition to the physical changes to the LP and HP turbines, the licensee also stated that the Overspeed Protection Controller (OPC), the associated OPC solenoid valves, the emergency trip turbine trip solenoid valve and the mechanical overspeed trip device are planned to be replaced as part of an overall turbine control system (TCS) upgrade to improve reliability and maintainability. The revised TCS will be provided by Westinghouse, which is called Ovation, and will be based on a standard design previously installed for other U.S. nuclear power plants. Two independent overspeed protection systems will be provided and each of these systems will include two out of three redundancies for speed sensing and turbine trip solenoid valve logic. The licensee justified this change to the TCS due to Westinghouse Topical Report WCAP-16501-P "Extension of Turbine Valve Test Frequency Up to 6 Months for BB-296 Siemens Power Generation Turbines with Steam Chests, Rev. 0."

In addition to the changes to the overspeed protection system, the licensee indicated that the proposed EPU will increase the power level and amount of trapped energy in the power generation system that taken independent of other changes would result in an increase in the expected peak turbine overspeed. However, the licensee determined that the power increase and the volume increase due to moisture separator reheater and FW heater changes will be offset by changes associated with the new replacement turbine rotors. The licensee also performed an evaluation to establish the post-EPU overspeed condition based on both the increased power and flow levels, as well as, the physical changes of the replacement rotors. The licensee concluded that the increased inertia of the rotors outweighed the impact due to the power increase from the uprate such that the net effect was a 1-percent reduction in the expected overspeed of the turbine.

The licensee also performed a revised turbine missile generation analysis on the LP rotors. The revised analysis focused on the changes to the normal operating condition and the new LP rotors to establish a revised probability for both the postulation of a LP rotor disk failure and the probability of a disk section exiting the casing given this failure. The licensee's assessment of the probability of the LP rotors missile generation due to run-away overspeed was based upon the original TCS values, in which the licensee found to be conservative.

The staff reviewed the licensee's assessment of the effects of proposed EPU on the turbine generator and the revised missile generation analysis for the LP rotors according to GDC 4. The staff found that the licensee did not provide justification for using the Siemens rotors with the revised Westinghouse TCS. The staff issued RAI 2.5.1.2.2, by letter dated May 27, 2011, to the licensee for further information describing the compatibility of the Siemens rotors with the revised TCS. The licensee provided its RAI response, by letter dated June 22, 2011, with additional information on the turbine missile generation analysis regarding the LP rotors. The licensee referenced the NRC's safety evaluation (ADAMS Accession Number ML040930616), which accepted the Siemens Westinghouse topical report TR-TP-04124, "Missile Probability Analysis for the Siemens 13.9M Retrofit Design of Low-Pressure Turbine by Siemens AG." The licensee used the topical report to provide its basis for using the new Siemens LP rotors with the revised Westinghouse TCS and concluded the current design analysis for missile protection along with the testing and maintenance requirements would remain consistent for EPU conditions.



Section 3.5 of the St. Lucie 1 FSAR specifies that missile barrier protection is based on missiles generated by disk failure at design overspeed of 120 percent, which does not encompass overspeed protection system failure. The Siemens Westinghouse topical report TR-TP-04124, provides an NRC-accepted licensing basis for failures at or below design overspeed. However, the staff found that the licensee did not clearly specify this analysis as the new licensing basis for protection against failure of the replacement rotors at or below design overspeed at EPU conditions. Also, the staff found that this topical report did not include an applicable evaluation of destructive overspeed failure probability.

The licensee stated in the EPU licensing report and in its RAI response to RAI 2.5.1.2.2 that the WCAP-16501-P report provides analyses for overspeed protection system failures for several plants, including St. Lucie 1. This topical report was based on the configuration of the existing TCS. However, the licensee indicated that the overspeed protection system would be replaced with the Ovation turbine control and protection system. The licensee stated in the RAI response that the Ovation system enhances control system reliability and continued usage of the existing overspeed protection system failure probability in the overspeed protection analysis cited in WCAP-16501 would be conservative.

Although the staff found the licensee's assessment of the new Siemens rotors acceptable, the staff found the licensee's initial RAI response regarding the overspeed protection system failure probability, along with the testing and maintenance requirements, for the turbine generator unacceptable. The staff initially rejected the licensee's use of WCAP-16501 as justification for the overspeed protection analysis because the report is not applicable to the proposed new turbine overspeed protection system. The staff also disagreed with the licensee's initial assessment that the existing testing and maintenance requirements for the previous TCS will be applicable to the new Ovation system since the new system has not been formally tested with the EPU parameters at St. Lucie 1. The staff transmitted a follow-up RAI to the licensee on November 15, 2011 for clarification of the proposed EPU licensing basis for protection against failure at or below design overspeed and provide a detailed technical basis for the continued use of the existing overspeed protection system failure probability with the Ovation overspeed protection system. The staff requested the licensee to address as part of its response the changes in design (e.g., elimination of mechanical overspeed trip), potential for common cause/mode failure of redundant components, potential for latent failures undetected by testing of trip paths, and commitments to turbine steam admission valve and overspeed trip system testing at frequencies necessary to support the proposed reliability.

The licensee provided its supplemental response to the RAI, by letter dated December 14, 2011, with a detailed discussion of its technical basis for using the new Ovation overspeed protection system with the existing criteria for the turbine generator. In the supplemental response, the licensee clarified that the Siemens Westinghouse Topical Report TP-04124 (and its associated Technical Report CT-27332, Revision 2), "Missile Probability Analysis for the Siemens 13.9 M2 Retrofit Design of Low-Pressure Turbine by Siemens AG," would form the St. Lucie 1 licensing basis for evaluation of turbine failures at or below design overspeed at EPU conditions. Since the NRC staff approved the methodology and issued a Final Safety Evaluation for CT-27332, Rev. 2 on March 30, 2004 (ADAMS Accession No. ML040410360), the revised licensing basis is acceptable.

The licensee references the WCAP-16501-P as its technical justification for using a 6-month steam admission valve testing interval at St. Lucie 1 as opposed to the 3-month interval proposed in the Siemens Westinghouse Topical Report TP-04124. The licensee provided

extensive detail as part of in the supplemental response to indicate that the effect of the Ovation overspeed protection system on the conditional probability of destructive overspeed is negligible for both intervals and the system reliability and overspeed probability are bounded by the current analysis for post-EPU conditions.

The licensee also referenced NUREG-1793, Supplement 2, "AP1000 Design Certification Amendment, Advanced Final Safety Evaluation Report, Chapter 10 - Steam and Power Conversion" (ADAMS Accession No. ML 100910522) as part of its technical justification for using the new Ovation overspeed protection system for the turbine generator during EPU conditions. The licensee indicated that the Ovation overspeed protection system's logic platform is similar to the platform integrated into the AP1000 Advanced Light-Water Reactor standard design that was evaluated and accepted by the NRC. The licensee also provided additional details in its supplemental response addressing how the Ovation overspeed protection system improves upon the current overspeed protection system at St. Lucie 1 and the functionality of the new Ovation overspeed protection system will remain bounded by the WCAP-16501-P analyses for St. Lucie 1 during EPU conditions.

The licensee also provided a set of the following commitments to address the testing and functionality of the new Ovation overspeed protection system as stated for Acceptance Criteria 11.1 in Section 10.2 of the NUREG-0800 Standard Review Plan (SRP):

- Testing of the speed probes will be performed off-line at refueling intervals. The analog signals are displayed for channel comparison. The analog signal quality discrimination is always active and an alarm occurs on speed deviation between any two of the three channels (for both passive and active probe sets).
- Testing of the Speed Detector Modules will be performed off-line at refueling intervals.
- Testing of the Testable Dump Manifolds will be performed on-line (one channel at a time) at a quarterly interval.
- Testing of the TCS Controller overspeed logic will be performed during startup at a refueling interval. This test will verify overspeed trip capability of the redundant controllers. The test will be conducted at a reduced setpoint. The setpoint is automatically returned to the overspeed trip setting following termination of the overspeed trip test. The reduced setpoint is used to minimize turbine stresses that occur during overspeed conditions.
- Testing of the steam admission valves will occur at the current 6 month interval.

The staff reviewed the licensee's supplemental response for using the new Ovation overspeed protection system using the existing criteria for the turbine generator missile generation analysis and finds that the licensee's assessment meets GDC 4. The staff also finds that the licensee provided adequate justification for using the six month steam admission valve testing interval as opposed to the three month interval. The staff also finds that the licensee adequately addressed how the technical attributes of the new Ovation overspeed protection system will meet the current overspeed protection analysis for St. Lucie 1 under EPU conditions. The staff also finds the testing commitments for the new Ovation overspeed protection system to be acceptable for EPU implementation. Therefore, the staff concluded that the licensee's analysis

for the turbine generator remains consistent with the St. Lucie 1 licensing basis and acceptable for proposed EPU operation.

### Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the turbine generator and concludes that the licensee has adequately accounted for the effects of changes in plant conditions on turbine overspeed. The NRC staff concludes that the turbine generator will continue to provide adequate turbine overspeed protection to minimize the probability of generating turbine missiles and will continue to meet the requirements of GDC 4 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the turbine generator.

#### 2.5.1.3 Pipe Failures

##### Regulatory Evaluation

The NRC staff conducted a review of the plant design for protection from piping failures outside containment to ensure that (1) such failures would not cause the loss of needed functions of safety-related systems and (2) the plant could be safely shut down in the event of such failures. The NRC staff's review of pipe failures included high and moderate energy fluid system piping located outside of containment. The NRC staff's review focused on the effects of pipe failures on plant environmental conditions, control room habitability, and access to areas important to safe control of post-accident operations where the consequences are not bounded by previous analyses. The NRC's acceptance criteria for pipe failures are based on GDC 4, which requires, in part, that SSCs important to safety be designed to accommodate the dynamic effects of postulated pipe ruptures, including the effects of pipe whipping and discharging fluids. Specific review criteria are contained in SRP Section 3.6.1.

##### Technical Evaluation

In Section 2.5.1.3 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the pipe failures analysis in comparison to its current design basis described in the St. Lucie 1 FSAR. The specific FSAR section evaluated by the licensee was Section 3.6, Protection Against Dynamic Effects Associated with the Postulated Rupture of Piping. The licensee evaluated the following systems outside containment with current piping break analyses for EPU conditions:

- Main Steam system
- Main FW system
- Chemical and Volume Control system (CVCS) (letdown and charging lines)
- SG Blowdown system
- Auxiliary Steam system
- Shutdown cooling/LPSI system

The licensee concluded in each of the above areas that no new high energy lines outside containment were identified as a result of EPU. The licensee also concluded that the EPU does not result in any new pipe break locations to piping outside containment in the above systems. The licensee also stated that no modifications are being made to any of the systems that would

impact the pipe failure analyses and the EPU effects of the temperature increase are either minimal or have no effect at all on the piping failure analyses for the systems.

The staff reviewed the licensee's assessment of pipe failures according to GDC 4 and found that the EPU would not affect the protection of SSCs important to safety due to postulated pipe failures. Therefore, the staff finds the area of pipe failures acceptable for EPU conditions and a further evaluation is not required.

### Conclusion

The NRC staff has reviewed the changes that are necessary for the proposed EPU and the licensee's proposed operation of the plant, and concludes that SSCs important to safety will continue to be protected from the dynamic effects of postulated piping failures in fluid systems outside containment and will continue to meet the requirements of GDC 4 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to protection against postulated piping failures in fluid systems outside containment.

#### 2.5.1.4 Fire Protection

### Regulatory Evaluation

The purpose of the fire protection program is to provide assurance, through a defense-in-depth design, that a fire will not prevent the performance of necessary plant safe-shutdown functions or significantly increase the risk of radioactive releases to the environment. The NRC staff's review focused on the effects of the increased decay heat on the plant's safe-shutdown analysis to ensure that structures, systems, and components (SSCs) required for the safe-shutdown of the plant are protected from the effects of the fire and will continue to be able to achieve and maintain safe-shutdown following a fire. The NRC's acceptance criteria for the fire protection program are based on (1) 10 CFR 50.48, "Fire protection," insofar as it requires the development of a fire protection program to ensure, among other things, the capability to safely shut down the plant; (2) GDC 3 of Appendix A to 10 CFR Part 50, insofar as it requires that (a) SSCs important to safety be designed and located to minimize the probability and effect of fires, (b) noncombustible and heat resistant materials be used, and (c) fire detection and suppression systems be provided and designed to minimize the adverse effects of fires on SSCs important to safety; and (3) GDC 5 of Appendix A to 10 CFR Part 50, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions. Specific review criteria are contained in Appendix D of NUREG-0800, Revision 0, "Standard Review Plan," Section 9.5.1.1, "Fire Protection Program," as supplemented by the guidance provided in Attachment 1 to Matrix 5 of Section 2.1 of RS-001, Revision 0, "Review Standard for Extended Power Upgrades." St. Lucie 1 was licensed to operate on March 1, 1976; and is a Combustion Engineering PWR nuclear steam supply system.

The St. Lucie 1 fire protection program describes the fire protection features of the plant necessary to comply with Branch Technical Position (BTP) Auxiliary and Power Conversion Systems Branch (APCSB) 9.5-1, Appendix A, dated August 23, 1976. The SER, dated August 17, 1979 and its supplements, describe the approved fire protection program for St. Lucie 1. The SER and supplements are listed in the St. Lucie 1 operating license. In addition to the SER and supplements, the St. Lucie 1 fire protection program was evaluated for

plant license renewal. The evaluation is documented in NUREG-1779, "Safety Evaluation Report Related to the License Renewal of the St. Lucie Nuclear Plant, Units 1 and 2," dated July 2003.

#### Technical Evaluation

FPL developed the LAR utilizing the guidelines in RS-001, Revision 0, *Review Standard for Extended Power Uprates*. In the LAR, the licensee evaluated the applicable SSCs and safety analyses at the proposed EPU core power level of 3020 MWt. The staff's review of the November 22, 2010, LAR, Section 2.5.1.4., "Fire Protection," Attachment 5, to L-2010-259, identified areas in which additional information was necessary to complete the review of the proposed EPU LAR. In an email dated April 27, 2011, the staff issued an RAI. By the letter dated May 24, 2011, FPL responded to the staff RAI as discussed below.

In RAI AFB-1, the staff noted that RS-001, Revision 0, *Review Standard for Extended Power Uprates*, states that "power uprates typically result in increases in decay heat generation following plant trips. These increases in decay heat usually do not affect the elements of a fire protection program related to (1) administrative controls, (2) fire suppression and detection systems, (3) fire barriers, (4) fire protection responsibilities of plant personnel, and (5) procedures and resources necessary for the repair of systems required to achieve and maintain cold shutdown. In addition, an increase in decay heat will usually not result in an increase in the potential for a radiological release resulting from a fire. However, the licensee's LAR should confirm that these elements are not impacted by the extended power uprate." The staff noted that LAR, Attachment 5, to L-2010-259, "Licensing Report," Section 2.5.1.4.2.3, on page 2.5.1.4-4, specifically addresses only items (1) through (3) above. The staff requested that the licensee provide statements to address items (4) and (5).

In its response the licensee stated that the St. Lucie 1, fire protection plan describes the fire protection responsibilities of the plant management personnel, the shift manager, the fire protection supervisor, the fire protection coordinator, the fire protection inspector, the fire brigade leader, and the fire brigade. In addition, the licensee stated that the fire protection responsibilities of the above-identified plant personnel are not affected by the EPU.

The licensee stated that St. Lucie 1 does not credit any repairs in order to achieve and maintain cold shutdown at current and EPU condition. Therefore, no repair procedures are required.

The licensee's response satisfactorily addresses the staff's concerns, and this RAI issue is considered resolved based on the following: The licensee indicated that the proposed EPU condition does not affect the fire protection responsibilities for plant personnel and shutdown analysis takes no credit for post fire repair of cold shutdown equipment. Therefore, no procedures are required. Since the elements are not impacted by the EPU, the staff finds the response acceptable.

In RAI AFB 2, the staff noted LAR, Attachment 5, to L-2010-259, Section 2.5.1.4.2.3., on page 2.5.1.4-5, states that, "...The impact of plant modifications being implemented in support of EPU (e.g., upgrade of main transformers with new coolers) on the FPP will be addressed in accordance with the plant change/modification process..."

The staff requested that the licensee clarify whether this request involves plant modifications or changes to the fire protection program (e.g., adding new cable trays, re-routing of existing

cables, increases in combustible loading affecting fire barrier ratings, or changes to administrative controls) at EPU conditions. If any, the staff requested the licensee to identify proposed modifications on the plant's compliance with the fire protection program licensing basis, 10 CFR 50.48, or applicable portions of 10 CFR Part 50, Appendix R.

In its response the licensee stated that there are no plant modifications planned in support of EPU that impact compliance with the fire protection program licensing basis, 10 CFR 50.48 or applicable portions of 10 CFR Part 50, Appendix R. The LAR does not involve changes to the fire protection program. Further, the licensee indicated that the modifications being implemented for EPU are evaluated in accordance with the engineering change process to assure continued compliance with the site's fire protection program licensing basis. Although features of the fire protection program, such as combustible material loading, fire barrier rating, and administrative controls, may be impacted by a proposed design change, the engineering change process requires that proposed modifications be evaluated against and comply with fire protection program requirements. EPU modifications do not reduce the effectiveness of fire protection for facilities, systems, and equipment, and do not adversely affect the capability of existing fire protection features and safe-shutdown following a fire. The EPU modifications do not result in adverse changes to the fire protection program's compliance with 10 CFR 50.48, or applicable portions of 10 CFR Part 50, Appendix R.

The licensee's response satisfactorily addresses the staff's concerns, and this RAI issue is considered resolved based on the following: for the EPU condition, the licensee indicated that there are no changes to the fire protection program or applicable portions of 10 CFR Part 50, Appendix R. Further, the licensee indicated that the existing fire protection features, such as combustible material loading, the fire barrier rating, and administrative control may be impacted by a proposed design change and the plant engineering process requires that proposed modifications be evaluated against and comply with the fire protection program requirements.

The licensee stated that these changes were evaluated and determined to have no impact on the existing fire protection features and post-fire safe-shutdown capability. Since these changes do not impact fire protection features or post-fire safe-shutdown capability, the staff finds the response acceptable.

In RAI AFB 3, the staff noted that Attachment 5, to L-2010-259, Section 2.5.1.4.2.3., on page 2.5.1.4-13, states that "...The above manual actions and manual action time limits following a fire have been reviewed and are not affected for EPU conditions, which include increased decay heat loads. Assumptions of time response considered in performing these operator actions do not change as a result of EPU. No new operator actions are required to be added to the SSA in support of the EPU..." The staff requested the licensee to discuss (1) the operator action response time, including any assumptions that may have been made in determining that the operator manual actions are feasible and reliable and can be accomplished to achieve and maintain hot and then cold shutdown conditions; (2) how additional heat in the plant environment from the EPU will not interfere with required operator manual actions being performed at their designated time; and (3) the addition of any new operator actions required to maintain hot shutdown and any new operator actions required to place reactor in a cold shutdown condition.

In its response the licensee stated that the primary effect of operating at uprate conditions is the increased decay heat in the reactor core post plant trip. Therefore, operator manual actions with allowable times that are affected by decay heat levels are the actions that need to be

reviewed for the impact from operating at uprated power conditions. The following operator manual actions were reviewed: Establishing AFW; Power operated relief valve (PORV) closure; Letdown isolation; Establishing charging flow; Tripping of the reactor coolant pumps (RCPs); Main FW isolation; and SG isolation. The licensee stated that for uprate conditions, allowable operator manual actions time remains valid for all above conditions. Further, the licensee stated that the additional heat load in the plant environment from EPU does not impact current operator manual actions that will remain unchanged after EPU and no new operator actions need to be added to the safe-shutdown analysis in support of the EPU.

The licensee's response satisfactorily addresses the staff's concerns for the EPU condition, the licensee reviewed plant areas where operator manual actions are being performed for safe-shutdown following a fire to determine if additional heat due to EPU conditions could adversely impact those defined operator actions. The licensee stated that the evaluation determined that any changes to existing operator actions will remain unchanged under EPU and no new or additional operator manual actions are required as a result of the EPU. Based on its review, the staff concludes that the proposed EPU does not adversely impact operator manual actions, including no new actions. Note that this safety evaluation does not approve any new or existing operator manual actions concerning St. Lucie 1 fire safe shutdown analysis.

In RAI AFB 4, the staff stated that some plants credit aspects of their fire protection system for other than fire protection activities (e.g., utilizing the fire water pumps and water supply as backup cooling or inventory for non-primary reactor systems). If St. Lucie 1 credits its fire protection system in this way, the staff requested that the LAR identify the specific situations and discuss to what extent, if any, the extended power and measurement uncertainty recapture uprates affect these "non-fire-protection" aspects of the plant fire protection system. If St. Lucie 1 does not take such credit, the staff requested that the licensee verify this as well. The staff further requested that the licensee discuss how any non-fire suppression use of fire protection water will impact the need to meet the fire protection system design demands.

In its response the licensee stated that the St. Lucie 1 does not credit the fire water pumps or the dedicated fire water supply for non-fire protection functions during normal plant operations. Non-fire protection uses of other features of the fire protection system are as follows.

The fire protection system (FPS) is utilized to support the following two non-fire protection activities: (1) The FPS is capable of providing alternative makeup water service to the component cooling water surge tank if the demineralized water system is not available; and (2) the FPS can supply makeup water to the fuel pool to maintain an adequate fuel pool level in the event of complete loss of the fuel pool cooling system. The licensee stated that there is no impact to the FPS due to implementation of the EPU. The volume of water available for fire protection remains the same as prior to implementation of EPU. Further, the licensee indicated that during off-normal or emergency conditions, St. Lucie 1 employs features of the fire protection system as necessary to ensure the safe operation of the plant. Procedural guidance is provided to ensure the fire system remains capable of responding to a fire if applicable. Provisions for using fire water for off-normal or emergency evolutions are not changed as a result of EPU.

The licensee's response satisfactorily addresses the staff's concerns. The licensee stated that St. Lucie 1 does not credit the fire water pumps or fire protection water supply to support the design basis for non-fire protection functions. The licensee identified the following two provisions to use other features of the fire protection system for non-fire protection functions:

provide makeup water service to the component cooling water surge tank if the demineralized water system is not available and makeup water to the fuel pool to maintain an adequate fuel pool level in the event of complete loss of the fuel pool cooling system. The staff finds the licensee's response to the RAI acceptable because (1) St. Lucie 1 does not credit the fire protection system to support the design basis for non-fire protection functions, and (2) any non-fire protection uses of the system would not adversely impact the system's demands during design basis accidents.

Based on the licensee's fire-related safe-shutdown assessment and responses to the RAIs, the staff finds this aspect of the capability of the associated fire protection SSCs to perform their design basis functions at an increased core power level of 3020 MWt acceptable with respect to fire protection.

### Conclusion

The NRC staff has reviewed the licensee's fire-related safe shutdown assessment and concludes that the licensee has adequately accounted for the effects of the increased decay heat on the ability of the required systems to achieve and maintain safe shutdown conditions. The NRC staff further concludes that the FPP will continue to meet the requirements of 10 CFR 50.48, Appendix R to 10 CFR Part 50, and GDC 3 and 5 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to fire protection.

### 2.5.2 Pressurizer Relief Tank

#### Regulatory Evaluation

The pressurizer relief tank (PRT) is a pressure vessel provided to condense and cool the discharge from the pressurizer safety and relief valves. The tank is design with a capacity to absorb discharge fluid from the pressurizer relief valve during a specified step-load decrease. The PRT system is not safety-related and is not designed to accept a continuous discharge from the pressurizer. The NRC staff conducted a review of the PRT to ensure that operation of the tank is consistent with transient analyses of related systems at the proposed EPU level, and that failure or malfunction of the PRT system will not adversely affect safety-related SSCs. The NRC staff's review focused on any design changes related to the PRT and connected piping, and changes related to operational assumptions that are necessary in support of the proposed EPU that are not bounded by previous analyses. In general, the steam condensing capacity of the tank and the tank rupture disk relief capacity should be adequate, taking into consideration the capacity of the pressurizer power-operated relief and safety valves; the piping to the tank should be adequately sized; and systems inside containment should be adequately protected from the effects of high-energy line breaks and moderate-energy line cracks in the pressurizer relief system. The NRC's acceptance criteria for the PRT are based on: (1) GDC 2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes; and (2) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate and be compatible with specified environmental conditions, and be appropriately protected against dynamic effects, including the effects of missiles. Specific review criteria are contained in SRP Section 5.4.11.



## Technical Evaluation

In Section 2.5.2 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the quench tank (QT) in comparison to its current design basis described in the St. Lucie 1 FSAR. The specific FSAR Section evaluated by the licensee was Section 5.5.4, Quench Tank. The licensee described its historical analysis for the QT ability to condense steam releases without challenging the QT rupture disk for two separate events (the loss of load event and the uncontrolled rod withdrawal event). The licensee calculated that the QT could condense 610 pounds of steam for the loss of load event plus 830 pounds of steam for the uncontrolled rod withdrawal event. The licensee concluded in its assessment that a total mass of 1440 pounds of steam could be successfully condensed without challenging the QT rupture disk for current plant conditions. The licensee used the historical analysis for the QT and its components for comparison to the proposed EPU conditions. The licensee concluded in its evaluation of the QT under EPU conditions that the bounding steam releases for the loss of load event analysis were determined to be 546 pounds of steam and 830 pounds of steam for the uncontrolled rod withdrawal event analysis. Both of the steam releases are less than the design basis mass of 1440 pounds of steam assessed for current plant conditions. The licensee also concluded that no changes to the QT water level or temperature limits were needed since the EPU analysis is bounded by the current historical analysis for the QT.

The staff evaluated the licensee's assessment for the QT according to GDC 2 and GDC 4 and found that no physical changes to the QT and its components are being made to support EPU conditions. The staff also reviewed Review Standard-001 (RS-001) as well as the FSAR for any other potential EPU effects on the QT and found that the QT should support EPU conditions as described above since there are no changes to the QT's design basis. Therefore, the staff concluded that the licensee's QT analysis remains consistent with the St. Lucie licensing basis and acceptable for proposed EPU operation.

## Conclusion

The NRC staff has reviewed the increase in pressurizer discharge to the PRT as a result of the proposed EPU and concludes that (1) the PRT will operate in a manner consistent with transient analyses of related systems and (2) safety-related SSCs will continue to be protected against failure of the PRT consistent with GDC 2 and 4. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the design of the PRT.

### 2.5.3 Fission Product Control

#### 2.5.3.1 Fission Product Control Systems and Structures

The purpose of the staff's review of fission product control systems and structures is to confirm that current analyses remain valid or have been revised, as appropriate, to properly reflect the proposed EPU conditions. Consequently, the staff's review focuses primarily on any adverse effects that the proposed EPU might have on the assumptions that were used in the analyses that were previously completed. Because the impact of EPU on plant and structures identified by the licensee as making up the fission product control system, such as the containment spray and control room emergency ventilation systems, are addressed in Section 2.6, "Containment Review Considerations," Section 2.7, "Habitability, Filtration, and Ventilation," and Section 2.9, "Source Terms and Radiological Consequences Analyses," of this safety evaluation, a separate review of this area is not required.

### 2.5.3.2 Main Condenser Evacuation System

#### Regulatory Evaluation

The main condenser evacuation system (MCES) generally consists of two subsystems: (1) the "hogging" or startup system which initially establishes main condenser vacuum and (2) the system which maintains condenser vacuum once it has been established. The NRC staff's review focused on modifications to the system that may affect gaseous radioactive material handling and release assumptions, and design features to preclude the possibility of an explosion (if the potential for explosive mixtures exists). The NRC's acceptance criteria for the MCES are based on (1) GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents; and (2) GDC 64, insofar as it requires that means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences and postulated accidents. Specific review criteria are contained in SRP Section 10.4.2.

#### Technical Evaluation

In Section 2.5.3.2 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the MCES in comparison to its current design basis described in the St. Lucie 1 FSAR. Specific FSAR Section evaluated by the licensee was Section 10.4.2, Main Condenser Evacuation System. The licensee determined that the design of the MCES does not require modification for the EPU and, therefore, St. Lucie 1 will continue to effectively control radioactive material and monitor radioactive material releases. The licensee also stated that the hogging function is unaffected by uprate because the physical volume of the steam space is not changing and the current steam jet air ejector capacity of 50 cubic feet per minute (cfm) meets these standards for both pre-EPU and EPU conditions. The overall design of the MCES will not be changed due to the proposed EPU implementation since the condenser air removal requirements remain within the capacity of the existing system.

The staff reviewed the licensee's assessment of the MCES for the effects of the proposed EPU according to GDC 60 and GDC 64. The staff finds the licensee's assessment acceptable since the MCES will not be physically changed to continue its current function during EPU conditions and the MCES current design being capable of handling EPU operation without any prescribed changes. Therefore, the staff concluded that the licensee's MCES analysis remains consistent with the St. Lucie licensing basis and acceptable for proposed EPU operation.

#### Conclusion

The NRC staff has reviewed the licensee's assessment of required changes to the MCES and concludes that the licensee has adequately evaluated these changes. The NRC staff concludes that the MCES will continue to maintain its ability to control and provide monitoring for releases of radioactive materials to the environment following implementation of the proposed EPU. The NRC also concludes that the MCES will continue meet the requirements of GDC 60 and 64. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the MCES.

### 2.5.3.3 Turbine Gland Sealing System

#### Regulatory Evaluation

The turbine gland sealing system is provided to control the release of radioactive material from steam in the turbine to the environment. The NRC staff reviewed changes to the turbine gland sealing system with respect to factors that may affect gaseous radioactive material handling (e.g., source of sealing steam, system interfaces, and potential leakage paths). The NRC's acceptance criteria for the turbine gland sealing system are based on (1) GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents; and (2) GDC 64, insofar as it requires that means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences and postulated accidents. Specific review criteria are contained in SRP Section 10.4.3.

#### Technical Evaluation

In Section 2.5.3.3 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the turbine gland sealing system in comparison to its current design basis described in the St. Lucie 1 FSAR. The specific FSAR sections evaluated by the licensee were Section 10.4.3, Turbine Gland Steam System; Section 11.4.2, Continuous Monitoring; and 12.1.4, Area Monitoring. The licensee discussed minor effects on the turbine gland sealing system due to the proposed EPU conditions and indicated that mostly all physical components will remain intact except for the increase to the spillover system to support the High Pressure (HP) turbine modification and higher HP exhaust pressures due to EPU. The increase is needed to provide sufficient margin to keep the supply zone pressure at acceptable levels. However, the current configuration and functions of the turbine gland sealing system remain unchanged for EPU as related to utilizing the steam from the main steam system, handling pressure from the Low Pressure (LP) turbines, managing increased steam flow and condensate cooling flow, and routing non-condensable gases to the plant vent stack for radioactivity monitoring.

The staff reviewed the licensee's assessment of the turbine gland sealing system for the effects of the proposed EPU according to GDC 60 and GDC 64. The staff finds the licensee's assessment acceptable since the design capacity for controlling the release of radioactive effluents remains unchanged for EPU conditions. The design capacity for the turbine gland sealing system for providing a means to monitor effluent discharge paths and the plant environs for radioactivity also remains unchanged for EPU conditions. Therefore, the staff concluded that the licensee's turbine gland sealing system analysis remains consistent with the St. Lucie licensing basis and acceptable for proposed EPU operation.

#### Conclusion

The NRC staff has reviewed the licensee's assessment of required changes to the turbine gland sealing system and concludes that the licensee has adequately evaluated these changes. The NRC staff concludes that the turbine gland sealing system will continue to maintain its ability to control and provide monitoring for releases of radioactive materials to the environment consistent with GDC 60 and 64. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the turbine gland sealing system.

## 2.5.4 Component Cooling and Decay Heat Removal

### 2.5.4.1 Spent Fuel Pool Cooling and Cleanup System (SFPCCS)

#### Regulatory Evaluation

The spent fuel pool provides wet storage of spent fuel assemblies. The safety function of the spent fuel pool cooling and cleanup system is to cool the spent fuel assemblies and keep the spent fuel assemblies covered with water during all storage conditions. The NRC staff's review for the proposed EPU focused on the effects of the proposed EPU on the capability of the system to provide adequate cooling to the spent fuel during all operating and accident conditions. The NRC's acceptance criteria for the spent fuel pool cooling and cleanup system are based on (1) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions, (2) GDC 44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided, and (3) GDC 61, insofar as it requires that fuel storage systems be designed with RHR capability reflecting the importance to safety of decay heat removal, and measures to prevent a significant loss of fuel storage coolant inventory under accident conditions. Specific review criteria are contained in SRP Section 9.1.3, as supplemented by the guidance provided in Attachment 1 to Matrix 5 of Section 2.1 of RS-001.

#### Technical Evaluation

In Section 2.5.4.1 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the SFPCCS in comparison to its current design basis described in the St. Lucie 1 FSAR. The specific FSAR section evaluated by the licensee was Section 9.1.3, Fuel Pool System. The licensee evaluated the design basis, bulk temperature and time-to-boil analyses for the effects of the proposed EPU. For bulk temperature, the licensee concluded the following:

- For normal partial core offload, the maximum fuel pool bulk temperature calculated for this condition remains less than 150 °F considering defueling rates in excess of those physically achievable in the plant, when offload is initiated at greater than or equal to 140 hours after shutdown.
- For normal full core fuel offload, the maximum fuel pool bulk temperature calculated for this condition remains less than 150 °F, considering average defueling rates of 4 to 7 assemblies per hour, based on the variation in CCW temperature from 100 °F to 95 °F, when offload is initiated at greater than or equal to 140 hours after shutdown.
- For full core offload, the maximum thermal overshoot of 12 °F was determined to result from a full core fuel offload initiated at 140 hours after reactor shutdown. The procedural upper limit for the spent fuel pool temperature during full core offload will be set so as to ensure that 150 °F limit is not exceeded in the event of a failure of one fuel pool cooling pump, after accounting for the maximum thermal overshoot.

The staff requested clarification of the analysis performed at 140 hours for EPU conditions as opposed to the 120 hours for the current design capability of the SFPCCS. The licensee responded by letter, dated June 22, 2011, that 140 hours was chosen for EPU analysis due to

the actual timing to initiate the full core offload that goes beyond 120 hours after shutdown with one and two fuel pool cooling pumps in operation. The licensee also indicated that the initiation time for core offload has been greater than 140 hours for past several cycles and the time to initiate core offload is controlled through plant procedures as verified every cycle based on the cycle-specific fuel pool heat load. The licensee further stated that extending the core offload time to 140 hours after shutdown is also based on the fact that the increased fuel pool heat load in the EPU conditions.

For the time-to-boil analysis, the licensee concluded that sufficient time exists to provide an alternate means of cooling prior to the onset of boiling in the racks and that makeup requirements remain well below the available 150 gpm makeup capability after boiling occurs. For the local temperature analysis, the licensee determined that the calculated peak local water temperature is less than the local saturation temperature for EPU conditions. The maximum local fuel cladding temperature has also been determined to be less than the local saturation temperature. Thus, no localized boiling occurs and heat transfer is adequate to preclude departure from nucleate boiling (DNB).

For the analysis of the SFPCCS general capability of managing the increased heat load for EPU, the licensee determined that the design basis temperature limits are met for both partial and full core fuel offload evolutions, considering a concurrent single active failure. The licensee will also provide administrative guidance developed to control performance of fuel offload evolutions during EPU conditions. Requirements for inventory makeup, to maintain fuel pool level following the onset of boiling, are within the capability of installed plant systems. The licensee also stated that the SFPCCS piping and valves are acceptable for EPU without changes or modifications.

The staff has reviewed the licensee's assessment of the SFPCCS for EPU operation according to GDC 5, GDC 44, and GDC 61. The staff provided RAI 2.5.4.1-02, by letter dated May 27, 2011, to the licensee regarding clarification of methods used to evaluate the SFPCCS analysis and provide detailed information on any new heat loss modeling as necessary. The licensee responded by letter, dated June 22, 2011, that its methods for assessing the SFPCCS for EPU conditions are the same as its current licensing basis. The methods were approved by the NRC staff with an SE on July 9, 2004(Reference 23). The licensee provided a table as part of its RAI response listing the methods used to perform SFPCCS analyses and those methods were unchanged for the EPU calculations.

The staff is satisfied with the licensee's assessment, in which the SFPCCS will continue to have the capability to handle increased heat loads from safety-related SSCs and handle decay heat removal for EPU conditions. Additionally, the staff is satisfied with the licensee's administrative and procedural limitations to be used to maintain the SFPCCS during normal operation and accident events. Therefore, the staff finds the licensee's assessment of the SFPCCS acceptable for EPU operation.

### Conclusion

The NRC staff has reviewed the licensee's assessment related to the spent fuel pool cooling and cleanup system and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the spent fuel pool cooling function of the system. Based on this review, the NRC staff concludes that the spent fuel pool cooling and cleanup system will continue to provide sufficient cooling capability to cool the spent fuel pool following

implementation of the proposed EPU and will continue to meet the requirements of GDC 5, 44, and 61. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the spent fuel pool cooling and cleanup system.

#### 2.5.4.2 Station Service Water System

##### Regulatory Evaluation

The station service water system (referred to as the intake cooling water (ICW) in the St. Lucie 1 FSAR) provides essential cooling to safety-related equipment through the component cooling water (CCW) heat exchanger and may also provide cooling to non-safety-related auxiliary components that support normal plant operation. The intake cooling water system is designed to supply sufficient cooling water with a design seawater temperature of 95 °F to the component cooling heat exchangers to fulfill emergency requirements in the event of the design basis LOCA. There are no safety-related ICW components or safety-related functions shared between St. Lucie 1 and 2. The ICW system includes two redundant trains and each train is capable of providing the heat removal necessary for mitigation of a design basis LOCA. The ICW system pumps, valves, and piping are located outdoors and protection for the system safety function is provided by physical separation of the trains. In addition, the ICW pumps are provided with missile shielding.

The staff's review covered the characteristics of the ICW components with respect to their functional performance as affected by adverse operational (i.e., water hammer) conditions, abnormal operational conditions, and accident conditions (e.g., a LOCA with the LOOP). The staff's review focused on the additional heat load that would result from the proposed EPU. The NRC's acceptance criteria are based on (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, including flow instabilities and loads (e.g., water hammer), maintenance, testing, and postulated accidents; and (2) GDC 44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided. Specific review criteria are contained in SRP Section 9.2.1, as supplemented by GL 89-13 and GL 96-06.

##### Technical Evaluation

In Section 2.5.4.2 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the ICW in comparison to its current design basis described in the St. Lucie 1 FSAR. The specific FSAR section evaluated by the licensee was Section 9.2.1, Intake Cooling Water System. The licensee determined that the ICW system will continue to meet the current licensing basis with respect to the requirements of GDC 4 at EPU conditions because the system is located outdoors and its existing design will not be changed to support EPU operations.

The licensee evaluated the following design aspects of the ICW system for operation at EPU conditions:

- ICW flow and heat removal requirements
- Design pressure/temperature of piping and components
- Fouling and tube plugging in heat exchangers cooled by service water

The EPU accident analyses for post-LOCA containment pressure and temperature demonstrates that one ICW train provides sufficient heat removal capability to maintain containment parameters within design limits. The staff evaluation of this analysis is provided in Section 2.6.5 of this Safety Evaluation. In Table 2.5.4.2-1 of the EPU licensing report, the licensee also provided a comparison of post-LOCA ICW system response between the EPU containment pressure and temperature analysis, which used assumptions minimizing the heat removal from containment, and a similar analysis that used assumptions maximizing the heat transfer to a single train of ICW via the CCW system. Both analyses demonstrated that one ICW train provided sufficient heat removal from the CCW system using a 95 °F design inlet temperature such that the ICW temperature at the outlet of the CCW heat exchanger remains bounded by the system design temperature of 125 °F.

The licensee stated that the ICW system will also continue to supply sufficient cooling water flow to support safety and non-safety systems, as described in the EPU licensing report, without modifying or creating new operating modes or system lineups. The licensee indicated that there is no change to the ICW pump head performance at EPU conditions. The ICW pumps, design pressure, and temperature do not require modification for EPU and will continue to operate within their design capacity. The ICW outlet temperatures for EPU conditions remain bounded by the design temperature.

The licensee also evaluated the applicability of NRC GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment," and GL 96-06, "Assurance of Equipment Operability and Containment Integrity during Design-Basis Accident Conditions," to St. Lucie 1 during EPU conditions. In the case of GL 89-13, the EPU will not impact the programs, procedures, and activities in place at St. Lucie 1 and the current routine inspection and maintenance program from GL 89-13 will continue to ensure that the ICW system will remain reliable and operable after EPU implementation. The issues described in GL 96-06 do not apply to the ICW system because system piping does not enter containment,

The staff reviewed the licensee's assessment of the ICW system against GDC 4 and GDC 44 and found that the impact of EPU operation on the systems and components that utilize the ICW will not affect their capabilities to perform their safety functions, especially in the event of accident scenarios such as a LOCA. The current design features of the ICW have been evaluated by the licensee to show that the increased heat removal requirements associated with EPU remain within the ICW system heat removal capability. The staff found the results of the licensee's assessment reasonable because the changes in ICW system heat removal requirements were dominated by changes in the LOCA energy release, which were small relative to the magnitude of the power uprate.

### Conclusion

The NRC staff has reviewed the licensee's assessment related to the effects of the proposed EPU on the ICW and concludes that the licensee has adequately accounted for the increased heat loads on system performance that would result from the proposed EPU. The NRC staff concludes that the ICW will continue to provide sufficient cooling for SSCs important to safety following implementation of the proposed EPU and that the EPU had no effect on the system protection against dynamic effects. Therefore, the NRC staff has determined that the ICW will continue to meet the requirements of GDC 4 and GDC 44. Based on the above, the staff finds the proposed EPU acceptable with respect to the ICW.

#### 2.5.4.3 Reactor Auxiliary Cooling Water Systems

##### Regulatory Evaluation

The NRC staff's review covered the reactor auxiliary cooling water system (referred to as the component cooling water (CCW) system in the St. Lucie 1 FSAR) that is required for (1) safe shutdown during normal operations, anticipated operational occurrences, and mitigating the consequences of accident conditions, or (2) preventing the occurrence of an accident. The CCW system includes closed-loop auxiliary cooling water systems for reactor system components, reactor shutdown equipment, ventilation equipment, and components of the ECCS. The NRC staff's review covered the capability of the CCW system to provide adequate cooling water to safety-related ECCS components and reactor auxiliary equipment for all planned operating conditions. The NRC staff's review focused on the additional heat load that would result from the proposed EPU. The NRC's acceptance criteria for the CCW system is based on (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation including flow instabilities and attendant loads (i.e., water hammer), maintenance, testing, and postulated accidents and (2) GDC 44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided. Specific review criteria are contained in SRP Section 9.2.2, as supplemented by GL 89-13 and GL 96-06.

##### Technical Evaluation

In Section 2.5.4.3 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the CCW system in comparison to its current design basis described in the St. Lucie 1 FSAR. The CCW system is described in FSAR Section 9.2.2. The CCW system is designed to remove heat from plant components during all phases of plant operation including startup, power operation, shutdown, refueling and post-accident conditions. The CCW system consists of two heat exchangers, three pumps, one surge tank, a chemical addition tank, and associated piping, valves and instrumentation. The CCW system is arranged into two essential trains and a non-essential header. The non-essential header is automatically isolated from both essential headers by valve closure on a safety injection actuation signal.

The licensee determined that the CCW system is capable of removing the required EPU heat loads under normal operating, shutdown, and accident conditions with the existing cooling water supply flow rates. The licensee also stated that maximum CCW temperatures will increase after EPU, but will continue to remain within allowable limits, while the time to cool down the plant will be extended. The licensee determined that the components experiencing an increased heat load at normal plant EPU full power operation are the letdown heat exchanger (+0.09 million british thermal units per hour (MBtu/hr)) and the spent fuel pool heat exchanger (+1.8 MBtu/hr). The licensee stated that other heat exchangers were evaluated at their design conditions, which remain bounding at EPU.

During normal plant cooldown, the maximum CCW heat load occurs when the shutdown cooling (SDC) system is first placed in service after reactor shutdown. With the higher reactor decay heat at the EPU power level, the heat loads imposed on the CCW system by the SDC heat exchangers would increase to maintain the same cooldown rate. The licensee stated that a dual train cooldown would continue to be utilized and the current administrative cooldown rate



limit of 75 °F/hr would be maintained. For single train cooldown with minimum CCW flow rates, the licensee stated operators would procedurally control the cooldown rate to less than 75 °F/hr in order to maintain the CCW piping temperatures within design limits. Maintenance of this limit with the higher reactor decay heat would lengthen the period to complete a normal cooldown. As described above in Section 2.5.4.2 for the ICW system, the licensee evaluated design basis LOCA heat removal for conditions that maximized containment pressure and temperature by minimizing heat removal and maximizing cooling water temperature by maximizing the amount of heat removed via a single CCW train. As evaluated in Section 2.6.5 of this SE, the maximum containment pressure and temperature evaluation demonstrated the CCW system would be capable of removing adequate heat for the design basis LOCA from EPU operating conditions. The licensee's evaluation of the maximum heat removal by a single CCW train indicated that the existing design piping temperatures would continue to bound accident temperatures in the CCW system.

The licensee evaluated flow considerations for the CCW system. The CCW flow rate does not change at the EPU conditions and no physical changes are being made to the system. There is no change to the CCW pump head performance at EPU conditions and the CCW system operating pressures are not affected by EPU conditions. The CCW system relief valves either have no change or small changes in temperatures that are bounded by the relief valve design. Therefore, the relief valves on the CCW piping at the reactor coolant pump thermal barrier are unaffected by EPU conditions.

The licensee evaluated application of GL 89-13 to the safety-related CCW heat exchangers cooled by ICW. The licensee concluded that the original responses are not affected by the EPU since the existing procedures and activities in support of GL 89-13 are unaffected and require no changes. The licensee will continue to periodically inspect, test, and maintain the CCW heat exchangers.

The licensee also evaluated the effects of the EPU at St. Lucie 1 on the corrective actions implemented in response to GL 96-06. The licensee stated that the implementation of EPU does not affect the previous corrective actions and responses to GL 96-06. The licensee determined as part of its assessment of GL 96-06 that the small increase in the peak containment post-LOCA temperature at EPU conditions has no impact on the CCW system over pressure protection inside containment. The analysis of containment temperature following a main steam line break at EPU conditions indicated that peak temperature would decrease. As part of its actions for GL 96-06, the licensee previously reviewed containment penetrations and installed thermal relief valves on CCW lines subject to over-pressurization. The licensee stated that the EPU condition remains below the system design temperature and pressure and that no additional analysis is required to demonstrate its acceptability.

By letter dated May 27, 2011, the staff requested that the licensee provide additional information regarding the water hammer analysis under EPU conditions. By letter, dated June 22, 2011, the licensee responded that the water hammer analysis performed as part of its resolution to GL 96-06 for St. Lucie 1, was approved by the NRC on March 11, 2004 (Reference 24). The licensee stated as part of its RAI response that the limiting event for water hammer (LOCA with a loss of offsite power) resulted in a minor increase in containment temperatures from EPU operation and that lead to slightly increased saturation pressures in the steam void. The licensee determined that the higher steam pressures will act to slightly reduce the pump water column velocity following pump restart, as well as the water column closing differential velocity. As a consequence of the reduced closing velocity, the licensee concluded that the EPU

calculated water hammer loads are lower than those previously calculated in its original analysis. The staff found the licensee's assessment of the water hammer analysis acceptable based on the minor expected changes in accident peak temperatures and the use of an approved methodology to calculate the potential water hammer effects.

The staff reviewed the licensee's assessment of the CCW system according to GDC 4 and GDC 44. The staff finds that the EPU will not impact the CCW system to perform its functions and not affect the SSCs from performing their safety functions during EPU conditions. The staff finds the licensee's assessment acceptable since no physical modifications are required to support EPU operation and the overall CCW system design is capable to handle the minimal increased heat load.

### Conclusion

The staff has reviewed the licensee's assessment of the effects of the proposed EPU on the reactor CCW system and concludes that the licensee has adequately accounted for the increased heat loads from the proposed EPU on system performance. The staff concludes that the CCW system will continue to be protected from the dynamic effects associated with flow instabilities and provide sufficient cooling for SSCs important to safety following implementation of the proposed EPU. Therefore, the staff has determined that the CCW system will continue to meet the requirements of GDC 4 and GDC 44. Based on the above, the staff finds the proposed EPU acceptable with respect to the CCW system.

#### 2.5.4.4 Ultimate Heat Sink

### Regulatory Evaluation

The ultimate heat sink (UHS) is the source of cooling water provided to dissipate reactor decay heat and essential cooling system heat loads after a normal reactor shutdown or a shutdown following an accident. The NRC staff's review focused on the impact that the proposed EPU has on the decay heat removal capability of the UHS. Additionally, the NRC staff's review included evaluation of the design-basis UHS temperature limit determination to confirm that post-licensing data trends (e.g., air and water temperatures, humidity, wind speed, water volume) do not establish more severe conditions than previously assumed. The NRC's acceptance criteria for the UHS are based on (1) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety; and (2) GDC 44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided. Specific review criteria are contained in SRP Section 9.2.5.

### Technical Evaluation

In Section 2.5.4.4 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the UHS in comparison to its current design basis described in the St. Lucie 1 FSAR. The specific FSAR section evaluated by the licensee was Section 9.2.7, Ultimate Heat Sink. The licensee described that St. Lucie 1 and 2 share the UHS. The St. Lucie FSAR described that the primary water source is the Atlantic Ocean via intake pipes to the intake canal, which is used as the source for normal plant operational modes and most accident situations. The secondary source of water is Big Mud Creek, which is connected to the Atlantic

Ocean via the Indian River. The intake bay in front of the intake structure is separated from Big Mud Creek by a barrier wall containing two 100 percent flow passages that would be opened following a design basis earthquake that disables the primary intake. The design basis of the UHS as described in Section 9.2.7 of the FSAR is to: (1) provide sufficient cooling water for safe shutdown of both units or to permit mitigation of a LOCA in one unit and concurrent safe shutdown of the second unit; and (2) to withstand the effects of severe natural phenomena or single failure of a manmade structural feature without a loss of safety function. Plant intake is taken directly from and discharge provided directly to the Atlantic Ocean such that there is no mixing or recirculation of discharge flow.

The licensee indicated that no changes to the UHS Technical Specification 3/4.7.5 are required for EPU conditions because the UHS would continue provide adequate cooling water to both Units after EPU implementation. The ICW system flow requirements are not changed by EPU and the ICW intake temperatures are consistent with existing UHS temperature limits.

The staff has reviewed the licensee's assessment of the UHS according to GDC 5 and GDC 44 and concludes that the UHS would remain capable of performing its safety functions during EPU operation. No modifications are needed for the UHS to support normal and accident conditions during EPU operation; therefore, the staff finds the licensee's assessment acceptable and no further evaluation of the UHS is needed.

#### Conclusion

The staff has reviewed the information that was provided by the licensee for addressing the effects that the proposed EPU would have on the UHS safety function, including the licensee's validation of the design-basis UHS temperature limit based on post-licensing data. Based on the information that was provided, the staff concludes that the proposed EPU will not compromise the design-basis safety function of the UHS, and that the UHS will continue to satisfy the requirements of GDC 5 and GDC 44 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the UHS.

#### 2.5.4.5 AFW System

##### Regulatory Evaluation

In conjunction with a seismic Category I water source, the AFW system (AFWS) functions as an emergency system for the removal of heat from the primary system when the main FW system is not available. The AFWS may also be used to provide decay heat removal necessary for withstanding or coping with an SBO. The NRC staff's review for the proposed EPU focused on the system's continued ability to provide sufficient emergency FW flow at the expected conditions (e.g., SG pressure) to ensure adequate cooling with the increased decay heat. The staff's review also considered the effects of the proposed EPU on the likelihood of creating fluid flow instabilities (e.g., water hammer) during normal plant operation, as well as during upset or accident conditions. The NRC's acceptance criteria for the AFWS are based on (1) GDC 4, insofar as it requires that SSCs important to safety be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids that may result from equipment failures; (2) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; (3) GDC 19, insofar as it requires that equipment at appropriate locations outside the control room be provided with (a) the capability

for prompt hot shutdown of the reactor, and (b) a potential capability for subsequent cold shutdown of the reactor; (4) GDC 34, insofar as it requires that an RHR system be provided to transfer fission product decay heat and other residual heat from the reactor core, and that suitable isolation be provided to assure that the system safety function can be accomplished, assuming a single failure; and (5) GDC 44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided, and that suitable isolation be provided to assure that the system safety function can be accomplished, assuming a single failure. Specific review criteria are contained in SRP Section 10.4.9.

### Technical Evaluation

In Section 2.5.4.5 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the AFWS in comparison to its current design basis described in the St. Lucie 1 FSAR. Specific FSAR Sections evaluated by the licensee were Sections 10.5, Auxiliary FW System; 9.2.8, Condensate Storage System; and 15, Accident Analysis.

The AFWS consists of two full-capacity motor driven AFW pumps, one greater-than-full-capacity turbine-driven AFW pump, one condensate storage tank (CST), and associated piping and valves. The licensee described that the AFWS ensures a makeup water supply to the SG secondary side to support decay and sensible heat removal for the reactor core. This heat removal capability allows plant operators to reduce the reactor coolant temperature to entry conditions for shutdown cooling. The AFWS normally operates to support plant startup, hot standby, and shutdown evolutions. The CST provides normal source of water for the AFWS with a nominal capacity of 250,000 gallons.

Implementation of the EPU would increase the decay heat removal required to mitigate the various design basis events and, consequently, the makeup water supplied by the AFWS necessary to support that heat removal. As listed in Section 2.8.5.0, "Accident and Transient Analysis," of the EPU licensing report, the licensee determined that 296 gpm was the minimum degraded flow from one motor-driven AFW pump and 600 gpm was the nominal flow from the variable speed steam turbine-driven pump. The licensee determined that the limiting event in terms of required AFW flow would be the loss of normal FW event. In a response to a request for additional information provided by letter dated June 22, 12011, the licensee stated that the required number of AFW pumps delivering flow to a specific set of SGs for the various accident scenarios considered does not change as a result of the EPU. Since the design and operation of the system components would remain within existing bounds for design and operation, the AFWS would be acceptable for operation at EPU.

The implementation of the EPU would change the required inventory of water stored in the CSTs. The current TS 3/4.7.1.3, "Plant Systems-Condensate Storage Tank," requires a minimum contained inventory of 116,000 gallons. This value bounds the approximate inventory of 110,000 gallons described in FSAR Section 10.5, "Auxiliary Feedwater System," as required for cool down under loss of offsite power conditions from the current licensed thermal power. The 110,000 gallon inventory was based on maintaining the plant at hot standby for 1 hour followed by a cooldown to RHR entry conditions. The licensee calculated the minimum usable inventory necessary to satisfy the existing licensing basis at EPU conditions and found that the necessary usable inventory would increase to 130,500 gallons. The licensee also calculated the unusable inventory in the condensate storage tank would be 22,900 gallons due to outlet nozzle location, vortex suppression, and instrument uncertainty. The licensee proposed an

increase in the TS 3/4.7.1.3 required minimum CST volume to 153,400 gallons based on the sum of the calculated values for unusable inventory and the usable inventory necessary for cool down from EPU operating conditions. The staff found the proposed change to TS 3/4.7.1.3 acceptable because the proposed value included margin for unusable inventory and an adequate increase in usable inventory to accommodate the increased decay heat at EPU operating conditions. Therefore, the staff has reasonable assurance an adequate inventory of CST water would be available for operation at EPU.

The licensee evaluated other operating parameters and capabilities related to the AFWS, including design pressure and temperature of piping and components, net positive suction head, flow rates to support normal startup and shutdown, containment isolation, and auxiliary FW actuation. The licensee concluded that these operating parameters and capabilities would be unaffected by the EPU. The staff reviewed the operating parameters and system capabilities against proposed modifications and changes associated with operation at EPU conditions, and the staff agreed that the identified operating parameters and capabilities would be unaffected by the EPU because the limiting operating conditions would not change as a result of operation at EPU conditions.

### Conclusion

The NRC staff has reviewed the licensee's assessment related to the AFWS. The NRC staff concludes that the licensee has adequately accounted for the effects of the increase in decay heat and other changes in plant conditions on the ability of the AFWS to supply adequate water to the SGs to ensure adequate cooling of the core. The NRC staff finds that the AFWS will continue meet its design functions following implementation of the proposed EPU. The NRC staff further concludes that the AFWS will continue to meet the requirements of GDC 4, 5, 19, 34, and 44. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the AFWS.

## 2.5.5 Balance-of-Plant Systems

### 2.5.5.1 Main Steam

#### Regulatory Evaluation

The main steam supply system (MSSS) transports steam from the NSSS to the power conversion system and various safety-related and non-safety-related auxiliaries. The NRC staff's review focused on the effects of the proposed EPU on the system's capability to transport steam to the power conversion system, provide heat sink capacity, supply steam to drive safety system pumps, and withstand adverse dynamic loads (e.g., water steam hammer resulting from rapid valve closure and relief valve fluid discharge loads). The NRC's acceptance criteria for the MSSS are based on (1) GDC 4, insofar as it requires that SSCs important to safety be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids that may result from equipment failures; (2) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; and (3) GDC 34, insofar as it requires that an RHR system be provided to transfer fission product decay heat and other residual heat from the reactor core. Specific review criteria are contained in SRP Section 10.3.

## Technical Evaluation

In Section 2.5.5.1 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the MSSS in comparison to its current design basis described in the St. Lucie 1 FSAR. Specific FSAR Sections evaluated by the licensee were Sections 10.3, Main Steam Supply System, and Section 6.2.4, Containment Isolation System. The licensee made the following determinations for the MSSS during EPU conditions:

### *Piping Design P-T*

The licensee indicated that the MSSS design P-T of 985 psig (1000 psia) and 550 °F bound the maximum EPU operating conditions and that the no load conditions are unaffected by the EPU.

### *Piping Flow Velocities*

The licensee indicated that the main steam velocities at current and EPU conditions are bounded by the industry design guidelines velocity, with the exception of two areas. But these areas will not have a significant impact on the MSSS component materials because of the steam's low water content.

### *Component Design P-T*

As described above under Piping Evaluations, Design P-T, the main steam design P-T are not affected by the EPU. The design conditions of the main steam components were reviewed and determined to be greater than the EPU operating conditions.

### *Main Steam Safety Valves Capacities and Setpoints*

The licensee indicated that the main steam safety valves (MSSV) setpoints will remain unchanged for EPU. The licensee stated that the current MSSVs are acceptable at EPU condition without physical modification. However, the licensee proposed changing the setpoint tolerance of the MSSVs specified in TS 3/4.7.1.1 for operational flexibility. The TS required MSSV setpoints are currently 1000 psia +1/-3 percent (eight valves) and 1040 psia +1/-3 percent (eight valves). The licensee proposed changing the tolerance to  $\pm 3$  percent for the MSSVs with the lower setpoint and +2 percent/-3 percent for the MSSVs with the higher setpoint. The licensee stated that this tolerance change has been factored into the plant's accident analyses, which the staff evaluated in Section 2.8.5 of this SE. The proposed change to the TS 3/4.7.1.1 MSSVs setpoint tolerance is acceptable because the change is consistent with the assumptions of the limiting accident analyses.

### *Atmospheric Dump Valves (ADVs)*

The licensee indicated that the performance of the ADVs is acceptable at EPU conditions with no plant changes required to satisfy the decay heat removal requirements in accordance with the current licensing basis requirements with respect to GDC 34. The steam release from the ADVs would be unchanged at EPU operating conditions because the valve design and the no-load SG pressure are unchanged. The licensee evaluated the capability of the ADVs to support plant cool down at the maximum required rate at EPU conditions and found the cooldown performance acceptable. The staff evaluation of the cool down analysis is provided in Section 2.8.7.2 of this SE.

### *Main Steam Isolation Valves (MSIV)*

The licensee indicated that the MSIVs current design pressures and temperatures are valid for EPU conditions since they are equal to the piping design pressure and design temperature. The MSIVs will also be modified to improve structural integrity and fatigue life in the event of spurious closure at EPU conditions due to a higher main steam flow rate from each SG. The MSIVs were found to be bounded by the original stress analysis and therefore acceptable at EPU conditions. The licensee concluded for the MSIVs that the factors of erosion, vibration, differential pressure, and flow turbulence were acceptable at EPU conditions.

### *Turbine Stop, Control, and Reheat Stop and Intercept Valves*

The licensee indicated that the HP turbine stop valves have been evaluated as being acceptable for EPU. The HP turbine control valves were evaluated by the licensee and are physically adequate for operation at EPU. The low pressure (LP) turbine reheats stop and intercept valves have also been evaluated and are adequate for EPU operation.

### *Auxiliary Main Steam Supply Flow Rates*

The MSSS supplies steam to the following auxiliary loads:

- Moisture separator reheaters (MSR)
- AFW pump turbine
- Auxiliary steam system
- Priming ejector
- Turbine gland sealing steam system

The licensee indicated that the MSRs are being replaced for EPU and are designed for the uprated steam flows. The MSSS will continue to supply the required steam flow to the MSRs at EPU. The licensee found the AFW pump turbine supply and exhaust piping to be acceptable for EPU conditions due to the pressure ratings of piping and valves remaining bounded at its current analysis. The licensee also stated that the MSSS will continue to supply steam to auxiliary components, including the turbine gland steam supply and the condenser air ejectors, and will not be affected by the EPU.

### *Main Steam Piping Drain Capacity*

The licensee indicated the MSSS piping drains are acceptable for EPU operation despite minor changes in steam pressure and temperature. This is due to the drain flow not being significantly affected.

The staff reviewed the licensee's assessment of the MSSS according to GDC 4 and GDC 5 and did not find any implications that would allow the MSSS system to negatively impact the SSCs important to safety at EPU conditions. The current analysis for normal and accident scenarios remain unchanged for EPU conditions and minimal modifications to the MSSS system are needed to support EPU operation. Therefore, the staff finds the licensee assessment of the MSSS acceptable for EPU operation.

## Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the MSSS and concludes that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the MSSS. The evaluation of the accident analyses in Section 2.8.5 and the analysis of natural circulation cool down in Section 2.8.7.2 provide reasonable assurance that the MSSVs and ADVs retain sufficient capacity to remove residual heat at the required rate to satisfy GDC 34. The NRC staff concludes that the MSSS will maintain its ability to relieve steam to the atmosphere for residual heat removal, transport steam to the power conversion system, supply steam to the auxiliary components, and continue to perform its functions at EPU conditions. The staff further concludes that the MSSS will continue to meet the requirements of GDC 4 and GDC 5. Therefore, the staff finds the proposed EPU acceptable with respect to the MSSS.

### 2.5.5.2 Main Condenser

The main condenser is designed to condense and deaerate the exhaust steam from the main turbine and provide a heat sink for the turbine bypass system, which is referred to as the steam bypass control system (SBCS) for St. Lucie 1. The NRC staff's review of the main condenser for proposed power uprates focuses primarily on the impact that an EPU will have on the control of radiological releases to the environment. For pressurized-water reactors, the effect of the proposed EPU on the concentration of radionuclides in the condenser is negligible because leakage from the RCS through the SG to the main steam system is limited. The licensee determined that the condenser would maintain structural integrity during operation because it satisfactorily removes the increased EPU heat loads, condenses the required steam flows, and maintains an acceptable vacuum using circulating water at the current normal operating flow rate. Therefore, the main condenser will continue to control the release of radioactive material that may be introduced to the main condenser and a detailed evaluation is not necessary.

### 2.5.5.3 Turbine Bypass

#### Regulatory Evaluation

The SBCS is designed to discharge a stated percentage of rated main steam flow directly to the main condenser system, bypassing the turbine. This steam bypass enables the plant to take step load reductions up to the SBCS capacity without the reactor or turbine tripping. The system is also used during startup and shutdown to control SG pressure. The staff's review focused on the effects that EPU has on load rejection capability, analysis of postulated system piping failures, and on the consequences of inadvertent SBCS operation. The NRC's acceptance criteria for the TBS are based on (1) GDC 4, insofar as it requires that SSCs important to safety be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids that may result from equipment failures; and (2) GDC 34, insofar as it requires that an RHR system is provided to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits (SAFDLs) and the design conditions of the reactor coolant pressure boundary (RCPB) are not exceeded. Specific review criteria are contained in SRP Section 10.4.4.



### Technical Evaluation

In Section 2.5.5.3 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the SBCS in comparison to its current design basis described in the St. Lucie 1 FSAR. The specific FSAR section evaluated by the licensee was Section 10.4.4, Steam Dump and Bypass System. The licensee provided a brief description of the SBCS and indicated that the SBCS piping design pressure of 985 psig (1000 psia) bounds the actuation setpoint pressure of 900 psia, which remains unchanged for EPU conditions. The licensee stated that a modification to the SBCS is being performed such that the system will be able to pass the greater rated steam flow for EPU operation. The modification will ensure that the system continues to comply with the current licensing basis requirements with respect to both the protection against dynamic effects (GDC 4) and the ability to provide a means for shutting down the plant during normal operations to reduce the demands on systems important to safety (GDC 34).

The staff evaluated the licensee's assessment of the SBCS according to GDC 4 and GDC 34 and found that the system modifications to the SBCS to support EPU conditions will have a minimal impact on the functionality of the SBCS. The staff also finds that the SBCS capability to handle steam bypass from the turbine will remain unchanged for EPU conditions. The staff finds the licensee's assessment of the SBCS acceptable.

### Conclusion

The staff has reviewed the licensee's assessment of the effects of the proposed EPU on the SBCS. The staff concludes that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the system. The staff further concludes that SBCS failures will not adversely affect essential systems or components. Based on this, the staff concludes that the SBCS will continue to meet GDC 4 and GDC 34. Therefore, the staff finds the proposed EPU acceptable with respect to the SBCS.

#### 2.5.5.4 Condensate and FW

### Regulatory Evaluation

The condensate and FW system (CFS) provides FW at the appropriate temperature, pressure, and flow rate to the SGs. The only part of the CFS classified as safety-related is the FW piping from the SGs up to and including the outermost containment isolation valve. The NRC staff's review focused on the effects of the proposed EPU on previous analyses and considerations with respect to the capability of the CFS to supply adequate FW during plant operation and shutdown, and to isolate components, subsystems, and piping in order to preserve the system's safety function. The NRC staff's review also considered the effects of the proposed EPU on the FW system, including the AFWS piping entering the SG, with regard to possible fluid flow instabilities (e.g., water hammer) during normal plant operation, as well as during upset or accident conditions. The NRC's acceptance criteria for the CFS are based on (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, and that such SSCs be protected against dynamic effects; (2) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; and (3) GDC 44, insofar as it requires that a system with

the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided, and that suitable isolation be provided to assure that the system safety function can be accomplished, assuming a single failure. Specific review criteria are contained in SRP Section 10.4.7.

### Technical Evaluation

In Section 2.5.5.4 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the CFS in comparison to its current design basis described in the St. Lucie 1 FSAR. The specific FSAR section evaluated by the licensee was Section 10.4.6, Condensate and Feedwater System. The licensee made the following assessments of the CFS:

#### *Design Pressures and Temperatures – Components and Piping*

The licensee indicated that current design pressures and temperatures of CFS components and piping bound the EPU operating conditions with the exception of the design temperature of the main FW pump recirculation valves. However, the valve body materials were evaluated by the licensee and determined to be acceptable for a range of temperatures which bound the maximum EPU operating temperatures.

#### *FW Heaters*

The licensee indicated that FW heaters and external drain coolers were acceptable for EPU conditions with the exception of the HP 5A/B FW heaters. The design and construction of the existing 1A/B through 4A/B FW heaters was evaluated by the vendor and found acceptable for operation at EPU conditions with specific monitoring measures in place to evaluate the potential for long term degradation. The 5A/B FW heaters are being replaced with new HP FW heaters designed for EPU conditions. The replacement HP FW heaters 5A/B will be supplied with new relief valves designed to meet the EPU conditions. The replacement HP FW heaters 5A/B will be supplied with new venting orifices designed to meet the EPU conditions. The standards contained in Heat Exchange Institute Standards for Feedwater Heaters along with the manufacturer's standards were used for acceptance criteria for the evaluation of the existing FW heaters. The licensee determined that the new FW heaters will meet the thermal performance requirements of the EPU conditions. The FW heaters shell and tube side design P-Ts bound the EPU operating conditions. The licensee also stated that the existing relief valve capacities and setpoints are acceptable for EPU operation since the design pressures are not changing.

#### *Flow Velocities – Piping*

The licensee indicated that the flow velocities through the CFS will remain below the industry standard guidelines at EPU conditions. The licensee will install LEFMs as part of EPU implementation, which will enhance FW flow measurement. Thermowells also extend into the flow steam and are used throughout the CFS for temperature measurement. The EPU velocities are bounded by the maximum velocities for which the thermowells are designed.

#### *FW Regulating Valves*

The licensee indicated that the existing FW regulating valves will be modified to provide the required flow at the required pressure drop at EPU conditions. The valve modifications will allow the valves to utilize approximately 80 percent of the valves' rated flow coefficient during

normal plant operation at EPU so as to provide sufficient control over a range of operating conditions and provide additional margin for transients. The licensee iterated that the EPU is not changing the function or monitoring features of the FW regulating valves.

### *Condensate and FW Pumps and Supporting Subsystems*

The licensee discussed several changes in the EPU licensing report to the CFS pumps and supporting systems for support of EPU operation. These changes do not impact any safety-related systems and are being made to increase efficiency of the CFS system in power generation.

### *FW Isolation Valves*

The licensee indicated that the MFIVs and main FW pump discharge isolation valves were evaluated for the increased flow rates, differential pressures, and temperatures at EPU. The MFIVs will continue to meet the existing required closure times at the EPU conditions. The licensee also stated that the containment isolation requirements are unaffected by EPU and the current plant design features remain acceptable.

The staff evaluated the licensee's assessment of the CFS according to GDC 4, GDC 5, and GDC 44 and found that the EPU operation will not prevent the CFS from performing its normal and transient functions, provided that the licensee make the evaluated changes to the CFS equipment prior to EPU implementation. The modifications to the CFS do not prevent the system from withstanding a water hammer or lead to the failure of SSCs important to safety. St. Lucie 1 also will maintain its isolation capacity to preserve the system safety function. The staff finds the licensee's assessment of the CFS acceptable for EPU operation.

## Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the CFS and concludes that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the CFS. The NRC staff concludes that the CFS will continue to maintain its ability to satisfy FW requirements for normal operation and shutdown, withstand water hammer, maintain isolation capability in order to preserve the system safety function, and not cause failure of safety-related SSCs. The NRC staff further concludes that the CFS will continue to meet the requirements of GDC 4, 5, and 44. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CFS.

## 2.5.6 Waste Management Systems

### 2.5.6.1 Gaseous Waste Management Systems

#### Regulatory Evaluation

Gaseous waste management systems (GWMS) involve the gaseous radwaste system, which deals with the management of radioactive gases collected in the offgas system or the waste gas storage and decay tanks. In addition, it involves the management of the condenser air removal system, the SG blowdown flash tank, and the containment purge exhausts; and the building ventilation system exhausts. The staff's review focused on the effects that the proposed EPU may have on (1) the design criteria of the gaseous waste management systems, (2) methods of

treatment, (3) expected releases, (4) principal parameters used in calculating the releases of radioactive materials in gaseous effluents, and (5) design features for precluding the possibility of an explosion if the potential for explosive mixtures exist. The NRC's acceptance criteria for the GWMS are based on (1) 10 CFR 20.1302, insofar as it provides for demonstrating that annual average concentrations of radioactive materials released at the boundary of the unrestricted area do not exceed specified values; (2) GDC 3, insofar as it requires that (a) SSCs important to safety be designed and located to minimize the probability and effect of fires, (b) noncombustible and heat resistant materials be used, and (c) fire detection and fighting systems be provided and designed to minimize the adverse effects of fires on SSCs important to safety; (3) GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents; (4) GDC 61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement; and (5) 10 CFR Part 50, Appendix I, Sections II.B, II.C, and II.D, which set numerical guides for design objectives and limiting conditions for operation to meet the "as low as is reasonably achievable" (ALARA) criterion. Specific review criteria are contained in SRP Section 11.3.

### Technical Evaluation

The licensee's evaluation of the impact that EPU will have on the capability of the GWMS to collect and process gaseous radioactive waste is provided in Sections 2.5.6.1 of the St. Lucie 1 EPU licensing report. The licensee determined that the EPU will result in a slight increase in the equilibrium radioactivity in the reactor coolant, which results in an increased concentration of radioactive nuclides in the radioactive waste system. The licensee found that the existing GWMS will remain capable of processing this increase in radioactive nuclide concentration. The proposed EPU activities would not add any new components to the GWMS, nor would they introduce any new functions for existing components. Operating experience confirms the small effect of EPUs on radioactive gas production.

Radiological and environmental monitoring of the waste streams is not affected by the proposed EPU and no new or different radiological release paths will be introduced. However, the proposed EPU will result in an increase in the activity associated with gaseous radioactive waste and, therefore, potential radiological releases and offsite doses will be impacted. The licensee determined that the estimated doses resulting from radioactive effluents following implementation of the EPU would remain a small percentage of allowable Appendix I doses. The licensee's evaluations of potential releases under accident and normal operating conditions are reviewed in Sections 2.9 and 2.10 of this SE, respectively.

Section 11.3 of the St. Lucie 1 FSAR describes that the oxygen content in the WGMS is continuously monitored to prevent development of a potentially explosive gas mixture. The monitoring is performed in accordance with TS 3.11.2.5, "Explosive Gas Mixture." The licensee also has measures in place, as described in FSAR Section 13.8.1.4, to purge cover gas containing high levels of oxygen to the gaseous waste system with nitrogen gas, thereby diluting the oxygen concentration. The staff determined these measures to control the potential development of explosive gas mixtures are unaffected by the proposed EPU.

Based on a review of the information that was submitted, the staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the GWMS to perform its functions. Because the increase in radioactive gas generation would be insignificant, the staff agrees that the capabilities of the GWMS will

continue to satisfy the plant licensing basis following implementation of the proposed power uprate.

### Conclusion

The NRC staff has reviewed the licensee's assessment related to the gaseous waste management systems. The NRC staff concludes that the licensee has adequately accounted for the effects of the increase in fission product and amount of gaseous waste on the abilities of the systems to control releases of radioactive materials and preclude the possibility of an explosion if the potential for explosive mixtures exists. The NRC staff finds that the gaseous waste management systems will continue to meet their design functions following implementation of the proposed EPU. The NRC staff further concludes that the gaseous waste management systems will continue to meet the requirements of 10 CFR 20.1302, GDC 3, 60, and 61, and 10 CFR Part 50, Appendix I, Sections II.B, II.C, and II.D. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the gaseous waste management systems.

#### 2.5.6.2 Liquid Waste Management Systems

##### Regulatory Evaluation

The staff's review for liquid waste management systems (LWMS) focused on the effects that the proposed EPU may have on previous analyses and considerations related to the liquid waste management systems' design, design objectives, design criteria, methods of treatment, expected releases, and principal parameters used in calculating the releases of radioactive materials in liquid effluents. The NRC's acceptance criteria for the LWMS are based on (1) 10 CFR 20.1302, insofar as it provides for demonstrating that annual average concentrations of radioactive materials released at the boundary of the unrestricted area do not exceed specified values; (2) GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents; (3) GDC 61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement; and (4) 10 CFR Part 50, Appendix I, Sections II.A and II.D, which set numerical guides for dose design objectives and LCOs to meet the ALARA criterion. Specific review criteria are contained in SRP Section 11.2.

##### Technical Evaluation

The licensee provided its evaluation of the EPU impact on the capability of the LWMS to collect and process liquid radioactive waste in Section 2.5.6.2 of the St. Lucie 1 EPU licensing report. The licensee determined that the proposed EPU conditions will have minimal effect on the volumes of radioactive waste generated; however, it will change the radioactivity content of the waste. The proposed EPU would not change the collection, segregation, processing, discharging or recycling of radioactive liquid wastes. Also, the proposed EPU would not change any of the sources of potentially contaminated leakage or create any new flow paths that would allow for the contamination of systems designed for uncontaminated liquids. The licensee determined that the estimated doses resulting from radioactive effluents following implementation of the EPU would remain a small percentage of allowable Appendix I doses. The methodology used to determine the effect of the change in radioactivity content in liquid waste is addressed in Section 2.10 of this safety evaluation.

Based on a review of the information that was submitted, the staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the

capability of the LWMS to perform its functions. Because the increase in offsite dose will be relatively small and the doses will remain a small fraction of the allowable Appendix I doses, the staff agrees that the capabilities of the LWMS will continue to satisfy the plant licensing basis following implementation of the proposed power uprate.

### Conclusion

The NRC staff has reviewed the licensee's assessment related to the LWMS. The staff concludes that the licensee has adequately accounted for the effects of the increase in fission product and amount of liquid waste on the ability of the LWMS to control releases of radioactive materials. The staff finds that the LWMS will continue to meet their design functions following implementation of the proposed EPU. The NRC staff further concludes that the licensee has demonstrated that the LWMS will continue to meet the requirements of 10 CFR 20.1302, GDC 60 and 61, and 10 CFR Part 50, Appendix I, Sections II.A and II.D. Therefore, the staff finds the proposed EPU acceptable with respect to the LWMS.

#### 2.5.6.3 Solid Waste Management Systems

Solid radioactive waste consists of wet and dry waste. Wet waste consists mostly of low specific activity spent secondary and primary resins and filters, and oil and sludge from various contaminated systems. The NRC staff's review relates primarily to the wet waste dewatering and liquid collection processes, and focuses on the impact that the proposed power uprate will have on the release of radioactive material to the environment via gaseous and liquid effluents. Because this is a subset of the evaluations performed in Sections 2.5.6.1 and 2.5.6.2 of this SE, a separate evaluation of solid waste management systems is not required.

#### 2.5.7 Additional Considerations

##### 2.5.7.1 Emergency Diesel Engine Fuel Oil Storage and Transfer System

#### Regulatory Evaluation

Nuclear power plants are required to have redundant onsite emergency power supplies of sufficient capacity to perform their safety functions (e.g., power diesel engine-driven generator sets), assuming a single failure. The NRC staff's review focused on increases in emergency diesel generator electrical demand and the resulting increase in the amount of fuel oil necessary for the system to perform its safety function. The NRC's acceptance criteria for the emergency diesel engine fuel oil storage and transfer system are based on (1) GDC 4, insofar as it requires that SSCs important to safety be protected against dynamic effects, including missiles, pipe whip, and jet impingement forces associated with pipe breaks; (2) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; and (3) GDC 17, insofar as it requires onsite power supplies to have sufficient independence and redundancy to perform their safety functions, assuming a single failure. Specific review criteria are contained in SRP Section 9.5.4.

#### Technical Evaluation

In Section 2.5.7.1 of the EPU licensing report, the licensee evaluated the impacts of the proposed EPU on the EDG fuel oil storage and transfer system in comparison to its current

design basis described in the St. Lucie 1 FSAR. The specific FSAR section evaluated by the licensee was Section 9.5.4, Diesel Generator Fuel Oil System. The licensee assessed the fuel oil inventory and consumption rate along with the EDG loading analysis following Loss of Offsite Power (LOOP) events for the proposed EPU conditions. The licensee indicated that the fuel consumption rates of the EDGs allow the maximum usable volume of the fuel oil storage system to run one EDG for 7.42 days and both EDGs for 3.70 days at their required post-LOCA loads. As stated in the FSAR, the total capacities of both fuel oil storage tanks are required to support the EDG run time. The licensee concluded that no modifications are needed for the EDGs or EDG fuel oil system to support EPU conditions. The licensee proposed a change to TS 3.8.1.1 that increases the minimum fuel storage system requirement for each EDG set from 16,450 gallons to 19,000 gallons. The licensee stated that the change is required to capture the additional volume of ultra-low sulfur fuel oil to support EPU operations.

The staff has reviewed the licensee's assessment of the EDG fuel oil storage and transfer system according to GDC 4, GDC 5, and GDC 17 and found that the system has the capability to perform its safety functions for EPU operation. The staff finds the change to TS 3.8.1.1 acceptable since the TS change is related to the characteristics of the fuel oil being used for EPU operation, and it is not impacting the current design analysis to be able to handle emergency power loads following a LOOP event. The licensee has indicated that the current EDG fuel oil inventory is capable of operation during EPU conditions, and the staff finds the increase of fuel oil volume in TS 3.8.1.1 to have a negligible effect on EPU operation. Therefore, the staff finds the licensee assessment of the EDG fuel oil storage and transfer system acceptable.

### Conclusion

The NRC staff has reviewed the licensee's assessment related to the amount of required fuel oil for the emergency diesel generators and concludes that the licensee has adequately accounted for the effects of the increased electrical demand on fuel oil consumption. The NRC staff concludes that the fuel oil storage and transfer system will continue to provide an adequate amount of fuel oil to allow the diesel generators to meet the onsite power requirements of GDC 4, 5, and 17. The staff also finds the proposed changes to TS 3.8.1.1 acceptable due to the change being related to accounting for the additional volume of ultra low sulfur fuel oil needed to support EPU operation. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the fuel oil storage and transfer system.

### 2.5.7.2 Light Load Handling System (Related to Refueling)

The light load handling system (LLHS) includes components and equipment used for handling new fuel at the receiving station, handling of new and irradiated fuel within the spent fuel pool and refueling cavity, and loading spent fuel into shipping casks. Because the licensee proposed no modifications to fuel handling equipment and the post-EPU fuel would be mechanically the same as the pre-EPU fuel, this area of review is not affected by the proposed power uprate and an evaluation of the LLHS is not required.

## 2.6 Containment Review Considerations

### 2.6.1 Primary Containment Functional Design

#### Regulatory Evaluation

The St. Lucie 1 containment is a right circular cylinder with a hemispherical dome that encloses the reactor system and is the final barrier against the release of significant amounts of radioactive fission products in the event of an accident. While operating at EPU condition, and following a DBLOCA or an MSLB accident, the peak containment internal pressure and its wall temperature must remain below the internal design pressure and the structural design temperature. The containment maximum internal design pressure is 44 psig, and the structural design temperature is 264 °F.

The NRC staff's review covered the P-T conditions in the containment due to a spectrum of postulated LOCAs and secondary system line breaks. The NRC's acceptance criteria for primary containment functional design are based on (1) GDC 16, insofar as it requires that reactor containment be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment; (2) GDC 50, insofar as it requires that the containment and its internal components be able to accommodate, without exceeding the design leakage rate and with sufficient margin, the calculated pressure and temperature conditions resulting from any LOCA; (3) GDC 38, insofar as it requires that the containment heat removal system(s) function to rapidly reduce the containment pressure and temperature following any LOCA and maintain them at acceptably low levels; (4) GDC 13, insofar as it requires that instrumentation be provided to monitor variables and systems over their anticipated ranges for normal operation and accident conditions; and (5) GDC 64, insofar as it requires that means be provided for monitoring the plant environs for radioactivity that may be released from normal operations and postulated accidents. Specific review criteria are contained in SRP Sections 6.2.1.1.A and 6.2.2.

#### Technical Evaluation

##### LOCA Containment Analysis

The licensee performed containment pressure and temperature response analysis to demonstrate that the peak pressure and temperature meet the SRP acceptance criteria and the containment heat removal system is acceptable for mitigation of the consequences of a design basis accident (DBA) LOCA inside the containment under EPU conditions.

The licensee used the current version of NRC-approved CONTRANS (Reference 8) computer code methodology for LOCA containment performance analyses. The CONTRANS topical report (Reference 8) provides the description of the analytical techniques, governing equations, and solution methods. Section 6.2.1.3.2, Part A.4 of St. Lucie 1 FSAR describes the changes and/or enhancements in the current version of the CONTRANS computer code.

The licensee listed conservative inputs and assumptions which differed from the current licensing basis (CLB) inputs and assumptions including those in which conservatism was increased.



The mass and energy (M&E) release analysis for calculating the LOCA containment pressure and temperature response is evaluated in Section 2.6.3.1 of this report. The limiting case which gave the highest peak pressure and temperature is the double-ended hot leg slot (DEHLS) break. For this case, the calculated peak pressure was 42.77 psig and a pressure of 7.55 psig (Reference 25) at 24 hours. The containment design pressure is 44 psig and the acceptance criteria includes allowing the containment leakage rate to decrease by 50 percent after 24 hours if the containment pressure is shown to decrease below 50 percent of the calculated peak pressure within 24 hours. Therefore the SRP acceptance criteria for both peak pressure being less than the design pressure and the pressure at 24 hours less than 50 percent of the calculated peak pressure are met. For the DEHLS break, the licensee calculated a peak containment vapor temperature of 265.57 °F, which exceeds the containment vessel design temperature of 264 °F for approximately 30 seconds. However, for this break, the calculated peak containment vessel temperature is 230 °F (Reference 25) which is well below the containment vessel design temperature of 264 °F. For the double-ended discharge leg slot (DEDLS) break, the licensee calculated a peak containment vapor temperature of 261.64 °F and the corresponding peak containment vessel temperature of 246 °F. In an RAI, the licensee was requested to explain why the containment vessel temperature of 245 °F corresponding to a vapor temperature of 261.64 °F for the DEDLS break is higher than the containment vessel temperature of 229 °F (Reference 2) corresponding vapor temperature of 265.57 °F for the DEHLS break, even though the vapor temperature for the DEDLS break is lower than for DEHLS. In its response the licensee states that the duration of the M&E releases to the containment is much longer for the DEDLS break than that for the DEHLS break due to the continued energy addition from the SGs. Thus, the containment vapor temperature in the DEDLS break will decrease more slowly than in the DEHLS break and after a short time, the vapor temperature in the DEDLS break exceeds the vapor temperature in the DEHLS break. The containment vessel liner temperature lags the containment vapor temperature with the peak liner temperature occurring at 1235 seconds and 1430 seconds later in the transient for the DEDLS and DEHLS breaks, respectively. Therefore, due to containment liner temperature lagging the containment vapor temperature, the peak containment liner temperature will be higher for the DEDLS break than that for the DEHLS break.

The staff agrees with the licensee that the calculated maximum containment vessel temperature under EPU conditions for LOCA event is less than its design temperature with sufficient margin.

In order to gain margin, the licensee proposes to revise the upper TS limit of containment normal operating pressure from +2.4 psig to +0.5 psig. To maintain consistency with the EPU results, the licensee proposed to revise the TS containment leakage rate test pressure (Pa) from 39.6 psig to 42.8 psig. The licensee calculated the limiting peak pressure of 42.73 psig for MSLB, which is less than the calculated limiting peak pressure of 42.8 psig for the DBLOCA. Referring to the definition of Pa given in the 10 CFR Part 50 Appendix J, for Option B, "Pa (psig) means the calculated peak containment internal pressure related to the design basis loss-of-coolant accident as specified in the Technical Specifications." The NRC staff agrees with the licensee's proposed EPU value of Pa as 42.8 psig because it meets its definition given in 10 CFR Part 50 Appendix J, for Option B.

### Main Steam Line Break Containment Analysis

The licensee performed MSLB containment analyses to calculate the containment P-T response by considering the break of the main steam line at the SG outlet nozzle, upstream of the main steam isolation valves (MSIVs). The licensee states that this break results in the maximum

possible steam flow for a given break size. The licensee states that the break flow would be limited to that from one SG because the main steam check valve prevents reverse flow from the unaffected SG. In an RAI, the licensee was requested to explain why considering failure of the reverse flow check valve which would allow the steam header volume to participate in the blowdown was not analyzed as one of the single failure cases. In its response (Reference 26) the licensee states that the main steam isolation check valve prevents reverse steam flow and is credited to prevent any blowdown of the steam header and the intact SG immediately following a MSLB, which is in agreement with the current Unit 1 FSAR. SRP Section 6.2.1.4, "Mass and Energy Release Analysis for Postulated Secondary System Pipe Ruptures" states: "steam and feedwater line break analyses should assume a single active failure in the steam or feedwater line isolations provisions." In accordance with Section 2.0 of SECY-77-439, failure of a check valve to close is considered a passive failure. Therefore a passive failure of the MSCV is not required to be considered in the MSLB analysis. The NRC staff considers the licensee's response acceptable.

The evaluation of MSLB M&E release analysis is given in Section 2.6.3.2 of this report. The licensee used the NRC-approved computer code SGNIII as in the current analysis for M&E release analysis and simultaneously calculated the pressure and temperature response obtained from the integrated module taken from the NRC-approved CONTRANS computer code (Reference 8). In an RAI the licensee was requested to describe how the computer code SGNIII and CONTRANS are used to simultaneously determine the time dependent containment pressure and temperature response with the M&E releases. In its response the licensee states that the CONTRANS code for containment response and the SGNIII code for M&E release have been combined to run together. For a given time step, the M&E release data generated by SGNIII code is fed to the CONTRANS code, which calculates the containment P-T for that time step. The containment P-T is subsequently fed back to the SGNIII and the M&E release rates for the next time step are generated. The licensee has maintained the name SGNIII for the integrated code.

The licensee listed conservative inputs and assumptions which differed from the CLB inputs and assumptions including those in which conservatism was increased. The licensee did not credit the operation of fan coolers in the analysis. The most limiting single active failure was determined to be the failure of one containment spray pump with offsite power available. The licensee states that the restart power can be over-predicted due to the conservatisms in the SGNIII code. In the EPU analysis the licensee limited the restart power to 20 percent, which has a significant margin over the peak restart value generated in the MSLB safety analysis. The licensee states that the 20 percent restart power assumed in the EPU analysis is not as conservative as it would go with the SGNIII code and conservative assumptions used in the analysis.

As described in Section 2.6.3.2 below, the licensee generated M&E release data for three cases of single failure at four power levels with offsite power available. The licensee states that it is conservative to analyze the peak pressure and EQ cases assuming offsite power available, because a LOOP results in a decrease of RCS flow which reduces the rate of energy transfer from the RCS to the secondary side. This results in lower energy release to containment thereby reducing the containment P-T response. The licensee confirmed this by running the limiting case for both offsite power available and LOOP. The licensee used the following conservative assumptions for the containment peak temperature analysis for EQ purposes and for the containment peak pressure response (Reference 27): (a) assumed increased RCS volume due to P-T expansion of metal by approximately 2 percent, which results in more energy

transfer from the primary to the secondary system, and in increased steam released from the SG, (b) assumed maximum RCS flow to allow the maximum possible heat transfer from the primary to the secondary system, (c) assumed no safety injection (SI), because SI decreases the primary system heat, (d) assumed no SG tube plugging, which otherwise would reduce the primary to secondary heat transfer, (e) assumed control rods fully out initially to maximize the time required to reduce core power, (f) assumed all main FW flow to be delivered to the ruptured SG which results in twice as much FW flow to ruptured SG.

For the peak pressure cases, the licensee used the following conservative inputs to obtain a limiting (higher) pressure response (Reference 27): (a) used the maximum initial containment pressure, (b) did not consider superheating upon SG U-tube uncover which is conservative for the containment pressure response, (c) did not consider re-evaporation of the heat sink condensate. The licensee determined that the analysis at the 100.3 percent thermal power resulted in the highest peak pressure. The licensee calculated the peak pressure of 42.73 psig (Reference 25) for the limiting case at 100.3 percent power with the failure of one CS pump to start which is lower than the current peak pressure value of 42.76 psig, but remains below the containment design limit of 44 psig.

For the EQ analysis cases, the licensee used the following inputs to obtain a limiting (higher) temperature response (Reference 27): (a) used the minimum initial containment pressure to delay the reactor trip which maximizes the M&E transfer to the containment, (b) used a superheat model in which the steam in the SG shell side is allowed to superheat as the tubes uncover, and (c) assumed re-vaporization of the condensate, as permitted by NUREG-0588 Appendix B, Section 1.b, which allows 8 percent of the condensation that collects on the heat sink walls to evaporate. The licensee reduced the conservatism by taking credit for the containment liner as a passive heat sink (Reference 25). The licensee states that the analysis at 100.3 percent thermal power gave the highest containment temperature for EQ purposes. The licensee calculated 387.0 °F (Reference 25) as the EPU peak EQ temperature which is less than the CLB peak EQ temperature of 404.53 °F. The licensee states that the reduction in peak EQ EPU temperature was attributed to reduced conservatism in the SGNIII restart power described above and due to taking credit for the containment liner as a passive heat sink (Reference 25). The calculated EPU peak containment vapor temperature of 387.0 °F exceeds the containment vessel design temperature of 264 °F; however the licensee determined that the peak containment vessel temperature based on the vapor temperature of 387.0 °F is 232.3 °F (Reference 25), which is well below its design temperature.

The NRC staff considers licensee's evaluation of EPU peak containment temperature for EQ purposes and peak containment pressure acceptable for MSLB because the licensee used an acceptable methodology and conservative input and assumptions.

The licensee evaluated the containment under EPU conditions for license renewal and determined that there are no new aging effects that require management and no changes are necessary to any existing aging management programs. The licensee states that EPU does not add any new or previously unevaluated materials, or introduce any new system or component functions nor does it change the functions of existing components that would affect the system boundaries for license renewal.

## Conclusion

The NRC staff has reviewed the licensee's assessment of the containment P-T transient and concludes that the licensee has adequately accounted for the increase of M&E that would result from the proposed EPU. The staff further concludes that containment systems will continue to provide sufficient P-T mitigation capability to ensure that containment integrity is maintained. The staff also concludes that the containment systems and instrumentation will continue to be adequate for monitoring containment parameters and release of radioactivity during normal and accident conditions and will continue to meet the requirements of GDC 13, 16, 38, 50, and 64 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to containment functional design.

### 2.6.2 Subcompartment Analyses

#### Regulatory Evaluation

A subcompartment is defined as any fully or partially enclosed volume within the primary containment that houses high-energy piping and would limit the flow of fluid to the main containment volume in the event of a postulated pipe rupture within the volume. The NRC staff's review for subcompartment analyses covered the determination of the design differential pressure values for containment subcompartments. The NRC staff's review focused on the effects of the increase in mass and energy release into the containment due to operation at EPU conditions, and the resulting increase in pressurization. The NRC's acceptance criteria for subcompartment analyses are based on (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, and that such SSCs be protected against dynamic effects, and (2) GDC 50, insofar as it requires that containment subcompartments be designed with sufficient margin to prevent fracture of the structure due to the calculated pressure differential conditions across the walls of the subcompartments. Specific review criteria are contained in SRP Section 6.2.1.2.

#### Technical Evaluation

The NRC staff evaluation of the containment subcompartment analysis consists of evaluation of P-T response of reactor cavity, shield wall, and pressurizer subcompartments due to postulated line breaks under EPU conditions. By a letter dated March 5, 1993, the NRC approved the St. Lucie 1 LBB analysis. As a result, compartment pressurization and dynamic effects associated with circumferential (guillotine) or longitudinal (slot) breaks in RCS hot leg or cold leg piping is no longer considered a licensing basis. Section 2.6.3 of this SE presents the evaluation of the postulated accidents M&E release analysis results that were used as an input for the subcompartment P-T response.

For the reactor cavity, the NRC staff agrees with the licensee that based on NRC staff approval of the application of LBB methodology, and as in the CLB, subcompartment analysis for the reactor cavity area is not required to be addressed for EPU conditions.

Regarding the secondary shield wall subcompartment, the licensee states that the CLB has a 40-percent margin in the design differential pressure for the secondary shield wall from the results of the limiting double-ended guillotine break in the hot leg. The licensee also states that

the differential pressure across the secondary shield wall structure at EPU conditions is bounded by CLB and the margin in the design differential pressure structure remains unchanged. The hot leg double ended guillotine break (eliminated due to LBB application) M&E release bounds all smaller postulated pipe breaks M&E release. The NRC staff agrees that the differential pressure across the secondary shield wall structure at the EPU conditions is bounded by the current basis and the design margin is unchanged.

The pressurizer cavity is divided into upper cavity and lower cavity and is affected by three breaks; the pressurizer relief line break, pressurizer spray line break, and the pressurizer surge line break. The upper pressurizer cavity is affected by the relief line break and the spray line break, whereas the lower cavity is affected by the surge line break.

The upper pressurizer cavity is designed for a differential pressure of 14 psid. As per the evaluation given in Section 2.6.3.1 of this report, the M&E release due to a guillotine break in the pressurizer relief line, under the EPU conditions is unchanged from the CLB. Therefore the pressure response of the upper cavity due to relief line break is unaffected under EPU conditions. As per the evaluation given in Section 2.6.3.1 of this report, the EPU mass release rate from the pressurizer spray line break is less than 5 percent greater than its current value, and the energy release rate is less than 2 percent greater than its current value, at the lowest analyzed EPU cold leg temperature of 543 °F. The licensee states that relative to compartment pressure response, the small increases in the M&E releases are compensated due to an increase in the vent area of approximately 190 square feet with the permanent removal of missile shield roof of the pressurizer cavity, which was not considered in the pre-EPU design analyses. Therefore, the licensee concludes and the NRC staff agrees with the licensee that the design margin for the upper pressurizer cavity wall structure may be conservatively assumed to remain unchanged under the EPU conditions.

The lower pressurizer cavity is designed for a differential pressure of 24 pounds per square inch (psi) differential (psid), which is same as the design differential pressure of the shield wall subcompartment because it is open to the shield wall subcompartment. Section 2.6.3.1 of this report provides an evaluation of the M&E release due to a break in the surge line, which is 0.9 percent and 0.4 percent higher than their pre-EPU values of M&E, respectively. The licensee states that it is conservative to assume that the pressure increase is proportional to the M&E release increase. Therefore the maximum differential pressure of the lower pressure cavity is conservatively estimated as approximately 22.7 psid at the EPU conditions which is 0.9 percent higher than its current value of 22.5 psid. The licensee concludes that the design margin for the lower pressurizer cavity is approximately 6 percent at EPU conditions. The NRC staff agrees with licensee's evaluation.

### Conclusion

The NRC staff has reviewed the subcompartment assessment performed by the licensee and the change in predicted pressurization resulting from the increased mass and energy release. The NRC staff concludes that containment SSCs important to safety will continue to be protected from the dynamic effects resulting from pipe breaks and that the subcompartments will continue to have sufficient margins to prevent fracture of the structure due to pressure difference across the walls following implementation of the proposed EPU. Based on this, the NRC staff concludes that the plant will continue to meet GDC 4 and 50 for the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to subcompartment analyses.

## 2.6.3 Mass and Energy Release

### 2.6.3.1 Mass and Energy Release Analysis for Postulated Loss of Coolant

#### Regulatory Evaluation

The release of high-energy fluid into containment from pipe breaks could challenge the structural integrity of the containment, including subcompartments and systems within the containment. The NRC staff's review covered the energy sources that are available for release to the containment and the M&E release rate calculations for the initial blowdown phase of the accident. The NRC's acceptance criteria for mass and energy release analyses for postulated LOCAs are based on (1) GDC 50, insofar as it requires that sufficient conservatism be provided in the mass and energy release analysis to assure that containment design margin is maintained and (2) 10 CFR Part 50, Appendix K, insofar as it identifies sources of energy during a LOCA. Specific review criteria are contained in SRP Section 6.2.1.3.

#### Technical Evaluation

##### LOCA M&E Release for Long Term Containment P-T Response

The licensee performed the EPU LOCA M&E releases using the current methodology documented in FSAR Section 6.2.1.3.2. The LOCA containment M&E release analysis initiated with the reactor operating at 100 percent EPU plus 0.3 percent measurement uncertainty, consists of four phases: (a) blowdown, (b) reflood, (c) post-reflood, and (d) long term cooldown phase. The licensee conservatively biased the energy release rate to the containment by assuming the heat transfer from the core to the reactor coolant to be always in the nucleate boiling regime. As a result, the cladding temperature remains low enough that its oxidation due to the metal-water reaction is insignificant. Therefore, the contribution to the energy release rate from the metal-water reaction is negligible and was not included in the M&E analysis. The staff considers this acceptable because the sensible heat transferred from the core to the reactor coolant is maximized in the nucleate boiling regime. The licensee simulated the blowdown phase of the LOCA using the NRC-approved CEFLASH-4A code (Reference 9) using biased inputs to conservatively calculate the M&E release during this phase.

In an RAI the licensee was requested to describe the impact of a code error in CEFLASH-4A identified by Westinghouse in calculating the M&E release and the containment P-T response. In its response (Reference 28) the licensee states that CEFLASH-4A/FII code error referred to in the RAI was actually an input deficiency. Analyses performed in the early 1990s used a print interval for tables of M&E that was too coarse to capture the peak values of M&E releases in the first half-second of RCS blowdown for a large break LOCA. Consequently, a large amount of M&E released in the containment on an integrated basis was not accounted for in the containment response portion of the analysis and, therefore, containment peak P-T were under predicted. This code input deficiency was identified prior to completion of the proposed EPU analysis. The proposed EPU analysis used a fine print interval to generate the M&E table and confirmed that the peak values of M&E calculated in the CEFLASH-4A/FII code were used in the containment response analysis. The NRC staff finds the licensee's response acceptable.

The licensee justified the differences in inputs and assumptions between the CLB and the EPU analysis. The reflood and post-reflood phases of the LOCA are simulated using the

FLOOD3Mod2 computer code, which is an extension of the NRC-approved FLOODMOD2 code (Reference 29) used in the CLB analysis. For cold leg breaks the effect of the SGs on the M&E discharged into the containment is important after the blowdown because the exiting steam passes through the SGs acquiring more energy prior to release to the containment. For the hot leg break, the licensee did not simulate the reflood and post-reflood phases because the break flow does not pass through the SGs prior to release to the containment. For the long term cooldown phase, the licensee used the current version of NRC-approved CONTRANS (Reference 30) computer code methodology for LOCA containment performance analyses. The long term analysis considers all residual energy in the primary and secondary systems and decay heat.

The NRC staff considers the M&E release analysis for LOCA acceptable because the licensee used conservative inputs and assumptions, used NRC-approved methodologies, and considered all sources of energy as well as the limiting break size and location as per SRP Section 6.2.1.3.

#### LOCA M&E Release for Short Term Subcompartment Analysis

The NRC has approved the LBB methodology for St. Lucie 1. According to the LBB methodology, RCS piping determined not to catastrophically rupture does not have to be considered for subcompartment analyses. Therefore as in the CLB, reactor cavity pressurization is not considered as a licensing basis under EPU conditions.

In an RAI the licensee was requested to state the computer code used and the assumptions made for the short term M&E release calculations for subcompartment analysis, and in case the assumptions differed from the CLB, provide justification. In its response the licensee states that there is no change in assumptions made for EPU from the assumptions in CLB and hand calculations were performed to evaluate the current M&E release calculations under EPU conditions.

For the LOCA M&E release evaluation for the pressurizer compartment, the licensee considered breaks in the pressurizer relief line, pressurizer spray line, and in the surge line. To accomplish this, the licensee evaluated the impact on the choked mass flux and energy flux under EPU conditions by using the Henry-Fauske correlation. For a conservative M&E release calculation the licensee used bounding inputs including measurement uncertainties, assuming (a) minimum core inlet temperature with uncertainty, (b) nominal reactor coolant flow rate with uncertainty, and (c) nominal full reactor power including uncertainty. The licensee followed the guidance given in SRP, Section 6.2.1.3, M&E Release Analysis for Postulated Loss-of-Coolant Accidents Subsection II, Part 3a to perform the calculation. The licensee used Henry-Fauske correlation that conservatively models the M&E release, which is directly related to the critical break mass flux at sub-cooled condition.

The M&E release from the three postulated breaks is evaluated in the following paragraphs.

The licensee states that for the guillotine break in the pressurizer relief line, the short-term M&E release which depends only on the initial pressurizer pressure is unaffected because the initial pressurizer pressure under the EPU conditions is unchanged from the pressure in the CLB.

The licensee states that the guillotine break in the pressurizer spray line will release M&E from the pressurizer side as well as the cold leg side. The M&E release from the cold leg side of a

pressurizer spray line break is dependent only on the initial pressure and enthalpy in the pumps discharge side of the cold leg. The licensee's evaluation showed that, as the cold leg temperature decreases, the mass and energy release rates would increase. For a guillotine break in the pressurizer spray line, the licensee determined that at the lowest initial temperature of 543 °F, the initial release of mass flux is less than 5 percent higher, and initial release of energy flux is less than 2 percent higher compared to their respective release rates at the CLB conditions.

For a guillotine break in the pressurizer surge line, the M&E will be released from the pressurizer side as well as the hot leg side. The M&E release rates from the pressurizer side of a surge line break depend only on the initial pressure and liquid enthalpy in the pressurizer. The St. Lucie 1 FSAR does not discuss the pressurizer surge line break. However the licensee used St. Lucie 2 pressurizer surge line guillotine break M&E release data by justifying similarity between the two units. The licensee conservatively estimated St. Lucie 1 M&E release rates increased by less than 0.9 percent in mass rate and less than 0.4 percent in energy rate than the pre-EPU St. Lucie 2 M&E release rates. In an RAI, the licensee was requested to explain how the St. Lucie 1 M&E release data for the pressurizer surge line break was conservatively estimated to be higher by the above percentage values than the pre-EPU M&E release data for the same break in St. Lucie 2. In its response the licensee indicated that the evaluation of differences in the RCS design between Units 1 and 2 concluded that the two units are sufficiently similar so that one M&E analysis can apply to both units. The licensee's evaluation did consider dissimilarities in the EPU operating conditions, and in the designs of (a) RSGs, (b) RV upper head, (c) pressurizer, and (d) surge line. Based on the evaluation of differences, the licensee determined that if the pre-EPU Unit 2 pressurizer surge line break M&E release data were adjusted to reflect the higher Unit 1 EPU reactor coolant flow, it could be applied to Unit 1 EPU conditions. The resulting Unit 1 EPU M&E release rates were conservatively estimated as 0.9 percent higher in mass flow rate and 0.4 percent higher in energy rate than the pre-EPU Unit 2 M&E release rates.

The NRC staff considers the evaluation of the short term EPU M&E release into the pressurizer subcompartment analysis acceptable because the licensee used conservative assumptions as in the Unit 2 CLB analysis and in the application of the Unit 2 analysis to Unit 1.

The short term evaluation of the pressurizer subcompartment P-T response is given in Section 2.6.2 of this safety evaluation report.

### Conclusion

The NRC staff has reviewed the licensee's mass and energy release assessment and concludes that the licensee has adequately addressed the effects of the proposed EPU and appropriately accounts for the sources of energy identified in 10 CFR Part 50, Appendix K. Based on this, the NRC staff finds that the mass and energy release analysis meets the requirements in GDC 50 for ensuring that the analysis is conservative. Therefore, the NRC staff finds the proposed EPU acceptable with respect to M&E release for postulated LOCA.



### 2.6.3.2 Mass and Energy Release Analysis for Secondary System Pipe Ruptures

#### Regulatory Evaluation

The NRC staff's review covered the energy sources that are available for release to the containment, the M&E release rate calculations, and the single-failure analyses performed for steam and FW line isolation provisions, which would limit the flow of steam or FW to the assumed pipe rupture. The NRC's acceptance criteria for M&E release analysis for secondary system pipe ruptures are based on GDC 50, insofar as it requires that the margin in the design of the containment structure reflect consideration of the effects of potential energy sources that have not been included in the determination of peak conditions, the experience and experimental data available for defining accident phenomena and containment response, and the conservatism of the model and the values of input parameters. Specific review criteria are contained in SRP Section 6.2.1.4.

#### Technical Evaluation

The licensee performed M&E release analysis for steam line break inside containment for several cases at power levels of hot 0, 25, 50, 75, and 100 percent plus 0.3 percent measurement uncertainty, and three single failure assumptions. The licensee used NRC-approved computer code SGNIII, which was also used in the current analysis. This computer code determines the M&E release, as well as the containment response. The licensee listed and justified differences in the major inputs and assumptions between the CLB and the EPU analysis. The analysis and acceptance criteria followed guidance provided in SRP 6.2.1.4. Additionally the licensee evaluated a LOOP accident case and confirmed that it is bounded by the non-LOOP cases. The NRC staff accepts the licensee's M&E evaluation because the licensee used the same computer code as in the CLB and with justified inputs and assumptions.

#### Conclusion

The NRC staff has reviewed the mass and energy release assessment performed by the licensee for postulated secondary system pipe ruptures and finds that the licensee has adequately addresses the effects of the proposed EPU. Based on this, the NRC staff concludes that the analysis meets the requirements in GDC 50 for ensuring that the analysis is conservative (i.e., that the analysis includes sufficient margin). Therefore, the NRC staff finds the proposed EPU acceptable with respect to mass and energy release for postulated secondary system pipe ruptures.

### 2.6.4 Combustible Gas Control in Containment

#### Regulatory Evaluation

Following a LOCA, hydrogen and oxygen may accumulate inside the containment due to chemical reactions between the fuel rod cladding and steam, corrosion of aluminum and other materials, and radiolytic decomposition of water. If excessive hydrogen is generated, it may form a combustible mixture in the containment atmosphere. The NRC staff's review covered (1) the production and accumulation of combustible gases, (2) the capability to prevent high concentrations of combustible gases in local areas, (3) the capability to monitor combustible gas

concentrations, and (4) the capability to reduce combustible gas concentrations. The NRC staff's review primarily focused on any impact that the proposed EPU may have on hydrogen release assumptions, and how increases in hydrogen release are mitigated. The NRC's acceptance criteria for combustible gas control in containment are based on (1) 10 CFR 50.44, insofar as it requires that plants be provided with the capability for controlling combustible gas concentrations in the containment atmosphere; (2) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; (3) GDC 41, insofar as it requires that systems be provided to control the concentration of hydrogen or oxygen that may be released into the reactor containment following postulated accidents to ensure that containment integrity is maintained; (4) GDC 42, insofar as it requires that systems required by GDC 41 be designed to permit appropriate periodic inspection; and (5) GDC 43, insofar as it requires that systems required by GDC 41 be designed to permit appropriate periodic testing. Specific review criteria are contained in SRP Section 6.2.5.

### Technical Evaluation

The licensee submitted a license amendment request by letter dated June 4, 2007, requesting revision in TS requirements associated with hydrogen recombiners and hydrogen monitors in accordance with a September 16, 2003 revision to 10 CFR 50.44. The NRC staff approved the license amendment request by the Reference 11 letter which removed hydrogen recombiners from the TS, and reclassified the monitoring system from safety-related to non safety-related consistent with RG 1.97. The licensee states that means to prevent stratification in containment is provided by the containment duct arrangements branching from the containment cooling system ring header duct. The licensee states that the containment atmosphere mixing mechanism following a design basis accident as described in the FSAR and the capability of hydrogen monitoring system to monitor beyond design-basis accident hydrogen concentrations is not impacted by the EPU. The NRC staff agrees that under EPU conditions, St. Lucie 1 will continue to satisfy the requirements of 10 CFR 50.44.

The licensee evaluated the combustible gas control system under EPU conditions for licensee renewal and determined that there are no new aging effects that require management and no changes are necessary to any existing aging management programs. The licensee states that the EPU does not add any new or previously unevaluated materials, or introduce any new system or component functions nor does it change the functions of existing components that would affect the system boundaries for license renewal.

### Conclusion

The NRC staff has reviewed the licensee's assessment related to combustible gas and concludes that the plant will continue to have sufficient capabilities, consistent with the requirements in 10 CFR 50.44, 10 CFR 50.46, and GDC 5, 41, 42, and 43 as discussed above. Therefore, the NRC staff finds the proposed EPU acceptable with respect to combustible gas control in containment.

## 2.6.5 Containment Heat Removal

### Regulatory Evaluation

Containment heat removal systems that consist of the spray system, fan cooler system and SDCS are provided to remove heat from the containment atmosphere and from the water in the containment sump. The NRC staff's review in this area focused on (1) the effects of the proposed EPU on the analyses of the available net positive suction head (NPSH) to the containment heat removal system pumps and (2) the analyses of the heat removal capabilities of the spray water system and the fan cooler heat exchangers. The NRC's acceptance criteria for containment heat removal are based on GDC 38, insofar as it requires that the containment heat removal system be capable of rapidly reducing the containment P-T following a LOCA, and maintaining them at acceptably low levels. Specific review criteria are contained in SRP Section 6.2.2, as supplemented by RG 1.82, Revision 3.

### Technical Evaluation

The containment heat removal system removes heat from the containment following a LOCA, or a secondary system line break in order to limit the containment P-T below the design conditions. The system is comprised of two separate ESF systems which are the CS system and the containment cooling system. The CS system consists of two redundant trains, each with a CS pump, SDC heat exchanger and CS header. During the recirculation phase, the system takes suction from the containment sump and directs flow through the SDC heat exchangers and sprays water into the containment through the spray header. The containment cooling system mainly consists of four containment fan cooler units, two of which are powered by the emergency diesel generator.

The EPU would increase the heat load on the containment heat removal system. The licensee performed containment integrity analysis and demonstrated that the current CS system and containment cooling system will limit the containment peak pressure and containment wall temperature below the design limits of 44 psig at 264 °F under EPU conditions. Section 2.6.1 of this report covers the SE of the containment integrity analysis.

In an RAI the licensee was requested to provide a summary of the NPSH analyses at the EPU conditions, including assumptions for the NPSH required, consideration of containment accident pressure (CAP), and the conservatism in calculating NPSH available (NPSHA). In its response (Reference 2), the licensee described the analysis under EPU conditions which determined that adequate NPSH margin is available during the injection and recirculation phases for the CS pumps, HPSI pumps, and the LPSI pumps. The licensee assumed the most limiting single active failure, used conservative inputs and assumptions to minimize the NPSHA during the safety injection and recirculation phases. Assuming the NPSHR based on the '3 percent head drop' Hydraulic Institute (HI) standard definition, the licensee showed that the available NPSH for the CS, HPSI, and LPSI pumps exceeds the required NPSH by more than 21 percent (Reference 31). The licensee did not take credit for the CAP to determine the NPSHA during the recirculation phase. The NRC staff considers the NPSH analysis acceptable because the licensee used conservative assumptions to minimize the NPSHA, showed adequate margin between the NPSHA and the '3 percent head drop' HI standard values of NPSHR, while not using the available CAP under EPU conditions.

In an RAI the licensee was requested to provide a discussion of how the post-accident debris generation is affected by the EPU, and describe its impact on the response to GL 2004-02 related to the resolution of Generic Safety Issue (GSI)-191. The licensee was also requested to describe the impact of EPU on the sump strainer head loss and on the pump NPSH evaluations during post-LOCA operation of the CS, HPSI and LPSI pumps. In its response (Reference 31), the licensee provided the results showing the NPSH margins and states (Reference 32) that the NPSH values used in calculating the margins reflect the integration of EPU conditions with the current GSI-191 resolution effort. The NRC staff accepts the licensee's response to NRC staff RAI regarding the impact of EPU on the response to GL 2004-02.

The licensee evaluated the EPU impact on the licensee's previous response to GL 96-06. The GL states, "Thermally induced overpressurization of isolated water-filled piping sections in containment could jeopardize the ability of accident-mitigating systems to perform their safety functions and could also lead to a breach of containment integrity via bypass leakage. Corrective actions may be needed to satisfy system operability requirements." The licensee's evaluation concluded that no EPU changes are required in the water-filled piping that penetrate the containment that supply cooling water to the containment cooling system and no new relief valves are required and the existing relief valves are acceptable.

The licensee evaluated the containment heat removal systems under EPU conditions for license renewal and determined that there are no new aging effects that require management and no changes are necessary to any existing aging management programs. The licensee states that EPU does not add any new or previously unevaluated materials, or introduce any new system or component functions nor does it change the functions of existing components that would affect the system boundaries for license renewal.

### Conclusion

The NRC staff has reviewed the containment heat removal systems assessment provided by the licensee and concludes that the licensee has adequately addressed the effects of the proposed EPU. The staff finds that the systems will continue to meet GDC 38 for rapidly reducing the containment P-T following a LOCA and maintaining them at acceptably low levels. Therefore, the staff finds the proposed EPU acceptable with respect to the containment heat removal system.

The NRC staff has reviewed the licensee's assessment of the impact that the proposed EPU would have on the resolution to GL 96-06 issue of overpressurization of water filled piping, due to thermal expansion of the piping fluid, that penetrate the containment and provide cooling water to the containment cooling system and considers it as resolved. Therefore, the staff finds the proposed EPU acceptable with respect to GL 96-06 issue of overpressurization of piping systems that penetrates containment.

Regarding the impact of EPU on the response to GL 2004-02, the licensee has included the EPU conditions with the GSI-191 resolution effort.

## 2.6.6 Pressure Analysis for ECCS Performance Capability

### Regulatory Evaluation

Following a LOCA, the ECCS will supply water to the reactor vessel to reflood and, thereby, cool the reactor core. The core flooding rate will increase with increasing containment pressure. The NRC staff reviewed analyses of the minimum containment pressure that could exist during the period of time until the core is reflooded to confirm the validity of the containment pressure used in ECCS performance capability studies. The staff's review covered assumptions made regarding heat removal systems, structural heat sinks, and other heat removal processes that have the potential to reduce the pressure. The NRC's acceptance criteria for the pressure analysis for ECCS performance capability are based on 10 CFR 50.46, insofar as it requires the use of an acceptable ECCS evaluation model that realistically describes the behavior of the reactor during LOCAs or an ECCS evaluation model developed in conformance with 10 CFR Part 50, Appendix K. Specific review criteria are contained in SRP Section 6.2.1.5.

### Technical Evaluation

The licensee performed the concurrent containment pressure analysis for the ECCS performance capability using the ICECON module within the NRC-approved realistic large-break LOCA (RLBLOCA) S-RELAP5 code (Reference 33). Using the phenomena identification and ranking table process, the licensee identified containment P-T as the two of several important parameters relative to the peak cladding temperature analysis. In an RAI the licensee was requested to specify which guidance of Branch Technical Position (BTP) 6-2 Rev. 3, was not used in setting the containment model input parameters and provide justification for not using the conservative guidance. In its response the licensee provided comments for each BTP 6-2 guidance indicating the one's used and not used in defining the containment model input parameters. The licensee states that where the BTP 6-2 guidance was not used, the applicable guidance provided in RG 1.157 was used. The licensee provided the limiting containment pressure response conservatively minimized by including the effects of operation of all installed pressure-reducing systems and processes. The NRC staff considers the licensee's analysis acceptable because, as required in Appendix K of 10 CFR Part 50, the containment pressure transient used in the calculation of peak cladding temperature is bounded by the minimum containment pressure response during the post-LOCA reflood phase.

The licensee evaluated the containment under EPU conditions for licensee renewal and determined that there are no new aging effects that require management and no changes are necessary to any existing aging management programs. The licensee states that EPU does not add any new or previously unevaluated materials, or introduce any new system or component functions nor does it change the functions of existing components that would affect the system boundaries for license renewal. The NRC staff accepts that the pressure analysis the EPU does not impact any license renewal evaluations.

### Conclusion

The NRC staff has assessed the impact that the proposed EPU would have on the minimum containment pressure analysis and concludes that the impact has been adequately addressed to ensure that St. Lucie 1 will continue to meet its CLB with respect to the requirements in 10 CFR 50.46 regarding ECCS performance following implementation of the proposed EPU.

Therefore the staff finds the proposed EPU acceptable with respect to minimum containment pressure analysis for ECCS performance.

## 2.7 Habitability, Filtration, and Ventilation

### 2.7.1 Control Room Habitability System

#### Regulatory Evaluation

The NRC staff reviewed the control room habitability system and control building layout and structures to ensure that plant operators are adequately protected from the effects of accidental releases of toxic and radioactive gases. A further objective of the NRC staff's review was to ensure that the control room can be maintained as the backup center from which technical support center personnel can safely operate in the case of an accident. The NRC staff's review focused on the effects of the proposed EPU on radiation doses, toxic gas concentrations, and estimates of dispersion of airborne contamination. The NRC's acceptance criteria for the control room habitability system are based on (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with postulated accidents, including the effects of the release of toxic gases; and (2) GDC 19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 Roentgen equivalent man (rem) whole body, or its equivalent, to any part of the body, for the duration of the accident. Specific review criteria are contained in SRP Section 6.4 and other guidance provided in Matrix 7 of RS-001.

#### Technical Evaluation

The licensee evaluated the effects of EPU on the control room habitability systems during normal and emergency operation and states that EPU would not cause any significant changes to the control room envelope integrity, equipment heat loads internal to the control room, heating and cooling capacity of the ventilation system to maintain the ambient temperatures required for personnel comfort and equipment operability, filtration of airborne contaminants and maintaining positive static pressure during emergency operation.

There licensee states that no modifications are performed for EPU that would significantly increase the equipment heat loads internal to the control room in comparison to the overall load and equipment capacity. Section 2.7.3.1 below provides an evaluation of the control room ventilation system to provide cooling to the control room under EPU conditions. The licensee also states that EPU will not introduce any toxic material hazards to the control room operators.

#### Conclusion

The NRC staff has reviewed the licensee's assessment related to the effects of the proposed EPU on the ability of the control room habitability system to protect plant operators against the effects of accidental releases of toxic and radioactive gases. The NRC staff concludes that the licensee has adequately accounted for the increase of toxic and radioactive gases that would result from the proposed EPU. The NRC staff further concludes that the control room habitability system will continue to provide the required protection following implementation of the proposed EPU. Based on this, the NRC staff concludes that the control room habitability

system will continue to meet the requirements of GDC 4 and 19. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the control room habitability system.

#### 2.7.2 Engineered Safety Feature Atmosphere Cleanup

##### Regulatory Evaluation

ESF atmosphere cleanup systems are designed for fission product removal in post-accident environments. These systems generally include primary systems (e.g., in-containment recirculation) and secondary systems (e.g., emergency or post-accident air-cleaning systems) for the fuel-handling building, control room, shield building, and areas containing ESF components. For each ESF atmosphere cleanup system, the NRC staff's review focused on the effects of the proposed EPU on system functional design, environmental design, and provisions to preclude temperatures in the adsorber section from exceeding design limits. The NRC's acceptance criteria for the ESF atmosphere cleanup systems are based on (1) GDC 19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent, to any part of the body, for the duration of the accident; (2) GDC 41, insofar as it requires that systems to control fission products released into the reactor containment be provided to reduce the concentration and quality of fission products released to the environment following postulated accidents; (3) GDC 61, insofar as it requires that systems that may contain radioactivity be designed to assure adequate safety under normal and postulated accident conditions; and (4) GDC 64, insofar as it requires that means shall be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including AOOs, and postulated accidents. Specific review criteria are contained in SRP Section 6.5.1.

##### Technical Evaluation

The systems that are included in the ESF atmosphere cleanup systems are: (1) containment spray system, (2) shield building ventilation system, (3) ECCS area ventilation system, and (4) control room ventilation system. For each ESF atmosphere cleanup system, the NRC staff's review focused on the effects of the proposed EPU on the system design for normal and emergency operation.

The containment spray system, along with the iodine removal system removes post-accident heat and fission products from the containment atmosphere. The licensee states that EPU does not affect the containment spray and iodine removal system. The licensee's evaluation demonstrates the ability of the existing containment spray system to maintain the releases within acceptable limits.

The shield building ventilation system reduces the concentration and the amount of fission products released to the environment following postulated accidents. During the post-accident conditions, the system limits the pressure rise and also maintains a negative pressure in the shield building annulus. The air inside the annulus, after mixing with the outside air leaking into the annulus, and with the air leaking from the containment, is discharged to the outside environment through a charcoal adsorber filter train. The licensee states that due to the EPU impact on the post-accident containment P-T transient, the annulus pressure transients are affected. The licensee's annulus pressure analysis under EPU conditions shows that it will increase to 5.3 inches water gage as compared to 5.0 inches water gage in the current analysis,

which is still bounded by the design differential pressure. In addition the time to establish a negative pressure in the annulus under EPU conditions will increase to 117 seconds as compared to 65 seconds in the current analysis, which remains bounded by 310 seconds assumed in the accident dose analysis. The licensee evaluated the affect of EPU on the charcoal adsorber temperature and determined that the cooling air flow is sufficient to maintain the adsorber temperature below its alarm setpoint of 200 °F. Therefore, the shield building annulus ventilation system is not affected by EPU. The licensee also states that the ability of the shield building ventilation system to reduce the concentration and quantity of post accident fission products released from the containment to the environment is not affected by EPU and is in compliance with GDC 41.

The ECCS area ventilation system provides post-LOCA filtration and adsorption of fission products in the exhaust air from areas of the reactor auxiliary building that contain safety-related equipment. The system maintains a slightly negative pressure in the ECCS area with respect to the atmosphere. The licensee states that because of less iodine loadings and heavier mass of the charcoal filter absorber compared to the shield building adsorber, its heating rate is significantly less than the shield building ventilation system adsorbers. Therefore, the licensee concludes that absorber heating by decay heat is not significant under EPU condition. The licensee also states that the ECCS area ventilation system charcoal filters are not impacted by EPU because their iodine loadings are significantly below that in the shield building ventilation system filters. The offsite dose analyses, presented in LAR Attachment 5, Section 2.9.2, demonstrate the effectiveness of the ESF atmosphere cleanup systems to minimize the release of radioactivity to the environment following a LOCA in compliance with GDC 41.

The control room ventilation system conditions the control room air and supplies fresh makeup air to maintain safe levels of oxygen under normal and emergency conditions. The system maintains a positive pressure in the control room. It also limits the airborne radioactivity in the control room during emergency conditions by passing a portion of the recirculation control room air through HEPA filters and charcoal adsorbers. During the post-accident conditions, the airborne fission products that reach the control room charcoal filters originate from filtered releases from the shield building ventilation system and unfiltered bypass leakage, both diluted with outside air. The licensee states that the fission products from these two pathways are less than that which is used to calculate the shield building filter adsorber inventory. Therefore the fission products that can potentially reach the control room outside air intakes and as unfiltered in-leakage is significantly reduced resulting in lower iodine loading and lower heat load per gram of charcoal on the control room adsorber. In addition, higher control room ventilation flow of 2000 cfm compared to 300 cfm for the shield building ventilation flow, the maximum temperature rise in the control room adsorber is expected to be much smaller than that of shield building adsorber.

### Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ESF atmosphere cleanup systems. The NRC staff concludes that the licensee has adequately accounted for the increase of fission products and changes in expected environmental conditions that would result from the proposed EPU, and the NRC staff further concludes that the ESF atmosphere cleanup systems will continue to provide adequate fission product removal in post-accident environments following implementation of the proposed EPU. Based on this, the NRC staff concludes that the ESF atmosphere cleanup systems will continue



to meet the requirements of GDC 19, 41, 61, and 64. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the ESF atmosphere cleanup systems.

### 2.7.3 Ventilation Systems

#### 2.7.3.1 Control Room Area Ventilation System

##### Regulatory Evaluation

The function of the CRAVS is to provide a controlled environment for the comfort and safety of control room personnel and to support the operability of control room components during normal operation, AOOs, and DBA conditions. The NRC's review of the CRAVS focused on the effects that the proposed EPU will have on the functional performance of safety-related portions of the system. The review included the effects of radiation, combustion, and other toxic products; and the expected environmental conditions in areas served by the CRAVS. The NRC's acceptance criteria for the CRAVS are based on (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (2) GDC 19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident; and (3) GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 9.4.1.

##### Technical Evaluation

The CRAVS maintains control room temperature and humidity for personnel comfort during normal conditions, limit control room dose due to airborne activity to within GDC 19 limits during post-accident conditions, permit personnel occupancy inside the control room during toxic gas release accident, and permit personnel occupancy and equipment functioning during normal and post-accident conditions assuming a single failure. Regarding changes in the control room equipment for EPU, the licensee proposes to replace the existing computer with a modern computer with a lesser heat load. Also the licensee proposes to add the new Cameron LEFM CheckPlus™ system computer in the control room, which has an insignificant affect on the heat load. The licensee states that there are no other EPU modifications that would increase the equipment heat loads internal to the control room in comparison to the overall load and equipment capacity. For the above changes, the licensee determined that the proposed EPU has no effect during normal, abnormal, or emergency conditions on the ability of the CRAVS to provide a controlled environment for the comfort and of control room personnel and to support the operability of the control room components.

The EPU evaluation and compliance with GDC 19 regarding adequate radiation protection of control room personnel under accident conditions is provided in Section 2.7.1. The licensee's EPU evaluation and compliance with GDC 60 with regard to means to control the release of radioactive effluents is provided in LAR Attachment 5, Sections 2.5.6.1, 2.5.6.2, and 2.5.6.3.

## Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ability of the CRAVS to provide a controlled environment for the comfort and safety of control room personnel and to support the operability of control room components. The NRC staff concludes that the licensee has adequately accounted for the increase of toxic and radioactive gases that would result from a DBA under the conditions of the proposed EPU, and associated changes to parameters affecting environmental conditions for control room personnel and equipment. Accordingly, the NRC staff concludes that the CRAVS will continue to provide an acceptable control room environment for safe operation of the plant following implementation of the proposed EPU. The NRC staff also concludes that the system will continue to suitably control the release of gaseous radioactive effluents to the environment. Based on this, the NRC staff concludes that the CRAVS will continue to meet the requirements of GDC 4, 19, and 60. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CRAVS.

### 2.7.4 Spent Fuel Pool Area Ventilation System

#### Regulatory Evaluation

The function of the spent fuel pool area ventilation system (SFPavs) is to maintain ventilation in the spent fuel pool equipment areas, permit personnel access, and control airborne radioactivity in the area during normal operation, AOOs, and following postulated fuel-handling accidents (FHAs). The NRC staff's review focused on the effects of the proposed EPU on the functional performance of the safety-related portions of the system. The NRC's acceptance criteria for the SFPavs are based on (1) GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents, and (2) GDC 61, insofar as it requires that systems which contain radioactivity be designed with appropriate confinement and containment. Specific review criteria are contained in SRP Section 9.4.2.

#### Technical Evaluation

The fuel handling building ventilation system is a non-safety system and is therefore not credited in the safety analysis. The licensee states that the decay heat in the SFP will increase under EPU conditions, however its water temperature during normal EPU operation and refueling operation under EPU conditions with 100-percent core off load remains below the current design temperature of 150 °F. This evaluation is provided in LAR Attachment 5, Section 2.5.4.1, Spent Fuel Pool Cooling and Cleanup System. The licensee states there are no additional heat sources introduced for EPU in the SFP building and the ambient outside conditions remains the same as in the current licensing basis. The fuel pool and the building ambient design temperatures are not affected by EPU. On this basis, the licensee concluded that the existing fuel handling building ventilation system will maintain the required temperature conditions for personnel and equipment during EPU operation. In a letter dated May 18, 2011 (Reference 31), in response to NRC staff RAI, the licensee states that during a loss of SFP cooling, the temperature of the area will follow the temperature of the pool water because of the heat transfer from the pool water to the surrounding area. The licensee also states that the SFP pumps and heat exchangers areas are ventilated by separate ventilation system that is not affected by EPU. The NRC staff accepts the licensee's evaluation because the SFP design temperature is unaffected by EPU and, therefore, the SFP area ventilation system will maintain the required temperature conditions for personnel and equipment during EPU operation. The

licensee states that since there will be no changes in the system air distribution, flow rates, and filtration under EPU conditions, there is no effect on the system capability to reduce plant personnel doses due to potential airborne activity resulting from fission products released from the SFP. The licensee's EPU evaluation of radiological consequences of FHAs is provided in LAR Attachment 5, Section 2.9.2. The licensee's evaluation of the airborne radioactivity released from the spent fuel in the pool that is collected by the system and discharged to the atmosphere via the fuel handling building vent stack is provided in LAR Attachment 5, Section 2.10.1.

### Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the SFP AVS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system's capability to maintain ventilation in the spent fuel pool equipment areas, permit personnel access, control airborne radioactivity in the area, control release of gaseous radioactive effluents to the environment, and provide appropriate containment. Based on this, the NRC staff concludes that the SFP AVS will continue to meet the requirements of GDC 60 and 61. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the SFP AVS.

### 2.7.5 Auxiliary and Radwaste Area and Turbine Areas Ventilation Systems

#### Regulatory Evaluation

The function of the auxiliary and radwaste area ventilation system (ARAVS) and the turbine area ventilation system (TAVS) is to maintain ventilation in the auxiliary and radwaste equipment and turbine areas, permit personnel access, and control the concentration of airborne radioactive material in these areas during normal operation, during AOOs, and after postulated accidents. The NRC staff's review focused on the effects of the proposed EPU on the functional performance of the safety-related portions of these systems. The NRC's acceptance criteria for the ARAVS and TAVS are based on GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Sections 9.4.3 and 9.4.4.

#### Technical Evaluation

The licensee evaluated the RAB ventilation systems and determined that EPU does not result in additional heat sources added to the areas served by the systems because no additional equipment is added in RAB. Since no additional batteries are being added, therefore EPU does change the requirements for maintaining hydrogen concentrations in the RAB from the current licensing basis. In addition EPU does not affect maintaining space pressurization and control of airborne radioactive effluents during normal and emergency conditions. Additional licensee's evaluation for compliance to GDC 60 is provided in LAR Attachment 5, Section 2.10.1. Refer to Section 2.7.6, engineered safety feature ventilation system for additional information regarding ventilation to the ECCS area during accident conditions. Regarding the turbine switchgear room ventilation system, the licensee states that the proposed EPU modifications will increase the load current for some of the existing motors without any change in the connected hp rating. The increase is less than 1-percent of the existing total nameplate motor ratings supplied by the switchgear and load centers in the turbine switchgear room. The licensee states that the existing ventilation system can accommodate this small increase and will still have an

11.6-percent margin under EPU conditions. The staff considers the licensee's evaluation of the RAB ventilation systems acceptable because the licensee demonstrated that a significant margin exists under EPU conditions.

### Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ARAVS and TAVS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the capability of these systems to maintain ventilation in the auxiliary and radwaste equipment areas and in the turbine area, permit personnel access, control the concentration of airborne radioactive material in these areas, and control release of gaseous radioactive effluents to the environment. Based on this, the NRC staff concludes that the ARAVS and TAVS will continue to meet the requirements of GDC 60. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the ARAVS and the TAVS.

### 2.7.6 Engineered Safety Feature Ventilation System

The following ESF ventilation systems are evaluated in the Sections given below:

- Control Room Habitability – Refer to Section 2.7.1 for safety evaluation
- Engineered Safety Feature Atmosphere Cleanup - Refer to Section 2.7.2 for safety evaluation
- Control Room Ventilation System - Refer to Section 2.7.3 for safety evaluation
- Auxiliary and Radwaste Area and Turbine Areas Ventilation Systems - Refer to Section 2.7.5 for safety evaluation
- Other Ventilation Systems (Containment) - Refer to Section 2.7.7 for safety evaluation

The following ESF ventilations systems are evaluated in this Section

- Emergency Core Cooling System (ECCS) Area Ventilation – safety evaluation provided in this Section
- Emergency Diesel Generator (EDG) Building Ventilation - safety evaluation provided in this Section

### Regulatory Evaluation

The function of the engineered safety feature ventilation system (ESFVS) is to provide a suitable and controlled environment for ESF components following certain anticipated transients and DBAs. The NRC staff's review for the ESFVS focused on the effects of the proposed EPU on the functional performance of the safety-related portions of the system. The NRC staff's review also covered (1) the ability of the ESF equipment in the areas being serviced by the ventilation system to function under degraded ESFVS performance; (2) the capability of the ESFVS to circulate sufficient air to prevent accumulation of flammable or explosive gas or fuel-vapor mixtures from components (e.g., storage batteries and stored fuel); and (3) the capability of the ESFVS to control airborne particulate material (dust) accumulation. The NRC's acceptance criteria for the ESFVS are based on (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (2) GDC 17, insofar as it requires onsite and offsite electric power

systems be provided to permit functioning of SSCs important to safety; and (3) GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 9.4.5.

### Technical Evaluation

The ECCS area ventilation system provides post accident filtration and adsorption of fission products in the exhaust air from areas of the RAB which contain safety-related equipment. Two ECCS area ventilation system exhaust monitors measure the airborne effluent from the ECCS area. The system maintains a slightly negative pressure in the ECCS area with respect to surrounding areas of the RAB. The licensee developed a GOTHIC computer model to calculate the temperature response in the ECCS rooms during a DBA and demonstrated that the temperature in the room remains below the design temperature under EPU conditions.

The EDG building ventilation system provides environment conditions suitable for occupancy in the EDG building when the EDGs are not in operation. During emergency conditions when the EDGs are operating, the engine cooling system fan provides the ventilation air flow through the EDG building to maintain its temperature at 104 °F. The licensee states that operation of the EDG under EPU conditions the load is increased but remains bounded by the current EDG ratings as demonstrated in LAR Attachment 5, section 2.3.3.

The licensee evaluated the ESF ventilation systems under EPU conditions and ensured their capability of circulating sufficient air for preventing accumulation of flammable or explosive gases, and also its ability to control airborne particulate material accumulation. The licensee states that the evaluation of the plant equipment changes for the EPU conditions did not require modification of these systems, and no plant equipment changes are required that could create a new potentially unmonitored radioactive release path. The staff accepts licensee's evaluation, because the licensee determined that an insignificant increase in the heat load did not impact the ventilation equipment and the capability to control and minimize the release of airborne particles to the environment is maintained.

### Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ESFVS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the ability of the ESFVS to provide a suitable and controlled environment for ESF components. The NRC staff further concludes that the ESFVS will continue to assure a suitable environment for the ESF components following implementation of the proposed EPU. The NRC staff also concludes that the ESFVS will continue to suitably control the release of gaseous radioactive effluents to the environment following implementation of the proposed EPU. Based on this, the NRC staff concludes that the ESFVS will continue to meet the requirements of GDC 4, 17 and 60. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the ESFVS.

### 2.7.7 Other Ventilation Systems (Containment)

#### Regulatory Evaluation

The functions of the containment ventilation systems is to provide heat removal from the containment atmosphere and selected areas within containment, to remove radioactive

materials from the containment atmosphere, and to provide containment pressure control under normal and accident conditions. The NRC staff review of the containment ventilation systems focused on the effects that the EPU will have on the functional performance of the systems. The acceptance criteria for the containment ventilation system are based on (1) GDC 4, insofar as it requires that safety-related SSCs be designed to accommodate the effects of and be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (2) GDC 38, insofar as it requires that the containment heat removal system(s) function to rapidly reduce the containment P-T following any LOCA and maintain them at acceptably low levels; (3) GDC 41, insofar as it requires that systems to control fission products released into the reactor containment be provided to reduce the concentration and quality of fission products released to the environment following postulated accidents; (4) GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents.

### Technical Evaluation

The containment ventilation systems consists of eight systems which are: (1) containment fan coolers, (2) control element drive mechanism (CEDM) cooling system, (3) reactor support cooling system, (4) reactor cavity cooling system, (5) containment airborne radioactivity removal units, (6) containment vacuum relief system, (7) containment purge system, and (8) hydrogen control system.

#### *Containment Cooling System*

The containment cooling system, which consists of fan coolers, removes heat from the containment during normal operation by supplying cooled air to various regions of the containment atmosphere. Also, following an accident, the containment cooling system in conjunction with the containment spray system, which is evaluated in Section 2.6.5 above, removes heat from the containment, thereby reducing the containment P-T, and maintaining them at acceptably low levels. The licensee states that under EPU condition, the increased heat load from the containment heat sources results in an increase of containment bulk air temperature by 1.7 °F so that the EPU containment temperature is approximately 110 °F which is 10 °F below the design temperature of 120 °F. Therefore there are no changes to the containment cooling system. The existing system will continue to perform its intended function under the EPU conditions.

#### *Control Element Drive Mechanism Cooling System*

The CEDM cooling system is designed to ventilate the CEDM magnetic jack coils and maintain them at a temperature below 350 °F. The licensee's evaluation of the CEDM cooling system concluded that the CEDM heat load does not change for EPU conditions. This licensee's EPU evaluation considered bounding values of the parameters that were used in the existing analysis and determined that the change under EPU conditions is negligible. Therefore EPU does not affect the CEDM cooling system will continue to perform its design function

#### *Reactor Support Cooling System*

The reactor support cooling system cools to limit the temperature of the lubrication plates between the reactor and support leg in order to restrict thermal growth of the supporting steel work for the reactor vessel. The licensee estimated an approximate 1-percent increase in the

heat load for the system and states that this increase is bounded by the design conditions. Therefore EPU does not affect the reactor support cooling system and will continue to perform its design function under EPU conditions.

#### *Reactor Cavity Cooling System*

The reactor cavity cooling system ventilates the annular space between the reactor vessel and the concrete primary shield wall to limit the concrete surface temperature in order to minimize the possibility of concrete dehydration. The licensee's evaluation of the heat load from the reactor vessel was shown to increase by approximately 1-percent. Therefore, the reactor cavity cooling system heat load from its heat sources would increase by the same amount (i.e., approximately 1 percent). The licensee states that the increase in heat load does not affect the reactor cavity cooling system. Therefore, the reactor cavity cooling system will continue to perform its design function following EPU.

#### *Containment Airborne Radioactivity Removal Units*

The containment airborne radioactivity removal units remove airborne radioactivity during normal operation. These units do not serve any function for post-accident dose reduction and are not credited in any event analysis. The licensee determined that the capability of the containment airborne radioactivity removal units bounds the increase in airborne radioactivity concentration during normal EPU conditions and does not require changes for EPU operation. The staff accepts licensee's evaluation for existing airborne radioactive removal units that they will continue to perform their intended function under EPU conditions.

#### *Containment Vacuum Relief System*

The containment vacuum relief system provides protection of the containment vessel against excessive external pressure by preventing the differential pressure between the containment and the shield building atmosphere from exceeding the design value of 0.70 psi. The licensee evaluated the containment vacuum relief system and confirmed that EPU does not affect the bounding design parameters for the operation of the system at its design basis event which is the inadvertent operation of the containment spray system while all fan coolers are in operation and the containment is at its maximum normal operating temperature of 120 °F. The licensee states that EPU does not affect the overall containment vacuum relief system. The staff considers licensee's evaluation of the containment vacuum relief system under EPU conditions acceptable.

#### *Containment Purge System*

The containment purge system is designed to reduce the level of radioactive contamination in the containment atmosphere below the limits of 10 CFR Part 20 so as to permit personnel access to the containment during shutdown and refueling. The containment hydrogen purge system is a subsystem of the hydrogen control system. The existing containment hydrogen purge system will be modified for EPU to provide a new function to control containment pressure. The modification will allow the plant to maintain a lower maximum normal operating pressure for EPU. The licensee states that the modified system will continue to be subject to the related technical specification and inservice inspection requirements and will continue to maintain the integrity of containment pressure boundary. The staff accepts the licensee's

evaluation and modification of the containment hydrogen purge system because it will continue to perform its design function after implementation of the EPU.

### *Hydrogen Control System*

This EPU evaluation of containment purge system, which is a subsystem of hydrogen control system, is discussed above. The other EPU modification of the hydrogen control system is providing fail-close air operators for the existing hydrogen purge containment exhaust isolation valves that will close during a LOCA or steam line break accident. The licensee states that the modified valves will be able to isolate containment in less than 30 seconds assumed in the dose analyses. The only contribution of purge to the activity release is during the short period of time prior to purge isolation at the beginning of the LOCA. These containment isolation valves will be controlled from and have indication in the control room, and are designed to close against the differential pressure during a LOCA under EPU conditions. The ability of the modified valves to close against the differential pressure in the event of a LOCA is addressed in LAR Attachment 5, Section 2.2.4.

### Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the containment ventilation systems. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the capability of these systems to perform their intended functions. The NRC staff also concludes that containment ventilation systems will continue to meet the requirements of GDC 4, 38, 41, and 60. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the containment ventilation systems.

## 2.8 Reactor Systems

### 2.8.1 Fuel System Design

#### Regulatory Evaluation

The fuel system consists of arrays of fuel rods, burnable poison rods, spacer grids and springs, end plates, and reactivity control rods. The NRC staff reviewed the fuel system to ensure that,

- (1) the fuel system is not damaged as a result of normal operation and AOOs,
- (2) fuel system damage is never so severe as to prevent control rod insertion when it is required,
- (3) the number of fuel rod failures is not underestimated for postulated accidents, and
- (4) coolability is always maintained.

The NRC staff's review covered fuel system damage mechanisms, limiting values for important parameters, and performance of the fuel system during normal operation, AOOs, and postulated accidents.



The NRC's acceptance criteria are based on:

- (1) 10 CFR 50.46, insofar as it establishes standards for the calculation of ECCS performance and acceptance criteria for that calculated performance;
- (2) GDC-10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs;
- (3) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and
- (4) GDC 35, insofar as it requires that a system to provide abundant emergency core cooling be provided to transfer heat from the reactor core following any LOCA. Specific review criteria are contained in SRP Section 4.2 and other guidance provided in Matrix 8 of RS-001.

The aforementioned GDC, published in 10 CFR Part 50, Appendix A, were not yet available at the time St. Lucie 1 was licensed to operate. St. Lucie 1 was designed and licensed according to earlier GDC, proposed by the AEC. Details concerning design relative to GDC are found in the FSAR Section 3.1, which addresses conformance to both the Atomic Industrial Forum, Inc. (AIF) GDC and the NRC GDC.

### Technical Evaluation

#### 2.8.1.1 Fuel System Design features

The key features of the CE14 high thermal performance (HTP) fuel assembly for the St. Lucie 1 consist of the following (Reference 2):

- The MONOBLOC guide tube design that may be implemented during the first or subsequent EPU cycle.
- One FUELGUARD lower tie plate (LTP),
- One Alloy 718 high mechanical performance (HMP) bottom spacer grid,
- Eight Zircaloy-4 high thermal performance (HTP) spacer grids,
- Four Zircaloy-4 standard or MONOBLOC corner guide tubes,
- One Zircaloy-4 instrumentation tube,
- 176 fuel rods featuring Zircaloy-4 cladding and end caps, and
- One stainless steel upper tie plate (UTP) with alloy X750 holddown springs

AREVA has tested the MONOBLOC guide tube design and determined that the lateral fuel assembly stiffness is slightly greater for the MONOBLOC design. Pressure drop testing on full scale prototype fuel assemblies has shown that the measured pressure drop of the inlet, rodded, and outlet regions of the two assembly types have been shown to be equal (within the test measurement uncertainty), and therefore the lift performance of both designs is considered to be the same. Therefore the NRC staff has determined that the transition to MONOBLOC guide tube design is not considered to introduce a mixed core configuration.

EPU thermal-hydraulic and neutronic operating conditions include increased minimum RCS flow rate of 375,000 gpm, slightly increased core inlet temperature of 551 °F, radial and axial power histories, and reduced peaking factor of 1.65.

## 2.8.1.2 Analyses and Evaluations

### 2.8.1.2.1 Fuel Rod Analyses

The NRC-approved fuel rod performance models (Reference 31) and (Reference 32) were used to model the anticipated EPU operating conditions and the fuel characteristics of the CE14 HTP design with MONOBLOC or standard guide tubes.

Internal Hydriding: The failure mechanism due to the absorption of hydrogen in cladding that results in reduced cladding ductility is precluded by controlling the moisture hydrogen impurities in the rod during fabrication. The moisture control is applied to minimize the total hydrogen within the fuel rod assemblies.

Cladding Collapse: Cladding creep analysis evaluated the creepdown and ovalization of the cladding using AREVA's RODEX2 and COLAPX (Reference 31) and (Reference 32) codes on cycle specific basis (Reference 31). The RODEX2 code is used to calculate the cladding creepdown and provides initial in-reactor fuel rod conditions to COLAPX. The COLAPX code calculates the cladding ovality changes as a function of time. The combination of the two evaluations performed at [ ] such that the combined creepdown shall not exceed [ ]. The creep collapse methodology uses [ ]

[ ] in order to calculate conservative creep collapse margins. The licensee reports that Cladding collapse calculations were performed and demonstrated that no axial gap within the fuel column can form during the initial densification for all fuel operating in EPU cycles.

The NRC staff has determined that the creep collapse analyses performed by AREVA satisfy the cladding collapse criterion for operation at EPU conditions.

Overheating of cladding and fuel pellets: Thermal margin criterion for departure from nucleate boiling ratio (DNBR) has satisfied the preclusion of cladding overheating in the Transients and Accidents Analyses Section, 2.8.5.0. Section 2.8.5.0 analysis has shown that no fuel centerline melting occurs for normal operation and AOOs.

Strain Limits, Fatigue and Fuel Thermal Conductivity: In addition to the ramping analysis using ramps in linear heat generation rate, cladding strain was analyzed in both steady-state conditions and under simulated Condition II events or AOOs. The degradation of fuel thermal conductivity at higher exposures will result in non-conservative RODEX2 based calculations of steady-state and AOO strain margins as well as margins to the cladding fatigue criterion due to the fact that higher fuel temperatures will result in larger fuel pellet diameters, which will in turn result in larger cladding strains and cladding fatigue.

NRC-approved RODEX2 code does not explicitly model degradation of fuel thermal conductivity with burnup. AREVA has developed penalties for the various applications that use the RODEX2 fuel performance code in order to bound the impact of the lack of fuel thermal conductivity

degradation in the code. The applications affected are cladding strain and cladding fatigue. AREVA has determined and the NRC staff agrees that the rod internal pressure predictions performed by RODEX2 code are adequately conservative and that no penalties are required for the rod internal pressure application (Reference 34).

RODEX2 has been benchmarked to extended Halden data that included thermal data beyond the approved burnup range that was used to benchmark the modern RODEX4 fuel performance code that models the degradation of thermal conductivity with burnup. The benchmarking of RODEX2 has resulted in burnup dependent adjustment factor applied to predicted temperatures. Thus the RODEX2 best estimate temperatures have been effectively increased to account for the degradation of fuel thermal conductivity over the burnup range. The adjustment factor increases with burnup to a maximum value of [ ] at the EOL. The factor was used to [ ]

The NRC staff conducted two audits to review the AREVA fuel thermal-mechanical performance calculations, specifically the application of RODEX2 augmentation (adjustment) factors that were developed to compensate for the lack of an exposure dependent fuel thermal conductivity model. During the audit, the staff reviewed several calculations on the impact of RODEX2 fuel thermal conductivity degradation on generic fuel mechanical design criteria. An accurate thermal conductivity model would likely predict higher fuel temperatures during normal operation and would result in an increase in fuel pellet outer diameter as well as increase in fuel swelling during upset conditions. In the AREVA calculation, the initial pellet diameter was adjusted by multiplying the original fuel average temperature by a factor of [ ] which represents a 95/95 adjustment relative to the empirical database at 60 GWd/MTU. An adjustment to the predicted transient fuel temperature is then made based on thermal uncertainties calculated using the expanded empirical database. During the process the maximum cladding strain increased to [ ] for Zr-4 and [ ] for M5. The adjusted values satisfy the 1% cladding strain criterion. For a similar reason (increase in pellet diameter), cladding fatigue calculations are impacted by RODEX2 lack of thermal conductivity degradation, AREVA determined that the fatigue usage factor increased by [ ]. The NRC staff has determined that the development of cladding strain and cladding fatigue augmentation factors are reasonable.

Based upon the review of AREVA fuel-mechanical design calculations, the staff has determined that the generic RODEX2 thermal conductivity augmentation factors have been correctly applied within the St. Lucie 1 EPU licensing amendment request. [ ]

]

The new values of strains and fatigue were applied as penalties to the original strain and fatigue values calculated using the approved RODEX2 code and methodology. The results reported by AREVA have been accepted by the NRC staff and the staff has determined that sufficient margins to the strain and fatigue criteria exist to offset the impact due to the degradation of fuel thermal conductivity (Reference 2) and (Reference 34).

Rod Internal Pressure: (Reference 2) reports that the rod internal pressure calculated using RODEX2 code continues to be within the pin pressure limit for all fuel operating at the EPU conditions for the reduced peaking factor.

In its response to an RAI from NRC staff, AREVA has reported that RODEX2 has been benchmarked against measured fission gas data up to 62 GWd/MTU rod average exposure and its fission gas release model was calibrated to provide [ ] fission gas release predictions up to 62 gigawatt days per metric ton of uranium (GWd/MTU) (Reference 34). Figures 3, 4, and 5 of (Reference 34) provides the rod internal free volume benchmarking results and show that the RODEX2 code performs well in predicting rod internal free volume. Both fission gas release and internal volume predictions indicate that degradation of thermal conductivity does not impact the rod internal pressure results.

The NRC staff performed independent confirmatory rod internal pressure calculations using the FRAPCON-3.4 statistical package with the limiting St. Lucie 1 EPU  $\text{UO}_2$  and  $\text{UO}_2 + \text{GdO}_2$  fuel rod power histories that bound expected transition and equilibrium cycles. For these calculations, the staff ran 500 cases with sampling the distribution of manufacturing tolerances for cladding inside diameter (ID) and OD, pellet OD, and plenum length. FRAPCON-3.4 predicts an upper tolerance for rod internal pressure of 2772 psi for the  $\text{UO}_2$  statistical case including both manufacturing tolerances and fission gas release uncertainty. For the  $(\text{U,Gd})\text{O}_2$  statistical case, the upper tolerance rod internal pressure was 1785 psi. For further confirmation, the staff ran an additional set of cases with a 5-percent rod power uncertainty. The maximum upper tolerance limit rod internal pressure was 2904 psi and 1820 psi for the  $\text{UO}_2$  and  $(\text{U,Gd})\text{O}_2$  fuel rods respectively. The staff's independent calculations confirmed that the rod internal pressure design limit of [ ] is satisfied for the St. Lucie 1 EPU.

The NRC-approved RODEX2 methodology for rod internal pressure predictions (Reference 31) establishes a conservative treatment of power histories to ensure that under prediction of rod internal pressure does not occur. The NRC staff has determined that the fuel design analysis methodology for determining limiting rod internal pressures is considered conservative and is acceptable for EPU applications at St. Lucie 1.

Fuel Rod Growth: The maximum predicted EOL fuel rod growth is calculated using conservative temperatures, worst case dimensional clearance, maximum rod growth, and minimum assembly growth. The fuel rod growth analysis is performed using the methodology approved in (Reference 35). The NRC staff has accepted the results of rod growth analysis, which demonstrated that the rod growth limits continue to be met for all fuel operating at the EPU conditions.

Fuel Coolability: The assembly must retain its rod-bundle geometry with adequate coolant channels to permit removal of residual heat. Reduction of coolability can result from cladding embrittlement, violent expulsion of fuel, generalized cladding melting, gross structural deformation, and extreme coplanar fuel rod ballooning. The loads that originate during faulted conditions caused by motions of the upper and lower core plates, and lateral deflections and impacts transmitted through adjacent assemblies, the core plates, and the core baffle should not result in fuel assembly deformations which would prevent coolability or the ability to insert control rods.

Mechanical analyses were performed to demonstrate that fuel coolability and the ability to insert control rods can be maintained at the EPU conditions.

Stress and Strain Limits: AREVA's criterion for transient (AOO) strain (elastic + plastic) must be limited to less than [ ], and [ ]. For overpower conditions, AREVA uses a "spiking" factor

for momentary excursion in power at various exposures throughout the design history. The “spiking” rod power factor is a ratio of [ ] RODEX2 returns to the condition of the rod before the spike and continues the steady-state analysis until the next power spike. In this way, preceding spikes do not affect subsequent spikes in the analysis. The methodology uses [ ]

The NRC staff has determined that the AOO strain analysis has satisfied the criterion for all fuel scheduled for operation at EPU conditions.

Fuel Centerline Melt (FCM): AREVA calculated the impact on FCM temperatures and limits due to the lack modeling the degradation fuel thermal conductivity with burnup by a code-to-code comparison between RODEX2 and COPENIC (Reference 35) fuel performance codes. COPENIC is a NRC-approved code that includes the degradation of fuel thermal conductivity with fuel burnup. AREVA has developed penalty factors that are function of burnup for application to RODEX2 FCM temperature. Temperature penalties to the melt limit were calculated as a function of fuel rod average burnup and fuel rod type (urania-gadolinia). These penalties were such that the burnup dependent FCM limits predicted by RODEX2 with the reduced melt limits are [ ] the FCM limits calculated with COPENIC (Reference 34). These adjustments range from [ ] for  $\text{UO}_2$  to [ ] for 8-percent Gd content.

The NRC staff performed independent power-to-melt calculations using the best-estimate FRAPCON-3.4 for the St. Lucie 1 EPU  $\text{UO}_2$  and 6% Gd fuel rod designs. For these cases, peak local power was manually adjusted until the predicted fuel centerline temperatures exceeded the melting temperatures at several exposure levels. The results show that for the  $\text{UO}_2$  fuel rod design, the predicted power-to-melt limits shows good agreement. For the (U,Gd) $\text{O}_2$  fuel rod, the adjusted RODEX2 power-to-melt limits are conservatively lower than the FRAPCON-3.4 predictions.

Based on review of documents at the regulatory audit and independent calculations performed by NRC staff, it was determined that the adjusted RODEX2 power-to-melt limits reported by the licensee are reasonable. Further, combined with an overall conservative accident analysis methodology, these fuel centerline limits are acceptable.

#### 2.8.1.2.2 Fuel Assembly Analyses

Stress, Strain, Loading Limits and Fatigue: The structural integrity of the fuel assemblies is ensured by setting design limits on stresses and deformations due to handling, operational and accident loads. The assembly design must withstand axial loads from handling operations. The analyses include a load factor times the dry assembly weight to satisfy this criterion. The accident strength criteria for the fuel assembly structure is that it shall sustain, without impairing coolability or insertability of control rods, the forces resulting from seismic and LOCA events.

The guide tube fatigue damage through the EOL was evaluated by using the stresses due to the combination of assembly weight, holddown forces, and differential thermal expansion at the BOL. Cyclic power variations were also used to estimate the fatigue usage factor for the spacer-to guide tube welds. The stress results were evaluated to determine the fatigue usage

for each cycle based on the O'Donnel and Langer design curve. These results were accumulated to determine the total fatigue usage factor.

A fatigue analysis was performed and demonstrated that the fatigue limits continue to be met for all fuel assemblies operating at the EPU conditions.

Fretting Wear: A combination of analysis and fretting tests demonstrated the prevention of fretting wear induced fuel rod failure in the HTP and HMP spacers. Flow test data has confirmed that the fretting related failure will not occur throughout the life of the assembly. The NRC staff has reasonable assurance that no fretting failure is expected at the EPU conditions based on the fretting wear data and grid-to-rod gap evaluations.

Oxidation, Hydriding, and Crud Buildup: AREVA's Zircaloy water corrosion methodology is presented in Reference 7. A peak local corrosion design limit of [ ] is conservatively established for Zircaloy-4 fuel rods (Reference 36). Cladding corrosion for Zircaloy-4 rods as a function of burnup is calculated using the MATPRO model contained in RODEX2 code with appropriate enhancement factors. An appropriate combination of data fitting and enhancement factors has resulted in the design limit for corrosion which shows compliance.

RODEX2 with MATPRO-11 correlations were used to determine the corrosion and hydrogen content of non-fueled Zircaloy cage components throughout life. The hydrogen uptake is linearly related to the oxide thickness. The methodology consists of [

] This methodology is benchmarked to corrosion measurements in unheated fuel rod plenum regions as well as corrosion measurements from guide tubes and spacers. The result of this calculation is then checked against a corrosion design limit to ensure that the structural integrity of these components is maintained throughout the design life of the fuel.

The NRC staff has determined that the cage component corrosion analysis by AREVA has shown that all fuel scheduled for EPU operation satisfy the corrosion criterion.

#### 2.8.1.3 Results

The mechanical analyses have been completed to demonstrate that the GDC can be satisfied for the CE14 HTP design with Zircaloy-4 MONOBLOC™ guide tubes and CE14 HTP design with Zircaloy-4 standard guide tubes under the planned operating conditions of a core power of 3020 MWt.

Based on its review of the licensee's application, the NRC staff concludes the following:

- The St. Lucie 1 fuel system is acceptable with respect to its ability to withstand fuel system damage at uprated conditions based on the acceptable results of fuel rod performance analyses clad stress and strain, oxidation, clad fatigue and calculations of the hydraulic loads.

- The St. Lucie 1 fuel system is acceptable with respect to its ability to withstand fuel rod failure at uprated conditions based on acceptable results of evaluations of rod internal hydriding, and clad collapse.
- The St. Lucie 1 fuel system is acceptable with respect to fuel coolability based on the hydrogen pickup criterion being met, and the internal rod pressure acceptance criterion being met to prevent DNB propagation to prevent fuel rod ballooning.

### Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the fuel system design of the fuel assemblies, control systems, and reactor core. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the fuel system and demonstrated that (1) the fuel system will not be damaged as a result of normal operation and AOOs, (2) the fuel system damage will never be so severe as to prevent control rod insertion when it is required, (3) the number of fuel rod failures will not be underestimated for postulated accidents, and (4) coolability will always be maintained. Based on this, the NRC staff concludes that the fuel system and associated analyses will continue to meet the requirements of 10 CFR 50.46, GDC 10, GDC 27, and GDC 35 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the fuel system design.

### 2.8.2 Nuclear Design

#### Regulatory Evaluation

The NRC staff reviewed the nuclear design of the fuel assemblies, control systems, and reactor core to ensure that fuel design limits will not be exceeded during normal operation and anticipated operational transients, and that the effects of postulated reactivity accidents will not cause significant damage to the RCPB or impair the capability to cool the core. The NRC staff's review covered core power distribution, reactivity coefficients, reactivity control requirements and control provisions, control rod patterns and reactivity worths, criticality, burnup, and vessel irradiation.

The NRC's acceptance criteria are based on:

- (1) GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs;
- (2) GDC 11, insofar as it requires that the reactor core be designed so that the net effect of the prompt inherent nuclear feedback characteristics tends to compensate for a rapid increase in reactivity;
- (3) GDC 12, insofar as it requires that the reactor core be designed to assure that power oscillations, which can result in conditions exceeding SAFDLs, are not possible or can be reliably and readily detected and suppressed;
- (4) GDC 13, insofar as it requires that instrumentation and controls be provided to monitor variables and systems affecting the fission process over anticipated ranges for normal

operation, AOOs and accident conditions, and to maintain the variables and systems within prescribed operating ranges;

- (5) GDC 20, insofar as it requires that the protection system be designed to initiate the reactivity control systems automatically to assure that acceptable fuel design limits are not exceeded as a result of AOOs and to automatically initiate operation of systems and components important to safety under accident conditions;
- (6) GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems;
- (7) GDC 26, insofar as it requires that two independent reactivity control systems be provided, with both systems capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes;
- (8) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and
- (9) GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core.

The aforementioned GDC, published in 10 CFR Part 50, Appendix A, were not yet available at the time St. Lucie 1 was licensed to operate. St. Lucie 1 was designed and licensed according to earlier GDC, proposed by the AEC. Details concerning design relative to GDC are found in FSAR Section 3.1, which addresses conformance to both the AIF GDC and the NRC GDC. Specific review criteria are contained in SRP Section 4.3 and other guidance provided in Matrix 8 of RS-001.

### Technical Evaluation

#### 2.8.2.1 Input Parameters, Assumptions, and Acceptance Criteria

The key features of the CE 14 HTP fuel design with or without the MONOBLOC guide tube fuel assemblies are the outside diameter, the active fuel length, eight Zr-4 HTP spacer grids, HMP bottom grid, lower tie plate, Zr-4 fuel rod cladding, and Zr-4 guide and instrumentation tubes.

Core safety parameters such as power distributions, peaking factors, rod worths, and reactivity parameters are core loading pattern dependent and they vary cycle-to-cycle.

The design limits for power densities (and thus for peaking factors) during normal operation should be such that acceptable fuel design limits are not exceeded during anticipated transients and that other limits, such as the peak cladding temperature allowed for LOCAs, are not exceeded during DBAs. The limiting power distributions are determined such that the limits on power densities and peaking factors can be maintained in operation. By GDC 11, the net effect of the prompt inherent nuclear feedback characteristics tend to compensate for a rapid increase



in reactivity must be satisfied by the existence of the Doppler and negative power coefficient values.

Table 2.8.2-1 of licensing report (Reference 2) provides listing of a range of current key safety parameters and their corresponding EPU equilibrium cycle analysis values. The list consist of nominal reactor core power, vessel average coolant inlet temperature, nominal coolant system pressure, moderator temperature coefficients, Doppler temperature coefficient, shutdown margin, linear heat generation rate, axial shape index, and hot zero power (HZIP) and hot full power (HFP) control rod worths.

#### 2.8.2.2 Description of Analyses and Evaluations

Nuclear design analysis and methods used for the St. Lucie 1 EPU are described in (Reference 37) and (Reference 38). The effect of extended burnup on nuclear design parameters was previously approved in (Reference 39).

Core characteristics of the transition and equilibrium cycles with typical loading patterns for fuel enrichment up to 4.6 weight % of U-235 was developed based on projected energy requirements for EPU at St. Lucie 1 is listed in Table 2.8.2-2 of (Reference 2).

The nuclear design evaluation models show that sufficient margin is maintained between typical safety parameters values and the corresponding limits to allow flexibility in designing the reload cores. Existing designs were used for comparison to evaluate the continued adequacy of margins between typical safety parameter values and the corresponding limits.

#### 2.8.2.3 Results

Margin to key safety parameter limits (Table 2.8.2-1 of Licensing Report, Reference 1) is not reduced by the CE14 HTP fuel design with or without MONOBLOC™ guide tubes operating at EPU conditions.

The changes in fuel design and discharge burnup resulted in only a small impact on the results of the reload transition core analysis relative to the current design. The variations are typical of the normal cycle-to-cycle variations due to the change in fuel loading pattern. Core power distributions and peaking factors typically vary cycle-to-cycle based on actual energy requirements. Compliance with TS values for peaking factors are assured using the NRC-approved methods.

The nuclear design analysis performed by the licensee in support of the EPU shows a maximum total peaking factor ( $F_Q$ ) of 1.788, all rods out, HZIP radial peaking factor ( $F_r$ ) of 1.535 and an end-of-cycle (EOC) Doppler temperature coefficient of (-1.401).

The small changes in the key safety parameters evaluated for the transition to EPU are typical of the normal cycle-to-cycle variations experience as loading pattern changes.

In view of the licensee's use of the CE14 HTP fuel design with MONOBLOC or standard guide tubes that accommodates the EPU and extended burnup operation, the fact that the reported EPU nuclear design data by the licensee indicates little changes from current nuclear design parameters, and the fact that each cycle's core will be analyzed using NRC-approved methods,

the NRC-staff finds reasonable assurance that the St. Lucie 1 uprated core nuclear design will remain acceptable.

### Conclusion

The NRC staff has reviewed the licensee's analyses related to the effect of the proposed EPU on the nuclear design of the fuel assemblies, control systems, and reactor core. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the nuclear design and has demonstrated that the fuel design limits will not be exceeded during normal or anticipated operational transients, and that the effects of postulated reactivity accidents will not cause significant damage to the RCPB or impair the capability to cool the core. Based on this evaluation and in coordination with the reviews of the fuel system design, thermal and hydraulic design, and transient and accident analyses, the NRC staff concludes that the nuclear design of the fuel assemblies, control systems, and reactor core will continue to meet the applicable requirements of GDC 10, 11, 12, 13, 20, 25, 26, 27, and 28. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the nuclear design.

### 2.8.3 Thermal and Hydraulic Design

#### Regulatory Evaluation

The NRC staff reviewed the thermal and hydraulic design of the core and the RCS to confirm that the design

- (1) has been accomplished using acceptable analytical methods,
- (2) is equivalent to or a justified extrapolation from proven designs,
- (3) provides acceptable margins of safety from conditions which would lead to fuel damage during normal reactor operation and AOOs, and
- (4) is not susceptible to thermal-hydraulic instability.

The review also covered hydraulic loads on the core and RCS components during normal operation and DBA conditions and core thermal-hydraulic stability under normal operation and anticipated transients without scram (ATWS) events. The NRC's acceptance criteria are based on:

- (1) GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; and
- (2) GDC 12, insofar as it requires that the reactor core and associated coolant, control, and protection systems be designed to assure that power oscillations, which can result in conditions exceeding SAFDLs, are not possible or can reliably and readily be detected and suppressed.

The aforementioned GDC, published in 10 CFR Part 50, Appendix A, were not yet available at the time St. Lucie 1 was licensed to operate. St. Lucie 1 was designed and licensed according to earlier GDC, proposed by the AEC. Details concerning design relative to GDC are found in

FSAR Section 3.1, which addresses conformance to both the AIF GDC and the NRC GDC. Specific review criteria are contained in SRP Section 4.4 and other guidance provided in Matrix 8 of RS-001.

### Technical Evaluation

The thermal-hydraulic analysis supporting the EPU incorporates the increased core power and addresses the DNB performance, that includes the effects of rod bow and bypass flow. The MONOBLOC guide tube has been evaluated in the thermal-hydraulic analysis and the licensee concludes that it has no significant impact on the pressure drop and the thermal-hydraulic characteristics of the core. This means that the fuel assembly flow area and the hydraulic resistance are unchanged between the pre-EPU and post EPU fuel design. Therefore there are no T-H compatibility or stability issues associated with the transition cores.

#### 2.8.3.1 Input Parameters, Assumptions, and Acceptance Criteria

The NRC-approved XCOBRA-IIIC T-H subchannel analysis code was used for EPU analysis (Reference 40) for DNBR analysis and the S-RELAP5 code was used for the transient analysis. The major parameters that are input to the XCOBRA-IIIC model listed in Table 2.8.3-1 of (Reference 2) are reactor core heat output (MWt), heat generated in fuel (percent), nominal core inlet temperature (°F), enthalpy rise hot channel factor, pressurizer pressure (psia), and RCS minimum flow rate (gpm). The limiting directions for these parameters for DNB analysis are shown in Table 2.8.3-2 of the LAR (Reference 2). For the transient analyses, uncertainties were deterministically applied. To ensure a conservative analysis, steady-state measurement and instrumentation errors were taken into account in an additive fashion. For statistical DNB calculations, uncertainties were statistically treated according to the approved methodology (Reference 41). The system related uncertainties bounded by the non-LOCA safety analyses listed in Table 2.8.3-1 of the LAR (Reference 2).

The reactor core is designed to meet the following thermal-hydraulic criteria:

- There is at least a 95 percent probability at a 95 percent confidence level that DNB will not occur on the limiting fuel rods during Modes 1 and 2, operational transients, or any condition of moderate frequency; and
- No fuel melting during any anticipated normal operating condition, operational transients, or any conditions of moderate frequency.

Analytical assurance that DNB will not occur is provided by showing the calculated DNBR to be higher than the 95/95 limit DNBR for conditions of normal operation, operational transients and transient conditions of moderate frequency.

#### 2.8.3.2 Analyses and Evaluations

The T-H analysis of the CE14 HTP fuel is based on the NRC-approved methodologies for performing DNB calculations (Reference 33) and (Reference 42). The S-RELAP5 code was used for the transient analysis and the XCOBRA-IIIC code was used to calculate the mDNBR using the HTP and Modified Barnett critical heat flux (CHF) correlations. The HTP DNB correlation is based entirely on rod bundle data and takes credit for the significant improvements

in DNB performance due to the flow mixing nozzles effects. (Reference 43) documents the NRC acceptance of a 95/95 HTP correlation safety limit of [ ] for the CE14x14 HTP fuel assemblies. The Modified Barnett CHF correlation used to calculate the DNBR for post-scam reactor conditions has an NRC accepted safety limit DNBR of [ ] as documented in an NRC SE (Reference 44). An NRC-accepted 2 percent mixed core penalty is applied to DNBR safety limits as per safety evaluation report for XN-NF-82-21(P)(A), Revision 1 (Reference 33). This sets the DNBR safety limits to [ ] for HTP correlation and [ ] for Modified Barnett correlation. EMF-1961(P)(A), Revision 0 (Reference 41) describes the methodology for statistical DNB analyses under two conditions: (1) the methodology is approved for CE type reactors with thermal margin/low pressure (TM/LP) limiting safety system setting (LSSS), local power density (LPD) LSSS, LPD LCO, and DNB LCO and (2) the methodology includes a statistical treatment of specific variables in the analysis.

Protection against the FCM SAFDL is calculated for the EPU. The FCM limit is set by the gadolinia rod since the thermal conductivity of fuel rods is limited by Gadolinium content. A FCM limit is established for UO<sub>2</sub> fuel rods such that, FCM is precluded for all fuel rod types.

Enthalpy content for a CEA ejection accident is calculated using the methodology described in XN-NF-78-44(NP)(A) (Reference 45). The licensee has determined that no rod bow penalty is required since the threshold burnups for rod bow are beyond the current licensing limit.

### 2.8.3.3 Results

The results of the analyses demonstrate that the event-specific acceptance criteria are met for EPU operation. The compliance with the acceptance criteria is verified on a cycle-by-cycle basis as part of the cycle specific reload evaluation. The results for non-LOCA events that were analyzed for EPU are listed in Table 2.8.5.0-10 of Section 2.8.5.0 of (Reference 2).

The CE14x14 HTP design allows power operation at a radial peaking limit of 1.65. The T-H design criteria are satisfied for the EPU. The anticipated reduction in margin has been offset by (1) reduction in the radial peaking limit and (2) an increase in the TS minimum flow rate.

### Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the thermal and hydraulic design of the core and the RCS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the thermal and hydraulic design and demonstrated that the design (1) has been accomplished using acceptable analytical methods, (2) is equivalent to proven designs, (3) provides acceptable margins of safety from conditions that would lead to fuel damage during normal reactor operation and AOOs, and (4) is not susceptible to thermal-hydraulic instability. The NRC staff further concludes that the licensee has adequately accounted for the effects of the proposed EPU on the hydraulic loads on the core and RCS components. Based on this, the NRC staff concludes that the thermal and hydraulic design will continue to meet the requirements of GDC 10 and 12 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to thermal and hydraulic design.

## 2.8.4 Emergency Systems

### 2.8.4.1 Functional Design of Control Rod Drive System

#### Regulatory Evaluation

The NRC staff's review covered the functional performance of the control rod drive system (CRDS) to confirm that the system can effect a safe shutdown, respond within acceptable limits during AOOs, and prevent or mitigate the consequences of postulated accidents. The review also covered the CRDS cooling system to ensure that it will continue to meet its design requirements. The NRC's acceptance criteria are based on:

- (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents;
- (2) GDC 23, insofar as it requires that the protection system be designed to fail into a safe state;
- (3) GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems;
- (4) GDC 26, insofar as it requires that two independent reactivity control systems be provided, with both systems capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes;
- (5) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained;
- (6) GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core; and
- (7) GDC 29, insofar as it requires that the protection and reactivity control systems be designed to assure an extremely high probability of accomplishing their safety functions in event of AOOs. Specific review criteria are contained in SRP Section 4.6.

The aforementioned GDC, published in 10 CFR Part 50, Appendix A, were not yet available at the time St. Lucie 1 was licensed to operate. St. Lucie 1 was designed and licensed according to earlier GDC, proposed by the AEC. Details concerning design relative to GDC are found in FSAR Section 3.1, which addresses conformance to both the AIF GDC and the NRC GDC. Specific review criteria are contained in SRP Section 4.4 and other guidance provided in Matrix 8 of RS-001.

## Technical Evaluation

The St. Lucie 1 control rod drive system is referred to as control element drive mechanism (CEDM). Each CEDM is capable of withdrawing, inserting, holding or tripping the CEA from any point within its travel in response to operating signals. Each CEDM is connected to the CEA by an extension shaft. The extension shaft assemblies connect the CEDMs to the CEAs. The assemblies are of two types: the single, which is coupled to only one CEA and the dual, which is coupled to two CEAs.

The impact of EPU on the CEDM results from the temperature effects associated with increase in St. Lucie 1 total NSSS thermal power level from 2714 MWt to 3034 MWt. This increase in rated thermal power results in an increase in reactor vessel best estimate average temperature from 571.4 °F to 577.0 °F. The increase in RCS average temperature is expected to increase the best estimate reactor vessel head and CEDM temperature from 594.27 °F to 602.9 °F. The vessel head and the CEDM temperature is conservatively set to the hot leg temperature for the structural analysis of the components.

As a result of EPU, there are no physical changes required to the CEDM, operating coil stacks, power supplies, or the solid state electronic control cabinets.

### 2.8.4.2 Input Parameters, Assumptions, and Acceptance Criteria

There is no fuel design change with respect to fuel column length and there is no change in the upper end fitting. Also the fuel assembly interface with the CEA remains unchanged.

The acceptance criteria is such that the CEDM design must demonstrate that the CEDM can effectively accomplish a safe shutdown, respond within acceptable limits during AOOs, and prevent or mitigate the consequences of postulated accidents under EPU conditions.

#### 2.8.4.2.1 Analyses and Evaluations

Analyses and evaluations of the impact of EPU on the structural integrity of the CEDM during normal, transient and accident conditions were performed using EPU conditions. The analyses were performed to determine the effects to the CEDM due to the increased power and associated increased thermal stresses associated with the structural integrity of the CEDMs associated with the increased RCS head temperatures, and the increased hydraulic, cyclic, and seismic forces associated with normal, transient, and accident conditions at EPU conditions. The analyses also included the evaluation of the effect of increased heat load to the CEDM cooling system resulting from the higher head temperatures.

The evaluation of the effects to the CEDM associated with EPU demonstrates that the CEDM can affect a safe shutdown, respond within acceptable limits during AOOs, and prevent or mitigate the consequences of postulated accidents.

#### 2.8.4.2.2 Results

The licensee has reviewed the functional design of the CEDM and the CEDM cooling system for the effects of EPU and has demonstrated that at EPU conditions the CEDM will continue to satisfy the design basis for reactivity control and ensure SAFDLs are not exceeded for any single malfunction of the reactivity control systems.

## Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the functional design of the CRDM. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system and demonstrated that the system's ability to effect a safe shutdown, respond within acceptable limits, and prevent or mitigate the consequences of postulated accidents will be maintained following the implementation of the proposed EPU. The NRC staff further concludes that the licensee has demonstrated that sufficient cooling exists to ensure the system's design bases will continue to be followed upon implementation of the proposed EPU. Based on this, the NRC staff concludes that the fuel system and associated analyses will continue to meet the requirements of GDC 4, 23, 25, 26, 27, 28, and 29 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the functional design of the CRDM.

### 2.8.4.3 Overpressure Protection during Power Operation

#### Regulatory Evaluation

Overpressure protection for the RCPB during power operation is provided by relief and safety valves and the reactor protection system. The NRC staff's review covered pressurizer relief and safety valves and the piping from these valves to the quench tank and RCS relief and safety valves. The NRC's acceptance criteria are based on (1) GDC 15, insofar as it requires that the RCS and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs and (2) GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that it behaves in a nonbrittle manner and that the probability of rapidly propagating fracture is minimized. Specific review criteria are contained in SRP Section 5.2.2 and other guidance provided in Matrix 8 of RS-001.

The St. Lucie Construction Permit was issued before the promulgation of these GDC. The licensee discusses the St. Lucie plant design, in terms of the requirements of each of these GDC, in the St. Lucie FSAR Section 3.1, *Conformance with the General Design Criteria*, and in the LAR Section 2.8.5.1.2.1. For further discussion, by the staff, see Section 2.8.5.0 in this SE.

#### Technical Evaluation

The review guidance of SRP Section 5.2.2 seeks an analysis or evaluation to show that the limiting overpressure AOO will not cause either the RCS or main steam system pressure to exceed 110 percent of design when the reactor is not tripped until the receipt of the second safety-grade signal from the RPS.

For St. Lucie 1, limiting overpressure AOO is the loss of external load (LOEL) event. In Section 2.8.4.2.1 of LAR Attachment 5 (Reference 2), the licensee referred to the LOEL analysis of LAR Attachment 5, Section 2.8.5.2.1, to show that SRP 5.2.2 criterion is met. This analysis, based upon a reactor trip from the first safety-grade signal (high pressurizer pressure), predicted a peak RCS pressure of 2708 psia. Consequently, the staff asked the licensee to provide an analysis of the LOEL event in which the reactor trips on the second safety-grade signal from the RPS, as per NUREG-0800, Section 5.2.2.II, SRP Acceptance Criterion 2.B.iii.

The staff reviewed the LOEL analysis during an audit, conducted on January 30 and 31, 2012, and noted that confirmed that, in this analysis, the first safety grade reactor trip signal is generated by low SG level (not credited), and that this is followed by the second safety-grade trip (credited) about 3 seconds later. The peak RCS pressure, about 2744 psia, is below the limit (2750 psia or 110 percent of design pressure). The analysis showed sufficient margin to account for uncertainties in the design and operation of the plant. The analysis conservatively assumed that MSSV Bank 1 and Bank 2 valves will lift at the +3 percent and +2 percent, respectively.

The analysis was based upon the reactor tripping on the second safety grade reactor trip signal from the RPS, and on conservative initial conditions and assumptions. The staff concludes that the analysis acceptably demonstrates that St. Lucie 1 plant will continue to have sufficient capacity at the uprated power to satisfy the the SRP Section 5.2.2 criterion.

### Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the overpressure protection capability of the plant during power operation. The NRC staff concludes that the licensee has (1) adequately accounted for the effects of the proposed EPU on pressurization events and overpressure protection features and (2) demonstrated that the plant will continue to have sufficient pressure relief capacity to ensure that pressure limits are not exceeded. Based on this, the NRC staff concludes that the overpressure protection features will continue to provide adequate protection to meet GDC 15 and GDC 31 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to overpressure protection during power operation.

#### 2.8.4.4 Overpressure Protection during Low Temperature Operation

### Regulatory Evaluation

Overpressure protection for the RCPB during low temperature operation of the plant is provided by pressure-relieving systems that function during the low temperature operation. The NRC staff's review covered relief valves with piping to the quench tank, the makeup and letdown system, and the RHR system which may be operating when the primary system is water solid. The NRC's acceptance criteria are based on (1) GDC 15, insofar as it requires that the RCS and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs; and (2) GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that it behaves in a nonbrittle manner and the probability of rapidly propagating fracture is minimized.

The St. Lucie Construction Permit was issued before the promulgation of these GDC. The licensee discusses the St. Lucie plant design, in terms of the requirements of each of these GDC, in the St. Lucie FSAR Section 3.1, *Conformance with the General Design Criteria*, and in the LAR Section 2.8.5.1.2.1. For further discussion, by the staff, see Section 2.8.5.0 in this SE.

Specific review criteria are contained in SRP Section 5.2.2. The NRC staff's review also considered the effects of the increase in vessel fluence, due to the EPU, on the P-T limit curves and PTS pursuant to 10 CFR 50.61.



## Technical Evaluation

The overpressure mitigation system (OMS) provides LTOP for the RCS. The OMS prevents exceeding the reactor vessel heatup and cooldown P-T operating limits presented in the TSs during periods of low temperature operation. The P-T limits, described in FSAR Section 5.4.2, are designed to protect the RV from potential brittle fracture.

The OMS is designed to mitigate pressure transients by using the pressurizer PORVs, with two temperature-dependent, low-range pressure setpoints as the pressure relief mechanism. The low-range setpoints are energized and de-energized from the main control board through the PORV mode selector switch. Also, means for alarming the various modes of operation have been provided.

St. Lucie has revised the LTOP analyses to support the EPU, the 60-year plant lifetime, and to improve operating margin. The EPU would normally result in an increase to the neutron fluence on the reactor pressure vessel. As shown in the LAR Attachment 5, Section 2.1.1, Table 2.1.1-2, there was actually a small decrease in the projected 60-year fluence based on 52 EFPY. That occurred because the EPU fluence analysis used more recent core power histories that enabled removal of excess conservatism from the pre-EPU 60-year fluence analysis, while adding a 10 percent factor of conservatism to the EPU fluence projections beginning with Cycle 25. The effect of the projected changes in operating conditions on reactor vessel integrity was evaluated. The evaluation is acceptable, since it followed the guidance of RG 1.190. New P-T limits have been generated for operation to 60 years (based on 54 EFPY fluence projection). See LAR Attachment 5, Appendix G, WCAP-17197. Discussion of the P-T limits and USE can be found in Section 2.1.2.

There are two design basis LTOP overpressure transients. The RCP start from a condition in which the SG liquid inventory is hotter than the RCS coolant inventory or energy addition event is one. The other is the design basis mass addition transient in which water is added to the RCS through charging or HPSI pumps. The transients credit the operation of only a single PORV even though TS requires both PORVs to be operable. The analysis was performed on both events and compared to the revised 60-year plant life P-T limits.

The results of the analysis show the current PORV setpoint pressures, RCS vent area in Mode 6, cooldown rates, LTOP enable temperature, and the cold leg temperature at which the PORV setpoint transition occurs can be maintained for cooldown. However, the licensee is proposing changing the TS Section 3.4.13 cold leg temperature at which the PORV setpoint transition occurs from 215 °F to 200 °F indicated temperature for the 60-year plant life P-T limits during cooldown.

The results of the analysis also show that the allowable heatup rates and LTOP enable temperature can be maintained for heatup. However, the licensee is proposing to change the TS Section 3.4.13 cold leg temperature at which the PORV setpoint transition will be changed from 193 °F to 200 °F indicated temperature for the 60-year plant life P-T limits during heatup.

The NRC staff reviewed the Licensee's analysis of the overpressure protection during low temperature operation and concluded that the licensee's analysis was performed using conservative assumptions.

## Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the overpressure protection capability of the plant during low temperature operation. The NRC staff concludes that the licensee has (1) adequately accounted for the effects of the proposed EPU on pressurization events and overpressure protection features and (2) demonstrated that the plant will continue to have sufficient pressure relief capacity to ensure that pressure limits are not exceeded. Based on this, the NRC staff concludes that the low temperature overpressure protection features will continue to provide adequate protection to meet GDC 15 and GDC 31 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to overpressure protection during low temperature operation.

### 2.8.4.5 Shutdown Cooling System

#### Regulatory Evaluation

The SDCS is used to cool down the RCS following shutdown. The SDCS is a low pressure system that removes decay heat and sensible heat at reduced RCS temperatures. The NRC staff's review covered the effect of the proposed EPU on the functional capability of the SDCS to cool the RCS following shutdown. The NRC's acceptance criteria are based on:

- (1) GDC 4, insofar as it requires that SSCs important to safety be protected against dynamic effects;
- (2) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; and
- (3) GDC 34, which specifies requirements for an SDCS.

The St. Lucie Construction Permit was issued before the promulgation of these GDC. The licensee discusses the St. Lucie plant design, in terms of the requirements of each of these GDC, in the St. Lucie FSAR Section 3.1, *Conformance with the General Design Criteria*, and in the LAR Section 2.8.5.1.2.1. For further discussion, by the staff, see Section 2.8.5.0 in this safety evaluation.

Specific review criteria are contained in SRP Section 5.4.7, and other guidance is provided in Matrix 8 of RS-001.

#### Technical Evaluation

The St. Lucie 1 SDCS consists of two centrifugal pumps, two heat exchangers, and various interconnecting piping and instrumentation. When the SDCS is in operation, the SDC pumps take suction from the RCS hot legs, route the flow through the tube sides of the SDC heat exchangers, and return the flow to each of the RCS cold legs. Cooling flow to the shell sides of the SDC heat exchangers is provided by the CCW system. The heat load is ultimately transferred to the SWS.

The SDCS is designed to remove residual and sensible heat from the core and reduce the temperature of the RCS during the second phase of a plant cool down. The EPU increases the residual heat generated in the core during normal cooldown, refueling operations, and accident conditions. The increase in decay heat increases the time it takes to cool down the RCS during normal cooldown and accident conditions.

The licensee states that SDCS design functions are not affected by EPU conditions. However, the EPU extends the plant cooldown time due to the increase in decay heat (due to the increase in core power). For normal plant cooldown, to 200 °F, Cold Shutdown (Mode 5) with both trains of SDC and CCW equipment in operation, the cooldown time increased by approximately 0.1 hours. The normal plant cooldown duration to 140 °F for Refueling (Mode 6) with both trains of SDC and CCW equipment in operation, the cooldown time increased by approximately 12 hours.

The licensee also evaluated the Appendix R/safe shutdown cooldown scenario. This worst case cooldown scenario assumes a loss of offsite power, one SG, one atmospheric dump valve and one train of SDC equipment in operation. The plant reaches SDCS entry in 63 hours. One train of SDC equipment is then placed in operation and 200 °F is achieved in 6 additional hours. Therefore the licensee demonstrated that the SDC will continue to comply with the Appendix R Cold Shutdown (Mode 5) within 72 hours requirement at EPU conditions.

These analyses assume conservative SDC heat exchanger input values, CCW system supply temperature of 120 °F, and American Nuclear Society (ANS) 1979 decay heat values. The analyses also support cooling the RCS in accordance with TS Action requirements without violating the administrative maximum cooldown rate of 75 °F per hour. The staff reviewed the provided analyses and found them to be conservative.

The results indicate that the SDCS at St. Lucie 1 is capable of supporting the proposed EPU.

### Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the SDCS. The staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system and demonstrated that the SDCS will maintain its ability to cool the RCS following shutdown and provide decay heat removal. Based on this, the staff concludes that the SDCS will continue to meet the requirements of GDC 4, 5, and 34, as well as SRP Section 5.4.7, following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the SDCS.

### 2.8.5 Accident and Transient Analyses

According to RS-001 (Reference 1), the NRC staff applies acceptance criteria, in its review of the accident and transient analyses in Section 2.8.5, that are based upon the GDC of 10 CFR Part 50, Appendix A. However, the St. Lucie 1 plant construction permit was issued before the GDC were published. The staff is directed by the Commission (Reference 46) not to apply the GDC of 10 CFR Part 50, Appendix A to plants with construction permits that were issued prior to May 21, 1971. This is based upon a determination that backfitting the GDC would not provide the significant safety benefit needed to justify the extensive commitment of resources that would be required.

RS-001 specifies 17 GDC that apply to the review of EPU applications for PWRs. These GDC are:

- GDC 4: Environmental and Missile Design Bases
- GDC 5: Sharing of Structures, Systems or Components
- GDC 10: Reactor Design
- GDC 15: RCS Design
- GDC 19: Control Room
- GDC 20: Protection System Functions
- GDC 25: Protection System Requirements for Reactivity Control Malfunctions
- GDC 26: Reactivity Control System Redundancy and Capability
- GDC 27: Combined Reactivity Control Systems Capability
- GDC 28: Reactivity Limits
- GDC 29: Protection against Anticipated Operational Occurrences
- GDC 31: Fracture Prevention of Reactor Coolant Pressure Boundary
- GDC 33: Reactor Coolant Makeup
- GDC 34: Residual Heat Removal
- GDC 35: Emergency Core Cooling
- GDC 54: Piping Systems Penetrating Containment
- GDC 62: Prevention of Criticality in Fuel Storage and Handling

The licensee discusses the St. Lucie 1 plant design, *vis-à-vis* each of these GDC, in the St. Lucie 1 FSAR Section 3.1, *Conformance with the General Design Criteria*, and in the pertinent sections of the LAR. The conformance of the St. Lucie 1 plant design to the GDC has already been considered in the staff's FSAR review. GDC conformance is considered, in this EPU review, within the context of the St. Lucie 1 licensing basis, and with respect to the predicted effects of the proposed power uprating in conjunction with the St. Lucie plant design.

RS-001 also identifies four applicable regulations. These regulations are:

- 10 CFR 50.46: Acceptance criteria for emergency core cooling systems for light-water nuclear power reactors
- 10 CFR 50.62(c)(4): Requirements for reduction of risk from anticipated transients without scram (ATWS) events for light-watercooled nuclear power plants
- 10 CFR 50.63: Loss of all alternating current power
- 10 CFR Part 50, App. K: ECCS Evaluation Models

The licensee's compliance with these regulations is considered in the staff's review of this EPU application.

RS-001 also provides the following guidance regarding the limits of the staff's review:

*The staff will review plants against their design bases. ... The staff does not intend to impose the criteria and/or guidance in this review standard on plants whose design bases do not include these criteria and/or guidance. No backfitting is intended or approved in connection with the issuance of this review standard.*

Although the staff follows this guidance in its reviews of EPU applications, it is possible that the staff's review could require some additional information from the licensee, regarding issues that are outside the plant's design basis in order to support a conclusion of reasonable assurance that the public health and safety will not be jeopardized if the plant is operated at the proposed EPU power uprating. In such cases, the staff's actions are controlled, as always, by the requirements of the Backfit Rule (10 CFR 50.109).

#### 2.8.5.1 Increase in Heat Removal by the Secondary System

##### 2.8.5.1.1 Decrease in FW Temperature, Increase in FW Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve

#### Regulatory Evaluation

Excessive heat removal causes a decrease in moderator temperature that increases core reactivity and can lead to a power level increase and a decrease in shutdown margin. Any unplanned power level increase may result in fuel damage or excessive reactor system pressure. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered: (1) postulated initial core and reactor conditions, (2) methods of thermal and hydraulic analyses, (3) the sequence of events, (4) assumed reactions of reactor system components, (5) functional and operational characteristics of the RPS, (6) operator actions, and (7) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations including AOOs; (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; (3) GDC 20, insofar as it requires that the RPS be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded during any condition of normal operation, including AOOs; and (4) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.1.1-4 and other guidance is provided in Matrix 8 of RS-001.

#### Technical Evaluation

A change in SG FW conditions that results in an increase in FW flow or a decrease in FW temperature could result in excessive heat removal from the RCS. Such changes in FW flow or FW temperature are a result of a failure of a FW control valve or FW bypass valve, failure in the FW control system, or operator error. Excessive heat removal causes a decrease in moderator temperature that increases core reactivity and can lead to an increase in power level. Any unplanned power level increase may result in fuel damage or excessive reactor system pressure. The RPS and safety systems are actuated to mitigate the transient. The acceptance criteria are based on CHF not being exceeded, pressure in the RCS and MSSS being maintained below 110 percent of the design pressures, and the peak linear heat generation rate not exceeding a value that would cause FCM. Specific review criteria are found in SRP Section 15.1.1-4.

### *Increase in Steam Flow*

The increase in steam flow (or excess load increase) event is initiated by a postulated failure or misoperation of the MSSS and results in an increase in steam flow from the SGs. As discussed in FSAR Section 7.7.2.3.2, the steam dump and bypass system is designed based on the criteria that no single component failure or operator incorrect action can cause the improper opening of more than one dump valve. However, for analysis purposes, the postulated initiating events include the opening of all steam dump and bypass valves or the opening of the turbine control valves due to controller failure.

At HFP, the increase in steam flow creates a mismatch between the energy being generated in the reactor core and the energy being removed by the secondary system and results in a cooldown of the primary system. A power increase will occur if the moderator temperature reactivity feedback coefficient is negative. If the power increase is sufficiently large, either overpower or thermal margin limits will be reached with the event being terminated by a reactor trip. If the power increase is less significant, the reactor will stabilize at an elevated power level without reaching a reactor trip and with no violation of any safety limit.

At HZP, the result of the increase in steam flow is a power mismatch between the primary and secondary systems. The immediate response to the additional steam flow demand is a rapid decrease in SG pressure. The SG temperature will also rapidly decrease, as more heat (steam) is being extracted than is being added. Since the reactor is not producing any heat, the secondary side cools down the primary side. The RCS temperatures will decrease and the pressurizer pressure and level will consequently decrease. In the presence of a negative moderator temperature coefficient (MTC) and a negative Doppler reactivity coefficient, positive reactivity insertion will occur in response to the decreasing coolant and fuel temperatures. These feedbacks cause an increase in core power which slows down the decrease in core coolant temperatures. As the core power and fuel temperatures increase, the negative Doppler reactivity coefficient tends to mitigate the rapid increase in power. The core power will increase at an exponential rate until the setpoint on the variable high power trip is reached and initiates a reactor trip. With the decreasing level and pressure, the charging pumps and pressurizer heaters will automatically turn on. Since the pressurizer pressure and level control systems are not safety grade, no credit is allowed for this automatic feature to mitigate the decrease in level and pressure.

The EPU event used S-RELAP5 code to model key system components and calculate neutron power, fuel thermal response, surface heat transport, fluid conditions, an estimated time of minimum departure from nucleate boiling ratio (MDNBR) and peak system pressures. The core fluid boundary conditions and average rod surface heat flux were then input to the XCOBRA-IIIC code, which was used to calculate the MDNBR using HTP CHF correlation.

The licensee provided a sequence of events for both the HZP and HFP cases with the initiating event at HZP being the turbine control valves fully opening and AFW reaching full deliver rate. The HFP case initiating event involves the SBCS system opening to full capacity. The HFP case was found to be the limiting MDNBR. The HFP MDNBR was calculated above the 95/95 CHF correlation limit. The calculated HFP MDNBR was 1.385 with a limit of 1.164. The licensee demonstrated that margin between the MDNBR limit and the bounding increase in steam flow event MDNBR exists at EPU conditions. The licensee also demonstrated that pressure in the RCS and MSSS were maintained below 110 percent of the design pressures at

EPU conditions, and the peak linear heat generation rate not exceeding a value that would cause fuel centerline melt at EPU conditions. The peak linear heat rate (LHR) was found to be 18.7 kW/ft with a limit of 22.3kw/ft.

#### *Decrease in FW Temperature*

This event is initiated by a reduced FW temperature at full power. A decrease in FW temperature may be caused by a loss of one of several FW heaters or an accidental starting of the AFWS. The sudden reduction in FW temperature results in a cooldown of the SG, a temperature and pressure decrease in the RCS, and a higher power with a most negative MTC at EOC. The increase in power and reduction in RCS pressure during the transient cause a decrease in DNB margin, while the decrease in RCS temperature during the transient causes an increase in DNB margin. The overall effect is a decrease in DNB margin and a challenge to the DNB SAFDL. The licensee stated that the heat removal due to the decrease in FW temperature is far less than that for the increase in steam flow event and is therefore bounded by the increase in steam flow event. The staff finds this conclusion acceptable.

#### *Increase in FW Flow*

An increase in FW flow event, initiated at HFP, is caused by the complete opening of a single FW control valve, because the two FW control valves and their control are independent. The licensee addressed this event is addressed in LAR Attachment 5, Section 2.8.5.2.5, Asymmetric Steam Generator Transient.

#### *Inadvertent Opening of a Steam Generator Relief or Safety Valve*

This event is initiated by the inadvertent opening of an ADV or a MSSV. The limiting scenario for this event is initiated by the inadvertent opening of an MSSV, since the MSSV flow capacity is greater than an ADV capacity. The purpose of this analysis is to address the potential for a return-to-criticality from a HZP, subcritical condition with all rods in condition (Mode 3).

The licensee used conservative assumptions in modeling this event. The licensee assumed HZP to maximize the initial SG pressure and inventory, which worsens the erosion of shutdown margin. EOC conditions were used as well to worsen the erosion of shutdown margin. No credit was taken for check valves in steam lines. No operator action to mitigate the erosion of shutdown margin was assumed before 30 minutes. At 30 minutes the operators are assumed to terminate AFW and begin boration to a cold shutdown condition. The licensee showed that the pressures in the RCS and main steam system remained less than 110 percent of design values and that fuel cladding integrity is maintained by ensuring that the SAFDLs are not exceeded.

The EPU event used S-RELAP5 code to model key system components and calculate neutron power, fuel thermal response, surface heat transport, fluid conditions, an estimated time of MDNBR and peak system pressures. Core neutronics analysis was performed at the time of peak post-scrum reactivity during the transient using power, RCS pressure and RCS temperature boundary conditions from S-RELAP5 to evaluate shutdown margin.

The NRC staff reviewed the licensee's analysis and concluded that the licensee's analysis was performed using acceptable analytical models. The staff found that the licensee demonstrated that the RPS and safety systems will continue to assure the CHF will not be exceeded and

pressures in the RCS and MSSS will be maintained below 110 percent of their respective design pressures. The staff concluded that the plant will continue to meet the regulatory requirements following implementation of the proposed EPU program. Therefore, the staff found the proposed EPU program acceptable with respect to the excessive heat removal due to FW system malfunction event.

### Conclusion

The NRC staff has reviewed the licensees analyses of the excess heat removal events described above and concludes that the licensees analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of these events. Based on this, the staff concludes that the plant will continue to meet the requirements of GDC 10, 15, 20, and 26 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the events stated.

#### 2.8.5.1.2 Steam System Piping Failures Inside and Outside Containment

### Regulatory Evaluation

The steam released through an MSLB is considered as an increase in steam flow, which causes reactor coolant temperature and pressure to drop, and core reactivity to rise. The core reactivity excursion leads to an increase in power level, and eventually, to a reactor scram. After the reactor scram, the continued reactivity excursion could overcome the shutdown margin, which would result in a resumption of power generation. If a rod is assumed to be stuck in its fully withdrawn position, the power generation that would result would be concentrated in the core region that lies under the stock rod. It is possible that DNB conditions will be reached in this core region, and this could cause fuel clad damage. There are several automatic reactor protection and safety systems that are available, and actuated, to mitigate the MSLB.

The MSLB is classified as a Postulated Accident. Its analysis results are judged against the ANS Condition IV acceptance criteria. The NRC staff's review covered

- (1) postulated initial core and reactor conditions;
- (2) methods of thermal and hydraulic analyses;
- (3) the sequence of events;
- (4) assumed responses of the reactor coolant and auxiliary systems;
- (5) functional and operational characteristics of the RPS;
- (6) assumed operator actions;
- (7) core power excursion due to the power demand created by excessive steam flow;
- (8) variables influencing neutronics; and



(9) the results of the accident analyses.

The NRC's acceptance criteria are based on:

- GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained;
- GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core;
- GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized;
- GDC 35, insofar as it requires the reactor cooling system (RCS) and associated auxiliaries be designed to provide abundant emergency core cooling.

The St. Lucie 1 construction permit was issued before the promulgation of these GDC. The licensee discusses the St. Lucie 1 plant design, in terms of the requirements of each of these GDC, in the St. Lucie 1 FSAR Section 3.1, *Conformance with the General Design Criteria*, and in the LAR Section 2.8.5.1.2.1. For further discussion, by the staff, see Section 2.8.5.0 in this SE. Specific review criteria are contained in SRP Section 15.1.5 and additional guidance is provided in Matrix 8 of RS-001.

#### Technical Evaluation

The MSLB is assumed to occur at a location in the steam pipe upstream of a main steam check valve. This check valve stops backflow to the break from the unaffected SG. However, there is still an increase in flow from the unaffected SG to compensate for the reduction in steam flow to the turbine from the affected SG.

The increased steam flows cause the SGs and the RCS to depressurize, and the RCS to cool down. The RCS cooldown, in the presence of a negative core MTC, causes the reactor power to increase. During an MSLB, the reactor could be tripped on:

- high indicated power level,
- asymmetric SG pressures, or
- high containment pressure.

Prior to the reactor trip, it is possible to reach DNB and FCM conditions, due to the increased reactor power and the asymmetric cooldown (i.e., the higher radial power peaking factors).

After the reactor trip, the affected SG pressure will continue to drop, and this will eventually generate a main steam isolation signal (MSIS). MSIS will close the MSIVs, and end the backflow of steam from the unaffected SG.

The cooldown of the RCS causes moderator and fuel temperature reactivity feedback to insert positive reactivity. This feedback is greatest at EOC conditions. The reactor scram causes all but the most reactive control rod to drop into the core. A conservatively small amount of shutdown margin is established. The continuing cooldown-induced reactivity excursion could overcome the shutdown margin (i.e., cause the core to return to criticality). Power generation would be highest in the region under the stuck rod. The addition of boron, by the ECCS, would damp the reactivity excursion. The MSLB (and the RCS cooldown) is effectively over when the affected SG dries out. Cooldown continues, at a low rate, until the continued delivery of AFW to the affected SG is ended. The licensee's analyses do not assume that AFW will be isolated automatically on SG differential pressure. AFW flow is assumed to be isolated manually at 10 minutes.

The limiting break size, for the pre-scram HFP MSLB, is a 3.0-ft<sup>2</sup> break located in a main steam line outside the reactor containment and upstream of the main steam check valve. The limiting case was determined from the results of a series of analyses, performed for a variety of break sizes, break locations, and MTC values. The limiting cases produced the lowest MDNBR and highest peak LHR.

The limiting break size, for the post-scram HZP MSLB, is a full double-ended guillotine break of a main steam line upstream of the MSIV was considered. The break flow, from the SG, chokes at the integral flow restrictor. The effective break flow area is the area of the flow restrictor (3.7 ft<sup>2</sup>), not the cross section of the main steam line (6.3 ft<sup>2</sup>). This break size and location has the potential to produce the largest cooldown, and consequently, the highest return-to-power in the core.

The analysis results of two cases, the pre-scram HFP case and the post-scram HZP case (both with offsite power available) predict that a small amount of fuel failure, due either to clad damage or to fuel centerline melting would occur. The Condition IV analysis acceptance criteria allow for some fuel damage.

<b>Case</b>	<b>Min DNBR</b>	<b>DNBR Limit</b>	<b>Peak LHR</b>	<b>LHR Limit</b>
Pre-scram HFP, with Offsite Power	0.994 (0.46% fuel failure)	≥ 1.164	21.449	≤ 22.279
Post-scram HZP, with Offsite Power	2.431	≥ 1.158	23.342 (0.02% fuel failure)	≤ 22.279
Post-scram HZP, without Offsite Power	1.282	≥ 1.158	12.788	≤ 22.279

During the audit, AREVA engineers verified that the failed fuel would not propagate throughout the core, and that the extent of the failed fuel was within the level that was analyzed for radiological dose consequences. When asked how the Condition IV MSLB results are said to bound the smaller (Condition III) MSLB break sizes, AREVA replied that the comparison is made on a common basis, since the Condition IV MSLB results satisfy the limited fuel damage acceptance criteria for Condition III MSLBs. The St. Lucie 1 licensing basis classifies events (e.g., the MSLB) according to the ANS-defined Condition II, III, and IV categories. The Condition II MSLB, or “credible break”, is addressed in Section 2.8.5.1.1.

### Conclusion

The NRC staff has reviewed the licensee’s MSLB analyses, and concludes that the analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the ability to insert CEAs is maintained, that the RCPB pressure limits will not be exceeded, that the RCPB will behave in a nonbrittle manner, that the probability of a propagating fracture of the RCPB is minimized, and that abundant core cooling will be provided. Based on this, the NRC staff concludes that St. Lucie 1 will continue to meet the requirements of GDC 27, 28, 31, and 35, as described in FSAR Section 3.1, *Conformance with the General Design Criteria*, and in LAR Section 2.8.5.1.2.1, following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to MSLBs.

### 2.8.5.2 Decrease in Heat Removal By the Secondary System

#### 2.8.5.2.1 Loss of External Load, Turbine Trip, Loss of Condenser Vacuum, and Steam Pressure Regulatory Failure

### Regulatory Evaluation

A number of initiating events may result in unplanned decreases in heat removal by the secondary system. These events result in a sudden reduction in steam flow and, consequently, result in pressurization events. Reactor protection and safety systems are actuated to mitigate the transients. This event is classified as an AOO, or an ANS Condition II event.

The NRC staff’s review covered the sequence of events, the analytical models used for analyses, the values of parameters used in the analytical models, and the results of the transient analyses. The NRC’s acceptance criteria are based on:

- (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs;
- (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and
- (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded.

The St. Lucie 1 construction permit was issued before the promulgation of these GDC. The licensee discusses the St. Lucie 1 plant design, in terms of the requirements of each of these GDC, in the St. Lucie FSAR Section 3.1, *Conformance with the General Design Criteria*, and in the LAR Section 2.8.5.1.2.1. For further discussion, by the staff, see Section 2.8.5.0 in this SE. Specific review criteria are contained in SRP Section 15.2.1-5, and other guidance is provided in Matrix 8 of RS-001.

### Technical Evaluation

A loss of external load event can result due to a loss of external electrical load or a turbine trip. Offsite electrical power is available to operate the RCPs and other station auxiliaries. A loss of generator load will cause the turbine control valves to close, and terminate the steam flow, which will cause the secondary system temperature and pressure to increase.

Primary-to-secondary heat transfer decreases as the secondary system temperature increases. If the reactor is not tripped when the turbine is tripped, the primary system temperature and pressure will continue to rise. If this continues, the reactor will trip on high pressurizer pressure, reducing the primary heat source. As the heat load into the primary decreases, the primary system pressurization will begin to diminish. If the setpoint for opening the pressurizer safety valves is reached during the initial system pressurization, then the pressurizer safety valves will open to relieve pressure and to mitigate the pressure transient. Energy is removed during the early phase of the transient through the SG safety valves, when the SG pressure reaches the safety valve opening setpoint.

The main purpose of analyzing this event is to demonstrate that the primary and MSSS pressure relief capability is sufficient to limit the pressures to less than 110 percent of their respective design values. This event is also analyzed to ensure that the SAFDLs are not exceeded under the limiting assumptions of no credit for a direct reactor trip on turbine trip.

The licensee analyzed this event using the approved S-RELAP5 code to calculate neutron power, fuel thermal response, surface heat transfer, fluid conditions (including peak pressures), and to estimate the time of mDNBR. Core fluid conditions and average rod surface heat flux were then input to the approved XCOBRA-IIIC code to calculate the mDNBR, using the HTP CHF correlation.

The licensee analyzed three cases for three effects: (1) primary side peak pressure, (2) MSSS peak pressure case, and (3) mDNBR. The licensee used conservative assumptions in the analyses. The peak pressures calculated for the primary and MSSS systems were 2744 psia (limit = 2750 psia) and 1092 psia (limit = 1100 psia), respectively. The mDNBR was 1.942 (limit = 1.164).

The NRC staff reviewed the licensee's analyses of the loss of external electric load and concluded that the licensee's analyses were performed using acceptable analytical models. The staff found the licensee demonstrated the mDNBR will remain above the safety analysis limit and pressures in the RCS and MSSS will remain below 110 percent of their respective design pressure values for the proposed EPU. The staff concluded that the St. Lucie 1 loss of external electric load/turbine trip analyses at EPU conditions show that St. Lucie 1 will continue to meet applicable regulatory requirements following implementation of the EPU. Therefore, the staff found the proposed EPU program acceptable with respect to the loss of external electrical load event.

## Conclusion

The NRC staff has reviewed the licensee's analyses of the loss of external load; turbine trip, and loss of condenser vacuum, and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of these events. Based on this, the staff concludes that the plant will continue to meet the requirements of GDC 10, 15, and 26 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the loss of external load; turbine trip, and loss of condenser vacuum.

### 2.8.5.2.2 Loss of Non-emergency AC Power to the Station Auxiliaries

#### Regulatory Evaluation

The loss of non-emergency AC power is assumed to result in the loss of all power to the station auxiliaries and the simultaneous tripping of all RCPs. This causes a flow coastdown and a decrease in heat removal by the secondary system, a turbine trip, an increase in P-T of the reactor coolant, and a reactor trip. Reactor protection and safety systems are actuated to mitigate the transient. This event is classified as an AOO, or an ANS Condition II event. The NRC's acceptance criteria are based on:

- (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs;
- (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and
- (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded.

The St. Lucie 1 construction permit was issued before the promulgation of these GDC. The licensee discusses the St. Lucie 1 plant design, in terms of the requirements of each of these GDC, in the St. Lucie FSAR Section 3.1, *Conformance with the General Design Criteria*, and in the LAR Section 2.8.5.1.2.1. For further discussion, by the staff, see Section 2.8.5.0 in this SE. Specific review criteria are contained in SRP Section 15.2.6 and other guidance is provided in Matrix 8 of RS-001.

#### Technical Evaluation

The loss of non-emergency AC power, an ANS Condition II event, cuts off all power to the station auxiliaries and trips all RCPs. The event causes the reactor and turbine to trip, the RCPs to coastdown, reactor coolant P-T to rise, and heat removal, by the secondary system, to decrease. Following the RCP trip, the reactor coolant flow necessary to remove residual heat is provided by natural circulation via the secondary system and the AFWS. The RPS generates the actuation signals needed to mitigate the transient. The ANS Condition II acceptance criteria

require that the SAFDLs not be exceeded, and that pressures in the RCS and MSSS remain below 110 percent of their design pressures. Specific review criteria are found in SRP Section 15.2.6.

The LAR does not present an analysis of the loss of non-emergency AC power. Instead, the licensee provides an evaluation of the event in terms of other, comparable AOOs that, by their nature, will pose a greater challenge to the AOO acceptance criteria. These AOOs have been analyzed, and their results are presented and discussed in the licensee's LAR. For example, since the loss of non-emergency AC power causes RCS flow to decrease, it is comparable to another flow decrease event, the loss of flow event. The loss of flow event would yield a lower mDNBR. Therefore, the licensee refers to the loss of flow event when evaluating the loss of non-emergency AC power as an AOO that could challenge the SAFDLs. Similarly, the loss of non-emergency AC power and the loss of load events both lead to a turbine trip, which is a loss of heat sink that could challenge the RCS and MSSS pressure limits. Since the loss of load presents the greater challenge, it is applied as a comparable event in this loss of non-emergency AC power evaluation.

For each of the three ANS Condition II acceptance criteria, listed in the table (below), the comparable AOO analysis that yields a more severe result is identified. There is an additional criterion listed: the ability of the AFWS to remove decay heat in the long term. This a demonstration that the AFWS, in combination with the establishment of natural circulation in the RCS, can remove all the decay heat in the long term after it has been shown that none of the other acceptance criteria have been violated.

Criterion	Measure	Comparable, limiting AOO
Protection of SAFDLs	$\min \text{DNBR} \geq 1.164$	loss of forced reactor coolant flow (LAR Attachment 5, Section 2.8.5.3.1)
RCS and MSSS pressure limits	$\max \text{RCS } P \leq 2750 \text{ psia}$ and $\max \text{MSSS } P \leq 1100 \text{ psia}$	loss of external electrical load, turbine trip, and loss of condenser vacuum (LAR Attachment 5, Section 2.8.5.2.1)
Escalation to a more serious event	$\max \text{pressurizer water volume} < 1532.5 \text{ ft}^3$ (full pressurizer)	loss of normal FW flow (LAR Attachment 5, Section 2.8.5.2.3) <sup>3</sup>
Long-term decay heat removal	decreasing RCS pressure and temperature	loss of normal FW flow (LAR Attachment 5, Section 2.8.5.2.3)

The staff agrees that the loss of non-emergency AC power event meets the AOO acceptance criteria by virtue of the fact that other, similar events are shown to meet the criteria, by analysis. Therefore, it is not necessary to perform the loss of non-emergency AC power analysis, to reach the same conclusion.

The NRC staff reviewed the licensee's evaluation of the loss of non-emergency AC power to plant auxiliaries and concluded that the licensee's evaluation was based upon valid

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<sup>3</sup> The loss of non-emergency AC power could produce a higher maximum pressurizer water volume. The loss of normal feedwater analysis indicates the maximum pressurizer level would not exceed 72 percent of span (LR Figure 2.8.5.2.3-3). The similarity of the events and the water volume margin, available in the loss of normal feedwater analysis results, support the judgment that the pressurizer would not fill during a loss of non-emergency AC power event.

comparisons, which showed that the loss of non-emergency AC power would satisfy the AOO acceptance criteria regarding the SAFDLs, peak primary and secondary system pressures, escalation to a more serious event, and in addition, the ability to establish natural circulation and remove all decay heat, via the AFWS, in the long term. Therefore, the staff found the proposed EPU acceptable with respect to the loss of non-emergency AC power to the plant auxiliaries.

### Conclusion

The NRC staff has reviewed the licensee's analyses of the loss of non-emergency AC power to station auxiliaries event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using an acceptable evaluation. The staff further concludes that the licensee has demonstrated that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the staff concludes that the plant will continue to meet the requirements of GDC 10, 15, and 26 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the loss of non-emergency AC power to station auxiliaries event.

#### 2.8.5.2.3 Loss of Normal FW Flow

##### Regulatory Evaluation

A loss of normal FW (LONF), due to pump failures, valve malfunctions, or a loss of offsite AC power, degrades the capability of the secondary system to remove the heat generated in the reactor core. This results in an increase in RCS temperature and pressure. If an alternative supply of FW were not supplied to the plant, core residual heat following reactor trip would heat the RCS water to the point where water relief from the pressurizer could occur, and cause a substantial loss of water from the RCS. The LONF requires a reactor trip and removal of decay heat to prevent fuel damage. This event is classified as an AOO, or an ANS Condition II event.

The NRC staff's review covered: (1) the sequence of events, (2) the analytical model used for analyses, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on:

- (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs;
- (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and
- (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded.

The St. Lucie 1 construction permit was issued before the promulgation of these GDC. The licensee discusses the St. Lucie 1 plant design, in terms of the requirements of each of these GDC, in the St. Lucie FSAR Section 3.1, *Conformance with the General Design Criteria*, and in the LAR Section 2.8.5.1.2.1. For further discussion, by the staff, see Section 2.8.5.0 in this SE. Specific review criteria are contained in SRP Section 15.2.7 and other guidance is provided in Matrix 8 of RS-001.

### Technical Evaluation

An LONF degrades the capability of the secondary system to remove heat from the primary side. This event is defined as a malfunction in the main FW (MFW) system that cuts off all normal FW flow to both SGs. The loss of MFW flow causes the SG levels to drop as the shell side inventory is boiled off. RCS temperature and pressure increase, and pressurizer level rises. Eventually, the reactor is tripped on low SG water level, and the AFWS is actuated on low-low SG water level.

Fission product decay heat must be transferred from the RCS following an LONF. This can be accomplished by the steam relief system, or steam bypass to the condenser, working in conjunction with the AFWS. The steam relief system, and steam bypass to the condenser are not assumed to be available, in conservative safety analyses, since they are not safety-grade systems. Instead, the MSSVs are used. The core cooling, by these means, improves as the rate of decay heat generation decreases, with time. Thus, the post-LONF RCS temperatures stabilize and begin to decrease.

The LONF was analyzed using the approved S-RELAP5 code. Offsite power was assumed to be available, since that adds pump heat (about 20 MWt) to the heat that must be removed by the AFWS. Only one SG received auxiliary FW, due to an assumed single failure in the AFWS.

The transient analysis time was greater than 1 hour. In that time, the results indicate that the SAFDLs were not exceeded, the RCS and MSSS pressure limits (110 percent of design pressure) were not exceeded, and that the LONF would not develop into a more serious event (i.e., the pressurizer did not fill and discharge water through the PORVs).

The LONF is also analyzed to verify that there is sufficient AFWS capacity for long term decay heat removal, so that the plant can reach a stabilized condition (SRP Section 15.2.7). The LONF is analyzed for a long time period (greater than one hour), and considered with and without offsite power. The case with offsite power models the RCPs and the heat they contribute to the heat removal load. The case without offsite power models the primary to secondary side heat transfer when the RCS flow is reduced to natural circulation levels.

The results, reported above, are from an LONF analysis that was based upon the assumption that offsite power is available, and all the RCPs are running. The licensee did not include an analysis of an LONF without offsite power. This makes the comparisons of LONF and LOOP (Section 2.8.5.2.2) problematic. It is difficult to draw conclusions from comparisons of a full-flow LONF event to a no-forced-flow LOOP event. The reduced primary-to-secondary heat transfer when RCS flow is low (e.g., natural circulation) could affect the time it takes for the transient to stabilize, and the maximum pressurizer water level.

The FW line break (FWLB), a Condition IV event, could be considered as an extreme loss of FW. The FWLB (Section 2.8.5.2.4) was considered with and without loss of offsite power. The results (Reference 47) show that the pressurizer will fill after 1000 seconds, in the case that assumes offsite power is not available. Filling the pressurizer, during a Condition IV event, is permissible, since the event cannot develop into an event that is more serious than Condition IV. Filling the pressurizer in 1000 seconds in a Condition II LONF or LOOP would be very conservative. It implies that analyses of these events, without offsite power, would be expected to show that the pressurizer would not be filled. The AOO acceptance criterion, which



prohibits filling the pressurizer, would be met if the operator can take appropriate corrective action before 1000 seconds.

The NRC staff reviewed the licensee's analysis for the LONF transient and concluded the analysis was performed using acceptable analytical models. The staff concluded the licensee's analysis showed that the SAFDLs are not challenged and the pressurizer would not fill. Therefore, the staff finds the proposed EPU acceptable with respect to the LONF event.

### Conclusion

The NRC staff has reviewed the licensee's analyses of the LONF flow event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of the LONF flow. Based on this, the staff concludes that the plant will continue to meet the requirements of GDC 10, 15, and 26 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the LONF flow event.

#### 2.8.5.2.4 FW System Pipe Breaks Inside and Outside Containment

### Regulatory Evaluation

A major FWLB, an ANS Condition IV event, is defined as a break in a FW line large enough to prevent the addition of sufficient FW to the SGs to maintain shell-side fluid inventory. Depending upon the size and location of the break and the plant operating conditions at the time of the break, the break could cause either an RCS cooldown (by excessive energy discharge through the break) or an RCS heatup (by reducing FW flow to the affected RCS loop). The cooldown situation resembles an MSLB, and heatup scenario resembles an LONF. In either case, reactor protection or safety systems are actuated to mitigate the transient.

The NRC staff's review covered (1) postulated initial core and reactor conditions, (2) the methods of thermal and hydraulic analyses, (3) the sequence of events, (4) the assumed response of the reactor coolant and auxiliary systems, (5) the functional and operational characteristics of the reactor protection system, (6) operator actions, and (7) the results of the transient analyses. The NRC's acceptance criteria are based on:

- (1) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained;
- (2) GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core;
- (3) GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; and

- (4) GDC 35, insofar as it requires the reactor cooling system and associated auxiliaries be designed to provide abundant emergency core cooling.

The St. Lucie 1 construction permit was issued before the promulgation of these GDC. The licensee discusses the St. Lucie 1 plant design, in terms of the requirements of each of these GDC, in the St. Lucie 1 FSAR Section 3.1, *Conformance with the General Design Criteria*, and in the LAR Section 2.8.5.1.2.1. For further discussion, by the staff, see Section 2.8.5.0 in this SE. Specific review criteria are contained in SRP Section 15.2.8 and other guidance is provided in Matrix 8 of RS-001.

#### Technical Evaluation

FWLB cases that can cause an RCS cooldown are covered by the analyses of the MSLB, also an ANS Condition IV event. In the St. Lucie 1 licensing basis, the licensee defines the FWLB as a cooldown event, and refers the reader to the MSLB analyses for further details.

Defining the FWLB as a cooldown event eliminates the FWLB from consideration as a Condition IV DBA. As a DBA, the FWLB tests fuel and RCPB integrity, and helps set the performance requirements for the AFWS. Although, the version of RG 1.70 that the St. Lucie 1 FSAR follows does not specifically mention analyzing the FWLB as a heatup event, the FWLB is listed as an initiating event in the "decrease in heat removal by the secondary system" category of Table 15-1 of RG 1.70, Revision 2, and FWLBs are in the class of events that are directly affected by an increase in authorized power level.

The FWLB analysis demonstrates the ability of the AFWS to remove core decay heat, and thereby ensure that the core will remain in a coolable geometry. It is inferred that the core is covered with water (and coolable) when the RCS hot leg temperature remains subcooled until the AFWS heat removal rate exceeds the RCS heat generation rate (mainly from decay heat).

In general terms, it is expected that a FWLB will begin as a heatup accident, when the break flow has a high water content, and develop into a cooldown event, as the SG shell-side inventory drops, and the break flow quality approaches dry steam. It is conservative to define the FWLB as a heatup event, throughout the transient, in order to determine the performance requirements for the AFWS, and to verify that the RCS pressure does not exceed the pressure limit.

Since an analysis of the FWLB as a heatup accident could allow the NRC staff to more readily reach a conclusion of reasonable assurance that the plant will meet the requirements of GDC 27 and GDC 35, the NRC staff asked the licensee to identify the FWLB as a limiting fault in the heatup category and to provide analyses of the worst cases to support their EPU application. The analyses were to be performed according to the specific review criteria in SRP Section 15.2.8 and the guidance in Matrix 8 of RS-001.

The licensee performed the requested FWLB analyses and discussed the results with the staff at the audit of January 30 and 31, 2012.

The FWLB was analyzed using the approved S-RELAP5 computer code. The code simulates the neutron kinetics, RCS, pressurizer, pressurizer PORVs and safety valves, pressurizer spray,

SG, and MSSVs, and calculates pertinent plant variables including temperatures, pressures, and power level. Thus, the minimum RCS subcooling margin is obtained.

The FWLB was assumed to occur in the MFW line, downstream of the check valve. Thus, there is no check valve between the SG and the break to stop the SG from blowing down through the break. The analysis considered the largest flow area, 1.117 ft<sup>2</sup>, which is found at the SG inlet nozzle. MFW was assumed to be lost to both SGs when the break occurred. In order to minimize the heat removal capability of the SGs, it is conservative to customize the SG shell side water inventories in the following manner. The water level in the SG that is connected to the broken FW line was assumed to be at its highest level consistent with full-power conditions in order to delay reactor trip on SG low level. The initial water level in the other SG was assumed to be relatively low in order to minimize the water inventory available for long-term heat removal.

The FWLB was analyzed assuming offsite power is available and offsite power is not available. Reactor trip was assumed to occur on a faulted SG low level signal received when level reached 5 percent of the narrow range span (NRS). In the EPU application, the licensee proposes to raise the low level reactor trip setpoint from 20.5 percent NRS to 35 percent NRS. Based upon the current 20.5 percent NRS low level trip setpoint, the FWLB would cause the reactor to trip when the SG level drops to 6.5 percent NRS (20.5 percent NRS minus 14 percent NRS allowance for harsh environment effects). The FWLB analysis was conservatively based upon a 5 percent NRS trip setpoint.

It was assumed that one motor-driven AFW pump pumped its flow through the break. The other motor-driven AFW pump was assumed to supply 296 gpm, after a 330-second delay, to the unfaulted SG. It was also assumed that the operator took no steps to divert the AFW flow from the faulted SG to the unfaulted SG. Since the AFW control logic would isolate the faulted SG, the turbine-driven AFW pump was assumed to be the single active failure. The turbine-driven AFW pump would supply more AFW flow to the intact SG than would the motor-driven AFW pump.

The PORVs were assumed to be operable, since opening of the PORVs would tend to limit the RCS pressure and saturation temperature, and thereby yield a low subcooling margin. The pressurizer heaters were not assumed to operate; also to limit subcooling margin.

The AFW flow under these conditions would not be sufficient to remove all the decay heat generated in the core. Primary-to-secondary heat transfer decreases, as SG level falls, and RCS temperature and pressure rises. Reactor trip and AFW actuation occur on low SG water level conditions. Eventually, the decay heat generation rate falls to a level that can adequately be removed by the AFWS. The FWLB analyses are performed to demonstrate that the RCPB pressure limits are not exceeded, and that saturation conditions are not reached in the RCS before all the decay heat can be removed by the AFWS.

The analysis results indicate that the PORVs can effectively limit the RCS pressurization to 2320 psia (the assumed PORV opening setpoint). This also determines a conservatively low RCS hot leg saturation temperature. The minimum subcooling margins, for the FWLB with offsite power and the FWLB case without offsite power, are 9 °F and 28 °F, respectively. These minimum subcooling margins are reached at the time the AFWS begins to remove all of the decay heat—more than half an hour after the occurrence of the FWLB.

Based upon the input parameters, assumptions, and modeling techniques described during the audit, NRC staff finds the St. Lucie 1 FWLB transient simulations and the identification of the limiting cases acceptable. The licensee provided reasonable assurance that all of the acceptance criteria continue to be met. The St. Lucie 1 AFWS capacities were adequate to remove decay heat, to prevent overpressurizing the RCS, and to prevent uncovering the reactor core (i.e., reaching saturation conditions in the RCS).

The NRC staff reviewed the FWLB analyses and concludes that the licensee's analyses adequately account for operation of the St. Lucie 1 plant at EPU conditions and were performed using acceptable analytical models. The staff further concludes that the licensee demonstrated that the RPS and safety systems will continue to assure that the ability to insert control rods is maintained, and the RCPB pressure limits will not be exceeded. Thus, the staff concludes that the plant will continue to meet the applicable regulatory requirements at EPU conditions with respect to the FWLB events.

### Conclusion

The NRC staff reviewed the FWLB analyses and concluded that (1) they were performed using acceptable analytical models, and (2) they adequately account for operation of the plant at the proposed EPU conditions. The staff further concluded that the licensee demonstrated that the reactor protection and safety systems will continue to assure that the ability to insert control rods is maintained, the RCPB pressure limits will not be exceeded, and adequate core cooling will be provided. Based on this, the staff concludes that the plant will continue to meet the requirements of GDC 27, 28, 31, and 35 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to FWLBs.

#### 2.8.5.2.5 Asymmetric Steam Generator Transient

### Regulatory Evaluation

The asymmetric SG transient (ASGT) is analyzed to confirm that DNBR and FCM design limits are not exceeded. The ASGT is characterized by events that result in unplanned, asymmetric changes in heat removal by the secondary system (e.g., sudden reduction in steam flow). Reactor protection and safety systems are actuated to mitigate such events. This event is classified as an AOO, or an ANS Condition II event.

The NRC staff's review covered (1) the sequence of events, (2) the analytical model used for analyses, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on:

- (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs;
- (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design conditions of the RCPB are not exceeded during AOOs; and
- (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded.

The St. Lucie 1 construction permit was issued before the promulgation of these GDC. The licensee discusses the St. Lucie 1 plant design, in terms of the requirements of each of these GDC, in the St. Lucie 1 FSAR Section 3.1, *Conformance with the General Design Criteria*, and in the LAR Section 2.8.5.1.2.1. For further discussion, by the staff, see Section 2.8.5.0 in this SE.

### Technical Evaluation

The ASGT is a malfunction in the main steam system that results in an increased steam demand on one SG and a decreased steam demand on the other SG. This causes the moderator temperature to be higher in one side of the core than in the other side, and creates a core tilt. The core tilt can lead to radial peaking and DNB concerns.

The approved S-RELAP5 code was used to calculate neutron power, fuel thermal response, surface heat transfer, and fluid conditions, and to estimate the time of mDNBR. Another approved code, XCOBRA-IIIC was used to calculate the mDNBR based upon the S-RELAP5 results.

Four asymmetric events were considered:

- loss of load to one SG
- excess load to one SG
- loss of FW to one SG
- excess FW to one SG

These events were assumed to occur when the plant was operating at HFP conditions. For the events that cause a core cooldown, a highly negative moderator temperature coefficient was assumed. This would cause a reactivity excursion in one core section.

It was assumed that the loss of load to one SG event is initiated by the inadvertent closure of one MSIV. When the MSIV closes, the SG temperature increases, and this reduces the primary-to-secondary heat transfer rate. The temperature in the RCS cold legs, connected to the SG, also increases. The unaffected SG will assume a greater steam demand, and the increase in steaming rate will cause the temperature in the RCS cold legs, connected to this SG, to decrease. The difference in core inlet temperatures skews the core power distribution, which can reduce thermal margin in a section of the core. The reactor is tripped by the variable high power trip (VHPT). The mDNBR occurs as the CEAs are falling into the core.

The results of the loss of load to one SG event analysis predict a mDNBR of 1.867, which remains above the DNBR limit of 1.164. The pressure transient is not as severe as the pressure transient caused by the loss of external electrical load event, since the unaffected SG takes on some of the steam load from the isolated SG.

It was assumed that the excess load to one SG event is caused by the inadvertent opening of one MSSV. The additional steam flow cools the portion of the RCS that is connected to the SG

and a portion of the core. This is essentially the same as the inadvertent opening of a SG relief or safety valve, presented in LAR Attachment 5, Section 2.8.5.1.1.

It was assumed that the loss of FW to one SG event is initiated by a malfunction of one of the FW controllers which causes one of the FW regulator valves to close. The temperature and pressure increase in the affected SG. The temperature in the RCS increases as the SG water level drops. This is similar to the LONF flow of LAR Attachment 5, Section 2.8.5.2.3, except that the loss of FW is to only one SG, which causes a small asymmetry in core inlet temperatures. The staff agrees that the increase in core power for this event would be lower than that for the loss of FW flow event, and hence this event is not limiting.

It was assumed that the excess FW to one SG is caused by the complete opening of a single FW control valve. The increased flow causes more heat to be transferred from the RCS and therefore a cooldown of the affected RCS cold legs. The unaffected RCS legs will also cool down but at a lower rate due to the unaffected SG picking up more load and producing more steam. The licensee stated that this event would have a very small asymmetry in the RCS cold leg coolant temperatures and would have a much smaller decrease in RCS coolant temperatures due to the increased MFW to one SG than for the excess load event resulting in a much smaller positive moderator reactivity feedback. The licensee showed that this event is bounded by the excess load event.

The staff agrees that the licensee was justified in analyzing only the first event, loss of load to one SG. The others would not be as severe as the events that are identified and reported in the EPU application. The staff also accepts the licensee's methodology and assumptions. The staff verified during an audit that St. Lucie 1 model is conservative with respect to asymmetry events since it does not provide for mixing in the reactor vessel lower plenum. Therefore, the asymmetry effect on one core section is not attenuated by water coming from the RCS portions that are connected to the unaffected SG.

### Conclusion

The NRC staff reviewed the licensee's analyses of the asymmetric SG transient concluded that the licensee's analyses were performed using approved analytical methods and conservative assumptions. The staff concluded that the analyses demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded by the asymmetric SG transient. The staff concluded that the plant will continue to meet GDC 10, 15, and 26 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the asymmetric SG transient.

### 2.8.5.3 Decrease in Reactor Coolant System Flow

#### 2.8.5.3.1 Loss of Forced Reactor Coolant Flow

### Regulatory Evaluation

A decrease in reactor coolant flow occurring while the plant is at power could result in a degradation of core heat transfer, which would cause an increase in fuel temperature. Fuel damage could result if the SAFDLs are exceeded during the transient. The reactor protection

system will automatically trip the reactor, and this will mitigate the transient (i.e., prevent violation of the SAFDLs).

The NRC staff's review covered (1) the postulated initial core and reactor conditions, (2) the methods of thermal and hydraulic analyses, (3) the sequence of events, (4) assumed reactions of reactor systems components, (5) the functional and operational characteristics of the reactor protection system, (6) operator actions, and (7) the results of the transient analyses. The NRC's acceptance criteria are based on:

- (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs;
- (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and
- (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded.

The St. Lucie 1 construction permit was issued before the promulgation of these GDC. The licensee discusses the St. Lucie 1 plant design, in terms of the requirements of each of these GDC, in the St. Lucie 1 FSAR Section 3.1, *Conformance with the General Design Criteria*, and in the LAR Section 2.8.5.1.2.1. For further discussion, by the staff, see Section 2.8.5.0 in this SE. Specific review criteria are contained in SRP Sections 15.3.1 and 15.3.2, and additional guidance is provided in Matrix 8 of RS-001.

#### Technical Evaluation

A loss of normal coolant flow (LOCF) could result from either a loss of electrical power to one or more of the four RCPs or from a mechanical failure, such as a pump shaft seizure (see Section 2.8.5.3.2). Each of two busses supplies electrical power to two RCPs. Therefore, the loss of a single bus could not cut the power supply to any more than two RCPs.

The LOCF analysis is assumed to be initiated by a disruption of the electrical power supplied to one or more RCPs. This can cause a complete or partial loss of forced coolant flow. The complete LOCF with scram on low flow rate is the most limiting transient, with respect to potential violation of the DNB SAFDL. This scenario can be the result of an underfrequency or undervoltage event causing the RCPs to trip without removing power from the CEAs. The reactor does not trip until the RCS flow falls below the low flow trip setpoint. Thus, the analysis of the LOCF event verifies that the low flow reactor trip setpoint can adequately protect the fuel from experiencing departure from DNB by preventing the calculated DNBR from dropping below the DNBR safety limit. The acceptance criterion for fuel-cladding integrity specifies that the mDNBR must remain above the 95 percent probability/95 percent confidence DNBR limit.

The LOCF analysis is evaluated according to AOO acceptance criteria, which are consistent with GDC 10, 15 and 26. This is also consistent with the licensee's FSAR, Table 15.1.1-4, which identifies the LOCF as an AOO that requires RPS action.

The licensee used the NRC-approved S-RELAP5 code to perform a complete loss of reactor coolant flow analysis. The S-RELAP5 code calculates neutron power, fuel thermal response, surface heat transport, and fluid conditions (such as coolant flow rates, temperatures and pressures), and estimates the time of mDNBR. The mDNBR was calculated using the NRC-approved XCOBRA-IIIC code, which applied the high thermal performance (HTP) CHF correlation to input values for core fluid boundary conditions, and average rod surface heat flux.

The LOCF was based upon beginning-of-cycle (BOC) HFP initial conditions, with a maximum core inlet temperature and minimum RCS flow rate, in order to minimize the initial margin to DNB. The assumed scram time incorporated conservatively long trip signal delay, and holding coil delay times. The assumed RCS flow coastdown was conservatively rapid. The maximum SG tube plugging level was assumed, and this increased the RCS flow resistance in the SG tubes.

The LOCF is assumed to occur at 100.3 percent of the EPU power,<sup>4</sup> with the loss of power to all four RCPs. An undervoltage or underfrequency condition could cause the RCPs to trip. The reactor trip would follow when the low flow trip setpoint is reached. The mDNBR is reached at about 3.75 seconds; one second after CEA insertion begins and before the CEAs are fully inserted. The mDNBR, 1.319, is greater than the DNBR SAFDL, 1.164.

For the LOCF event, it is also required that the peak RCS and MSSS pressures remain below 110 percent of their respective design pressures.

Figure 2.8.5.3.1-3 indicates that the peak pressurizer pressure, which is greater than 2400 psia, occurs more than 5 seconds after the beginning of the LOCF event, after the CEAs are fully inserted. The lack of a plateau at the PORV opening setpressure of 2400 psia is interpreted to mean that the two, 153,000 lbm/hr PORVs were not assumed to be operable for this analysis. This assumption is conservative with respect to peak RCS pressure; but not for mDNBR. In this instance, the assumption does not affect mDNBR since the mDNBR had already been reached before 5 seconds. Figure 2.8.5.3.1-3 indicates that the peak pressurizer pressure is not predicted to exceed 2425 psia, which is well below 110 percent of design RCS pressure limit.

The NRC staff finds the LOCF analysis, performed for the proposed EPU power level, shows that the acceptance criteria are met. The NRC staff also notes that the LOCF analysis has been performed using NRC-approved codes and methods, and with conservative assumptions and initial conditions.

### Conclusion

The NRC staff has reviewed the licensee's analysis of the complete LOCF event and concludes that the licensee's analysis has adequately accounted for operation of the plant at the proposed EPU power level, and was performed using acceptable analytical models. The staff further concludes that the licensee has demonstrated that the RPS will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the staff concludes that the plant will continue to meet the requirements of GDC 10, 15, and 26 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the LOCF event.

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<sup>4</sup> This includes a power measurement uncertainty of 0.3% power.



### 2.8.5.3.2 Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break

#### Regulatory Evaluation

If an RCP rotor seizes, or an RCP shaft breaks, then the RCS flow, in that loop, falls rapidly and causes the reactor and turbine to trip. The sudden decrease in RCS flow while the reactor is at power degrades the rate of fuel to coolant heat transfer, and this could result in fuel damage. The locked rotor or shaft break (LR/SB) event is classified as a postulated accident or ANS Condition IV event. The NRC staff's review covered:

- (1) The postulated initial and long-term core and reactor conditions,
- (2) The methods of thermal and hydraulic analyses,
- (3) The sequence of events,
- (4) The assumed reactions of reactor system components,
- (5) The functional and operational characteristics of the RPS, and
- (6) The results of the transient analyses.

The NRC's acceptance criteria are based on:

- (1) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained.
- (2) GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RV internals so as to significantly impair the capability to cool the core.
- (3) GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized.

The St. Lucie 1 construction permit was issued before the promulgation of these GDC. The licensee discusses the St. Lucie 1 plant design, in terms of the requirements of each of these GDC, in the St. Lucie 1 FSAR Section 3.1, *Conformance with the General Design Criteria*, and in the LAR Section 2.8.5.1.2.1. For further discussion, by the staff, see Section 2.8.5.0 in this SE. Specific review criteria are contained in SRP Sections 15.3.3 and 15.3.4 and other guidance is provided in Matrix 8 of RS-001.

#### Technical Evaluation

The RCS flow drops more rapidly, immediately following a locked rotor, than after a shaft break. Longer term, the shaft break causes a lower net core flow due to the effect of reverse flow

through the affected loop. In either instance, the automatic reactor protection and safety systems are actuated to mitigate the event.

For St. Lucie 1, the licensee has determined that the locked rotor is more severe than the shaft break. The relatively faster RCS flow reduction following an RCP locked rotor is attributed to the higher flow resistance imposed by the seized rotor than the flow resistance that is imposed by a free-spinning rotor. This faster flow decrease leads to an earlier reversal of flow in the affected loop, and consequently a lower net core flow.

Like the LOCF, the LR/SB event leads to a reactor trip on low flow rate very early in the transient. Table 2.8.5.3.2-1 indicates that the low flow rate trip signal is generated less than 0.2 seconds after the RCP rotor is assumed to seize. The mDNBR is reached at about 3.1 seconds, while the CEAs are dropping into the core. The mDNBR, 1.175, is greater than the DNBR safety limit of 1.164. The St. Lucie 1 LR/SB does not result in any fuel rod damage.

The NRC-approved S-RELAP5 code was used to calculate neutron power, fuel thermal response, surface heat transport, and fluid conditions (such as coolant flow rates, temperatures and pressures), and to estimate the time of mDNBR. Core fluid boundary conditions and average rod surface heat flux were used as inputs into the XCOBRA-IIIC code, which calculated the mDNBR value by applying the HTP CHF correlation.

The LR/SB event was analyzed assuming BOC HFP initial conditions, with maximum core inlet temperature, and minimum RCS flow rate, to minimize the initial margin to DNB. The CEAs were assumed to drop into the core after conservatively long trip signal processing and holding coil delay times. Offsite power was assumed to be lost when the turbine tripped, causing the undamaged RCPs to coast-down, which conservatively reduced the RCS flow for the DNBR calculation. The maximum SG tube plugging level was assumed in order to add the flow resistance associated with reduced SG total tube flow area.

The LR/SB event was assumed to occur at 100.3 percent EPU power with the seizure of one RCP rotor. The reactor is tripped when the low RCS flow trip setpoint value is reached; followed by a turbine trip and loss of offsite power.

Figure 2.8.5.3.2-3 indicates that the peak pressurizer pressure, which is greater than 2400 psia, occurs more than five seconds after the beginning of the LR/SB event, after the CEAs are fully inserted. The lack of a plateau, at the PORV opening setpressure, 2400 psia, is interpreted to mean that the two, 153,000 lbm/hr PORVs were not assumed to be operable for this analysis. This assumption is conservative with respect to peak RCS pressure; but not for mDNBR. In this instance, the assumption does not affect mDNBR since the mDNBR had already been reached before five seconds. Figure 2.8.5.3.2-3 indicates that the peak pressurizer pressure is not predicted to exceed 2425 psia, which is well below 110 percent of design RCS pressure limit.

The NRC staff finds the LR/SB analysis, performed for the proposed EPU power level, shows that the acceptance criteria are met. The NRC staff also notes that the LR/SB analysis has been performed using NRC-approved codes and methods and with conservative assumptions and initial conditions.

## Conclusion

The NRC staff has reviewed the licensee's analyses of the sudden decrease in core coolant flow events and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the ability to insert control rods is maintained, the RCPB pressure limits will not be exceeded, the RCPB will behave in a nonbrittle manner, the probability of propagating fracture of the RCPB is minimized, and adequate core cooling will be provided. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC 27, 28, and 31 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the sudden decrease in core coolant flow events.

### 2.8.5.4 Reactivity and Power Distribution Anomalies

#### 2.8.5.4.1 Uncontrolled Control Rod Assembly Withdrawal from a Subcritical or Low Power Startup Condition

## Regulatory Evaluation

An uncontrolled CEA withdrawal from subcritical or low power startup conditions could be caused by malfunction of the reactor control or CEA control systems, or by an operator error. This withdrawal will add positive reactivity to the reactor core, and cause a power excursion. This event is classified as an AOO, or an ANS Condition II event.

The NRC staff's review covered (1) the description of the causes of the transient and the transient itself, (2) the initial conditions, (3) the values of reactor parameters used in the analysis, (4) the analytical methods and computer codes used, and (5) the results of the transient analyses. The NRC's acceptance criteria are based upon:

- (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs;
- (2) GDC 20, insofar as it requires that the reactor protection system be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs; and
- (3) GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems.

The St. Lucie 1 construction permit was issued before the promulgation of these GDC. The licensee discusses the St. Lucie 1 plant design, in terms of the requirements of each of these GDC, in the St. Lucie 1 FSAR Section 3.1, *Conformance with the General Design Criteria*, and in the LAR Section 2.8.5.1.2.1. For further discussion, by the staff, see Section 2.8.5.0 in this SE. Specific review criteria are contained in SRP Section 15.4.1 and other guidance is provided in Matrix 8 of RS-001.

### Technical Evaluation

The CEA withdrawal is assumed to occur when the plant is in a Mode 2 startup (critical) condition at zero power. The result is a large, rapid positive reactivity insertion that causes a power excursion that can lead to DNB or to FCM and high RCS pressure. The power excursion is limited, before reactor trip, by Doppler reactivity feedback.

The S-RELAP5 code was used to calculate neutron power, fuel thermal response, surface heat transfer, fluid conditions, and to estimate the time of mDNBR. S-RELAP5 was also used to calculate the peak transient fuel centerline temperature using a hot-spot model. The core fluid conditions and average fuel rod surface heat flux were used by the XCOBRA-IIIC code to calculate the mDNBR using the HTP CHF correlation. S-RELAP5 and XCOBRA-IIIC are NRC-approved codes.

Conservatively high core inlet temperatures, and a low RCS flow rate were assumed in order to test the SAFDLs and the RCS pressure limit (i.e., 110 percent of the RCS design pressure, or 2750 psia).

HZP cases were considered at BOC and EOC conditions, and the reactor scram was modeled to yield the minimum shutdown margin. BOC conditions produced the higher power excursion.

The RPS automatically tripped the reactor on the VHPT. The high rate-of-change trip, which would have responded sooner, was not credited in these analyses.

The pressurizer sprays and PORVs were assumed to be operable for the SAFDL-oriented analyses, to limit the RCS pressure and yield a low mDNBR. For the high pressure cases, the pressurizer sprays and PORVs were not assumed to be operable, in order to produce a very high maximum RCS pressure.

It was assumed that a CEA, with a high differential worth, was withdrawn at the maximum CEA withdrawal speed, and continued to be withdrawn, even after time of reactor trip.

Table 2.8.5.4.1-2 indicates the results for the limiting uncontrolled CEA withdrawal from subcritical cases. The SAFDL cases produced a mDNBR that is greater than 6 (limit greater than or equal to 1.164), and a maximum fuel centerline temperature of 2036 °F (limit less than or equal to 4908 °F). The maximum pressure cases predicted a peak pressure of 2568 psia (limit less than or equal to 2750 psia).

### Conclusion

The NRC staff has reviewed the licensee's analyses of the uncontrolled CEA withdrawal from a subcritical or low power startup condition and concludes that the licensee's analyses have adequately accounted for the changes in core design necessary for operation of the plant at the proposed EPU power level. The NRC staff also concludes that the licensee's analyses were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs are not exceeded, and RCS integrity is maintained. Based on this, the NRC staff concludes that St. Lucie 1 will continue to meet the requirements of GDC 10, 20, and 25 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed

EPU acceptable with respect to the uncontrolled CEA withdrawal from a subcritical or low power startup condition.

#### 2.8.5.4.2 Uncontrolled Control Rod Assembly Withdrawal at Power

##### Regulatory Evaluation

An uncontrolled CEA withdrawal at power may be caused by a malfunction of the reactor control or CEA control systems, or by operator error. This withdrawal will add positive reactivity to the reactor core, and cause a power excursion. This event is classified as an AOO, or an ANS Condition II event.

The NRC staff's review covered (1) the description of the causes of the AOO and the description of the event itself, (2) the initial conditions, (3) the values of reactor parameters used in the analysis, (4) the analytical methods and computer codes used, and (5) the results of the associated analyses. The NRC's acceptance criteria are based upon:

- (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs;
- (2) GDC 20, insofar as it requires that the reactor protection system be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs; and
- (3) GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems.

The St. Lucie 1 construction permit was issued before the promulgation of these GDC. The licensee discusses the St. Lucie 1 plant design, in terms of the requirements of each of these GDC, in the St. Lucie 1 FSAR Section 3.1, *Conformance with the General Design Criteria*, and in the LAR Section 2.8.5.1.2.1. For further discussion, by the staff, see Section 2.8.5.0 in this SE. Specific review criteria are contained in SRP Section 15.4.2 and other guidance is provided in Matrix 8 of RS-001.

##### Technical Evaluation

The CEA withdrawal at power is assumed to occur when the plant is operating in Mode 1. The result is a large, rapid positive reactivity insertion, which causes a power excursion that can lead to DNB or to FCM, and to high RCS pressure.

The CEA withdrawal at power analysis consists of a series of analyses, designed to cover the range of possible operating power levels, CEA worths, and times in core life. The results of these cases reveal the conditions under which the mDNBR is reached.

CEA worths and withdrawal speeds are modeled by several reactivity insertion rates, and used as initiating events in case studies of this event occurring at five initial power levels: 25 percent, 50 percent, 75 percent, 97.39 percent, and HFP. All of these analyses are performed for BOC and EOC core conditions.

The CEA withdrawal at power analyses were performed to demonstrate that the SAFDLs and the RCS pressure limit are not exceeded. Operation of the pressurizer PORVs and sprays is assumed for the SAFDL analyses, since they tend to keep the RCS pressure low, which would produce a lower mDNBR. The pressurizer PORVs and sprays are not assumed to operate for the peak RCS pressure analyses.

The S-RELAP5 code was used to calculate neutron power, fuel thermal response, surface heat transfer, fluid conditions, and to estimate the time of mDNBR. S-RELAP5 was also used to calculate the peak transient fuel centerline temperature, using a hot-spot model. The core fluid conditions and average fuel rod surface heat flux were used by the XCOBRA-IIIC code to calculate the mDNBR using the HTP CHF correlation. S-RELAP5 and XCOBRA-IIIC are NRC-approved codes.

The reactor protection system reactor trips that protect against exceeding the SAFDLs and the pressure limit are derived from the variable high power, thermal margin/low pressure, and high pressurizer pressure conditions. The high pressurizer pressure reactor trip is not credited in the analyses intended to test the SAFDLs.

The mDNBR, 1.239 (limit  $\geq 1.164$ ), was calculated for the EOC HFP case. The peak LHR, 17.9 kW/ft (limit  $\leq 22.279$  kW/ft) was reached in the BOC 75 percent RTP case. The maximum RCS pressure, 2657 psia (limit  $\leq 2750$  psia), was reached in the BOC HFP high pressure case. None of the reported cases caused the pressurizer to fill. Therefore, the CEA withdrawal at power event would not develop into an event of a more serious classification.

### Conclusion

The NRC staff has reviewed the licensee's analyses of the uncontrolled CEA withdrawal at power, and concludes that the licensee's analyses have adequately accounted for the changes in core design necessary for operation of the plant at the proposed EPU power level. The NRC staff also concludes that the licensee's analyses were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs are not exceeded, and RCS integrity is maintained. Based on this, the NRC staff concludes that the St. Lucie plant will continue to meet the requirements of GDC 10, 20, and 25 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the uncontrolled CEA withdrawal at power.

#### 2.8.5.4.3 Control Rod Misoperation

##### Regulatory Evaluation

The NRC staff's review covered the types of control rod misoperations that are assumed to occur, including those caused by a system malfunction or operator error.

The review covered (1) descriptions of rod position, flux, pressure, and temperature indication systems, and those actions initiated by these systems (e.g., turbine runback, rod withdrawal prohibit, rod block) that can mitigate the effects or prevent the occurrence of various misoperations; (2) the sequence of events; (3) the analytical model used for analyses;

(4) important inputs to the calculations; and (5) the results of the analyses. The NRC's acceptance criteria are based on:

- (1) GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs;
- (2) GDC 20, insofar as it requires that the protection system be designed to initiate the reactivity control systems automatically to assure that acceptable fuel design limits are not exceeded as a result of AOOs and to initiate automatically operation of systems and components important to safety under accident conditions; and
- (3) GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems.

The St. Lucie 1 construction permit was issued before the promulgation of these GDC. The licensee discusses the St. Lucie 1 plant design, in terms of the requirements of each of these GDC, in the St. Lucie 1 FSAR Section 3.1, *Conformance with the General Design Criteria*, and in the LAR Section 2.8.5.1.2.1. For further discussion, by the staff, see Section 2.8.5.0 in this SE. Specific review criteria are contained in SRP Section 15.4.3 and other guidance is provided in Matrix 8 of RS-001.

SRP Section 15.4.3 considers four control rod misoperation events:

- |                                 |                            |
|---------------------------------|----------------------------|
| 1) static misalignment of CEAs, | an ANS Condition II event  |
| 2) single CEA withdrawal,       | an ANS Condition III event |
| 3) dropped CEA bank,            | an ANS Condition II event  |
| 4) dropped CEA,                 | an ANS Condition II event  |

For St. Lucie 1, only the fourth event (dropped CEA) is reported in the plant's licensing basis.

#### Technical Evaluation

Since the St. Lucie 1 plant is not equipped with an automatic CEA control system, the CEA drop event is considered as an operator error. Inadvertently releasing a CEA will cause it to drop into the core, where it will be detected directly by a position limit switch or as a reduction in core power by the ex-core detectors.

The negative reactivity, that is inserted as the CEA drops into the core, causes the core power and reactor coolant temperatures to decrease. When the MTC is very negative (e.g., at EOC conditions), the reduction in RCS temperature introduces positive reactivity into the core that can return the core power to nominal. However, the radial power peaking distribution is altered by the dropped CEA. The resultant increase in heat flux and fuel temperature, in the hot assembly, can lead to DNB and FCM (i.e., violation of the SAFDLs).

Protection is afforded, during normal (steady-state) operation, by maintaining the margin to DNB. The RPS is available to automatically trip the reactor, if necessary, on variable high power, and TM/LP. This event can result in a return to steady power generation, with an altered radial power distribution, or in a reactor trip. The result depends chiefly on the worth of the dropped CEA.

The dropped CEA analysis was performed with NRC-approved S-RELAP5 and XCOBRA-IIIC codes. The S-RELAP5 code was used to calculate neutron power, fuel thermal response, surface heat transfer, and fluid conditions (e.g., RCS flow, temperature, and pressure), and to estimate time of mDNBR. The core fluid conditions and average rod surface heat flux were used by the XCOBRA-IIIC code to calculate the mDNBR.

The analysis was performed assuming EOC HFP conditions, maximum TS core inlet temperature, and minimum RCS flow rate. This includes the use of most negative HFP MTC, which inserts the most positive moderator reactivity feedback. This is conservative for an event in which the RCS temperature is reduced.

The results of the dropped CEA analysis indicate that a CEA, worth 200 percent millirho (pcm), would not result in a reactor trip. Power level to a minimum value in 3 seconds and returns to nominal. The mDNBR, 1.566 (limit  $\geq 1.164$ ), remains above the DNB SAFDL. The peak linear heat rate, 20.750 kW/ft (limit  $\leq 22.279$ ), does not exceed the FCM SAFDL.

### Conclusion

The NRC staff has reviewed the licensee's analysis of the dropped CEA event and concludes that the licensee's analyses have adequately accounted for the changes in core design required for operation of the plant at the proposed power level. The NRC staff also concludes that the licensee's analysis was performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection system will continue to ensure the SAFDLs will not be exceeded during normal or anticipated operational transients. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC 10, 20, and 25 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the dropped CEA event.

#### 2.8.5.4.4 Startup of an Inactive Loop at an Incorrect Temperature

The St. Lucie 1 plant TSs require that, in Modes 1 and 2, both RCS loops and all four RCPs be in operation. Therefore, if St. Lucie 1 is operated according to requirements of the TSs, this event could not occur.

The startup of an inactive loop at an incorrect temperature is not in the St. Lucie 1 licensing basis. It is also not an event that is required to be evaluated, given the St. Lucie 1 plant TSs. Accordingly, the applicant has not provided an evaluation.

The staff concludes that the proposed EPU is acceptable with respect to the startup of an inactive loop at an incorrect temperature, since this event cannot occur as long as the St. Lucie 1 plant TSs are followed.

#### 2.8.5.4.5 Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant

### Regulatory Evaluation

In this event, unborated water is added to the RCS, via the CVCS, due to an operator error or CVCS malfunction, and this causes an unplanned increase in core reactivity. If the reactor is



operating at power, then the reactor will be automatically tripped by a TM/LP trip or a VHPT. After the reactor trip, the unborated water addition will continue to dilute the core boron concentration, and reduce the available shutdown margin. If the reactor is initially in a subcritical condition, then the boron dilution simply erodes the shutdown margin. In both cases, the boron dilution must be ended by the operator before the core becomes critical. This event is grouped into the AOO, or ANS Condition II category.

The NRC staff's review covered (1) conditions at the time of the unplanned dilution, (2) causes, (3) initiating events, (4) the sequence of events, (5) the analytical model used for analyses, (6) the values of parameters used in the analytical model, and (7) results of the analyses. The NRC's acceptance criteria are based on:

- (1) GDC 10, insofar as it requires that the reactor core and associated coolant, control, and protection systems be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including AOOs;
- (2) GDC 15, insofar as it requires that the RCS and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs; and
- (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded.

The St. Lucie 1 construction permit was issued before the promulgation of these GDC. The licensee discusses the St. Lucie 1 plant design, in terms of the requirements of each of these GDC, in the St. Lucie 1 FSAR Section 3.1, *Conformance with the General Design Criteria*, and in the LAR Section 2.8.5.1.2.1. For further discussion, by the staff, see Section 2.8.5.0 in this SE. Specific review criteria are contained in SRP Section 15.4.6 and other guidance is provided in Matrix 8 of RS-001.

#### Technical Evaluation

The CVCS controls the chemistry and amount of coolant in the RCS. Changing the boron concentration in the RCS during normal operation compensates for long-term reactivity effects such as fuel burnup, xenon buildup and decay, and aids plant startup and cooldown operations. In the refueling modes, borated water is drawn from the RWT to establish adequate core shutdown margin.

Boron dilution operations are planned and conducted under administrative procedures, which control the rate and extent of the intended change in boron concentration. The resulting change in boron concentration is monitored by sampling the RCS.

An inadvertent boron dilution that results in power generation (i.e., in Modes 1 and 2) can reduce the margin to, and possibly violate, the DNB and FCM SAFDLs.

SRP Section 15.4.6 provides review guidance for boron dilution analyses covering all six modes of operation. In addition to the AOO acceptance criteria, the SRP lists the minimum time intervals that must be available for operator action to terminate the transient before criticality

can occur: 30 minutes in the refueling mode, and 15 minutes in all the other modes. These time intervals are to begin at the time of an alarm, alerting the operators to the possibility that a boron dilution might be in progress. However, the licensing bases of some plants contain time intervals that begin earlier, at the time of initiation of the boron dilution event. The NRC staff decided (Reference 48) that plants that were operating in 1985 would not be backfitted to meet the alarm criterion. This was the result of a cost-benefit study that considered, *inter alia*, the cost of installing the required alarms. Since the St. Lucie 1 plant was operating in 1985, it was among the plants that were considered in the generic letter (Reference 48).

The licensee applied an approved methodology (Reference 42) to show that adequate time exists for the operator to terminate the boron dilutions events occurring in the six modes of plant operation.

#### Power operation (Mode 1)

During power operation, the reduction in core boron concentration causes a power excursion that can lead to DNB or FCM. The TM/LP reactor trip and VHPT functions are designed to detect this condition and trip the reactor. The licensee does not provide an analysis of the boron dilution in Mode 1, since this power excursion, and the response it elicits from the reactor protection system, are addressed in Section 2.8.5.4.2, Uncontrolled CEA Withdrawal at Power.

After the reactor is tripped, the continuing dilution of boron would tend to erode the core shutdown margin. If manual action is not taken to end the delivery of unborated water to the RCS, the core could return to critical and generate power. If a CEA is assumed to be stuck out of the core, then the relatively high rate of power production in the region of the stuck CEA could lead to a violation of the DNB and FCM SAFDLs.

The licensee states that the time to overcome the shutdown margin, following the reactor trip, is evaluated in the analysis of the boron dilution occurring in Mode 2 (below).

#### Startup (Mode 2) and Hot Standby (Mode 3)

Table 2.8.5.0-11, Plant Operational Modes, indicates that Mode 2 (startup) and Mode 3 (hot standby) differ only by core criticality conditions. The core, in Mode 2 could be critical and producing up to 5 percent power. The core, in Mode 3, is subcritical by at least 1 percent  $k_{\text{eff}}$ . The RCS fluid conditions (e.g., temperature and pressure), and core boron concentration conditions (e.g., initial and critical boron concentrations) are the same. Therefore, the time to criticality, after the reactor is tripped, would be expected to be the same for Modes 2 and 3. The boron dilution analysis results in Table 2.8.5.4.5-2 show that the time to criticality for Modes 2 and 3 is the same (about 85 minutes). This meets the 15-minute acceptance criterion for that operator action time that must be available for termination of the event.

#### Hot Shutdown (Mode 4)

When the proper P-T conditions are reached in Mode 4, the RCPs are turned off and decay heat is removed by the shutdown cooling system (SDCS). Therefore, the time to criticality is determined with and without the RCPs running.

When the RCPs are running and the boron is assumed to be diluted instantaneously, the time to criticality is about 94 minutes, well above the 15 minute acceptance criterion. The

instantaneous mixing model is applicable when at least one RCP is operating. This model mixes the unborated water instantaneously with the entire RCS water inventory.

When none of the RCPs are running (i.e., when the SDCS is operating), the flow rate of coolant through the RCS is much lower. Under these conditions, assuming that the unborated water mixes instantaneously with the entire RCS water inventory is not warranted. With the SDCS in operation, the licensee applied the dilution front model (Reference 49) to calculate the time to criticality. The result was a shorter time to criticality, about 28 minutes; but still greater than the 15-minute acceptance criterion.

The calculated time to criticality is based upon a minimum SDCS flow rate of 780 gpm. The SDCS is described in FSAR Section 9.3.5, and governed by TS Sections 3.4.1.3, 3.4.1.4.1, 3.4.1.4.2, 3.9.8.1, and 3.9.8.2.

#### Cold Shutdown (Mode 5)

The SDCS is also in operation when the plant is in Mode 5. However, the RCS temperature is less than 200 °F, and the RCS is in a drained down to mid-loop conditions (i.e., the mixing volume is reduced). Using the dilution front model (Reference 49), the calculated time to criticality is about 25 minutes; based upon a minimum SDCS flow rate of 780 gpm. This also meets the 15-minute acceptance criterion.

#### Refueling (Mode 6)

In Mode 6, a conservative (i.e., small) RCS mixing volume, characteristic of mid-loop conditions, was assumed. The minimum SDCS flow rate was assumed to be 3000 gpm.

The initial and critical boron concentrations are based on the values that correspond to the shutdown margin, 5 percent, required by TSs for Mode 6.

Using the dilution front model (Reference 49), the calculated time to criticality is about 40 minutes; based upon a minimum SDCS flow rate of 3000 gpm. This time meets the 30-minute acceptance criterion for boron dilution events in Mode 6.

#### Conclusion

The NRC staff has reviewed the licensee's analyses of the decrease in boron concentration in the reactor coolant due to a CVCS malfunction and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the decrease in boron concentration in the reactor coolant due to a CVCS malfunction when the minimum SDCS flow rate is maintained above the values assumed in the licensee's analyses.

#### 2.8.5.4.6 Spectrum of Rod Ejection Accidents

##### Regulatory Evaluation

A CEA is assumed to be ejected as the result of a complete circumferential break of either the CEDM housing or its nozzle section on the reactor vessel head. Abrupt removal, or ejection, of a CEA causes a rapid positive reactivity insertion, and creates an adverse power distribution in the core, which could lead to localized fuel rod damage. Fuel temperatures rapidly increase, prompting fuel pellet thermal expansion. The reactivity excursion is initially mitigated by Doppler feedback and delayed neutron effects followed by reactor trip.

The NRC staff evaluates the consequences of a CEA ejection accident to determine the potential damage caused to the RCPB and to determine whether the fuel damage resulting from such an accident could impair cooling water flow. The NRC staff's review covered initial conditions, rod patterns and worths, scram worth as a function of time, reactivity coefficients, the analytical model used for analyses, core parameters that affect the peak reactor pressure or the probability of fuel rod failure, and the results of the transient analyses.

The NRC's acceptance criteria are based on GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RV internals so as to impair significantly the capability to cool the core.

The St. Lucie 1 construction permit was issued before the promulgation of these GDC. The licensee discusses the St. Lucie 1 plant design, in terms of the requirements of each of these GDC, in the St. Lucie 1 FSAR Section 3.1, *Conformance with the General Design Criteria*, and in the LAR Section 2.8.5.1.2.1. For further discussion, by the staff, see Section 2.8.5.0 in this safety evaluation. The spectrum of rod ejection accidents is classified as a postulated accident or ANS Condition IV event. Specific review criteria are contained in SRP Sections 15.4.8 and 4.2 (Appendix B). Other guidance is provided in Matrix 8 of RS-001.

##### Technical Evaluation

The CEA Ejection event is discussed in the St. Lucie 1 FSAR Chapter 15.4.5, and in LAR Attachment 5, Sections 2.8.5.4.6 and 2.3.5 (part-power cases).

The licensee stated the acceptance criteria for this event are the following:

- (1) Fuel failures due to DNB and FCM should be limited, so as not to impair the capability to cool the core. Additionally, the fuel failures should be within the limits of fuel failures used in the radiological analysis.
- (2) Reactivity excursions should not result in a radially averaged enthalpy greater than 280 calories per gram (cal/gm) at any axial location in any fuel rod.
- (3) The maximum reactor pressure during any portion of the assumed excursion should be less than the value that will cause stresses to exceed the faulted condition stress limits.

As a result of a fuel failure that occurred during a test at the CABRI reactor in France in 1993, and another fuel failure at the NSRR test reactor in Japan in 1994, the NRC staff recognized that high-burnup fuel cladding could fail at lower enthalpy levels during a CEA ejection event. The staff also learned that, due to reduced reactivity content, the enthalpy levels of high burnup fuel calculated using the 3D neutronics models are expected to be much lower than 100 cal/gm. Application of the 280-cal/gm acceptance criterion to high-burnup fuel could be non-conservative with respect to fuel coolability concerns since this could underpredict the number of fuel failures and the resultant radiological consequences.

The staff does not agree that 280 cal/gm could be used as acceptance criterion. It is more appropriate to apply 230 cal/gm as the acceptance criterion.

Appendix B to SRP Section 4.2 provides the following interim acceptance criteria for reactivity initiated accidents (e.g., CEA ejection):

#### *Fuel Coolability*

1. Peak radial average fuel enthalpy must remain below 230 cal/g.
2. Peak fuel temperature must remain below incipient fuel melting conditions.
3. Mechanical energy generated as a result of (1) non-molten fuel-to-coolant interaction and (2) fuel rod burst must be addressed with respect to reactor pressure boundary, reactor internals, and fuel assembly structural integrity.
4. No loss of coolable geometry due to (1) fuel pellet and cladding fragmentation and dispersal and (2) fuel rod ballooning.

#### *Fuel Cladding Failures*

The high cladding temperature failure criteria for zero power conditions is a peak radial average fuel enthalpy greater than 170 cal/g for fuel rods with an internal rod pressure at or below system pressure, and 150 cal/g for fuel rods with an internal rod pressure exceeding system pressure. For intermediate (greater than 5 percent RTP) and full power conditions, fuel cladding failure is presumed if local heat flux exceeds thermal design limits (e.g., DNBR).

The EPU CEA ejection analyses were performed using the S-RELAP5 code (Reference 48), to calculate neutron power, fuel thermal response, surface heat transfer, coolant flow rates, temperatures, and pressures), and to estimate the time of mDNBR). Then the XCOBRA-IIIC code (Reference 33) was used to calculate the mDNBR, using the HTP CHF (Reference 43). Deposited enthalpy was calculated using the approved methodology of XN-NF-78-44 (Reference 45).

Four cases are analyzed for the event: two HFP cases at BOC and EOC conditions, and two HZP cases at BOC and EOC conditions. Four additional cases, at part-power levels, were also analyzed, at BOC and EOC conditions (LAR Attachment 5, Section 2.3.5).

The CEA ejection analysis results are summarized below.

	Min DNBR	Fuel C-L Temp (°F)	Enthalpy (cal/gm)
BOC, HZP (limit)	2.442 (1.164)	4,038 (4,908)	21.2 (150)
BOC, [ ] (limit)	[ ] (1.164)	[ ] (4,908)	[ ] (230)
BOC, [ ] (limit)	[ ] (1.164)	[ ] (4,908)	[ ] (230)
BOC, HFP (limit)	1.234 (1.164)	4,607 (4,908)	166.4 (230)
EOC, HZP (limit)	2.917 (1.164)	3,212 (4,623)	29.1 (150)
EOC, [ ] (limit)	[ ] (1.164)	[ ] (4,623)	[ ] (230)
EOC, [ ] (limit)	[ ] (1.164)	[ ] (4,623)	[ ] (230)
EOC, HFP (limit)	1.984 (1.164)	4,385 (4,623)	155.9 (230)

The CEA ejection analysis results indicate that fuel damage, due to FCM, is not predicted. Fuel enthalpy remains below 230 cal/gm for the full and part-power cases. At HZP, the fuel enthalpy remains below 150 cal/gm. The peak fuel temperatures remain below the FCM temperature limits for all BOC and EOC cases. Therefore, fuel coolability criteria (1) and (2) are met.

The CEA ejection analysis results also indicate that fuel damage, due to DNB is not predicted. Therefore, fuel coolability criteria (3) and (4) are met.

Another CEA ejection analysis was performed to verify that the RCS pressure limit (110 percent of design pressure or 2750 psia) is not exceeded. Analysis assumptions and uncertainties were conservatively biased to produce a high RCS pressure. For example, the hole in the RV head, through which the CEA is ejected, is not considered as a pressure relief path. The analysis predicts a peak RCS pressure of 2696 psia.

### Conclusion

The NRC staff has reviewed the licensee's analyses of the spectrum of CEA ejection accidents and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed EPU power level, and that they were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that appropriate RPS and safety systems will prevent postulated reactivity accidents that could (1) result in damage to the RCPB greater than limited local yielding, or (2) cause sufficient damage that would significantly impair the capability to cool the core. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC 28 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CEA ejection accident.

### 2.8.5.5 Inadvertent Operation of ECCS and Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory

#### Regulatory Evaluation

An equipment malfunction, or a spurious actuation signal, or an operator error could lead to an unplanned increase in RCS inventory. The boron concentration and temperature of the incoming water relative to the boron concentration and temperature of the coolant in the RCS could cause a change in core reactivity and power level. If the power level increases, it could cause a violation of the SAFDLs and fuel damage. The effect of this event upon core reactivity

and power is evaluated in LAR Attachment 5, Section 2.8.5.4.5, Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant.

The inadvertent operation of ECCS and CVCS malfunction that increases reactor coolant inventory is classified as an AOO, or ANS Condition II event. The following AOO analysis acceptance criteria apply:

- (1) Pressures in the RCS and MSSS are less than 110 percent of design values.
- (2) Fuel cladding integrity is maintained by ensuring that SAFDLs are not exceeded.
- (3) The event does not generate a more serious plant condition without other faults occurring independently.

The first and second criteria, regarding pressure limits and fuel cladding integrity, imply an increase in power or a decrease in heat removal rate. They are addressed in LAR Attachment 5, Section 2.8.5.4.5, Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant. The third criterion, which relates to an increase in RCS inventory, is applied in the evaluation of this event.

The NRC staff's review covered (1) the sequence of events, (2) the analytical model used for analyses, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. Specific review criteria are contained in SRP Sections 15.5.1 and 15.5.2 and other guidance is provided in Matrix 8 of RS-001 and RIS-2005-29.

### Technical Evaluation

The third criterion, which relates to an increase in RCS inventory, is violated if the inadvertent operation of ECCS or CVCS malfunction that increases reactor coolant inventory develops into a more serious event (e.g., a Condition III or IV event) without the occurrence of another, independent fault. This can occur in plants that are equipped with ECCSs capable of pressurizing the RCS to levels greater than the opening setpoint pressures of any of their pressurizer relief or safety valves. Such ECCSs typically employ charging pumps in a safety injection mode. In these plants, this event, a Condition II event, can become a SBLOCA, a Condition III event, if the ECCS flow fills the pressurizer and a pressurizer relief or safety valve opens, discharges water, and then fails to close.

In its EPU application, the licensee claims that the St. Lucie 1 HPSI pumps are not capable of injecting water into the RCS at normal operating pressure. Consequently, an analysis of this event is not in the EPU application or in the St. Lucie 1 licensing basis. However, the EPU application contains a proposal to revise the St. Lucie 1 TSs to add three positive-displacement charging pumps to the ECCS. In fact, the current St. Lucie 1 ECCS configuration already includes these charging pumps. Therefore the staff asked the licensee to provide analyses for the inadvertent operation of ECCS and CVCS malfunction that increase reactor coolant inventory to show that the pressurizer will not fill and cause the PORVs to relieve water before the operator can shut off the charging flow.

The licensee provided an analysis of a conservative combination of the inadvertent operation of ECCS and the CVCS malfunction events (Reference 50) (Reference 51). The analysis was reviewed by the staff and audited. The licensee conservatively assumed that all three charging

pumps would be injecting into the RCS. Normal plant alignment would have one charging pump running and one in auto and one in manual. The flow from each charging pumps is 49 gpm for a total of 147 gpm. The analysis results showed that more than 10 minutes are available for operator action, from the receipt of the high pressurizer level alarm until the pressurizer reaches a water solid condition. The evaluation conservatively ignored the VCT low level alarm, which occurred before the high pressurizer level alarm.

In both the inadvertent operation of ECCS and the CVCS malfunction events, the RCS pressure is at or above nominal pressure. Only the charging pumps can deliver flow at that pressure. The relatively low charging flow fills the pressurizer at a rate that allows time for the operator to end the event by ending the charging flow.

The inadvertent opening of a pressurizer relief valve, in LAR Attachment 5, Section 2.8.5.6.1, causes the RCS to depressurize. The reduced RCS pressure allows the HPSI pumps to deliver water to the RCS. Therefore, the inadvertent opening of a pressurizer relief valve could fill the pressurizer at a faster rate than the inadvertent operation of ECCS. In fact, the analysis results indicate that the inadvertent opening of a pressurizer relief valve would be more limiting than the inadvertent operation of ECCS with respect to pressurizer fill rate and satisfaction of the third acceptance criterion, which prohibits the event from becoming an event of a more serious class of events.

### Conclusion

The NRC staff reviewed the licensee's analysis of inadvertent operation of ECCS and the CVCS malfunction event at power and concluded that the licensee's analyses were performed using previously approved analytical methods. The staff concluded that the plant will continue to meet the SRP acceptance criteria, particularly with regard to the possibility that the event might develop into a more serious event, following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the inadvertent operation of ECCS and the CVCS malfunction at power event.

### 2.8.5.6 Decrease in Reactor Coolant Inventory

#### 2.8.5.6.1 Inadvertent Opening of Pressurizer Pressure Relief Valve

### Regulatory Evaluation

A pressurizer relief valve could be opened when a spurious opening signal is generated by a fault in a pressure sensor that controls the valve. It could also be opened as the result of an operator error. The NRC's acceptance criteria are based upon:

- (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs;
- (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs; and



- (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded.

The St. Lucie 1 construction permit was issued before the promulgation of these GDC. The licensee discusses the St. Lucie 1 plant design, in terms of the requirements of each of these GDC, in the St. Lucie 1 FSAR Section 3.1, *Conformance with the General Design Criteria*, and in the LAR Section 2.8.5.1.2.1. For further discussion, by the staff, see Section 2.8.5.0 in this SE.

The inadvertent opening of a pressure relief valve is classified as an AOO, or ANS Condition II event. As an AOO, the inadvertent opening of a pressure relief valve is required to meet the following AOO analysis acceptance criteria:

- (1) Pressures in the RCS and MSSS are less than 110 percent of design values.
- (2) Fuel cladding integrity is maintained by ensuring that SAFDLs are not exceeded.
- (3) The event does not generate a more serious plant condition without other faults occurring independently.

The NRC staff's review covered (1) the sequence of events, (2) the analytical model used for analyses, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. Specific review criteria are contained in SRP Section 15.6.1, and other guidance is provided in Matrix 8 of RS-001.

#### Technical Evaluation

The inadvertent opening of a pressure relief valve causes RCS inventory and pressure to decrease. This results in a degradation of thermal margin that could lead to DNB. A reactor trip is expected from the TM/LP trip signal. The low pressurizer pressure reactor trip is available, as a backup.

The inadvertent opening of a pressure relief valve, by definition, meets the first AOO analysis acceptance criterion. The licensee has provided analyses to show that the SAFDLs are not exceeded (second AOO analysis acceptance criterion), and that the event would not develop into a more serious event (third AOO analysis acceptance criterion) by causing the relief valve to stick open and creating a SBLOCA at the top of the pressurizer.

The RCS depressurization that is caused by an inadvertent opening of a pressurizer relief valve could result in a violation of the SAFDLs. The RPS is designed to prevent the occurrence of DNB by automatically tripping the reactor via the TM/LP trip function. Analysis of the inadvertent opening of a pressure relief valve is one of the AOO analyses that are used to verify the effectiveness of the TM/LP calculated setpoint.

The LAR presents an analysis of this event to show that the SAFDLs are not exceeded. At the staff's request, the licensee provided another analysis to show that the event would not develop into a more serious event.

Both analyses of inadvertent opening of a pressurizer relief valve event were performed using the approved S-RELAP5 code. This code calculates neutron power, fuel thermal response, surface heat transfer, and coolant flow rates, temperatures, and pressures, and estimates the time of mDNBR. The core fluid conditions and average rod surface heat flux were then used by the approved XCOBRA-IIIC code to calculate the mDNBR.

The analysis to demonstrate the SAFDLs are not exceeded was based upon the assumption that both pressure relief valves are spuriously opened. This is a very conservative assumption, since there is no single fault that would cause both valves to open. In addition to the excessive relief rate, the analysis was performed at BOC HFP conditions, maximum TS core inlet temperature and minimum RCS flow rate, in order to yield a very low mDNBR.

The analysis results indicate that the mDNBR, reached less than 40 seconds after the pressure relief valves are opened, is 1.350, and this value is greater than the DNBR safety limit (1.164).

At the staff's request, the licensee provided an analysis to demonstrate the event would not develop into a more serious event. This analysis was based upon the opening of only one pressure relief valve. This is consistent with the definition of an AOO, since it is the expected result of a single fault in the relief valve control system. It is also conservative, since the smaller relief rate would permit the safety injection system to fill the pressurizer sooner.

If action is not taken to terminate the RCS depressurization, by either closing the pressure relief valve or its block valve, then the safety injection system will be actuated by the low pressurizer pressure RPS signal. The ECCS flow, which includes flow from three positive displacement charging pumps, could fill the pressurizer, open the pressure relief valves, and cause them to discharge water. The pressure relief valves are not qualified for water relief. If they discharge water, then they must be assumed to fail to close. Thus, the scenario begins with an ANS Condition II event (i.e., an inadvertent opening of a pressurizer relief valve), and develops into an ANS Condition III event (i.e., a SBLOCA at the top of the pressurizer). This would be a violation of the third AOO analysis acceptance criterion that requires that the event must not generate a more serious plant condition without other faults occurring independently.

The inadvertent opening of a pressurizer relief valve analysis was based upon the assumption that no operator actions are taken. The analysis results (Reference 52) indicate that:

- (1) A reactor trip signal is generated when the TM/LP setpoint is reached, at 1 minute (this is later than the previous, DNB analysis, since only one pressure relief valve is open).
- (2) The safety injection system is actuated when the pressurizer pressure falls to the LPSI system setpoint, at 107 seconds. The pressurizer pressure continues to fall, throughout the transient, and the falling RCS backpressure leads to an increasing HPSI delivery rate.
- (3) The pressurizer water volume decreases, as steam is relieved through the pressurizer relief valve. The rate of decrease accelerates when the reactor is tripped, and continues until HPSI water begins to enter the RCS. Then the pressurizer water volume begins to increase.
- (4) The pressurizer fills at 445 seconds.

This event, when viewed from the mass addition perspective, can be evaluated in two phases: (1) an inadvertent opening of a pressurizer relief valve, followed by (2) an inadvertent ECCS actuation.

In the first phase, this event can be mitigated by closing the open pressurizer relief valve. If the valve cannot be closed, then its block valve can be closed. Closing a pressurizer relief valve is a simple, prompt action that does not require a reference to written procedures. In December 2011, the licensee demonstrated this operation in a simulator exercise, which was conducted as part of another EPU application. A pressurizer relief valve opened, the operator checked the pressure channels and determined the cause was one failed pressure channel, and closed the valve. The operation took less than 10 seconds.

If the operator does not close the pressurizer relief valve before the safety injection system is actuated, at 107 seconds, the event enters the second phase. In the second phase, actuation of the safety injection system is added. It becomes necessary to shut off the charging flow as well as close the open pressurizer relief valve. The HPSI flow, if not terminated by the operator, will end when the RCS is pressurized by the ECCS flow to the shutoff head of the HPSI pumps. The analysis results indicate that the operator has 445 seconds to close the open pressurizer relief valve, and to shut off the charging flow. If the operator closes the pressurizer relief valve early (i.e., shortly after the safety injection system is actuated), then the RCS depressurization will stop, and there will be little or no safety injection delivery. The pressurizer fill rate will be determined mainly by the charging flow rate. This will increase the amount of time that is available to shut off the charging flow.

If, for example, the operator closes the pressurizer relief valve at the time that safety injection is actuated, then there will be no safety injection delivery according to the analysis results since the RCS pressure will not have depressurized to below the shutoff head of the HPSI pumps. Meanwhile, the pressurizer level will have dropped by about 300 ft<sup>3</sup>. Therefore, the time to fill the pressurizer, under these circumstances, would be greater than the time predicted by the inadvertent ECCS actuation analysis (Reference 50), which is based upon a higher, nominal pressurizer level. The staff estimates that, at 147 gpm, it would take the three positive displacement pumps about 9 minutes to add 300 ft<sup>3</sup> to the pressurizer. Therefore, the time available to the operator to shut off the charging flow would range from 445 seconds, if the pressurizer relief valve is not closed, to more than 22 minutes (greater than 832 seconds (Reference 50) + 9 minutes) if the valve is closed at the time that safety injection is actuated. Similarly, if water were to be added to the pressurizer at a constant rate of 147 gpm, the time to fill the pressurizer (i.e., from 700 ft<sup>3</sup> to 1532.5 ft<sup>3</sup>) would be 25 minutes.

The staff has observed the licensee's operator close an open pressurizer relief valve in less than ten seconds. Closing the valve within 107 seconds ends the transient. Closing the valve after 107 seconds would slow the rate of ECCS delivery and extend the time it would take to fill the pressurizer. The operator could then terminate the charging flow during that extended time.

If the operator does nothing, then the pressurizer will fill in 445 seconds. This is the most pessimistic scenario. The staff does not deem this to be a reasonable outcome since it requires the operator to take no action at all for more than 7 minutes. Therefore, the staff agrees that the licensee's analysis of the inadvertent opening of a pressurizer relief valve event shows that all the AOO acceptance criteria are satisfied.

Furthermore, the staff is aware that the inadvertent opening of a pressurizer relief valve analysis, when extended beyond the time of reactor trip, becomes a mass addition event that could be more limiting than either of the mass additions events specified in RG 1.70. For St. Lucie 1, it is the more limiting scenario. The staff will further consider the inadvertent opening of a pressurizer relief valve as a mass addition event on a generic basis.

### Conclusion

The NRC staff has reviewed the licensee's analyses of the inadvertent opening of a pressure relief valve event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the RPS and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC 10, 15, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the inadvertent opening of a pressure relief valve event.

#### 2.8.5.6.2 Steam Generator Tube Rupture

### Regulatory Evaluation

A SG tube rupture (SGTR) event causes a direct release of radioactive material contained in the primary coolant to the environment through the ruptured SG tube and main steam condenser, the MSSVs, or the ADVs. RPS and ESFs are actuated to mitigate the accident and restrict the offsite dose to within the guidelines of 10 CFR 50.67. The NRC staff's review covered

- (1) Postulated initial core and plant conditions
- (2) Method of thermal and hydraulic analysis
- (3) The sequence of events
- (4) Assumed reactions of reactor system components
- (5) Functional and operational characteristics of the RPS
- (6) Operator actions
- (7) The results of the accident analysis

The NRC staff's review of the SGTR focused on the thermal and hydraulic analysis for the SGTR in order to: (1) confirm that the faulted SG would not overfill; and (2) determine whether the calculated mass releases, which are input to the dose analysis, would be conservative (i.e., would lead to the highest dose releases). The prevention of SG overfill is necessary in order to keep the main steam lines intact, which prevents the dumping of radioactive liquid into the environment. It also validates the SGTR mass release analysis assumption that only steam is released.

The review criteria for the SGTR are provided in SRP Section 15.6.3. Additional guidance is provided in SRP 15.0.1, "Radiological Consequence Analyses Using Alternative Source Terms," and in RG 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors". The additional guidance is relevant to St. Lucie 1, since the radiological consequence analyses discussed in LAR Attachment 5, Section 2.9 are based upon an alternative source term (AST). Accordingly, the NRC staff has reviewed the licensee's

analyses in order to determine whether there is reasonable assurance that the SGTR analysis, which provides input to the radiological consequences analyses, is appropriately conservative.

Other applicable regulations are:

- (1) 10 CFR 50.34, "Contents of construction permit and operating license applications; technical information," requires that safety analysis reports be submitted that analyze the design and performance of SSCs of the facility with the objective of assessing the risk to public health and safety resulting from operation of the facility and including determination of the margins of safety during normal operations and transient conditions anticipated during the life of the facility, and the adequacy of SSCs provided for the prevention of accidents and the mitigation of the consequences of accidents. As part of the licensing application process, licensees perform safety evaluation to ensure that their safety analyses remain bounding or continue to meet the applicable acceptance criteria for the licensing application conditions. To achieve the goals, licensees confirm that key inputs (such as neutronic and thermal hydraulic parameters) to the safety analyses are and will remain conservative with respect to the current design bases. If key safety analysis parameters are not bounded, a reanalysis or re-evaluation of the affected transients or accidents is performed to ensure that the applicable acceptance criteria are satisfied.
- (2) RG 1.183, Regulatory Position 1.3.2 states that an analysis is considered to be affected if the proposed modification changes one or more assumptions or inputs used in that analysis such that the results, or the conclusions drawn on those results, are no longer valid.
- (3) RG 1.183, Section 5.1.3 states that the numeric values that are chosen as inputs to the analyses should be selected with the objective of determining a conservative postulated dose.

#### Technical Evaluation

A SGTR accident results in the passage of radioactive reactor coolant into the shell side of the SG through a ruptured SG tube, and ultimately, into the atmosphere. Therefore, the SGTR analyses for the proposed power uprate were performed to show that the resulting onsite and offsite doses would not exceed the allowable guidelines, and that there was sufficient margin available to provide reasonable assurance that the SG would not overfill.

The margin-to-overfill (MTO) and steam release analyses of an SGTR event are used to validate the assumption, in the dose analysis, that the SG would not overfill and to support the assumption that only steam would be released during an SGTR event. The steam release analysis is used to calculate the steam releases from the SGs that are input values in the dose analysis that is used to show that the applicable dose limits are met. The NRC staff's evaluation of the dose analysis is documented in Section 2.9 of this SE.

##### 2.8.5.6.2.1 SG MTO Analysis

This analysis, discussed in LAR Attachment 5, Section 2.8.5.6.2, calculates the steam releases to atmosphere, which are input to the radiological doses analyses. In the analysis, the licensee assumes that no AFW is delivered to the affected SG, which results in a relatively low shell-side

water inventory in the affected SG. This assumption leads to a conservative over-prediction of the concentration of activity in the affected SG since there would be less dilution of the RCS activity in the tube break flow. However, this assumption would not be conservative with respect to the MTO since it results in a lower inventory of water in the secondary side of the affected SG. The staff judged that it would not be acceptable for the MTO analysis. If the affected SG fills with water (i.e., overfills), then the water could spill into the steam lines. The weight of this water could cause the steam line(s) to break, and discharge water into the atmosphere. Water releases have a significantly greater concentration of radioactive material when compared with that of the steam releases that are assumed in the dose analysis. The result would be higher radiological releases. Such a water discharge would invalidate the SGTR radiological dose analysis.

The NRC staff requested an analysis performed with an accepted computer code and based upon a conservatively biased combination of plant initial conditions that would yield a minimum margin to SG overfill. The licensee stated that the MTO analysis was performed with the NRC-approved S-RELAP5 code which modeled the key primary and secondary system components, RPS and ESFs actuation trips and core kinetics. In addressing its compliance with the conditions specified in the SER approving the use of S-RELAP5, the licensee provided the following information (Reference 53):

- The nodalization of S-RELAP5 used for the SGTR analysis was specific to St. Lucie 1 and the method used was consistent with that in the NRC-approved EMF-2310 (Reference 42). Nodalization diagrams used for the analyses of the non-LOCAs for the EPU were shown in Figures 2 through 4 of the licensee's analysis (Reference 53). The normal non-LOCA model lumped all of a SG's tubes together. For the SGTR analysis, the computer code explicitly modeled one SG tube, with the remainder lumped together. The rupture model was a double-ended guillotine break in one tube, just above the tube sheet.
- In the analysis, the parameters and equipment states were chosen to provide a conservative calculation of the MTO for the affected SG, at the time the operators terminate AFW flow to the affected SG. The adequacy of the assumptions for key parameters is discussed in the following section, "Initial Conditions."
- The S-RELAP5 code assessments (Reference 42) validated the ability of the code to predict the response of the RCS response during transients including the SGTR events.

The SGTR analyses did not model operator actions to cooldown and depressurize the RCS, equilibrate RCS and affected SG pressures, and terminate break flow. The analyses predicted a break flow rate to the time that operators terminated AFW to the affected SG, based on a much larger pressure difference between the RCS and affected SG that would occur when operators initiated EOP actions to stabilize and terminate the break flow.

The SGTR event was defined as a double-ended break of a single SG tube, at the cold-side of the U-tube, at the top surface of the tube sheet above the SG outlet plenum. A cold-side break would produce a higher total break flow rate than would a hot-side break. The higher break flow is conservative for the SG overfill analysis. A LOOP was assumed to occur at the time of reactor trip, actuated by the TM/LP trip signal, since the lack of RCS pump flow would degrade primary side to secondary side heat transfer, which would slow the rate of RCS depressurization and keep SG tube break flow high.

The staff concluded that the licensee's use of the approved S-RELAP5 code for the SGTR analysis is adequate and acceptable.

#### *Initial Conditions*

The analysis used conservative values of the plant initial conditions that resulted in a minimum MTO. The values used in the analysis were discussed in Table 2 of the licensee's analysis (Reference 53). The table provided information for each key parameter: the nominal value, uncertainty, analysis value, and rationale for the selection of the value used in the analysis. The analysis was performed with the power level based on the proposed EPU power level plus calorimetric uncertainties. Various initial parameters were set at nominal values plus uncertainties to minimize the MTO. These parameters included the initial RCS pressure, pressurizer water flow level, charging temperature, safety injection temperature and safety injection actuation signal setpoint. Maximum flow for two HPSI pumps and maximum flow for three charging pumps were assumed to offset break flow and maintain RCS inventory and pressure. A higher RCS pressure produced a higher break flow rate that resulted in a reduced MTO at the time that the operator terminated the AFW to the affected SG. The AFW actuation signal was set at a value that was based on the nominal setpoint plus uncertainty. This assumption was conservative with respect to the MTO since an earlier AFW start time resulted in a higher integrated AFW, which would decrease the affected SG pressure, resulting in an increase in the break flow and the SG water level.

The setpoints of the MSSVs in both the affected and intact SGs were based on the nominal setpoints minus 3 percent uncertainty. The use of lower MSSV setpoints on the affected SG would maintain a lower affected SG pressure and maximize break flow after reactor trip as well as increase AFW flow, which would reduce the MTO.

The SG water level is controlled by the plant SG level control program. SG water level is higher at the lower power levels. The analysis used the initial SG water level corresponding to 85 percent of the proposed EPU level. As discussed in the response to RAI SRXB-53, the licensee confirmed that based on the power history of St. Lucie 1 for each of the last two cycles, the power level corresponding to one-side 95/95 percent probability was greater than 85 percent power level. Also, the licensee's analysis (Reference 53) showed that the MTO was not sensitive to the initial SG water level. The MTO was more sensitive to the AFW flow. A high AFW flow was used, assuming the worst single failure was an open flow control valve for the turbine-driven AFW pump, feeding the affected SG. Basically, the AFW flow for 15 minutes from the time of reaching the AFW actuation system reset setpoint, along with the break flow, determined the minimum MTO.

#### *Single Failure Consideration on turbine-driven AFW*

The analysis assumed that flow from both a motor-driven and turbine-driven AFW pumps was injected to the affected SG up to the high reset level (based on the nominal value plus uncertainty discussed in Table 2 of the licensee's analysis (Reference 53)). The AFW flow rates to the affected SG were shown in Table 4 of the licensee's analysis (Reference 53), which included an uncertainty bias high. The AFW reset logic would prevent AFW flow to the affected SG when the SG was above the setpoint. The use of a high reset setpoint resulted in a high integrated AFW flow to SG and minimized the MTO. As discussed in the response to RAI SRXB-7 of the licensee's analysis (Reference 53), the analysis assumed that the single failure

used was a failure to close one AFW flow control valve on the affected SG. Specifically, the valve was assumed failed open on the turbine-driven AFW pump after reaching the AFW actuation signal reset. The AFW control valves normally would open on AFW actuation signal and close at AFW actuation signal reset setpoint. Above a high value of the reset level (based on the nominal reset point plus uncertainty), turbine-driven AFW at a constant maximum flow rate was assumed to inject to the affected SG due to a single failure consideration. The turbine-driven AFW flow was terminated by operators with a delay time of 15 minutes. The increased AFW flow from the single failure would reduce the MTO.

Based on the above discussion, the NRC staff found that the values of the key parameters and single failure assumed in the analysis were conservative, and resulted in the minimum MTO.

### *Operator Actions*

Table 5 of the licensee's analysis (Reference 53) listed the following key operator actions in St. Lucie 1 EOPs for the SGTR event relevant to MTO:

- Trip the turbine and locally close both main steam isolation valves;
- Verify that at least one SG level is being restored to a range of 60 percent to 70 percent of the NRS by using FW or AFW;
- Maintain RCS average temperature between 525 °F and 535 °F and SG pressure between 835 psig and 915 psig by using the SBCS or opening the ADVs. The ADVs can be locally opened;
- Verify every 15 minutes to assure that the unisolated SG water level is being restored to 60 percent to 70 percent of NRS. For a high SG level, the level is reduced by controlling or stopping AFW, lowering RCS pressure, or by steaming with ADVs. The actions for water level control would prevent the SG level from overfilling;
- Cooldown the RCS to less than 510 °F using SBCS, all ADVs, motor-driven and turbine-driven AFW pumps by releasing steam from and injecting AFW to the least affected SG;
- Depressurize RCS using pressurizer sprays, PORVs or reactor coolant gas vent system to maintain RCS below 930 psia and within 50 psia of most affected SG;
- Isolate the most affected SG and maintain pressure less than 915 psig using MSIV bypass or ADVs;
- Cooldown to SDC using SBCS or ADVs; and
- Maintain isolated SG water less than 90 percent NRS.

The MTO analysis did not model the above operator actions to control SG water level, cooldown and depressurize the RCS, equilibrate RCS and affected SG pressures, and terminate break flow. The NRC staff agreed with the licensee that the MTO analysis was conservative since it predicted (1) a conservative break flow rate relative to that which would occur when operators initiate EOP actions to equilibrate RCS and affected SG pressure to terminate the break flow to the affected SG, and (2) conservative SG water levels for both intact and affected relative to that would occur when operators take EOP actions to control SG water level in the range of 60 percent to 70 percent of NRS.

The only operator action directly accounted for in the MTO analysis was termination of turbine-driven AFW flow to the affected SG following AFW actuation signal reset when the affected SG NR level reached a high reset point, plus a 15-minute delay time for operator



actions. Since the AFW actuation signal reset logic would prevent AFW flow to the affected SG when the nominal SG level was above a nominal setpoint, the value used in the analysis was a nominal value plus uncertainty, resulting in a greater amount of the AFW injected to the affected SG. The assumption was conservative with respect to the MTO and was acceptable. The use of operator action time of 15 minutes was acceptable based on adequate mitigation procedures discussed in the response to RAI SRXB-57 as follows:

- In the St. Lucie 1 EOPs, the acceptance criteria of the Safety Function Status Check Sheet, including SG water level, is required to be verified every 15 minutes;
- EOP-4 for SGTR includes steps for ensuring that SG levels are maintained within specified limits;
- EOP-99, Appendix R, provides instructions to isolate AFW by ensuring AFW pump discharge isolation valves are closed and that the steam supply to the turbine-driven AFW pump is isolated (Either one of these actions is sufficient to terminate turbine-driven AFW flow to the affected SG);
- Isolation of the affected SG is considered a critical task in operator training and is required in order to satisfactorily complete the training in the STGR scenario; and
- Isolation is accomplished via closing of valves that can be operated from the control room.

The licensee also confirmed that the AFWS and the main steam supply for the turbine-driven AFW pump were safety-grade systems. In the MTO analysis, it was assumed that ADVs could be operated for RCS cooldown. Although the instrument air system required for ADV operation is not a safety-grade system, St. Lucie 1 EOPs provided guidance to require that operator action be taken to manually open the ADVs locally. Since opening of the ADVs by operators locally did not rely on the non-safety related instrument air system, the NRC staff determined that this mode of operation of ADVs was acceptable for cooldown during an SGTR event.

### *Results of the Analysis*

The results of the licensee's analysis (Reference 53) showed that for the total SG secondary side volume of 7733.7 ft<sup>3</sup>, the maximum affected SG liquid volume at the time of 28 minutes, when operators terminated the turbine-driven AFW flow to the affected SG, was calculated to be 5879.1 ft<sup>3</sup>. Thus, the MTO was 1854.6 ft<sup>3</sup>. This MTO, calculated with conservative break flow, would be sufficient to prevent SG overfill. The licensee indicated that the break flow rate at time of termination of AFW flow was about 42 pounds mass per second (lbm/sec). Assuming continuation of this break flow up to 45 minutes into the transient with no other operator action, the licensee calculated that the MTO would remain greater than 1000 ft<sup>3</sup>.

Based on its review of the MTO analysis, the NRC staff found that (1) the licensee's MTO analysis had adequately accounted for operation of the plant at the proposed EPU conditions, (2) the analysis was performed with an NRC-approved computer code, (3) the initial conditions and assumptions used in the analysis were conservative, resulting in a minimum MTO, (4) the calculated MTO of greater than 1000 ft<sup>3</sup> at 45 minutes into the transient with no other operator action than terminating the turbine-driven FW, and (5) the St. Lucie 1 EOPs provided instructions for operators to periodically monitor and reduce SG water level within the specified limits for SG overfill prevention. Therefore, the NRC staff concluded that the MTO analysis was acceptable to show MTO during an SGTR event for the EPU application.

#### 2.8.5.6.2.2 Steam Release Analyses for an SGTR Event

LAR Attachment 5, Section 2.8.5.6.2 discussed the calculation of the steam releases to the atmosphere for input to the radiological dose analyses for the SGTR event. During the course of the review, the NRC staff requested the licensee to provide additional information related to computer code, initial conditions, mitigation procedures and operator training program in support of acceptance of the mass release analysis. In response, the licensee provided the following requested information (Reference 43) (Reference 45).

The licensee indicated that the cooldown rate, the total break flow, and steam releases from the affected and intact SGs were calculated by the approved S-RELAP5 code. Its use is discussed in EMF-2310(P)(A) (Reference 42). Therefore, the NRC staff has accepted this code for use in the SGTR analysis.

Subsequent to the isolation of the affected SG, the ADV in the intact SG was used to cool down the RCS to the SDC entry conditions. An energy balance was performed to determine the steam releases from 45 minutes to SDC condition. The SDC entry conditions are defined as  $(325^{\circ}\text{F} \pm 25^{\circ}\text{F})$  and 267 psia. For calculating conservative steam releases, the analysis assumed cooldown to a temperature of  $212^{\circ}\text{F}$ . Since the energy balance considered the energy contribution from decay heat, heat structures and the fluid within the primary and secondary systems, the NRC staff determined that the energy balance was acceptable in determining the steam releases. Steam releases for the period between the affected SG isolation and the RCS cooldown to  $212^{\circ}\text{F}$  were calculated for various cooldown rates (100, 38, 30, 25, and  $20^{\circ}\text{F/hr}$ ). The maximum calculated steam releases were selected for input to the dose analyses. The staff has accepted this approach.

##### *Initial Conditions*

The steam release analysis for a SGTR event was based upon a double-ended break of a single SG tube at full power. A LOOP was assumed at reactor trip. This assumption resulted in the loss of SBCS for removal of decay heat. Heat removal from the RCS was achieved by actuation of the SG MSSVs until the time of operator action, at which time the ADV in the intact SG was used for heat removal, resulting in steam releases to the atmosphere. If offsite power were available, the steam would have been routed to the condenser by the SBCS. The analysis used conservative values of the plant initial conditions that resulted in maximum steam releases. The values used were listed in Table 8 of the licensee's analysis (Reference 53). The table provided information for each key parameter: the nominal value, uncertainty, analysis value, and rationale for the selection of the value used in the analysis. The analysis was based on the proposed EPU power level plus calorimetric uncertainties. A higher power level would maintain a higher RCS pressure, which would produce a higher break flow rate. The higher power level would also produce a higher stored energy and decay heat, which would produce higher steam releases. Various initial parameters were set at nominal values plus uncertainties to maximize the mass release. These parameters include initial RCS pressure, pressurizer water flow level, charging temperature, safety injection temperature and safety injection actuation signal setpoint. The maximum flow for two safety injection pumps and maximum flow for three charging pumps were assumed to offset the SG tube break flow and to maintain the RCS inventory and pressure. Minimum flow from one motor-driven AFW was assumed to deliver only to the intact SG in order to preclude a cooling effect in the affected SG and to maximize the steam release from the affected SG.

The setpoints of the MSSVs were based on the nominal setpoints minus 3 percent and plus 3 percent uncertainty for the affected and intact SGs, respectively. This assumption maximized the steam release from the affected SG MSSVs.

### *Operator Actions*

The licensee discussed the following key operator actions in St. Lucie 1 EOPs for the SGTR event relevant to steam releases:

- Maximize safety injection flow and ensure all charging pumps are running. (The analysis modeled the maximum HPSI and charging flow).
- Cool down the temperature in the RCS hot-leg to be less than 510 °F using ADVs locally from both SGs. This action is to reduce the pressure difference between the RCS and SGs. (The analysis modeled steam release with no operator action to reduce the pressure difference between the RCS and the affected SG to minimize the break flow rate).
- Depressurize the RCS by maintaining pressure within 50 psi of the affected SG. (The analysis did not model depressurization since the effect would be beneficial in reducing break flow.)
- Restore instrument air on LOOP. ADVs operated locally until instrument air was restored. (The analysis assumed that ADVs did not operate prior to 45 minutes.)
- Cool down the RCS to SDC condition using the ADV in the unisolated SG. (The analysis used ADV from the intact SG for cooldown.)
- Maintain the affected SG level to be less than 90 percent NRS by lowering RCS pressure. (The affected SG level did not reach 90 percent NRS by 45 minutes in the analysis. Minimizing SG inventory increased the concentration of the radioactive releases.)
- Restart the RCPs if criterion is met. (The analysis assumed natural cooldown to increase the time to SDC entry conditions.)
- Cool and depressurize the isolated SG. (The least preferred means from a radiological point of view is steaming to the atmosphere using the ADV. The analysis assumed that the cooldown to SDC entry conditions was not by steaming the affected SG to the atmosphere. This assumption was consistent with the EOP actions to cool and depressurize the affected SG by means other than steaming to atmosphere.)

Up to 45 minutes, the systems actuated during the event analysis were RPS, ESFs actuation signal for HPSI, AFW and charging, and steam line MSSVs. The licensee confirmed that all the systems discussed above were safety-grade systems. No operator action was assumed for the first 45 minutes after which the affected SG was isolated in accordance with the EOPs.

From 45 minutes to the time of SDC entry, the analysis assumed that operators would take actions to isolate the affected SG by closing the main steam isolation valves and begin to cool the plant down to SDC entry conditions by steaming through the intact SG ADV. The above operator actions with delay time of 45 minutes were acceptable based on the adequate mitigation procedure and operator training programs discussed in the response to RAI SRXB-52 as follows:

- St. Lucie 1 EOP-4, "Steam Generator Tube Rupture," provides instructions for operators to mitigate the effects of the SGTR event, initiate plant cooldown, isolate and control the affected SG, and place the plant in shutdown cooling;
- EOP-4 directs operator to isolate the most affected SG and refers to EOP-99, Appendix R;
- EOP-99, Appendix R, "Steam generator Isolation," provides instructions to isolate AFW by ensuring AFW pump discharge isolation valves are closed and that the steam supply to the turbine-driven AFW pump is isolated;
- EOP-4 directs operators to maintain level in the affected SG at less than 90 percent NRS, when the affected SG is isolated.

The licensee also indicated that isolation of an affected SG was included in licensed operator continuing training and was identified on St. Lucie's INPO-accredited licensed operator continuing training program task list at a frequency of every 2 years. The SGTR event scenario was included as a simulator training exercise and isolation of an affected SG was accomplished by implementing EOP-99, Appendix R. Every licensed operator participated in this simulator exercise during the course of the 2-year licensed operator continuing training program. In addition, there was a critical task contained in the St. Lucie training department's simulator evaluation guides and training department guidelines required satisfactory completion of critical tasks in order to receive a satisfactory grade during a simulation evaluation. Furthermore, the operator action time of 45 minutes represents an increase from the operator action time of 30 minutes, in FSAR Chapter 15.4.4.5.4.

LAR Attachment 5, Section 2.8.5.6.2 describes the calculation of the steam release for input to the SGTR dose analyses (identified herein as the reference case). Five additional cases were performed to quantify the sensitivity of the steam release to various input values for initial pressure, pressurizer level, AFW delay, safety injection temperature, charging temperature, charging actuation signal, and TM/LP trip. The initial conditions used and the results of the analyses for the reference case and five cases for sensitivity study were shown in Tables 6 and 7 of the licensee's analysis (Reference 53). As shown in Table 7, the key difference between the reference case in the LAR and the sensitivity study cases relative to dose releases was the difference in the steam releases from the affected SG. In the reference case, the results showed that from initiation of the event through 45 minutes, the contaminated steam of 182,750 lbm was released from the affected SG. The steam releases would be treated in the dose analyses as if all were at the affected SG activity level. As for the sensitivity study cases, the maximum steam releases through the affected SG were significantly lower than those for the reference case. The NRC staff agreed with the licensee that the reference case with a higher steam release from the affected SG remained bounding for dose calculations.

From 45 minutes to the initiation of SDC, several cooldown rates (100, 38, 30, 25, and 20 °F/hr) were considered. The maximum calculated steam releases, corresponding to these cooldown rates, were used as input for the dose calculations documented in LAR Attachment 5, Section 2.9.

At an audit of the St. Lucie EPU safety analyses, conducted by the staff at Westinghouse's facility in Rockville, Maryland, on February 14 and 15, 2012, the NRC staff requested the licensee to provide a discussion of the adequacy of the St. Lucie 1 procedures regarding the operator actions that would be taken to avoid SG overfill during the period from 45 minutes to the time of break flow termination, for the limiting SGTR mass release case.

In response (Reference 54), the licensee indicated that at the end of the EPU SGTR event of 45 minutes, the mass release analysis, discussed in LAR Attachment 5, Section 2.8.5.6.2, predicted an SG MTO of approximately 6,458 ft<sup>3</sup>. The SG tube break flow, through a break of 0.56 ft<sup>3</sup>, was about 26 lb/sec. The licensee calculated that, without operator action, it would take approximately 3 hours to lose the available MTO. The operator actions, required to be completed in the event of a SGTR event, were provided in St. Lucie 1 EOP-04. One of the goals of the procedure was to maintain the isolated (or affected) SG level less than 90 percent NRS. As listed in the order presented in the St. Lucie 1 EOP, any of the following methods could be used:

- Lower RCS pressure to below the isolated (or affected) SG pressure, thus enabling back flow. EOP-04 identified this as the preferred method to control isolated SG level. The back flow method could be accomplished using safety-related equipment (i.e., use of charging pumps and auxiliary spray valves to depressurize the RCS);
- Blowing down the isolated SG to the monitor storage tanks;
- Steaming the isolated SG to the condenser; and
- Steaming the isolated SG to the atmosphere via the ADVs. EOP-04 noted that this was the least preferred method to control the isolated SG level. A cautionary note was also provided in the EOP stating "Steaming the isolated SG to atmosphere should only be performed as the least resort."

In addition, the St. Lucie 1 EOPs for the SGTR event would require the operator to "Cool down the RCS to SDC condition using the ADV in the insulated SG." This cooldown step would depressurize the RCS and reduce the break flow, and make available more than 3 hours to overfill in the affected SG.

Since the sufficient instructions in the EOPs were available to control and avoid SG overfill, and since more than 3 hours was available to the operators to cool down the plant, terminate the break flow, and limit the affected SG level to less than 90 percent NRS, the NRC staff agreed that no SG overfill was predicted to occur. Therefore, the assumption that only steam would be released in the analysis for the limiting mass release case was verified. Therefore, the NRC staff concluded that the steam release provided in the EPU SGTR analysis remained bounding.

Based on its review of the mass release analyses, the NRC staff found that (1) the licensee's steam release analysis had adequately accounted for operation of the plant at the proposed EPU conditions, (2) the analysis was performed with an NRC-approved computer code, (3) the assumptions used in the analysis were conservative, resulting in maximum steam releases, (4) the St. Lucie 1 EOPs provided adequate instructions for operators to isolate the affected SG and cool down the RCS to shutdown cooling conditions, and (5) the sensitivity study showed that the reference case documented in the remained bounding, resulting in maximum mass releases. Therefore, the NRC staff concluded that the results of the steam release analyses were acceptable for use in the dose calculations during an SGTR event in support of the EPU application.

### Conclusion

Based on its review, the NRC staff found that (1) the MTO analysis was performed with an NRC-approved computer code, (2) the assumptions used in the analysis were conservative,

resulting in a minimum MTO, and (3) the results showed that the SGTR event would not result in an overfill of the SG with the ruptured tube. Therefore, the NRC staff concluded that the MTO analysis was acceptable to show that SG overfill will not occur during an SGTR event, and the assumption of the only steam releases in the dose analysis remains valid. Also, the NRC staff determined that the mass release analysis was acceptable because it was based on acceptable methods and conservative assumptions

#### 2.8.5.6.3 Emergency Core Cooling System and Loss-of-Coolant Accidents

##### Regulatory Evaluation

LOCAs are postulated accidents that would result in the loss of reactor coolant from piping breaks in the RCPB at a rate in excess of the capability of the normal reactor coolant makeup system to replenish it. Loss of significant quantities of reactor coolant would prevent heat removal from the reactor core, unless the water is replenished. The reactor protection and ECCS systems are provided to mitigate these accidents. The NRC staff's review covered:

- (1) the licensee's implementation of the methodology
- (2) the licensee's determination of break locations and break sizes
- (3) postulated initial conditions
- (4) the sequence of events
- (5) the analytical model used for analyses, and calculations of the reactor power, pressure, flow, and temperature transients
- (6) calculations of peak cladding temperature, total oxidation of the cladding, total hydrogen generation, changes in core geometry, and long-term cooling
- (7) functional and operational characteristics of the reactor protection and ECCS systems
- (8) operator actions

The NRC's acceptance criteria are based on the following:

- (1) 10 CFR 50.46, insofar as it establishes standards for the calculation of ECCS performance and acceptance criteria for that calculated performance
- (2) 10 CFR Part 50, Appendix K, insofar as it establishes required and acceptable features of evaluation models for heat removal by the ECCS after the blowdown phase of a LOCA;
- (3) GDC 4, insofar as it requires that SSCs important to safety be protected against dynamic effects associated with flow instabilities and loads such as those resulting from water hammer;
- (4) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and
- (5) GDC 35, insofar as it requires that a system to provide abundant emergency core cooling be provided to transfer heat from the reactor core following any LOCA at a rate so that fuel clad damage that could interfere with continued effective core cooling will be prevented.

The St. Lucie 1 construction permit was issued before the promulgation of these GDC. The licensee discusses the St. Lucie 1 plant design, in terms of the requirements of each of these

GDC, in the St. Lucie 1 FSAR Section 3.1, *Conformance with the General Design Criteria*, and in the LAR Section 2.8.5.1.2.1. For further discussion, by the staff, see Section 2.8.5.0 in this SE. Specific review criteria are contained in SRP Sections 6.3 and 15.6.5 and other guidance provided in Matrix 8 of RS-001.

### Technical Evaluation

#### 2.8.5.6.3.1 Large Break Loss-of-Coolant Accident

##### 2.8.5.6.3.1.1 Methodology implementation and the analytical model

The licensee's best estimate, large break LOCA (LBLOCA) analyses supporting EPU operation was performed by Areva NP and documented in ANP-2903(P) Revision 1, "St. Lucie Nuclear Plant Unit 1 EPU Cycle Realistic Large Break LOCA Summary Report With Zr-4 Fuel Cladding." The analysis was conducted in accordance with EMF-2103(P)(A), "Realistic Large Break LOCA Methodology for Pressurized Water Reactors," that received generic approval by NRC SE on April 9, 2003. EMF-2103 is a best estimate code and uses a statistical method based on order statistics to produce an estimate of the upper tolerance limit for predicted peak cladding temperature, consistent with the "high level of probability" statement contained in 10 CFR 50.46(a)(1)(i). Upper tolerance limit estimates are also produced for the maximum local oxidation and hydrogen generation, as well. The NRC SE approving EMF-2103(P)(A), Revision 0, included 13 conditions and limitations restricting its use. The licensee provided Table 3-4 in ANP-2903(P), which listed the conditions and limitations and included information to demonstrate that adherence to each had been attained. The NRC staff reviewed this information and concluded that the licensee's implementation of EMF-2103 adheres to each of the conditions and limitations.

Subsequent to its approval of Revision 0 to EMF-2103(P)(A), the NRC staff has found that certain modeling assumptions and constitutive relationships contained in the EMF-2103 methodology are not suitable for demonstrating compliance with the 10 CFR 50.46(b) acceptance criteria, as described in a draft SE dated April 3, 2007<sup>5</sup>. Therefore, the staff also considered the conditions and limitations in this draft SE, and the corresponding departures from NRC-approved EMF-2103(P)(A), Revision 0, required to adhere to these conditions and limitations. The licensee provided information to address these issues in Sections 4, "Generic Support for Transition Package" and 6, "Supplemental Information Regarding NRC Issues with the Use of AREVA RLBLOCA Methodology."

The power assumed in the analyses, 3029.1 MWt, includes 10 percent power uprate and 1.7 percent measurement uncertainty recapture (MUR) relative to the current rated thermal power. It also includes a 0.3 percent uncertainty remaining after the MUR. This departure from the previously approved methodology is acceptable because it is conservative in that the previously approved methodology permitted ranging the assumed power level, meaning that some cases could have initiated at a power level less than 3029.1 MWt had the analysis been performed using the previously approved methodology. It is also acceptable because it is

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<sup>5</sup> This SE was never formally issued, and the vendor withdrew the topical report revision that it supported. Therefore, there is no publicly available copy of this report. Nonetheless, the NRC staff has continued to use adherence to the conditions and limitations listed in this SE as a basis for its approval of requests to implement EMF-2103, Revision 0, as an interim review approach until a second revision to EMF-2103 is submitted to the NRC for review and approval. While EMF-2103(P)(A) is an acceptable evaluation model as described in 10 CFR 50.46, the NRC staff requires these deviations for plant-specific application of the methodology.

consistent with the NRC staff's position that parametrically ranging the assumed initial power level is inconsistent with 10 CFR 50.46 requirements, whereas deterministically including uncertainty in the assumed initial power level is acceptable.

The RLBLOCA analysis was performed with a version of S-RELAP5 that requires both the void fraction to be less than 0.95 and the clad temperature to be less than 900 °F before the rod is allowed to quench. During its review of EMF-2103(P), Revision 1, the NRC staff determined that the S-RELAP5 evaluation model could allow rod quench to occur once the temperature drops below the minimum film boiling temperature regardless of the void fraction in the channel. Contrarily, NUREG-0915 demonstrated that the void fraction must also be less than 0.95 for rod rewet to occur. To address this concern for St. Lucie, the licensee stated that the clad temperature must be less than the minimum temperature for film boiling heat transfer ( $T_{min}$ ) and the void fraction must be less than 0.95 before the rod is allowed to quench.  $T_{min}$  is a sampled parameter and the licensee confirmed that  $T_{min}$  was never sampled above 849.3 °F. The staff finds this departure from the methodology acceptable because the departure provides for analytic predictions that are not only more consistent with observed data, but also more conservative than predictions obtained using the previously NRC-approved methodology.

The RLBLOCA analysis was performed with a version of S-RELAP5 that limits the contribution of the Forslund-Rohsenow model to no more than 15 percent of the total heat transfer at and above a void fraction of 0.9. This departure from the approved methodology accounts for experimentally observed phenomena that appear to inhibit droplet contact with heated fuel rods at high void fractions. Thus, this departure is conservative relative to the approved methodology because it corrects for any potential to over-predict heat transfer through conduction to entrained droplets, which experimental observations have shown not to come in contact with the fuel rods at such high void fractions. The net effect of this conservatism would serve to increase the overall predicted peak cladding temperature (PCT) compared to evaluations performed using the previously NRC-approved methodology.

The analyses addressed the availability of offsite power correctly by ranging each case separately. This is acceptable because it satisfies GDC 35 of 10 CFR Part 50 Appendix A, in that each distribution type has been accounted for separately with its own set of cases, thereby addressing possible concerns associated with the mixing of two separate statistical spectra. The NRC staff finds this treatment acceptable because it is consistent with the staff's position regarding compliance with GDC 35 as noted in ANP-2834(P).

Downcomer boiling is caused by metal heat release from vessel and core barrel walls to fluid in the downcomer gap. Metal heat from the vessel lower head and structures in the lower plenum also contribute to downcomer boiling. As heat is released to the downcomer fluid, its temperature is gradually increased, eventually subcooled, and saturated boiling takes place. Voids generated by these processes displace water in the downcomer and reduce the driving head that forces water into the core during the reflood phase of a LBLOCA. This loss in head can significantly reduce the core flooding rate, and increase the peak cladding temperature.

The NRC staff has historically identified differences in results between staff confirmatory calculations and those produced using the AREVA RLBLOCA evaluation model, attributable to downcomer boiling modeling, that cause significant differences in peak cladding temperature results. As discussed in Section 1.0 of ANP-2834(P), AREVA attributes this to an underprediction of cold leg condensation efficiency. To correct for this, AREVA has identified appropriate multipliers to force fluid entering the downcomer to saturated conditions following



the deployment of the safety injection tanks. The staff finds this departure from the previously approved methodology acceptable because (1) the artificially saturated fluid conditions will conservatively reduce both the downcomer driving head and the core flooding rate, which becomes conducive to portions of the fuel remaining in a vapor-cooled environment, thus presenting a greater challenge to clad surface cooling, and (2) conditions in the downcomer following SIT discharge are expected to be slightly subcooled, meaning that assuming fully saturated conditions is conservative.

The licensee's treatment of downcomer boiling is stated to depend on the heat release model and on the ability to track steam rising through the downcomer. The heat release model in S-RELAP5 was validated by a sensitivity study on wall mesh point spacing and through benchmarking against a closed form solution. The steam tracking was validated through both an axial and an azimuthal fluid control volume sensitivity study done at low pressures. The licensee states that the studies demonstrate that S-RELAP5 appropriately predicts the delivery rate of energy to the downcomer liquid volume and contains sufficient downcomer nodalization detail to track the distribution of any steam formed. The downcomer model for St. Lucie 1 contains six axial nodes and four azimuthal nodes, the same as the base case for the sensitivity studies. The staff notes that increasing form losses between the four azimuthal sectors can lead to a later quench time. In future applications, particularly for those introducing increases to the peak LHR, the staff will require the use of non-zero form losses to assure future changes to the plant do not cause these conditions to produce higher PCTs than that for the current assumptions with zero form losses assumed. The staff is not requiring St. Lucie 1 to perform these calculations now because the highest PCT cases occur during blowdown and downcomer boiling has been shown not to have a large impact during blowdown. The AREVA studies showed that the effects of non-zero form losses served to delay the onset of reflood, but not necessarily increase the PCT. Additionally, there is more than a 500 °F margin to the regulatory limit of 2200 °F. The staff therefore finds that the licensee has appropriately considered downcomer boiling in its analyses.

The staff continues to have concerns that AREVA's omission of a model representing fuel rod swell, rupture, and pellet relocation is unjustified and possibly non-conservative. However, the St. Lucie-specific argument provided by the licensee stated that [

]. In consideration of this, and the fact that the predicted peak cladding temperatures at St. Lucie 1 do not exceed 1800 °F, the NRC staff finds that there is reasonable assurance that blowdown cladding ruptures would not occur during a postulated LOCA at St. Lucie 1, and thus the model is acceptable because it provides an acceptable representation of the LBLOCA progression without modeling a blowdown cladding rupture.

NRC IN 2009-23, "Nuclear Fuel Thermal Conductivity Degradation," describes a recently identified issue concerning the ability of legacy thermal-mechanical fuel modeling codes to predict the exposure-dependent degradation of fuel thermal conductivity accurately. Some legacy codes, including RODEX-3A, non-conservatively over-predict fuel thermal conductivity at higher burnups. A safety concern with fuel thermal conductivity degradation in a LOCA would be that fuel temperatures modeled incorrectly would affect the heat transfer to the cladding surface, causing the LOCA evaluation model to predict potentially erroneous PCTs. To correct for this issue, AREVA has applied a polynomial transformation that is used to bias the fuel pellet centerline temperature based on empirical data collected supporting the more recent RODEX4 fuel performance code.

Information provided by the licensee explained the polynomial transformation applied to the fuel centerline temperature, but did not explain how the temperature augmentation propagated out to the cladding surface. The licensee provided additional information in FPL letter L-2011-418 Attachment 1 to explain that the clad surface temperature is unaffected by the fuel centerline temperature bias because pellet power is not adjusted. The clad surface temperature is affected by changes in the heat transfer properties from the pellet surface through the gap, through the cladding, and to the coolant. The polynomial transformation does not change any of these heat transfer properties and therefore has a minor effect on the clad surface temperature. The bias does provide an adjustment to the entire fuel pellet. The licensee stated that the polynomial transformation provides a bias adjustment to the fuel centerline temperature and a sampled parameter provides a random assessment and adjustment of the centerline temperature uncertainty. These are combined and the total adjustment is achieved by iterating a multiplicative adjustment to the fuel thermal conductivity until the desired fuel centerline temperature is reached. This treatment causes an increase to the cladding heat load during the initial phases of the transient that corrects for thermal conductivity degradation and treats the uncertainty associated with the correction. The staff finds that this polynomial bias adequately accounts for fuel thermal conductivity degradation.

Consistent with NRC regulatory guidance for realistic LOCA evaluation models described in RG 1.157, "Best-Estimate Calculations of Emergency Core Cooling System Performance," the licensee uses the ANS-1979 standard for decay heat power in light-water reactors. In the analysis provided, the uncertainty for the decay heat parameter is set to zero and no sampling is done on this parameter, resulting in the decay heat being used with a 1.0 multiplier. This is a change from the EMF- 2103 evaluation model. The decay heat in the analysis is always the 1979 ANS standard for decay heat from uranium-235 with fully saturated decay chains, corresponding to infinite operation, assuming 200 MeV per fission. The infinite operation decay chain was compared to several finite decay chains that incorporated a 2-sigma uncertainty. In FPL letter L-2012-072 Attachment 4, the licensee provided a detailed comparison of the infinite case without uncertainty to various finite cases that included uncertainty in order to demonstrate that uncertainty is properly accounted for in the infinite chain by bounding the finite chains. It was shown that, 2 seconds after shutdown, the infinite chain bounds all of the finite chains. During the first 2 seconds when the infinite chain is not bounding, it was determined that the difference in energy deposited between the infinite chain and the bounding finite chain would have an insignificant effect on clad temperature because stored energy will have a much greater influence on PCT that early in the transient. The NRC staff finds this treatment of decay heat acceptable because the licensee appropriately incorporated an acceptable model identified in RG 1.157 and demonstrated that uncertainty was accounted for using a bounding method.

The licensee stated, "By procedure, FPL maintains plant documentation current, and directly communicates with AREVA on plant design and operational issues regarding reload cores. FPL and AREVA will continue to interact in that fashion regarding the use of AREVA fuel in St. Lucie 1. Both entities have ongoing processes that assure the ranges and values of input parameters for the St. Lucie Nuclear Plant Unit 1 RLBLOCA analysis bound those of the as-operated plant." These statements, together with the NRC staff's review of the results of the best-estimate LOCA analyses, provided reasonable assurance that the AREVA methodology with derivations applies to St. Lucie 1, pursuant to 10 CFR 50.46(c)(2), and that the licensee has properly applied it.

### *Determination of break locations and break sizes*

The analyses ranged in area between the minimum break area ( $A_{\min}$ ) and an area of twice the size of the broken pipe. The licensee stated that  $A_{\min}$  was calculated to be 26.7 percent of the double-ended guillotine break area. This information demonstrates that the total number of sampled cases is appropriate because the phenomenology dominating the limiting aspects of the event for all sampled break areas is consistent. That is, a certain number of sampled cases are appropriate, because the limiting results of the accident for pipe ruptures ranging from about 20 to 100 percent of the double-ended pipe rupture size are all limited by dispersed flow film boiling ahead of the quench front. If the sampled break area included a greater range (i.e., break sizes less than 20 percent of the double-ended guillotine rupture), additional phenomenology would govern the limiting events, and additional cases would be required to provide the necessary high level of statistical confidence that a bounding upper tolerance limit had been identified.

The licensee stated that the worst break location was generically addressed by deterministic studies, and determined to be in the cold leg between the RCP and the RV for the RCS loop containing the pressurizer. The NRC staff reviewed the methodology and confirmed this to be true. The method did not consider slot breaks because St. Lucie 1 does not have any loop seals with bottom elevation below the top elevation of the core. The NRC reviewed this information and confirmed that Condition 8 of the SE approving EMF-2103 was satisfied. On this basis, the NRC staff finds the licensee's conclusion that the St. Lucie 1 PCT-limiting transient is a double-ended cold leg guillotine break acceptable, because uncertainties related to break type and size were included in the modeling approach.

### *Postulated initial conditions and sequence of events*

The current rated thermal power for St. Lucie 1 is 2700 MWt plus 2 percent power measurement uncertainty. The assumed uprated reactor core power used in the RLBLOCA analysis is 3029.1 MWt. 3029.1 MWt represents the 10 percent power uprate and the 1.7 percent MUR relative to the current RTP (2700 MWt) with a remaining 0.3 percent uncertainty. The RLBLOCA analysis also assumed a SG tube plugging level of 10 percent in all SGs, a total LHR of 15.0 kW/ft (no axial dependency),  $F_Q$  up to a value of 2.161, and a nuclear enthalpy rise factor ( $F_r$ ) up to a value of 1.810 (including 6 percent measurement uncertainty and 3.5 percent control rod insertion uncertainty).

The licensee provided additional information to clarify that the SIT temperature is sampled with a uniform distribution over the range of TS temperatures. The SIT pressure is sampled over the range of SIT pressures. The provided SIT pressure surveillance data did not fall in the center of the sampled range because the SIT pressure is being increased as a part of the EPU. Adding the increase in pressure to the surveillance data places it in the center of the sampled range of pressures. The RWT temperature is not sampled; it is set to 104 °F (TS maximum plus uncertainty).

The single failure assumption was based on of the approved RLBLOCA evaluation model (EM), EMF-2103(P)(A) Rev. 0. The single failure scenario is a diesel loss with fully functional containment sprays at TS minimum temperature and pumped ECCS injection at TS maximum temperature. Containment pressure is indirectly sampled through containment volume. A sensitivity study on the limiting case for a maximum ECCS injection scenario is provided in Section 6.3 of ANP-2903 Rev. 1. While the maximum ECCS scenario resulted in the same PCT

as the RLBLOCA EM single failure, the quench time and oxidation calculated were greater for the RLBLOCA EM single-failure case, therefore the RLBLOCA EM single failure remains the most limiting.

#### 2.8.5.6.3.1.2 Results

The RLBOCA analyses were performed to demonstrate that the system design would provide sufficient ECCS flow to transfer the heat from the reactor core following a LBLOCA at a rate such that (1) fuel and clad damage that could interfere with continued effective core cooling would be prevented, and (2) the clad metal-water reaction would be limited to less than would compromise cladding ductility and result in excessive hydrogen generation. The NRC staff reviewed the analyses to assure that they reflected suitable redundancy in components and features; and suitable interconnections, leak detection, isolation, and containment capabilities were available such that the safety functions could be accomplished, assuming a single failure, for LBLOCAs considering the availability of onsite and offsite electric power (assuming offsite electric power is not available, with onsite electric power available; or assuming onsite electric power is not available, with offsite electric power available). The acceptance criteria for ECCS performance, provided in 10 CFR 50.46, were used by the staff in assessing the acceptability of the AREVA EMF-2103 methodology for St. Lucie 1.

In its submittal, the licensee provided the analysis results for the best-estimate LOCA analyses at the proposed EPU conditions, which were produced in accordance with the EMF-2103 methodology. The licensee's results for the calculated PCTs, the maximum cladding oxidation (local), and the maximum core-wide cladding oxidation are provided in the following table along with the acceptance criteria of 10 CFR 50.46(b).

Parameters	Fresh UO <sub>2</sub> Fuel	Once Burned UO <sub>2</sub> Fuel	10 CFR 50.46 Limits
<b>Cladding Material</b>	Zircaloy	Zircaloy	Zircaloy
<b>Peak Clad Temperature</b>	1667 °F	1639 °F	2200 °F (10 CFR 50.46(b)(1))
<b>Maximum Local Oxidation</b>	2.5268 %	3.8793 %	17.0% (10 CFR 50.46(b)(2))
<b>Maximum Total Core-Wide Oxidation (All Fuel)</b>	0.0209 %	NA	1.0% (10 CFR 50.46(b)(3))

The licensee's analytic limiting local maximum oxidation is 3.8793 percent, and the transient oxidation contribution was shown to decrease from the BOL value to a negligible value at EOL. This result is expected because fuel is generally more susceptible to transient oxidation at the BOL. The licensee also confirmed that the sum of pre-transient plus transient oxidation remains below 17 percent at all times in life for the AREVA NP HTP fuel.

The limiting core-wide oxidation is based on the maximum values of core-wide transient oxidation computed for the case set. Because the oxidation is 0.0209 percent, there is significant margin to the regulatory limit, and the NRC staff finds that the licensee has adequately demonstrated that the core-wide oxidation will remain less than 1 percent.

#### 2.8.5.6.3.2 Small Break Loss of Coolant Accident

##### 2.8.5.6.3.2.1 Methodology implementation and the analytical model

The licensee's SBLOCA analyses supporting EPU operation was performed by AREVA NP and documented in Section 2.8.5.6.3.3.1 of the LAR, Attachment 5 (Reference 2). The analysis was conducted in accordance with EMF-2328(P)(A) Revision 0, "*PWR Small Break LOCA Evaluation Model, S-RELAP5 Based*," that received generic approval by NRC SE on March 15, 2001. The NRC SE approving EMF-2328 included 1 condition restricting its use. The NRC staff reviewed the licensee's implementation and confirmed that the condition was met.

Since March 2001, the NRC staff has identified several issues with the EMF-2328 methodology in the following areas, break spectrum, loop seal clearing, safety injection line break, and delayed RCP trip. The licensee provided a revised SBLOCA analysis in a letter dated May 27, 2011 (Reference 55). In a letter dated May 3, 2012 (Reference 56), the licensee confirmed that the May 27, 2011 analysis will be the new analysis of record. This revised analysis was conducted in accordance with EMF-2328(P)(A) Revision 0 and included additional enhancements to better reflect data and plant phenomenology. The enhancements are discussed below.

The NRC staff has observed selected break spectra based on generic geometry that does not reflect plant phenomenology that can result in significant under prediction of PCT. To address this, the licensee reanalyzed the EPU with the EMF-2328 EM using a refined break spectrum. Specifically, the break spectrum was refined in the range between [ ]. The refined spectrum addresses those break sizes that prevent SIT deployment until immediately before and after the time of PCT. The additional analysis did not reveal a more limiting case.

The NRC staff has noted that the EMF-2328 EM does not necessarily provide for a conservative representation of reactor coolant loop seal clearing. To address this issue the licensee reanalyzed the EPU with a revised method. [ ]

[ ] The revised analysis had a lower predicted limiting PCT than the original analysis. The licensee provided further clarification on this issue in In L-2012-207 dated May 3, 2012. The decrease in PCT was due in large part to the loop seal clearing treatment. The original analysis provided in Section 2.8.5.6.3.3.1 of the LAR, Attachment 5 (Reference 2) showed that an unbroken loop would clear, but only one leg which suppressed the core mixture level exposing more of the core to steam cooling and driving up the PCT. The licensee stated that only one leg of a loop clearing is not in line with examination of experimental data and analytical expectations for loop seal clearing at CE 2x4 plants and therefore provided overly conservative results. The staff finds the revised loop seal modeling approach acceptable because it increases the hydrostatic pressure in the loops and reduces core inventory levels.

Generally, this treatment will tend to increase the predicted PCT in applications; however, as is the case with the St. Lucie results, the loop seal biasing approach employed in the generic method can result in higher predicted peak cladding temperatures. [ ]

] The staff finds the revised approach acceptable because it is reflective of the available experimental data and tempers the erratic behavior observed in the break spectrum results when the original biasing method is applied. The licensee provided an analysis of a double-ended-guillotine break in an SIT line. The analysis included appropriate conservative assumptions for ECCS flow. The results showed that the SIT line break was not limiting when compared to the limiting case from the break spectrum analysis.

#### *Determination of break locations and break sizes*

The break location that results in the largest amount of inventory loss and the largest fraction of ECCS fluid being ejected out through the break is a break in the cold leg pipe on the discharge side of the RCP. This is the break analyzed by the licensee. A variety of break sizes were considered including a re-analysis with a more refined break spectrum as mentioned above. The staff finds that the licensee has evaluated a break spectrum that covers all appropriate plant phenomenology.

For the limiting break, the HPSI pumps cannot overcome the rate of inventory loss before there is significant core uncover. The slow depressurization means that SIT injection will not be able to assist with core recovery. Core recovery begins when HPSI flow exceeds that lost out the break. This tends to maximize the heatup time of the hot rod producing the maximum PCT and local cladding oxidation.

#### *Postulated initial conditions and sequence of events*

The current rated thermal power for St. Lucie 1 is 2700 MWt plus 2 percent power measurement uncertainty. The assumed reactor core power used in the SBLOCA analysis is 3029.1 MWt. The 3029.1 MWt represents the 10 percent power uprate and the 1.7 percent MUR relative to the current RTP (2700 MWt) with a remaining 0.3 percent uncertainty. The SBLOCA analysis also assumed a SG tube plugging level of 10 percent in all SGs and LOOP concurrent with reactor scram on low pressurizer pressure. The single failure criterion required by Appendix K was satisfied by assuming the loss of one EDG, leading to a single operable HPSI pump. Charging pump flow was credited in the analysis. Initiation of the HPSI system was delayed by 30 seconds beyond the time of SIAS to account for the time required for EDG startup and switching.

#### **2.8.5.6.3.2.2 Results**

The SBLOCA analyses were performed to demonstrate that the system design would provide sufficient ECCS flow to transfer the heat from the reactor core following a SBLOCA at a rate such that (1) fuel and clad damage that could interfere with continued effective core cooling would be prevented, and (2) the clad metal-water reaction would be limited to less than would compromise cladding ductility and result in excessive hydrogen generation. The NRC staff reviewed the analyses to ensure that they reflected suitable redundancy in components and features; and suitable interconnections, leak detection, isolation, and containment capabilities were available such that the safety functions could be accomplished, assuming a single failure and the LOOP. The acceptance criteria for ECCS performance, provided in 10 CFR 50.46, were used by the staff in assessing the acceptability of the AREVA EMF-2328 methodology for St. Lucie 1.

In its submittal, the licensee provided the analysis results for the SBLOCA analyses at the proposed EPU conditions, which were produced in accordance with the EMF-2328 methodology. The licensee provided a revised analysis as discussed in the above methodology section. The licensee's results at the limiting break size of 0.073 ft<sup>2</sup> for the calculated PCT, the maximum cladding oxidation (local), and the maximum core-wide cladding oxidation are provided in the following table along with the acceptance criteria of 10 CFR 50.46(b).

Parameters	EPU Analysis	10 CFR 50.46 Limits
Cladding Material	Zircaloy	Zircaloy
Peak Clad Temperature	[       ]	2200 °F (10 CFR 50.46(b)(1))
Maximum Local Oxidation	[       ]	17.0% (10 CFR 50.46(b)(2))
Maximum Total Core-Wide Oxidation (All Fuel)	[       ]	1.0% (10 CFR 50.46(b)(3))

### Conclusion

The NRC staff has reviewed the licensee's analyses of the LOCA events. The NRC staff concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and that the analyses were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the RPS and the ECCS will continue to ensure that the peak cladding temperature, total oxidation of the cladding, total hydrogen generation, and changes in core geometry, and long-term cooling will remain within acceptable limits. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC 4, 27, 35, and 10 CFR 50.46 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the LOCA.

### 2.8.5.7 Anticipated Transients without Scrams

#### Regulatory Evaluation

An ATWS event is defined as an AOO or ANS Condition II event, such as a LONF, loss of condenser vacuum or LOOP, which requires automatic protection (i.e., a reactor trip); but the required reactor trip does not occur. Since the RPS is designed to perform its function despite a single failure, the failure of the RPS is assumed to be attributed to a common cause fault.

The combination of an AOO and a common mode failure in the RPS (i.e., an ATWS) is a very low probability event. ATWS is considered as an event that is outside the plant design basis.

On June 26, 1984, the NRC staff promulgated 10 CFR 50.62, "Requirements for reduction of risk from anticipated transients without scram (ATWS) events for light-water-cooled nuclear power plants." Section 50.62 of 10 CFR requires the licensee/operators of nuclear power plants to reduce the likelihood of failure to shut down the reactor following an AOO, and to mitigate the consequences of an ATWS event, by installing equipment that is specified for each plant design. This equipment must be reliable and diverse from the existing RPS, and must be capable of being tested at power.

The NRC staff's review was conducted to ensure that the St. Lucie 1 plant is in compliance with 10 CFR 50.62 as it relates to CE plants. In addition, the NRC staff verified that the consequences of an ATWS would be acceptable. The acceptance criterion, as specified in SRP Section 15.8, is that the peak primary system pressure should not exceed the ASME Service Level C limit (3200 psig). Review guidance is provided in Matrix 8 of RS-001 (Notes 7 and 10), and in SRP Chapter 15.8.

### Technical Evaluation

The basic requirements for the PWRs manufactured by CE are specified in paragraphs (c)(1) and (c)(2) of 10 CFR 50.62 that state, in part,

"Each pressurized water reactor must have equipment from sensor output to final actuation device, that is diverse from the reactor trip system, to automatically initiate the auxiliary (or emergency) FW system and initiate a turbine trip under conditions indicative of an ATWS" (Paragraph (c)(1)), and "Each pressurized water reactor manufactured by Combustion Engineering or by Babcock and Wilcox must have a diverse scram system from the sensor output to interruption of power of the control rods" (Paragraph (c)(2)).

LAR Attachment 5, Section 2.8.5.7 states that the St. Lucie 1 plant is equipped with a safety-related DSS, designed to be diverse and independent from the RPS and to satisfy 10 CFR 50.62 requirements. The St. Lucie 1 plant is also equipped with a diverse turbine trip (DTT), which is independent of the RPS and automatically initiates a turbine trip, and a diverse auxiliary FW actuation system (DAFAS), which is diverse from the RPS and automatically initiates the AFWS. The NRC staff has previously reviewed the St. Lucie 1 designs for DSS, DTT, and DAFAS (Reference 57), and has accepted them as compliant with 10 CFR 50.62.

The EPU application indicates that the DSS, DTT, and DAFAS setpoints are unchanged. However, there was no ATWS analysis based on the EPU conditions, to verify that these setpoints continue to provide effective protection. The NRC staff requested the licensee to demonstrate that the St. Lucie 1 ATWS response at EPU conditions would meet the RCS pressure limit applicable to the ATWS event. In response (Reference 58), the licensee indicated that another ATWS evaluation (Reference 59), which was performed for St. Lucie 2, is applicable to St. Lucie 1, since both St. Lucie 1 and St. Lucie 2 are plants with CE-manufactured reactors, referred to as the 2560 MWt class of plants, and both St. Lucie 1 and St. Lucie 2 have replaced the original SGs with new SGs having similar performance characteristics.

The current ATWS analysis for the 2560 MWt class of CE plants predicts a peak RCS pressure of about 2600 psia. This is based upon a DSS/DTT setpoint of 2450 psia, which is higher than the RPS high pressurizer pressure trip setpoint; but lower than the pressurizer safety valve opening setpoint.

Since ATWS is not a design basis event, it is evaluated using more realistic assumptions and conditions. ATWS analyses in CE plants include a (delayed) reactor trip, which is demanded by the DSS. Therefore, ATWS begins to resemble realistic (i.e., less conservative) evaluations of events, especially AOOs, that are in the plants' licensing bases. The licensee evaluates the St. Lucie 1 ATWS by comparison with St. Lucie 2 ATWS, which is, in turn, evaluated by comparison with conservative analyses of certain pressurization events (e.g., loss of FW and loss of condenser vacuum) in the St. Lucie 2 licensing basis. It remains only to verify that the reactor trip, turbine trip, and AFWS actuation, from the DSS, DTT, and DAFAS, are not delayed



so long as to make them ineffective. This has been done for the current power level. The licensee has provided additional information to show that the unchanged DSS, DTT, and DAFAS setpoints continue to provide adequate ATWS protection at the higher, EPU power level. The ATWS evaluation results are summarized below:

	Case description	Peak RCS Pressure (psia)	EPU Peak RCS Pressure (psia)
1	St. Lucie 2 loss of load ATWS	2600	
2	St. Lucie 2 loss of condenser vacuum ATWS		2776
3	St. Lucie 2 loss of FW ATWS		2747
4	St. Lucie 1 loss of load ATWS		> 2776

Increasing the power level from 2700 MWt to 3020 MWt increases the loss of load ATWS peak pressure by about 176 psi (Case 2 – Case 1). The loss of FW (Case 3) does not attain as high a pressure as the loss of load. This is consistent with ATWS analysis results seen in other plants.

The peak pressure from Case 2 is adjusted to account for a small difference between St. Lucie 1 and St. Lucie 2, and the result is listed in Case 4. St. Lucie 1 has a 3 percent smaller pressurizer safety valve capacity (618,000 vs. 636,546 lbs/hr) than St. Lucie 2. St. Lucie 1 also has a 3.4 percent smaller RCS volume (11,061 vs. 11,453 ft<sup>3</sup>) than St. Lucie 2. These would tend to increase the peak RCS pressure, as compared to St. Lucie 2. The table shows this as > 2776 for Case 4. The increase in peak pressure is not quantified, since there is a large amount of margin between the St. Lucie 2 peak pressure, 2776 psia, and the pressure limit, 3200 psia. One way to estimate the potential increase in the St. Lucie 1 peak pressure, due to the St. Lucie 1 smaller RCS volume and smaller pressurizer safety valve capacity, is to consult Westinghouse's ATWS submittal (Reference 59), which contains the results of a series of sensitivity studies for a Westinghouse four-loop plant. These results indicate that decreasing the RCS volume by 10 percent could increase the peak pressure by 44 psi, and decreasing the pressurizer relief capacity by 13 percent could increase the peak pressure by 144 psi. Therefore, the peak pressure, for St. Lucie 1, would not exceed 2964 psia. This is an extremely conservative estimate, since it is not scaled down to reflect the smaller differences between the St. Lucie 2 and St. Lucie 1 RCS volume and pressurizer relief capacity values, and it does not account for the fact that the Westinghouse ATWS sensitivity cases do not model a reactor trip.

The NRC staff concluded that the results of the ATWS evaluation for St. Lucie 2, along with the plant data comparison of St. Lucie 1 and St. Lucie 2, provided reasonable assurance that the DSS with a setpoint of 2450 psia at St. Lucie 1 would provide adequate ATWS protection (i.e., the peak RCS pressure, due to ATWS would not exceed the ATWS pressure limit of 3200 psia).

The ATWS analyses did not credit the reactor trip on turbine trip. Therefore, the time of DTT had no effect upon the peak RCS pressure. The results of the analyses also showed that the AFW did not enter the SGs before the peak RCS pressure had been reached. The DAFAS also had no effect upon the peak RCS pressure. The current setpoints of the DTT and DAFAS can remain unchanged, since they have no effect on the peak RCS pressure.

## Conclusion

The NRC staff has reviewed the information submitted by the licensee related to ATWS and concludes that the licensee has adequately accounted for the effects of the proposed EPU on ATWS. The NRC staff determines that the licensee has demonstrated that the DSS will continue to meet the requirements of 10 CFR 50.62 following implementation of the proposed EPU. Additionally, the licensee's analysis has demonstrated that the current setpoints of the DSS, DTT and DAFAS were adequate to prevent the peak primary system pressure, following an ATWS event, from exceeding the acceptance limit. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the ATWS event.

### 2.8.6 Fuel Storage

#### 2.8.6.1 New Fuel Storage

## Regulatory Evaluation

Nuclear reactor plants include facilities for the storage of new fuel. The quantity of new fuel to be stored varies from plant to plant, depending upon the specific design of the plant and the individual refueling needs. The NRC staff's review covered the ability of the storage facilities to maintain the new fuel in a subcritical array during all credible storage conditions. The review focused on the effect of changes in fuel design on the analyses for the new fuel storage facilities. The NRC's acceptance criteria are based on GDC 62, insofar as it requires the prevention of criticality in fuel storage systems by physical systems or processes, preferably utilizing geometrically safe configurations. Specific review criteria are contained in SRP Section 9.1.1.

## Technical Evaluation

In a letter dated October 14, 2011, the licensee submitted HI-2094346, "Criticality Safety Evaluation of the St. Lucie Unit 1 New Fuel Storage Vault." The new fuel storage vault (NFV) is intended for the receipt and storage of fresh fuel under normally dry conditions. For analysis of the NFV, the licensee used the three-dimensional Monte Carlo code MCNP5 and assumed the EX 14x14 fuel assembly design will be the only assembly type that will be stored in the NFV. The acceptability of NFV criticality is based on fresh fuel condition. Therefore, the effects of EPU fuel depletion do not enter the new fuel storage analysis.

The NFV consists of two 4x10 arrays for a total of 80 storage locations. The calculations considered several manufacturing tolerances such as:

- Fuel assembly pitch tolerance
- Fuel enrichment tolerance
- Pellet outside diameter (OD) tolerance
- Clad ID tolerance
- Clad OD tolerance
- Guide tube ID tolerance
- Guide tube OD tolerance

All cases were performed with maximum fuel pellet density. In addition, eccentric fuel positioning was considered. The effects of the manufacturing tolerances along with eccentric fuel positioning were combined with the MCNP5 bias uncertainty to determine the total uncertainty.

The licensee determined the maximum  $k_{\text{eff}}$  values at 100 percent water density and the optimum hypothetical low density moderation occurs at 9 percent water density. The resultant maximum  $k_{\text{eff}}$  values are below the regulatory limits at a 95 percent probability, 95 percent confidence level.

### Conclusion

The NRC staff has reviewed the licensee's analyses related to the effect of the new fuel on the analyses for the new fuel storage facilities and concludes that the new fuel storage facilities will continue to meet the requirements of GDC 62 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the new fuel storage.

#### 2.8.6.2 Spent Fuel Storage

##### Regulatory Evaluation

Nuclear reactor plants include storage facilities for the wet storage of spent fuel assemblies. The safety function of the spent fuel pool and storage racks is to maintain the spent fuel assemblies in a safe and subcritical array during all credible storage conditions and to provide a safe means of loading the assemblies into shipping casks. The NRC staff's review covered the effect of the proposed EPU on the criticality analysis (e.g., reactivity of the spent fuel storage array and boraflex degradation or neutron poison efficacy). The NRC's acceptance criteria are based on

- (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents,
- (2) GDC 62, insofar as it requires that criticality in the fuel storage systems be prevented by physical systems or processes, preferably by use of geometrically safe configurations. Specific review criteria are contained in SRP Section 9.1.2., and
- (3) 10 CFR Part 50, Section 68(b) (4), that requires, in part:  
  
if credit is taken for soluble boron, the  $k_{\text{eff}}$  of the spent fuel storage racks loaded with fuel of the maximum fuel assembly reactivity must not exceed 0.95, at a 95 percent probability, 95 percent confidence level, if flooded with borated water, and the  $k_{\text{eff}}$  must remain below 1.0 (subcritical), at a 95 percent probability, 95 percent confidence level, if flooded with unborated water.

On September 29, 2011, the NRC staff issued the Interim Staff Guidance (ISG) DSS-ISG-2010-1 (ADAMS Accession No. ML110620086). The purpose of the ISG is to provide updated review guidance to the NRC staff to address the increased complexity of recent SFP

license applications. The NRC staff used ISG DSS-ISG-2010-1 for the review of the current application

## Technical Evaluation

### 2.8.6.2.1 Selection of Bounding Fuel Assembly

Section 2.3.1 of HI-2104714 provides information on fuel assembly selection. The SFP contains two fuel assembly types, CE14x14 and EX14x14. The pre-EPU conditions are applicable to both types of fuel assemblies, while the post-EPU conditions are only applicable to the EX assemblies. Section 7.1 of HI-2104714 describes the analysis to support the design basis fuel assembly selection. To determine the limiting fuel design, the licensee analyzed both fuel designs in all proposed storage configurations at applicable burnup and enrichment combinations.

The results as delineated in Tables 7.1 through 7.7 of HI-2104714 show, in most cases, the EX assembly operating under EPU conditions is bounding, although in some cases involving fresh or low burned fuel, the CE assembly shows more reactivity. In fresh or low burnup conditions where the CE assembly was shown to be more reactive, the higher reactivity may be offset by the available margin to the regulatory limit. Based on the calculations, the NRC accepts the selection of the EX assembly as the bounding fuel assembly.

### 2.8.6.2.2 Depletion Analysis

Section 2.2.2 of HI-2104714 provides information on the depletion analysis. To take credit for the reduction in reactivity due to fuel burnup, the spent fuel composition should be based on an appropriate depletion analysis with proper assumptions regarding depletion uncertainty, depletion parameters, and axial burnup profile.

#### 2.8.6.2.2.1 Depletion Uncertainty

The licensee used the two-dimensional code CASMO-4 to calculate the isotopic composition of the spent fuel as a function of fuel burnup, initial feed enrichment, and decay time. The uncertainty in the  $k_{\text{eff}}$  introduced by the depletion calculation was addressed by applying the 5 percent of the reactivity decrement from depletion as an uncertainty component in the determination of the maximum  $k_{\text{eff}}$ . The NRC staff finds that this uncertainty treatment is consistent with ISG DSS-ISG-2010-1.

#### 2.8.6.2.2.2 Depletion Parameters

ISG DSS-ISG-2010-1 provides guidance that depletion simulations should be performed with parameters that maximize the reactivity of the depleted fuel assembly. ISG-DSS-2010-1 references NUREG/CR-6665, "Review and Prioritization of Technical Issues Related to Burnup Credit for LWR fuel," which discusses treatment of depletion parameters. For fuel and moderator temperatures, NUREG/CR-6665 recommends using the maximum operating temperatures to maximize plutonium production. The HI-2104714 analysis used temperatures for the fuel and moderator that bound the proposed EPU operating conditions.

Regarding boron concentration, NUREG/CR-6665 recommends using a conservative cycle average boron concentration. The licensee used a boron concentration that bounds past and future (EPU) cycle average boron concentrations.

NUREG/CR-6665 does not have a specific recommendation for specific power and operating history. Based on the difficulty of reproducing a bounding or even a representative power operating history, NUREG/CR-6665 merely recommends using a constant power level and retaining sufficient margin to cover the potential effect of a more limiting power history. The licensee used a constant core power for the depletion calculations and the licensee retained a 1000 pcm margin to the regulatory limit.

The licensee has used two different types of integral burnable absorbers: fuel rods with gadolinium, and absorber rods containing boron carbide. NUREG/CR-6760, "Study of the Effect of Integral Burnable Absorbers for PWR Burnup Credit," showed that throughout burnup, the reactivity for fuel assemblies containing gadolinia remain lower than the reactivity for fuel assemblies without gadolinia due to the residual poison that will not completely burn out of an assembly. The licensee confirmed this conclusion by conducting studies that explicitly modeled the gadolinia in the depletion analyses, so that the fuel composition transferred to the MCNP criticality calculation on a pin-by-pin basis contained the effect of the absorber. In all cases, the results for the cases without gadolinium are higher than those with gadolinium; therefore all design basis calculations are performed without gadolinium.

#### 2.8.6.2.2.3 Axial Burnup Profiles

Section 7.12 of HI-2104714 discusses the axial burnup profiles. Three different axial enrichment distributions need to be considered at St. Lucie. The three distributions are fuel with non-enriched blankets, fuel with enriched blankets, and fuel without blankets. Separate axial profiles were established for each of the enrichment distributions. Each of the profiles was developed from both plant specific and generic axial burnup profiles. For the blanketed assemblies, both natural and enriched, the profile database consisted of a total of 744 profiles, with 620 profiles from cycles 14 through 23 and the remaining 124 for the projected EPU fuel. For non-blanketed assemblies, no plant-specific profiles were available, so 772 generic CE assembly profiles were used from NUREG/CR-6801 to determine the bounding profile. Additionally, a flat burnup profile (uniform burnup) was used for axially constant enrichment assemblies, since this profile may result in a higher reactivity at lower burnups. All applicable profiles and the flat profile were analyzed for each burnup and enrichment combination, and the result with the highest maximum  $k_{eff}$  was used for the loading curve.

For each axial node in each profile type, the nodal values were considered as a function of the assembly average burnup, and a linear expression was determined bounding the values in all profiles for the node. The profiles using this approach are shown in Tables 7.34 through 7.36 of HI-2104714. The NRC staff finds this approach acceptable because the resulting profile bounds the nodal burnups of all profiles in the database.

#### 2.8.6.2.3 Criticality Analysis

##### 2.8.6.2.3.1 Normal Conditions

The licensee utilizes high density racks that were designed with Boraflex neutron absorber inserts. The criticality analysis does not credit any remaining Boraflex neutron absorber

material. Section 1 of HI-2104714 describes the seven normal storage configurations for use throughout the St. Lucie Unit 1 pool (Case 1 through Case 7). Beyond the normal storage configurations, the licensee discussed additional conditions considered normal.

- Single fresh fuel assembly in water, which bounds the situation of a fuel assembly in the fresh fuel elevator.
- Evolutions where fuel assembly is removed from the normal storage rack for fuel assembly cleaning, inspection, reconstitution, and sipping.
- The insertion and removing fuel assemblies into and from racks.

For all cases reactivity will remain within the regulatory limits with 500 ppm of soluble boron under normal conditions.

The licensee analyzed three types of interfaces in the normal condition.

- Interfaces of different storage configuration within one rack
- Interfaces between different racks of the same type
- Interfaces between different rack types

For interfaces for different storage configurations within each rack, the licensee proposed to require that all 2x2 arrays that could be constructed from each of the storage configurations, including overlapping patterns, meet one of the analyzed cases. Interfaces between different rack types only exist between Region 1 and Region 2 racks, and cask pit rack (CPR) and Region 2 racks. The licensee analyzed both interfaces considering several interface configurations. All analyzed interface configurations retain about 1000 pcm margin to the regulatory limit and the licensee proposed rack-to-rack interface requirements in the TS.

#### 2.8.6.2.3.2 Abnormal Conditions

Section 2.5 of HI-2104714 presents the abnormal conditions considered in the analysis. The licensee considered the following abnormal conditions:

- Spent fuel temperature outside of operating range
- Horizontal dropped fuel assembly
- Vertical dropped fuel assembly (into a storage cell)
- Misloaded fresh fuel assembly
- Mislocated fresh fuel assembly
- Missing Metamic™ insert
- Incorrect loading curve

The misloading accident was determined to be the limiting abnormal condition. The bounding condition was analyzed to be a cell that is required to be empty according to analyzed cases, since this would maximize the reactivity effect of the misloaded assembly. The various configurations where this type of misload can occur are Cases 2, 4, and 7, as well as fuel inspection configurations in Cases 5, 6, and 7 as described in Sections 2.5 and 7.14. A misload in Case 7 or in any of the fuel inspection configurations will require a soluble boron level of 1500 ppm, while all other conditions require soluble boron levels of 1000 ppm to comply with the regulatory  $k_{\text{eff}}$  limit of 0.95.

The licensee stated that the dropped fuel assembly, both vertical and horizontal, is non-limiting because of the available separation between the dropped assemblies at the active regions of the fuel in the racks. The licensee stated that a mislocated fuel assembly will also be non-limiting because at least two sides of the assembly will not be facing fuel.

A single missing insert accident and an incorrect loading curve accident are considered for Cases 3 and 6. Both of these accidents are bounded by the misloading accident. The temperature accident was analyzed and was also determined to be non-limiting.

Based on the above, the NRC staff finds the licensee's evaluation of the accident conditions acceptable.

#### 2.8.6.2.3.3 Criticality Code Validation

The purpose of the criticality code validation is to ensure that appropriate code bias and bias uncertainty are determined for use in the criticality calculation. ISG DSS-ISG-2010-1 references NUREG/CR-6698, "Guide for Validation of Nuclear Criticality Safety Calculational Methodology."

NUREG/CR-6698 states that:

In general, the critical experiments selected for inclusion in the validation must be representative of the types of materials, conditions, and operating parameters found in the actual operations to be modeled using the calculational method. A sufficient number of experiments with varying experimental parameters should be selected for inclusion in the validation to ensure as wide an area of applicability as feasible and statistically significant results.

The NRC staff used NUREG/CR-6698, "Guide for Validation of Nuclear Criticality Safety Calculational Methodology," as a guide for review of the code validation methodology presented in the application. NUREG/CR-6698 outlines the basic elements of validation, including identification of operating conditions and parameter ranges to be validated, selection of critical benchmarks, modeling of benchmarks, statistical analysis of results, and determination of the area of applicability.

For the criticality calculation, the licensee used MCNP5 Version 1.40. MCNP5 is a three-dimensional Monte Carlo code. The MCNP5 calculations use continuous energy cross-section data predominately based on ENDF/B-V and ENDF/B-VI. Fuel depletion analyses during core operation were performed with a two-dimensional transport code CASMO-4 (using the 70-group cross-section library).

The licensee performed the validation of MCNP5 by comparing the calculated  $k_{\text{eff}}$  values with several different sets of critical configurations. A total of 243 critical experiments were included. The licensee determined and applied the set of bias to the storage configurations. The sources of critical configurations are the International Handbook of Evaluated Criticality Safety Benchmark Experiments, NUREG/CR-6361, "Criticality Benchmark Guide for Light-Water-Reactor Fuel in Transportation and Storage Packages," and NUREG/CR-6979, "Evaluation of the French Haut Taux de Combustion (HTC) Critical Experiment Data."

To address the fission product validation gap as well as the uncertainty associated with lumped fission products, the licensee applied an additional uncertainty in the determination of the maximum  $k_{\text{eff}}$ .

Based on the above, the NRC staff finds MCNP5 acceptable for use in the criticality safety analysis.

### Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the spent fuel storage capability and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the spent fuel rack temperature and criticality analyses. The NRC staff also concludes that the spent fuel pool design will continue to ensure an acceptably low temperature and an acceptable degree of subcriticality following implementation of the proposed EPU. Based on this, the NRC staff concludes that the spent fuel storage facilities will continue to meet the requirements of GDC 4 and 62 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to spent fuel storage.

### 2.8.7 Additional Review Areas (Reactor Systems)

#### 2.8.7.1 Loss of Decay Heat Removal at Mid-Loop Operation

### Regulatory Evaluation

NRC GL 88-17, identified actions to be taken to preclude loss of decay heat removal during nonpower operations. These actions included operator training and the development of procedures and hardware modifications as necessary to prevent the loss of decay heat removal during reduced reactor coolant inventory operations, to mitigate accidents before they progress to core damage, and to control radioactive material if a core damage accident should occur. Procedures and administrative controls were required that cover reduced inventory operations and ensure that all hot legs are not blocked by nozzle dams unless a vent path is provided that is large enough to prevent pressurization and loss of water from the reactor vessel. Instrumentation was required to provide continuous core exit temperature and reactor water level indication. Sufficient equipment was required to be maintained in an operable or available status so as to mitigate the loss of SDC or loss of RCS inventory should such an event occur during mid-loop or reduced inventory conditions.

- Provide training prior to operating in a reduced inventory condition (RV level lower than 3 ft. below the RV flange).
- Implement procedures and administrative controls that reasonably ensure that containment closure will be achieved prior to the time at which core uncover could result from a loss of decay heat removal coupled with an inability to initiate alternate cooling or addition of water to the RCS inventory.
- Provide at least two independent, continuous temperature indications that are representative of the core exit conditions whenever the RCS is in a mid-loop condition and the RV head is located on top of the RV.
- Provide at least two independent, continuous RCS water level indications whenever the RCS is in a reduced inventory condition.



- Implement procedures and administrative controls that generally avoid operations that deliberately or knowingly lead to perturbations to the RCS and/or systems that are necessary to maintain the RCS in a stable and controlled condition while the RCS is in a reduced inventory condition.
- Provide at least two available or operable means of adding inventory to the RCS that are in addition to pumps that are a part of the normal decay heat removal systems.
- Implement procedures and administrative controls that reasonably ensure that all hot legs are not blocked simultaneously by nozzle dams unless a vent path is provided that is large enough to prevent pressurization of the upper plenum of the RV.
- Programmed enhancements should be developed in parallel with the expeditious actions and they may replace, supplement, or add to the expeditious actions.

The NRC found St. Lucie 1's commitments to comply with and implement the expeditious actions in GL 88-17 acceptable and FPL confirmed that all modifications with these commitments have been completed. The FSAR Section 9.3.5.5 describes the St. Lucie 1 design and the actions taken in response to GL 88-17.

### Technical Evaluation

Mid-loop operation at St. Lucie 1 is described as fuel in the reactor and the RV water level is below the top of the flow area of the RCS hot leg nozzles on the RV.

The licensee showed the 7 procedural limitations that they currently impose during mid-loop operation and evaluated how they would be affected by EPU conditions. Those procedural limitations and the EPU impact were evaluated by the staff and are the following:

#### 1. Personnel training:

Shift personnel, by procedure, are briefed on the risks and operating restrictions associated with mid-loop and reduced inventory operations once per shift. In addition, maintenance, chemistry, health physics, and projects personnel are restricted from entering the power block during reduced inventory or mid-loop operations unless they have been adequately briefed. The licensee stated that the EPU does not impact this commitment.

#### 2. Availability of instrumentation to verify the state of RCS and cooling systems performance:

Operating procedures require that two core exit thermocouples be operable when the RV head is on the RV flange. In addition, the wide and narrow range refueling level indicators are required to be operable, as well as the tygon hose level indicator. Continuous indication and recording of the SDCS supply and return temperatures is available for operators in the control room. The licensee stated that there are no modifications that impact the operability of the core exit thermocouples, refueling level indicators, or SDC temperature indication and procedures require their operability during mid-loop operation. They also stated that the EPU does not impact their compliance with the commitment.

3. Procedures for normal and off-normal reduced inventory SDC operation and administrative controls for containment closure prior to core uncover:

Normal operating and administrative procedures are used to enter, exit, and operate in reduced inventory and mid-loop conditions. The procedures establish prerequisites and precautions to minimize the risk of a loss of decay heat removal during these conditions. Off-normal procedures are provided that direct operators to restore core cooling and RCS inventory in a rapid and controlled manner while ensuring the timely closure of containment penetrations.

4. HPSI pump and charging pump availability to maintain RCS in stable and controlled condition:

The procedure governing reduced inventory or mid-loop conditions requires at least one HPSI pump and its associated flowpath to be available for RCS inventory control. One or two charging pumps are also required to be available, depending on the elapsed time since reactor shutdown. Sufficient makeup capacity is required to replace RCS inventory lost due to steaming in the event of core boiling. As decay heat diminishes with time after shutdown, less makeup capacity is required, and after a certain point, a single charging pump could provide all the required makeup flow. The licensee stated that the higher EPU decay heat generation rate requires higher makeup water flow rates to maintain the core covered during postulated core boiling conditions. The GL 88-17 requires at least two independent means for adding inventory to the RCS. St. Lucie 1 uses one HPSI pump and one or two charging pumps. The licensee stated that plant procedures governing entry into reduced inventory or mid-loop will be revised to reflect increased decay heat associated with EPU conditions.

5. The performance of RCS time to boil, core uncover, and vent area analyses to supplement design information and support procedures/ instrumentation:

FPL maintains analyses of the time to RCS boil, time to core uncover, and required RCS vent area to preclude excessive pressurization. The analyses consider various initial conditions for RCS temperature, previous operating cycle length, RCS water volume, and time since shutdown. Results of the analyses support St. Lucie 1 operating procedures in specifying the following:

- Minimum required shutdown time prior to reduced inventory or mid-loop operation based on the available RCS vent area. The licensee stated that current analyses show that a vent area of at least 0.56 ft<sup>2</sup> is required to preclude pressurizing the reactor vessel to greater than 2.9 psig at 108 hours after shutdown. The licensee stated that, following EPU, operating procedures will be revised to require additional shutdown time prior to reduced inventory or mid-loop operation to ensure existing vent paths can accommodate the EPU condition steam flow.
- Required number of charging pumps as a function of time since shutdown. The licensee stated that currently two charging pumps are required to be operable in reduced inventory or mid-loop conditions if the reactor has been shut down 12 days or fewer and one is required to be operable beyond 12 days. The licensee stated that they will revise the procedures to require that two charging pumps be operable for a longer duration than currently required.

- Containment closure requirements based on the calculated RCS time to boil. The licensee stated that for EPU conditions the procedures will be revised to account for the increased decay heat generation after shutdown and shorter calculated times to the onset of core boiling and the administrative requirement to determine the time to core boil at least once per shift will continue to apply. The licensee also calculated various times to boil for EPU conditions. The licensee also stated that they will revise off-normal procedures that document the minimum required flow to makeup for RCS boil-off and minimum required flow to prevent boiling to higher flow requirements at the EPU conditions.
- Required secondary water level in a SG to maintain additional heat sink capacity before primary manways are removed. The licensee stated that procedures require operators to maintain a minimum of 10 percent indicated narrow range level in at least one SG before entering reduced inventory conditions and as long as the primary side SG manways are installed. The licensee does not credit the SGs as possible heat sinks but will keep the procedural requirement to maintain 10 percent narrow range secondary water level.

6. Guidelines to ensure perturbation-causing operations are minimized:

St. Lucie 1 minimizes perturbation-causing operations by the following procedural limitations:

- Concurrent switchyard maintenance is restricted.
- Concurrent maintenance and operations are prohibited on systems that could jeopardize the RCS, RCS makeup, SDCS, or support systems.
- Access to the power block is restricted to only individuals who have been briefed on reduced inventory operations.
- Two SDC loops are required to be operable in reduced inventory or mid-loop operations.
- SDC flow and RCS draindown rates are procedurally limited to preclude LPSI pump failure due to insufficient net positive suction head, suction voiding, or air ingestion due to vortex formation.
- A minimum RCS water level is maintained in part to preclude vortex formation in the partially filled RCS piping at the SDC suction line.

The licensee stated that since there are no physical configuration changes in the RCS or SDC piping at EPU conditions that there are no effects on the maximum allowable SDC or RCS draindown for or the minimum RCS water level for LPSI pump operation. They also stated that the above procedural and administrative limitations are not affected by EPU conditions

7. Controls to avoid RCS pressurization when hot leg nozzle dams are in place simultaneously:

SG primary side manway and nozzle dam removal/installation are procedurally sequenced to prevent RCS pressurization and loss of inventory in the event that SDC becomes inoperable

with fuel in the reactor vessel. The licensee stated that since there are no changes to the RCS configuration there are no changes to the sequence of installation and removal of manways and nozzle dams based on EPU conditions.

The staff reviewed the conclusions by the licensee based on their evaluation of their commitments to be in compliance with GL 88-17 licensing commitments it made and found the licensee's review and conclusions to be acceptable.

### Conclusion

The NRC staff reviewed the licensee's analyses of the effects of the EPU on the loss of decay heat removal at mid-loop operation. The NRC staff finds that the licensee's evaluation of the effect of the power uprate on the loss of decay heat removal acceptable because multiple, redundant backup systems are available to mitigate a loss of SDC, and the licensee will establish administrative controls to ensure that sufficient pump capacity to match the boil-off rate is available. Therefore, the staff finds the proposed EPU acceptable with respect to the loss of decay heat removal at mid-loop operation.

#### 2.8.7.2 Natural Circulation Cooldown

### Regulatory Evaluation

Natural circulation cooldown capabilities were identified as an issue under the auspices of NRC GL 81-21, which discussed operating experience at St. Lucie 1. St. Lucie 1 experienced a natural circulation event that resulted in the formation of a steam bubble in the upper head region of the reactor vessel. The NRC staff concern identified in GL 81-21 was the difficulty an operator would have diagnosing and controlling an RCS in a two-pressurizer configuration.

GL 81-21 requested licensees to provide the following three items. First, licensees were requested to provide a demonstration that controlled natural circulation cooldown from operating conditions to cold shutdown conditions, conducted in accordance with plant procedures, would not result in RV voiding. Second, licensees were requested to provide verification that supplies of condensate grade AFW are sufficient to support the cooldown method. Finally, licensees were requested to provide a description of the training program and revisions to the emergency procedures.

The staff reviewed the results of the analysis performed by the licensee.

### Technical Evaluation

The licensee analyzed two cases. A case with a cooldown rate of 30 °F/hr and a case with a cooldown rate of 50 °F/hr. The licensee used conservative assumptions throughout. Natural circulation evaluation demonstrates the ability to cool the plant on natural circulation to SDC entry conditions (less than 275 psia and less than 325 °F in the RCS) within a reasonable period of time. The current analysis for St. Lucie used RETRAN to show cooling at 50 °F/hr to 325 °F and then maintain temperature for 20.4 hours would allow for SDC pressure to be reached in a total time of 25.7 hours.

For EPU analysis, the CENTS code was used. The EPU analysis shows that SDC entry conditions can be reached in less than 13 hours (12.5 hours with 30 °F/hr and uses

177,000 gallons of condensate, or 11.0 hours with 50 °F/hr and uses 170,000 gallons of condensate). The EPU analysis results are lower than CLB analysis due to the use of more sophisticated analysis code with no soak time. The EPU analyses show that the condensate volume requirement in the CLB is bounding for the EPU conditions.

The analyses showed that the licensee could cool the reactor and maintain pressure control in the RCS with no voids. The analyses also showed that the current ADVs are sufficient at EPU conditions to achieve cooldown to the SDC entry conditions.

### Conclusion

The NRC staff finds the licensee's evaluation of natural circulation cooldown acceptable. The staff finds that the licensee demonstrates acceptable loop delta-temperatures can be achieved during natural circulation cooldown from EPU conditions and that sufficient condensate is available to achieve natural circulation cooldown to the RCS shutdown cooling entry conditions.

#### 2.8.7.3 Boron Precipitation

##### Regulatory Evaluation

The staff evaluation of the St Lucie 1 ECCS performance consisted of reviewing the results of the post-LOCA long-term cooling analyses at 3030 MWt (3020 MWt plus 0.3 percent uncertainty). This analysis was reviewed to show that the plant EOPs can properly mitigate the boric acid accumulation in the RCS following both LBLOCAs and SBLOCAs. The EOPs specify the latest time at which simultaneous hot and cold leg injection must be initiated to prevent further build up and boric acid precipitation following all LOCAs.

The NRC staff evaluation included an audit of the Westinghouse calculations for analyses pertaining to boric acid precipitation analyses and timing for the switch to hot leg injection. The licensee employed the NRC-approved CENPD-254 post-LOCA long-term cooling evaluation model.

In areas where the licensee and its contractors used NRC-approved methods in performing analyses related to the proposed EPU, the NRC staff reviewed relevant material to ensure that the licensee used the methods consistent with the limitations and restrictions placed on those methods. In addition, the NRC staff considered the effects of the changes in plant operating conditions on the use of these methods to ensure that the methods are appropriate for use at the proposed EPU conditions.

##### Technical Evaluation

###### *Small Break Behavior*

The licensee has provided an assessment of post-SBLOCA long-term cooling. The assessment covers the full spectrum of break sizes, from the double-ended guillotine break down to and including the 0.005 ft<sup>2</sup> cold leg break in the reactor coolant discharge leg. Control of boric acid precipitation for SBLOCAs has also been demonstrated. Of particular importance is the EOP action to initiate a cooldown for small breaks no later than one hour post-LOCA. This will ensure small breaks, which may not allow sufficient hot and cold leg injection to establish a flushing flow, will refill with injection and re-establish single phase natural circulation that will

remove the boric acid built up during the early portion of the SBLOCA. Single phase natural circulation disperses the boric acid built up in core throughout the primary system, thereby reducing the boric acid concentration well below precipitation limits following all small breaks. The staff finds the procedures and analysis of intermediate and SBLOCA boric acid control acceptable.

It is important to also note that the SDCs for St. Lucie 1 are not single-failure proof. Since the initiation of SDC is a requirement for long-term cooling following small breaks, the staff noted that this consideration was not included in the submittal. As such, the licensee verified that sufficient time is available to demonstrate that, should the SDC heat exchangers be unavailable to remove heat following small breaks, "feed and bleed" could be initiated in a timely manner to assure long-term cooling is maintained and boric acid concentrations are maintained at low levels. To address the loss of SDC for small breaks, the licensee's long-term cooling analysis demonstrated that for breaks sizes 0.013 ft<sup>2</sup> and smaller, which require SG heat removal, refill occurs with pumped injection in less than 16 hours. As such, for all small breaks less than 0.013 ft<sup>2</sup> where simultaneous injection is not guaranteed to flush the boric acid from the core, refill of the RCS disperses the boric acid that builds up in the inner vessel region. Entry into SDC was calculated to occur as early as 13.5 hours assuming a cooldown rate of 50 °F/hr for these smaller breaks. At 16 hours, if SDC is not available, "feed and bleed" can be initiated to maintain the core covered with two-phase mixture. Since the boiloff at 16 hours is 25 lb/sec, the HPSI injection rate of 523 gpm at 212 °F (70 lbs/sec) ensures the core remains covered with a two-phase mixture during the long term.

#### *Large Break Behavior*

The limiting break location for assessments of boric acid precipitation is the discharge of the RCP in the cold leg. The staff audit calculations of large breaks confirm that precipitation is precluded with a boric acid concentration of 27.5 weight % at 8.5 hours when simultaneous injection is initiated at no later than 6 hours post-LOCA. The licensee calculated a maximum acid concentration in the core of 29.1 weight % at 9.9 hours. Note that the staff performed calculations modeling the flushing flow to confirm the maximum calculated concentration when simultaneous injection is initiated. The precipitation limit for Unit 1 was chosen to be 29.27 weight % based on the minimum containment pressure of 14.7 psia.

The licensee also confirmed that the temperature of the lower plenum at about 2 hours post-LOCA, when the mixing from the core to the lower plenum begins, is greater than 140 °F. Staff calculations showed that the concentration in the core was about 12.5 weight % suggesting that the temperature must be greater than 140 °F to preclude precipitation in the lower plenum.

The major assumptions in the boric acid precipitation analysis are:

Core power	3020 MWt (plus uncertainty)
Decay heat standard	1971 ANS decay heat standard (1.2 multiplier)
Mixing volume	50% lower plenum, core, and upper plenum below top of hot leg elevation
Concentration of RWST	2300 ppm
Limiting axial power shape	bottom peaked axial power distribution
Hot leg injection flow	229 gpm
Limiting break location	cold leg at RCP discharge

Hot and cold leg injection is required to be aligned at 4 to 6 hours post-LOCA, but no later than 6 hours. At 6 hours, the hot-side injection of 229 gpm is about 25 gpm below the injection needed to match core boiloff. Even though the hot-side injection is less than boiloff, injection from the cold legs maintains the core covered with a two-phase mixture. The injection does not exceed boiloff until about 8 hours post-LOCA. The delayed flushing flow causes the boric acid concentration to increase until sufficient flushing flow develops to arrest the concentration increase at about 9 hours post-LOCA, according to the licensee evaluation.

While the maximum concentration is very near the precipitation limits it is important to note the conservatism inherent in these analyses. The minimum containment pressure is about 25 psia. Containment calculations show the minimum containment pressure to be greater than 25 psia at 6 hours into the event. This demonstrates that the core pressure is about 30 psia, producing a precipitation limit greater than 35 weight %. A summary of the additional conservatisms in the St Lucie 1 long-term cooling analyses are:

- Saturated fluid enters the core to minimize precipitation timing
- Loop frictional and geometric losses increased by 10 percent inside the reactor vessel and 20 percent in the loops
- Vapor exiting the core contains no boric acid
- Entrainment of liquid from the core is neglected
- Hot leg injection maximum flow rate was reduced by 75 percent
- Maximum boric acid concentrations for all sources were assumed with a 100 ppm uncertainty added.
- The boric acid makeup tanks were assumed to completely discharge into the reactor vessel

The staff model includes the impact of the loop resistance on the mixing volume, which slowly increases with time. The loop resistance included a locked rotor K-factor for the RCPs. The void distribution was determined using a drift-flux methodology to model the axial gradient in void in the core region. The staff drift flux model has been validated against separate effects two-phase level swell and bundle uncover and heat-up test data (GE level swell, THTF, G-2 level swell and uncover data, Achilles level swell data, and THETIS void data). The staff model also assumes the break is located on the top of the discharge leg so that the loop seals completely fill with liquid. This increases the loop resistance and retards the growth of the mixing volume during the event and causes earlier precipitation limits to be reached.

The staff also notes that entrainment of the hot-side injection would not occur prior to the initiation of simultaneous injection at 4 hours. Both the Wallis-Steen and the Ishii-Grolmes correlations support this conclusion. Based on these calculations, hot and cold-side injection is not initiated during the period of time entrainment could preclude injection into the hot legs. The

staff finds this analysis to be acceptable since the earliest switch time is 4 hours following opening of the break.

Since the switch to simultaneous is a key operator action to assure boric acid buildup is precluded, the licensee also confirmed that the operators would be tested annually to ensure that the operator action timing of no later than 6 hours post-LOCA for realignment of HPSI would be maintained and verified as part of the operator qualification and training program.

### Conclusion

A review of the boric acid precipitation analyses performed for St Lucie 1 demonstrates acceptable ECCS performance. Evaluation of boric acid precipitation timing for all break sizes demonstrates that prevention of precipitation is also ensured and the EOPs reflect the analysis timing for operator action to align the ECCS for hot-side injection to preclude the precipitation. Based on these results, the staff finds that, for St. Lucie 1 at the power level of 3030 MWt (including uncertainty), acceptable ECCS performance is ensured for all break sizes and locations where control of boric acid is required for compliance with the requirements set forth in 10 CFR 50.46 and 10 CFR Part 50, Appendix K.

## 2.9 Source Terms and Radiological Consequences Analyses

### 2.9.1 Source Terms for Radwaste Systems Analyses

#### Regulatory Evaluation

The NRC staff reviewed the radioactive source term associated with EPU's to ensure the adequacy of the sources of radioactivity used by the licensee as input to calculations to verify that the radioactive waste management systems have adequate capacity for the treatment of radioactive liquid and gaseous wastes. The NRC staff's review included the parameters used to determine (1) the concentration of each radionuclide in the reactor coolant, (2) the fraction of fission product activity released to the reactor coolant, (3) concentrations of all radionuclides other than fission products in the reactor coolant, (4) leakage rates and associated fluid activity of all potentially radioactive water and steam systems, and (5) potential sources of radioactive materials in effluents that are not considered in the St. Lucie 1 FSAR related to liquid waste management systems and gaseous waste management systems. The NRC's acceptance criteria for source terms are based on (1) 10 CFR Part 20, insofar as it establishes requirements for radioactivity in liquid and gaseous effluents released to unrestricted areas; (2) 10 CFR Part 50, Appendix I, insofar as it establishes numerical guides for design objectives and limiting conditions for operation to meet the as low as is reasonably achievable criterion; and (3) GDC 60, insofar as it requires that the plant design includes means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 11.1.

#### Technical Evaluation

The core isotopic inventory is a function of the core power level, while the reactor coolant isotopic activity concentration is a function of the core power level, the migration of radionuclides from the fuel, radioactive decay and the removal of radioactive material by coolant purification systems. Radiation sources in the reactor coolant include activation products, activated corrosion products and fission products. During reactor operation, some stable isotopes in the coolant passing through the core become radioactive (activated) as a result of



nuclear reactions. For example, the non-radioactive isotope oxygen-16 (O-16) is activated to become radioactive nitrogen-16 (N-16) by a neutron-proton reaction as it passes through the neutron-rich core at power. The increase in the activation of the water in the core region is in approximate proportion to the increase in thermal power.

The licensee stated, in Section 2.10.1, Occupational and Public Radiation Doses of the St. Lucie 1 LAR, Attachment 5 (Reference 2), that there will be no changes, as a result of the EPU, to the existing gaseous and liquid radioactive waste systems design, plant operating procedures or waste inputs as defined by NUREG-0017, Revision 1. Therefore, a comparison of releases can be made based on current versus EPU inventories and radioactivity concentrations in the reactor coolant, secondary coolant, and steam. As a result, the licensee states that the impact of the EPU on radwaste releases and Appendix I doses can be estimated using scaling techniques.

The licensee used scaling techniques based on NUREG-0017, Revision 1, methodology to assess the impact of EPU on radioactive gaseous and liquid effluents at St. Lucie 1. Use of the adjustment factors presented in NUREG-0017, Revision 1, allows development of coolant activity scaling factors to address EPU conditions.

The licensee's EPU analysis used the plant core power operating history during the years 2003 to 2007, the reported gaseous and liquid effluent and offsite dose calculation data during that period, NUREG-0017, Revision 1, equations and assumptions, and conservative methodology to estimate the impact of operation at the analyzed EPU core power level. The results were then compared to the comparable data from current operation on radioactive gaseous and liquid effluents and the calculated off-site doses from normal operation.

### Conclusion

The NRC staff has reviewed the radioactive source term associated with the proposed EPU and concludes that the proposed parameters and resultant composition and quantity of radionuclides are appropriate for the evaluation of the radioactive waste management systems. The NRC staff further concludes that the proposed radioactive source term meets the requirements of 10 CFR Part 20, 10 CFR Part 50, Appendix I, and GDC 60. Therefore, the NRC staff finds the proposed EPU acceptable with respect to source terms.

### 2.9.2 Radiological Consequences Analyses Using Alternative Source Terms

#### Regulatory Evaluation

The NRC staff reviewed the DBA radiological consequences analyses. The radiological consequences analyses reviewed are the LOCA, FHA, control rod ejection accident, MSLB, SGTR, locked-rotor accident, and inadvertent opening of a main steam safety valve (IOMSSV). The NRC staff's review for each accident analysis included (1) the sequence of events; and (2) models, assumptions, and values of parameter inputs used by the licensee for the calculation of the total effective dose equivalent (TEDE). The NRC's acceptance criteria for radiological consequences analyses using an alternate source term are based on (1) 10 CFR 50.67, insofar as it sets standards for radiological consequences of a postulated accident, (2) GDC 19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem TEDE, as defined in 10 CFR 50.2, for the

duration of the accident, and (3) RG 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," insofar as it describes accident specific dose guidelines for events with a higher probability of occurrence.

Specific review criteria are contained in SRP Section 15.0.1, and guidance from Matrix 9 of RS-001.

### Technical Evaluation

To determine the effect of the EPU on the design basis radiological analyses, the licensee reanalyzed the following accidents: LOCA, FHA, SGTR accident, MSLB accident, locked rotor accident, CEA ejection accident and the rod ejection accident, and the IOMSSV. The licensee performed radiological consequence analyses for the various accidents using input assumptions consistent the proposed EPU conditions. As appropriate, the licensee determined the TEDE at the EAB for the limiting 2-hour period, at the LPZ outer boundary for the duration of the accident, and in the control room for 30 days.

The dose consequence analyses were performed by the licensee using the RADTRAD-Numerical Applications, Inc. (NAI) computer code. RADTRAD-NAI estimates the radiological doses at offsite locations and in the control room of nuclear power plants as consequences of postulated accidents. The code considers the timing, physical form and chemical species of the radioactive material released into the environment.

RADTRAD-NAI was developed from the "RADTRAD: Simplified Model for RADionuclide Transport and Removal and Dose Estimation," computer code. NRC sponsored the development of the RADTRAD radiological consequence computer code, as described in NUREG/CR-6604. The RADTRAD code was developed by Sandia National Laboratories for the NRC. The code estimates transport and removal of radionuclides and radiological consequence doses at selected receptors. The NRC staff uses the RADTRAD computer code to perform independent confirmatory dose evaluations as necessary to ensure a thorough understanding of the licensee's methods. The results of the evaluations performed by the licensee, as well as the applicable dose acceptance criteria from RG 1.183, are shown in Table 1 of this SE.

### *Source Terms*

The licensee used the ORIGEN-2.1 computer code to generate the core radionuclide inventory for use in determining the bounding source term. The licensee used the following inputs to determine the bounding source term:

- An enrichment range of 1.5 weight % to 5.0 weight % Uranium-235,
- A power level of 3030 MWt (3020 MWt plus 0.3 percent calorimetric uncertainty),
- A core average burnup of up to 49,000 megawatt days per metric ton of uranium (MWd/MTU).

The licensee revised the primary coolant source term as determined for EPU conditions based upon maximum equilibrium concentrations of isotopes with small defects in 1 percent of the fuel

rod cladding. The licensee derived the primary coolant corrosion product inventory from ANSI/ANS-18.1-1999.

The licensee adjusted the primary coolant iodine activities to achieve the TS 3.4.8 limit of 1.0 micro-Curies per gram ( $\mu\text{Ci/gm}$ ) Dose Equivalent (DE) I-131. The non-iodine species are adjusted to achieve a proposed TS limit of 518.9  $\mu\text{Ci/gm}$  DE Xe-133 using effective air submersion dose conversion factors (DCFs) from Table III.1 of Federal Guidance Report (FGR) No. 12. The licensee derived the proposed TS DE Xe-133 limit from the prior TS 100/E-bar limit for non-iodine isotopes, such that the air submersion dose produced by the non-iodine isotopes would be approximately the same.

The licensee evaluated releases from the secondary coolant system activity by assuming the TS limited value of  $\leq 0.10 \mu\text{Ci/gm}$  DE I-131. The licensee assumed that noble gases entering the secondary coolant system are immediately released resulting in a noble gas activity concentration in the secondary coolant system of  $0.0 \mu\text{Ci/gm}$ .

#### *Dose Conversion Factors*

The licensee used committed effective dose equivalent (CEDE) and effective dose equivalent (EDE) DCFs from FGR 11 and 12, as is appropriate for an AST evaluation. The use of ORIGEN and DCFs from FGR 11 and FGR 12 is in accordance with RG 1.183 guidance and is acceptable to the NRC staff.

#### *Atmospheric Dispersion Estimates*

In the application dated November 22, 2010, the licensee generated new control room (CR), EAB, and LPZ atmospheric dispersion factors ( $\chi/Q$  values) for use in evaluating the radiological consequences of the limiting DBAs. The CR  $\chi/Q$  values were based on meteorological measurements made from 2001 through 2004 and 2006. The EAB and LPZ  $\chi/Q$  values were calculated using the measurements from 2004 through 2007. The licensee provided a description of the methodologies, other inputs, and assumptions used to calculate the  $\chi/Q$  values. Based on the RAs generated during the NRC staff's review, the licensee provided revisions to the original data sets outlined in RA responses dated August 12, 2011 (Reference 60), and September 2, 2011 (Reference 61). The revised CR, EAB and LPZ  $\chi/Q$  values used in this analysis are based on data from the years 1997, 1998, 1999, 2002, and 2003.

#### *Meteorological Data*

The licensee provided the initial meteorological data set for years 2001 through 2004 and 2006 in the form of hourly data formatted for input into the ARCON96 atmospheric dispersion computer code (NUREG/CR-6331, Revision 1, "Atmospheric Relative Concentrations in Building Wakes"). In addition, the licensee provided the meteorological data for the 2004 through 2007 period in the form of a joint wind speed, wind direction, and atmospheric stability frequency distribution (JFD) for input to the PAVAN atmospheric dispersion computer code (NUREG/CR-2858, "PAVAN: An Atmospheric Dispersion Program for Evaluating Design Basis Accidental Releases of Radiological Materials from Nuclear Power Stations").

The meteorological data originated from the meteorological measurements program for St. Lucie 1. This program is described in detail in Section 2.3.3 of the Unit 1 FSAR. The onsite

meteorological program is designed to provide dispersion climatology for use in the planning of radioactive effluent releases and as a means of determining the meteorological parameters to be used in estimating the potential radiological consequences of hypothetical accidents. The licensee periodically acquired and saved the data from the meteorological tower data logging system and converted the data from the individual time period files to a common spreadsheet format. During processing of annual composite spreadsheet files, the licensee checked the meteorological data for validity. In certain files, stability class was not recorded for extended time periods, but temperature data at 10 and 57.9-meter elevations were available so that stability class could be calculated from this data using the vertical temperature difference in accordance with guidance in RG 1.23. Where data from "A" channel of the logging system was valid at 10 and 57.9-meters, it was used for the stability calculation. If data from "A" channel was missing or invalid and "B" was available and valid, it was used.

In response to the NRC staff's June 20, 2011, RAIs on the initial meteorological data, the licensee reviewed the data files with METD (NUREG-0917, "Nuclear Regulatory Commission Staff Computer Programs for Use with Meteorological Data") and manual/visual plotting tools. Based on this higher level of screening, the licensee chose to replace the original submittal data set with a new set of screened and validated data. The METD programs were used to screen the original submittal data set, as well as a replacement 5-year data set. All available meteorological data (1996 (partial), 1997, 1998, 1999, 2000 (partial), 2001, 2002, 2003, 2004, 2006, 2007, 2008, and 2010) were evaluated. Application of METD and manual/visual trend plotting tools identified 5 years in which the minimum recovery percentage of 90 percent, as outlined in RG 1.23 Section C-5, was met for both ARCON96 and PAVAN inputs. The years were 1997, 1998, 1999, 2002, and 2003.

The revised meteorological data set does not show the same anomalous high number of consecutive hours of same-stability-class behavior, persistent winds from one direction for extended periods of time, or anomalous (multiples of 10, or severely rounded) values that occurred in the initial data set and were noted in the NRC staff's June 20, 2011, RAIs. The licensee's screening tools identified such anomalies, and when confirmed to be anomalous, the data was eliminated from the final data set used for  $\chi/Q$  determination. No data substitution was applied by the licensee to assign 57.9-meter data to 10-meter values during this post-processing activity.

NRC staff performed a quality review of the revised meteorological data. The staff found wind direction frequency distributions were reasonably similar from year to year between both measurement heights. Wind speed frequency distributions were also found to be similar from year to year for each measurement level. For the atmospheric stability, measured as the temperature difference between the 57.9-meter and 10.0-meter levels, the time of occurrence and duration of reported stability conditions were generally consistent with the expected meteorological conditions of neutral and slightly stable conditions predominating during the year, stable and neutral conditions occurring at night, and unstable and neutral conditions occurred during the day. Also, a comparison of the JFD derived by the NRC staff from the ARCON96 formatted hourly data to the JFD developed by the licensee for input into the PAVAN atmospheric dispersion model showed good agreement.

On the basis of this review, NRC staff determined that the revised meteorological data provided an acceptable basis for making estimates of atmospheric dispersion for the proposed EPU LAR for St. Lucie 1.

### *Control Room Atmospheric Dispersion Factors*

The licensee used the revised data set from the years 1997, 1998, 1999, 2002, and 2003 to generate CR  $\chi/Q$  values using the ARCON96 computer code and guidance provided in NRC RG 1.194: "Atmospheric Relative Concentrations for Control Room Radiological Habitability Assessments at Nuclear Power Plants", which states that ARCON96 is an acceptable methodology for assessing CR  $\chi/Q$  values for use in design basis accident radiological analyses. The NRC staff determined that there was no unusual siting, building arrangements, release characterization, release-receptor configuration, meteorological regimes, or terrain conditions that precluded the use of the ARCON96 model in support of the LAR for St. Lucie 1.

The wind speed, wind direction, and atmospheric stability measured at the 10.0 meter and 57.9 meter heights above ground level served as inputs for the CR  $\chi/Q$  calculations. Other inputs included the release/source height, the CR receptor heights, and the straight-line distance between the source and intake/receptor, all in meters. The direction between intake to source in degrees, the default values of 0.2 meters for surface roughness, 0.5 m/s for minimum wind speed, and a sector averaging constant of 4.3 (found in Table A-2 of RG 1.194) were also used. No diffuse area sources were used in the estimated  $\chi/Q$  analysis for the purpose of dose assessment.

The licensee notes in the August 12, 2011, RAI responses that the release heights are calculated as 19 ft less than the referenced elevations to account for plant grade elevation. When converting feet to meters, all significant figures reflect rounding down. The fuel handling building's closest release point elevation is taken as the roof elevation since the southwest corner of the roof is the closest building point to the CR intakes. Release and receptor points are considered to be at the center point or centerline of all openings. Releases from the plant stack have release/receptor combinations that do not have the intakes in the same wind direction window. The licensee takes credit for intake dilution for these releases as allowed per Section 3.3.2.2 of RG 1.194.

In some cases for a release/receptor combination, the receptor point is located halfway between the CR outside air intakes from the north-south direction. The receptor point is taken as being on the outside of the CR east wall. The receptor elevation is taken as the average of the receptor elevations for the two outside air intakes. Atmospheric dispersion factors for the releases to the midpoint between the CR intakes are required for the limiting case to be used during the time period when the CR intakes are isolated. The midpoint receptor location is used to calculate the  $\chi/Q$  value to be used for the unfiltered CR inleakage dose. The closest containment/shield building penetration to the intakes that is directly exposed to the atmosphere is the closest FW line penetration.

NRC staff reviewed the licensee's ARCON96 control room atmospheric dispersion estimates. This included a review of the inputs and assumptions which the NRC staff found generally consistent with site configuration drawings, input tables, and the NRC staff practice. In addition, the NRC staff generated sample comparative  $\chi/Q$  value estimates and found the resultant  $\chi/Q$  values to be similar to the revised values calculated by the licensee. On the basis of this review, the NRC staff determined that the CR  $\chi/Q$  values in Table 2 of this SE are acceptable for use in DBA CR dose assessments.

### *Offsite Atmospheric Dispersion Factors*

The licensee generated a JFD using the revised meteorological data set of screened and validated data from the years 1997, 1998, 1999, 2002, and 2003. The licensee calculated EAB and LPZ offsite  $\chi/Q$  values using guidance provided in RG 1.145: "Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants," and the PAVAN atmospheric dispersion computer code. All releases were modeled as ground-level pursuant to guidance provided in RG 1.145 in which no release heights were more than 2.5 times the adjacent structures. Atmospheric stability class was calculated using the temperature difference between the 57.9-meter and 10.0-meter heights on the primary meteorological tower.

In the offsite  $\chi/Q$  determinations, the licensee assumed a minimum containment cross-sectional area of 1565 m<sup>2</sup> and a containment height of 62.9 meters above ground level. The licensee considered an overall site ground-level EAB distance of 1537 meters and LPZ distance of 1585 meters.

NRC staff performed a qualitative review of the inputs and assumptions used in the licensee's PAVAN computer calculations and the resulting  $\chi/Q$  values. Staff calculated comparative  $\chi/Q$  values, and found the results to be similar to the revised EAB and LPZ  $\chi/Q$  values calculated by the licensee. Therefore, on the basis of this review, the NRC staff determined that the resulting offsite EAB and LPZ  $\chi/Q$  values generated by the licensee and presented in Table 3 of this SE are acceptable for use in DBA dose assessments.

### *Atmospheric Dispersion Factor Summary*

NRC staff reviewed the revised meteorological data provided in support of this application and determined that it serves as an acceptable basis for making atmospheric dispersion estimates. The NRC staff's review of the CR, EAB, and LPZ  $\chi/Q$  values found that the licensee used methodologies, assumptions, and inputs consistent with applicable regulatory guidance. The NRC staff determined that the CR  $\chi/Q$  values generated by the licensee and presented in Table 2 of this SE are acceptable for use in DBA CR dose assessments. Additionally, the NRC staff determined that the offsite  $\chi/Q$  values generated by the licensee and presented in Table 3 of this SE are acceptable for use in DBA dose assessments.

#### 2.9.2.1 EPU LOCA Radiological Consequences

##### 2.9.2.1.1 Description of Event

The radiological consequence design basis LOCA analysis is a deterministic evaluation based on the assumption of a major rupture of the primary RCS piping. The accident scenario assumes the deterministic failure of the ECCS to provide adequate core cooling that results in a significant amount of core damage as specified in RG 1.183. This general scenario does not represent any specific accident sequence, but is representative of a class of severe damage incidents that were evaluated in the development of the RG 1.183 source term characteristics. Such a scenario would be expected to require multiple failures of systems and equipment and lies beyond the severity of incidents evaluated for design basis transient analyses.

The LOCA considered in this evaluation is a complete and instantaneous circumferential severance of the primary RCS piping, which would result in the maximum fuel temperature and

primary containment pressure among the full range of LOCAs. Due to the postulated loss of core cooling, the fuel heats up, resulting in the release of fission products. The fission product release is assumed to occur in phases over a 2-hour period.

When using the AST for the evaluation of a design basis LOCA for a PWR, it is assumed that the initial fission product release to the containment will last for 30 seconds and will consist of the radioactive materials dissolved or suspended in the RCS liquid. After 30 seconds, fuel damage is assumed to begin and is characterized by clad damage that releases the fission product inventory assumed to reside in the fuel gap. The fuel gap release phase is assumed to continue until 30 minutes after the initial breach of the RCS. As core damage continues, the gap release phase ends and the early invessel release phase begins. The early invessel release phase continues for the next 1.3 hours. The licensee used the LOCA source term release fractions, timing characteristics, and radionuclide grouping as specified in RG 1.183 for evaluation of the AST.

In the evaluation of the LOCA design basis radiological analysis, the licensee considered dose contributions from the following potential activity release pathways:

- Containment leakage via the secondary containment system.
- Containment leakage bypassing the secondary containment.
- ESF system leakage into the RAB.
- ESF system leakage into the RWT.
- Hydrogen purge at event initiation.

The licensee considered the following potential DBA LOCA dose contributors to the control room habitability envelope (CRHE) analysis:

- Contamination of the CR atmosphere by intake and infiltration of radioactive material from the containment leakage and ESF system leakage.
- External radioactive plume shine contribution from the containment and ESF leakage releases with credit for CR structural shielding.
- A direct shine dose contribution from the containment's contained accident activity with credit for both containment and CR structural shielding.

A direct shine dose contribution from the activity collected on the CR ventilation filters.

#### 2.9.2.1.2 Analysis Parameters and Assumptions

##### 2.9.2.1.2.1 LOCA Source Term

The licensee followed all aspects of the guidance outlined in RG 1.183, Regulatory Position 3, regarding the core inventory and the release fractions and timing for the evaluation of the LOCA.

The LOCA analysis assumes that iodine will be removed from the containment atmosphere by both containment sprays and natural diffusion to the containment walls. As a result of these removal mechanisms, a large fraction of the released activity will be deposited in the containment sump. The sump water will retain soluble gaseous and soluble fission products, such as iodines and cesium, but not noble gases. The guidance from RG 1.183 specifies that the iodine deposited in the sump water can be assumed to remain in solution as long as the containment sump pH is maintained at or above 7.

The licensee conducted an evaluation of containment sump pH and has determined that the sump pH will be maintained at or above 7. This ensures that particulate iodine deposited into the containment sump water will not re-evolve beyond the amount recognized in the DBA LOCA analysis. Therefore, in accordance with the guidance in RG 1.183, the licensee assumed that the chemical form of the radioiodine released to the containment is 95 percent cesium iodide (CsI), 4.85 percent elemental iodine, and 0.15 percent organic iodide. With the exception of elemental iodine, organic iodide and noble gases, fission products are assumed to be in particulate form.

#### 2.9.2.1.2.2 Assumptions on Transport in the Primary Containment

##### 2.9.2.1.2.2.1 Containment Mixing, Natural Deposition, and Leak Rate

Section 6.2.1.2 of the St. Lucie 1 FSAR describes the containment vessel as a low leakage steel shell, including all its penetrations, designed to confine the radioactive materials that could be released by accidental loss of integrity of the reactor coolant pressure boundary. Physically, the containment vessel is a right circular cylinder with hemispherical dome and ellipsoidal bottom which houses the RPV, the reactor coolant piping and pumps, the SGs, the primary coolant pressurizer and pressurizer QT, and other branch connections of the RCS including the SITs.

In accordance with RG 1.183, the licensee assumed that the activity released from the fuel is mixed instantaneously and homogeneously throughout the free air volume of the containment. The licensee used the core release fractions and timing, as specified in RG 1.183, with the termination of the release into containment set at the end of the early in-vessel phase.

The licensee credited the reduction of airborne radioactivity in the containment by natural deposition. The licensee credited an elemental iodine natural deposition removal coefficient of  $2.89 \text{ hr}^{-1}$ . The licensee did not credit the removal of organic iodide by natural deposition. The licensee applied the elemental iodine natural deposition removal coefficient of  $2.89 \text{ hr}^{-1}$  to both the sprayed and unsprayed volume of the containment.

The licensee credited a natural deposition removal coefficient of  $0.1 \text{ hr}^{-1}$  for all aerosols in the unsprayed region of containment. In addition, the licensee credited a natural deposition removal coefficient of  $0.1 \text{ hr}^{-1}$  for all aerosols in the sprayed region after spray is terminated at 8 hours.

RG 1.183, Regulatory Position 3.7 states that, "The primary containment should be assumed to leak at the peak pressure technical specification leak rate for the first 24 hours. For PWRs, the leak rate may be reduced after the first 24 hours to 50 percent of the technical specification leak rate." Accordingly, the licensee assumed a containment leak rate of 0.5 percent per day for the



first 24 hours, after which the containment leak rate is reduced to 0.25 percent per day for the duration of the accident.

#### 2.9.2.1.2.2.2 Containment Spray Assumptions

RG 1.183, Appendix A, Regulatory Position 3.3 states that, "The containment building atmosphere may be considered a single, well mixed volume if the spray covers at least 90 percent of the volume and if adequate mixing of unsprayed compartments can be shown." In addition, SRP Section 6.5.2, III, 1, c states, "The containment building atmosphere may be considered a single, well mixed space if the spray covers regions comprising at least 90 percent of the containment building space and if a ventilation system is available for adequate mixing of any unsprayed compartments."

For St. Lucie 1, the volume of the sprayed region is 2,155,160 ft<sup>3</sup> and the volume of the unsprayed region is 350,840 ft<sup>3</sup>. Since the sprayed region represents approximately 86 percent of the total containment volume, the licensee used a two-volume model to represent the sprayed and unsprayed regions of the containment. The licensee used a mixing rate between the sprayed and unsprayed regions of containment of four unsprayed volumes per hour as described in the St. Lucie 1 FSAR, Section 6.2.6.3.4.

Using the guidance from SRP 6.5.2, the licensee determined that the aerosol removal rate from the effects of the containment spray system, which actuates 0.0222 hours (80.0 seconds) after the LOCA, is 6.07 per hour until a decontamination factor (DF) of 50 is reached at 2.334 hours post-LOCA. After the DF of 50 is reached, the licensee assumed that the aerosol removal rate is reduced by a factor of 10 in accordance with RG 1.183.

Using the guidance from SRP 6.5.2, the licensee determined that the elemental iodine removal rate from the effects of the containment spray system, which actuates 0.0222 hours (80.0 seconds) after the LOCA, is in excess of 20 per hour. However, in accordance with the guidance in SRP 6.5.2, the licensee limited the removal rate constant for elemental iodine to 20 per hour. The licensee applied this elemental iodine removal rate in the dose analysis from the time of spray actuation until the maximum allowable DF of 200 is reached at 2.331 hours post-LOCA.

The NRC staff has reviewed the licensee's application of credit for iodine removal from the operation of the containment spray system and has found that the analysis follows the guidance in RG 1.183, is conservative, and is therefore acceptable.

#### 2.9.2.1.2.3 Assumptions on Dual Containments

Section 6.2.1.2 of the St. Lucie 1 FSAR describes the shield building, also referred to as the secondary containment, as a medium leakage reinforced concrete structure surrounding the containment vessel. The shield building is designed to provide biological shielding during normal operation and LOCA conditions, environmental protection for the containment vessel from adverse atmospheric conditions and external missiles, and a means for collection and filtration of fission product leakage from the containment vessel following a LOCA. Physically, the shield building is a right circular cylinder with a shallow dome roof.

The licensee assumed that the leakage from primary containment will be collected by the secondary containment and processed by the ESF shield building ventilation system (SBVS)

filters prior to release from the plant stack. The licensee credited secondary containment filtration efficiencies of 95 percent for elemental iodine and organic iodide and 99 percent for particulates. The licensee assumed that the leakage into the secondary containment is released directly to the environment as a ground-level release prior to the effective drawdown of the secondary containment which is assumed to be completed at 310 seconds after accident initiation.

The licensee credited the SBVS as being capable of maintaining the shield building annulus at a negative pressure with respect to the outside environment considering the effect of high wind speeds and LOCA heat effects on the annulus as described in FSAR Section 6.2. The licensee stated that no exfiltration through the concrete wall of the Shield Building is expected to occur.

The licensee did not credit dilution of the primary containment leakage within the secondary containment volume. In addition, the licensee assumed that 9.6 percent of the primary containment leakage will bypass the secondary containment and be released at ground level without credit for filtration.

#### 2.9.2.1.2.4 Assumptions on ESF System Leakage

To evaluate the radiological consequences of ESF leakage, the licensee used the deterministic approach as prescribed in RG 1.183. This approach assumes that except for the noble gases, all of the fission products released from the fuel mix instantaneously and homogeneously in the containment sump water. Except for iodine, all of the radioactive materials in the containment sump are assumed to be in aerosol form and retained in the liquid phase. As a result, the licensee assumed that the fission product inventory available for release from ECCS leakage consists of 40 percent of the core inventory of iodine. This amount is the combination of 5 percent released to the containment sump water during the gap release phase and 35 percent released to the containment sump water during the early in vessel release phase. This source term assumption is conservative in that 100 percent of the radioiodines released from the fuel are assumed to reside in both the containment atmosphere and in the containment sump concurrently. ECCS leakage develops when ESF systems circulate containment sump water outside containment and leaks develop through packing glands, pump shaft seals and flanged connections.

For the LOCA analysis of ESF leakage, the licensee used a value of 4750 cc/hour, representing two times the current licensing basis value of 2375 cc/hour, as specified in RG 1.183, Appendix A, Item 5.2. The licensee assumed that ESF leakage will start at 20 minutes into the event, coinciding with the beginning of the recirculation phase of emergency core cooling, and continue for the 30-day duration of the accident evaluation.

#### 2.9.2.1.2.4.1 Assumptions on ESF System Leakage to the Reactor Auxiliary Building

RG 1.183, Appendix A, Regulatory Position 5.5, states that, "If the temperature of the leakage is less than 212°F or the calculated flash fraction is less than 10 percent, the amount of iodine that becomes airborne should be assumed to be 10 percent of the total iodine activity in the leaked fluid."

The licensee calculated the fractional iodine release or flashing fraction for ESF leakage as 5.5 percent. However, the licensee used a flashing fraction of 10 percent, as prescribed in

RG 1.183, for conservatism. The licensee has determined that the pH of the containment sump will not fall below 7.0 for the duration of the accident.

The licensee assumed that the ECCS leakage is released directly into the RAB and released instantaneously into the environment with credit for RAB ECCS area filtration. The licensee credited ECCS area filtration efficiencies of 95 percent for elemental iodine and organic iodide and 99 percent for particulates. As noted previously, the licensee assumed that 100 percent of the particulate activity is retained in the sump water. The licensee did not credit a reduction of activity released to the RAB as a result of dilution or holdup.

In accordance with RG 1.183, for ESF leakage into the RAB, the licensee assumed that the chemical form of the released iodine is 97 percent elemental iodine and 3 percent organic iodide.

The NRC staff has reviewed the licensee's analysis of the dose consequence from ECCS leakage and has determined that the analysis follows the guidance in RG 1.183, is conservative, and is therefore acceptable.

#### 2.9.2.1.2.4.2 Assumptions on ESF System Back leakage to the Refueling Water Tank

The licensee evaluated the dose consequence from ECCS backleakage to the RWT by assuming an initial backleakage rate of 2 gpm based upon doubling the current bounding value of 1 gpm. The licensee assumed that this leakage starts at 20 minutes into the event when recirculation begins and continues throughout the 30-day analysis period. Based on sump pH remaining at 7 or above, the iodine in the sump solution is assumed to all be nonvolatile. However, when introduced into the acidic solution of the RWT inventory, there is a potential for the particulate iodine to convert into the elemental iodine form. The fraction of the total iodine in the RWT which becomes elemental iodine is both a function of the RWT pH and the total iodine concentration. The amount of elemental iodine in the RWT fluid that then enters the RWT air space is a function of the temperature-dependent iodine partition coefficient. The licensee determined the time-dependent concentration of the total iodine in the RWT from the tank liquid volume and leak rate. The licensee calculated that the total iodine concentration ranged from a minimum value of 0 at the beginning of the event to a maximum value of  $4.07\text{E-}05$  gm-atom per liter at 30 days.

Based upon the backleakage of sump water, the licensee determined that the RWT pH slowly increases from an initial value of 4.5 to a maximum pH of 4.968 at 30 days. Using the time-dependent RWT pH and the total iodine concentration in the RWT liquid space, the licensee determined the amount of iodine that will be converted to the elemental iodine form using the guidance provided in NUREG/CR-5950. The licensee determined that the RWT elemental iodine concentration will range from 0 at the beginning of the event to a maximum of  $2.532\text{E-}06$  gm-atom per liter at 30 days.

The licensee assumed that the elemental iodine in the liquid region of the RWT will become volatile and partition between the liquid and vapor space in the RWT based upon the partition coefficient for elemental iodine as described in NUREG/CR-5950. The licensee developed a model using the GOTHIC computer code to determine the RWT temperature as a function of time. The licensee conservatively used the peak temperature to calculate the elemental iodine partition coefficient for the full 30 day analysis period.

Because the RWT is vented to the atmosphere, there will be no pressure transient in the air region that would affect the partition coefficient. Since no boiling occurs in the RWT, the licensee calculated the flow rate of the released activity from the vapor space within the RWT based upon the displacement of air by the incoming backleakage. The licensee calculated the elemental iodine release rate from the RWT by multiplying the displacement air flow rate times the elemental iodine concentration in the RWT vapor space.

The licensee used the same approach to evaluate the organic iodide release rate from the RWT. The licensee used an organic iodide fraction of 0.0015 from RG 1.183 in combination with a partition coefficient of 1.0 for organic iodide. Consistent with RG 1.183 guidance, the licensee assumed that the particulate portion of the leakage is retained in the liquid phase of the RWT. Therefore, the total iodine release rate is the sum of the elemental iodine and organic iodide release rates.

The NRC staff has reviewed the licensee's analysis of the dose consequence from ECCS backleakage into the RWT and has determined that the analysis follows the guidance in RG 1.183, is conservative, and is therefore acceptable.

#### 2.9.2.1.2.5 Assumptions on Containment Hydrogen Purging

The licensee evaluated the radiological effects of containment leakage via open hydrogen purge lines, which is assumed to occur for the first 30 seconds of the DBLOCA. The licensee assumed that 100 percent of the radionuclide inventory of the RCS is released instantaneously into the containment at the beginning of the event. The containment purge consists of a volumetric flow rate of 500 cfm released to the environment via the plant vent for a period of 30 seconds with no credit for filtration.

During the time period of 30 seconds following accident onset, the licensee assumes that fuel failure has not occurred. This assumption follows the guidance in Table 4 of RG 1.183, which indicates that the initial release of the RCS into containment for a PWR would occur within the first 30 seconds of the accident prior to the onset of fuel damage. Per RG 1.183, the hydrogen purge release evaluation should assume that 100 percent of the radionuclide inventory in the RCS liquid is released to the containment at the initiation of the LOCA and that this inventory should be based on the TS RCS equilibrium activity.

The licensee used conservative assumptions to evaluate the containment hydrogen purge contribution to the LOCA dose and therefore, the NRC staff finds this evaluation acceptable for the EPU LOCA analysis.

#### 2.9.2.1.2.6 Control Room Habitability for the LOCA

##### 2.9.2.1.2.6.1 CR Ventilation Assumptions for the LOCA

The control room air conditioning system and control room emergency ventilation system (CREVS) are required to assure CR habitability. The design of the CR envelope and overall descriptions of both the control room air conditioning system and the CREVS are contained in Sections 6.4 and 9.4.1 of the St. Lucie 1 FSAR.

During normal plant operation, the control room envelope is pressurized relative to the surrounding areas at all times with outside air continuously introduced to the control room envelope at a rate of 750 cfm. For conservatism, the licensee used a value of 920 cfm in the dose analyses.

For the LOCA analysis, the CR ventilation system is initially assumed to be operating in normal mode. The air flow distribution during the normal mode of operation is 920 cfm of unfiltered fresh air with an assumed value of 460 cfm for unfiltered inleakage. After the start of the event, the CR is assumed to be isolated due to a CIAS as a result of a high containment pressure signal. The licensee applied a 50-second delay to account for the time required to reach the CIAS, the time to start the diesel generator and the time for damper actuation. After isolation, the air flow distribution is assumed to consist of 0 cfm of makeup flow from the outside, 460 cfm of assumed unfiltered inleakage, and 1760 cfm of filtered recirculation flow.

At 1.5 hours into the event, the operators are assumed to initiate makeup flow from the outside into the control room to restore a positive pressure differential and to maintain air quality. Makeup air for CR pressurization is filtered before entering the control room. During this operational mode, the air flow distribution consists of up to 504 cfm of filtered makeup flow, 460 cfm of assumed unfiltered inleakage and 1256 cfm of filtered recirculation flow.

The CR ventilation filter efficiencies that are applied to the filtered makeup and recirculation flows are 99 percent for particulates, 95 percent for elemental iodine, and 95 percent for organic iodide.

#### 2.9.2.1.2.6.2 CR Direct Shine Dose Assumptions

The total CR LOCA dose includes direct shine contributions from the following DBLOCA radiation sources:

- Contamination of the CR atmosphere by the intake and infiltration of the radioactive material contained in the radioactive plume released from the facility.
- Direct shine from the external radioactive plume released from the facility with credit for CR structural shielding.
- Direct shine from radioactive material in the containment with credit for both the containment and CR structural shielding.
- Radiation shine from radioactive material in systems and components inside or external to the CR envelope including radioactive material-buildup on the CR ventilation filters.

RG 1.196 defines the CR envelope as follows: "The plant area, defined in the facility licensing basis, that in the event of an emergency, can be isolated from the plant areas and the environment external to the CRE [CR envelope]. This area is served by an emergency ventilation system, with the intent of maintaining the habitability of the control room. This area encompasses the control room, and may encompass other non critical areas to which frequent personnel access or continuous occupancy is not necessary in the event of an accident."

The licensee evaluated the contribution to the total dose to the CR operators from direct radiation sources, such as the control room filters, the containment atmosphere, and the released radioactive plume for the LOCA event. The licensee asserts and the NRC staff agrees that the LOCA shine dose contribution is bounding for all other events. The 30-day direct shine dose to a person in the control room, considering occupancy, is provided in Table 4 of this SE. For conservatism, the licensee assumed the bounding LOCA CR shine dose for all the DBAs evaluated.

The licensee determined the direct shine dose from three different sources to the CR operator after a postulated LOCA event. These sources are the containment, the CR air filters, and the external airborne activity cloud that envelops the CR. The licensee asserts, and the NRC staff agrees, that per Table 6.4-2 of the FSAR, all other sources of direct shine dose to the CR can be considered negligible. The licensee used the MicroShield 5 shielding code to determine direct shine exposure to a dose point located in the control room. Each source required a different MicroShield case structure that included different geometries, sources, and materials. The licensee modeled the external cloud by assigning a source length of 1000 meters in MicroShield to approximate an infinite cloud. The licensee ran multiple cases to determine an exposure rate from the radiological source at given points in time. These sources were taken from RADTRAD-NAI runs that output the nuclide activity at a given point in time for the event. The RADTRAD-NAI output provides the time dependent results of the radioactivity retained in the CR filter components, as well as the activity inventory in the environment and the containment. A bounding CR filter inventory is established using a case from the sensitivity study with an assumed unfiltered leakage that produced a control room dose slightly in excess of the 5 rem TEDE dose limit to control room operators without the application of the occupancy factors described in RG 1.183. The direct shine dose calculated due to the filter loading for this conservative unfiltered leakage case is used as a conservative assessment of the direct shine dose contribution for all accidents.

The RADTRAD-NAI sources were then input into the MicroShield case file to yield the source activity at a later point in time. The exposure results from the series of cases for each source term were then corrected for occupancy using the occupancy factors specified in RG 1.183. The cumulative exposure and dose are subsequently calculated to yield the total 30-day direct shine dose from each source. The results of the licensee's CR direct shine dose evaluation are presented in Table 4 of this SE.

The NRC staff finds that the licensee's evaluation of the potential direct shine dose contributions to the CR LOCA dose analysis used conservative assumptions and sound engineering judgment and is therefore acceptable.

#### 2.9.2.1.3 Conclusion

The licensee evaluated the radiological consequences resulting from the postulated LOCA and concluded that the radiological consequences at the EAB, LPZ, and CR comply with the reference values and the CR dose criterion provided in 10 CFR 50.67 and the accident specific dose guidelines specified in SRP Section 15.0.1 and RG 1.183. The NRC staff's review found that the licensee used analysis, assumptions, and inputs consistent with applicable regulatory guidance identified in Section 2.0 of this SE. The assumptions found acceptable to the NRC staff are presented in Table 5 and the licensee's calculated dose results are given in Table 1. The NRC staff finds, with reasonable assurance, that the licensee's estimates of the dose

consequences of a DBLOCA will comply with the requirements of 10 CFR 50.67 and the guidelines of RG 1.183, and are therefore acceptable.

#### 2.9.2.2 Fuel-Handling Accident

##### 2.9.2.2.1 Description of Event

This accident analysis postulates that a spent fuel assembly is dropped during fuel handling and strikes an adjacent assembly during the fall. All of the fuel rods in the dropped assembly are conservatively assumed to experience fuel cladding damage, releasing the radionuclides within the fuel rod gap to the fuel pool or reactor cavity water. The affected assemblies are assumed to be those with the highest inventory of fission products of the 217 assemblies in the core. Volatile constituents of the core fission product inventory migrate from the fuel pellets to the gap between the pellets and the fuel rod clad during normal power operations. The fission product inventory in the fuel rod gap of the damaged fuel rods is assumed to be instantaneously released to the surrounding water as a result of the accident. Fission products released from the damaged fuel are retained in the overlaying water in the reactor cavity or SFP, depending on their physical and chemical form.

The licensee conservatively assumed no overlying water retention for noble gas activity, a DF of 200 for radioiodines, and retention of all particulate fission products. As prescribed in RG 1.183, the FHA is analyzed based on the assumption that 100 percent of the fission products released from the reactor cavity or SFP are released to the environment in 2 hours. The licensee did not credit filtration, holdup, or dilution of the released activity. Since the assumptions and inputs are identical for the FHA within containment and the FHA outside containment, the results of the two events are identical.

The licensee considered the analysis of the FHA both within the containment and within the fuel handling building (FHB). The dropped fuel assembly inside the containment is assumed to occur with the equipment maintenance hatch fully open and the fuel assembly drop inside the FHB credits no filtration of the exhaust. The water level above the damaged fuel assembly is maintained at 23 feet minimum for release locations both inside containment (i.e., reactor cavity) and the FHB (i.e., SFP). This water cover acts as a barrier to many of the radionuclides released from the dropped assembly. The licensee assumed retention of all non-iodine particulate in the pool, while the iodine releases from the fuel gap into the pool are assumed to be decontaminated by an overall factor of 200. This DF results in 0.5 percent (i.e., 99.5 percent of the iodine are retained in the pool) of the radioiodine escaping the overlying water with a composition of 70 percent elemental iodine and 30 percent organic iodide. In accordance with Regulatory Position 3 of RG 1.183, the licensee assumes 100 percent of the noble gas exits the pool. All fission products released to the environment occurs over a 2-hour period. In the subject FHA analysis, the licensee does not credit dilution within the surrounding structures prior to release to the atmosphere. These assumptions follow the guidance of RG 1.183 and are therefore acceptable to the staff.

##### 2.9.2.2.2 Analysis Parameters and Assumptions

###### 2.9.2.2.2.1 FHA Source Term

For the purpose of this analysis, the licensee assumed a conservative estimate of 72 hours decay time for the movement of fuel, as accounted for in the RADTRAD code analysis. This

indicates that any fuel accounted for in the analyzed FHA would have experienced radioactive decay for a period of 72 hours prior to any susceptibility to dropping either in the reactor cavity or SFP. The core fission product inventory that constitutes the source term for this event is the gap activity in the 176 fuel rods assumed to be damaged as a result of the postulated design basis FHA. Volatile constituents of the core fission product inventory migrate from the fuel pellets to the gap between the pellets and the fuel rod cladding during normal power operations. The fission product inventory in the fuel rod gap of the damaged fuel rods is assumed to be instantaneously released to the surrounding water as a result of the accident per Regulatory Position 1.2 of RG 1.183.

Guidance provided in RG 1.183, Footnote 11, states that the gap activity release fractions, as specified in Table 3 of RG 1.183, have been determined acceptable for use with currently approved LWR fuel with a peak burnup up to 62,000 MWd/MTU provided that the maximum LHR does not exceed 6.3 kW/ft peak rod average power for burnups exceeding 54,000 MWd/MTU. In order to account for the gap fraction uncertainty in fuel that does not meet the criteria specified in Footnote 11 of RG 1.183, the licensee conservatively adjusted these gap fractions by a factor of 2.0 as discussed below.

The licensee stated that the St. Lucie 1 core design allows for a maximum of 150 rods, which may exceed the burnup limits specified in Footnote 11 of RG 1.183. Considering 217 assemblies in the core and 176 fuel rods per assembly, the 150 high burnup rods represent 0.393 percent of the core. The licensee stated that the number of rods exceeding the burnup/LHR for St. Lucie 1 will be limited to 150 rods. Conservatively, the licensee evaluated the EPU AST analyses assuming a total of 1760 rods, the equivalent of ten fuel assemblies, exceed the high burnup limit. The licensee doubled the activity gap fractions for all rods in ten assemblies in addition to applying a peaking factor of 1.65 to account for the high burnup rods that exceed the limits specified in RG 1.183. This approach increases the impact of the high burnup fuel rods from the actual 0.393 percent of the core to 4.608 percent of the core. Doubling the gap release fraction of 4.608 percent of the core yields a core-wide high burnup adjustment factor of 1.04608. The licensee applied this factor to the release fractions for all events in which fuel damage causes the core wide inventory of the fuel rod gaps to be released into the reactor coolant. For the FHA, in which 100 percent of the rods in the dropped fuel assembly are assumed to release their gap activity, the licensee addressed the high burnup issue by increasing the gap release fraction of the entire assembly by a factor of 2.0. The staff agrees that the licensee's approach to the evaluation of the high burnup issue at St. Lucie 1 is conservative and therefore acceptable.

#### 2.9.2.2.2.2 Transport

Pursuant to guidance provided in RG 1.183, the St. Lucie 1 FHA is analyzed based on the assumption that all of the fission products released from the reactor cavity or SFP are released to the environment over a 2-hour period. The licensee utilized a ground-level release for all scenarios considered for the subject FHA. A drop of a single fuel assembly and a subsequent release from the closest point of the FHB to the CR was found to be the most limiting FHA.

For the FHA occurring inside containment, the licensee assumed that the equipment maintenance hatch is open at the time of the accident and that the release from the containment occurs with no credit taken for containment isolation, no credit for dilution or mixing in the containment atmosphere, and no credit for filtration of the released effluent. For the FHA



occurring in the FHB, the licensee also assumed no credit for filtration of the activity released from the SFP water prior to being released to the environment.

As corrected by Item 8 of RIS 2006-04 (Reference 62), RG 1.183, Appendix B, Regulatory Position 2, should read as follows:

"If the depth of water above the damaged fuel is 23 feet or greater, the decontamination factors for the elemental and organic species are 285 and 1, respectively, giving an overall effective decontamination factor of 200 (i.e., 99.5 percent of the total iodine released from the damaged rods is retained by the water). This difference in decontamination factors for elemental iodine (99.85 percent) and organic iodide (0.15 percent) species results in the iodine above the water being composed of 70 percent elemental iodine and 30 percent organic iodide species."

As noted previously, the licensee assumed a minimum water depth of 23 feet covers the underlying damaged fuel assembly in both the reactor cavity and SFP for the FHA analyzed in the subject LAR. The assumed 176 damaged fuel rods in the pool releases 100 percent of its gap activity within the water, which is scrubbed by the water column as it rises throughout. This scrubbing decontaminates the gap releases with an overall DF of 200. This DF results in 0.5 percent (i.e., 99.5 percent of the iodine are retained in the pool) of the radioiodine escaping the overlying water with a composition of 70 percent elemental iodine and 30 percent organic iodide. Additionally, 100 percent of the noble gas is assumed to exit the pool per Regulatory Position 3 of RG 1.183.

#### 2.9.2.2.2.3 CR Ventilation Assumptions for the FHA

In order to evaluate the CR habitability for the postulated design basis FHA, the licensee assumed three modes of operation for the control room. During normal mode of operation (i.e., prior to CR isolation), there is an even, unfiltered air flow from dual air intakes to the CR at a rate conservatively adjusted to 920 cfm. After the radiation monitors activate the emergency signal, both north and south CR intakes are closed simultaneously. This occurs approximately 50 seconds into the postulated FHA. Accordingly, the air flow distribution during this post CR isolation mode consists of 0 cfm of outside makeup flow, 460 cfm of assumed unfiltered leakage, and 1760 cfm of filtered recirculation flow. After 90 minutes from the onset of the accident, the operator acts to open the more favorable CR air intake based on the output of the radiation monitors, maintaining positive pressure and initiating filtered air makeup into the CR. Air flow during this period consists of up to 504 cfm filtered makeup flow, 460 cfm of assumed unfiltered leakage, and 1256 cfm of filtered recirculation flow. This filtered air makeup continues throughout the remainder of the 30-day event. This process is discussed in more detail in Section 3.2.2, "Control Room Atmospheric Dispersion Factors" of this SE. The licensee considered CREVS filtration efficiencies, as applied to both the filtered makeup flow and the recirculation flow, of 99 percent for particulate activity, 95 percent for elemental iodine, and 95 percent for organic iodide.

#### 2.9.2.2.3 Conclusion

The licensee evaluated the radiological consequences resulting from a postulated FHA at St. Lucie 1 and concluded that the radiological consequences at the EAB, outer boundary of the LPZ, and CR are within the reference values and the CR dose criterion provided in 10 CFR 50.67 as well as the accident specific dose guidelines specified in SRP 15.0.1. The staff's review has found that the licensee used analyses, assumptions, and inputs consistent

with applicable regulatory guidance identified in Section 2.0 of this SE. The assumptions found acceptable to the staff are presented in Table 6 and the licensee's calculated dose results are given in Table 1. The staff finds that all doses estimated by the licensee for the St. Lucie 1 FHA will comply with the requirements of 10 CFR 50.67 and the guidelines of RG 1.183, and are therefore acceptable.

### 2.9.2.3 Main Steam Line Break (MSLB) Accident

#### 2.9.2.3.1 Description of Event

The postulated MSLB accident assumes a double-ended break of a main steam line. This leads to an uncontrolled release of steam from the steam system. The resultant depressurization of the steam system causes the MSIVs to close and, if the plant is operating at power when the event is initiated, causes the reactor to trip. For the MSLB DBA radiological consequence analysis, a LOOP is assumed to occur shortly after the trip signal. Following a reactor trip and turbine trip, the radioactivity is released to the environment through the SG PORVs. Because the LOOP renders the main condenser unavailable, the plant is cooled down by releasing steam to the environment.

The licensee evaluated the radiological consequences of a MSLB outside containment. In addition, the licensee considered the radiological consequences of a MSLB inside containment. For the MSLB outside containment, the affected SG, hereafter referred to as the faulted SG, rapidly depressurizes and releases the initial contents of the SG to the environment. For the MSLB inside containment, the faulted SG rapidly depressurizes and releases the initial contents of the SG to the containment atmosphere. The MSLB accident is described in Section 15.4.6 of the St. Lucie 1 FSAR. RG 1.183, Appendix E, identifies acceptable radiological analysis assumptions for a PWR MSLB.

The steam release from a rupture of a main steam line would result in an initial increase in steam flow, which decreases during the accident as the steam pressure decreases. The increased energy removal from the RCS causes a reduction of coolant temperature and pressure. Due to the negative MTC, the cooldown results in an insertion of positive reactivity. In addition, the conservative analysis assumes that the most reactive control rod is stuck in its fully withdrawn position after the reactor trip, thereby increasing the possibility that the core will become critical and return to power. The core is ultimately shut down by the boric acid delivered by the safety injection system.

#### 2.9.2.3.2 Analysis Parameters and Assumptions

##### 2.9.2.3.2.1 MSLB Source Term

Appendix E of RG 1.183 identifies acceptable radiological analysis assumptions for a PWR MSLB accident. RG 1.183, Appendix E, Regulatory Position 2, states that if no or minimal fuel damage is postulated for the limiting event, the released activity should be the maximum coolant activity allowed by TS including the effects of pre-accident and concurrent iodine spiking. The licensee's evaluation indicates that fuel damage is assumed to occur as a result of a MSLB accident. The licensee determined that the activity released from the damaged fuel will exceed that released by the two iodine spike cases. Therefore, the licensee performed the MSLB dose consequence analysis based on the assumption of fuel damage and did not analyze the two iodine spike cases.

The licensee determined the allowable levels of fuel failure for DNB and FCM for both the MSLB outside of containment and the MSLB inside of containment. The licensee based the MSLB source term on the total core inventory of the radionuclide groups as described in RG 1.183, Regulatory Position 3.1. The licensee adjusted the source term for the fraction of fuel damaged and applied a radial peaking factor of 1.65 to the inventory of the damaged fuel. The fraction of fission product inventory in the gap available for release due to DNB is consistent with Regulatory Position 3.2 and Table 3 of RG 1.183. The licensee increased the gap release fractions by a factor of 1.04608 to account for high burnup fuel rods as described previously in this SE. For the fraction of the core that is assumed to experience fuel centerline melt, the licensee applied the guidance provided in RG 1.183, Appendix H, and Regulatory Position 1, to determine the release. This guidance states that the release attributed to fuel melting should be based on the fraction of the fuel that reaches or exceeds the initiation temperature for fuel melting and that for the secondary system release pathway, 100 percent of the noble gases and 50 percent of the iodines in that fraction are released to the reactor coolant.

RG 1.183, Appendix E, Regulatory Position 4 states that, "The chemical form of radioiodine released from the fuel should be assumed to be 95 percent cesium iodide (CsI), 4.85 percent elemental iodine, and 0.15 percent organic iodide. Iodine releases from the SGs to the environment should be assumed to be 97 percent elemental iodine and 3 percent organic iodide. These fractions apply to iodine released as a result of fuel damage and to iodine released during normal operations, including iodine spiking." Accordingly, the licensee assumed that the iodine releases to the environment or to the containment from both the faulted SG and the unaffected SG consist of 97 percent elemental iodine and 3 percent organic iodide. The licensee evaluated the radiological dose contribution from the release of secondary side activity using the equilibrium secondary side specific activity TS LCO of 0.1  $\mu\text{Ci/gm}$  dose-equivalent iodine (DEI).

#### 2.9.2.3.2.2 Transport

The licensee evaluated two cases for the MSLB; one case is based upon a double-ended break of a main steam line outside of containment, and the second case is based upon a double-ended break of a main steam line inside of containment. The primary difference between these two models is the transport of the primary-to-secondary leakage through the affected SG. The postulated MSLB will result in the rapid depressurization of the affected or faulted SG. The rapid secondary depressurization causes a reactor power transient, resulting in a reactor trip. Plant cooldown is achieved via the remaining unaffected SG. The analysis for both cases assumes that activity is released as reactor coolant enters the SGs due to primary-to-secondary leakage. The licensee adjusted the source term for this activity for the fraction of damaged fuel, the non-LOCA fission product gap fractions from Table 3 of RG 1.183 including an adjustment for high burnup fuel, and an adjustment for a radial peaking factor of 1.65. All noble gases associated with this leakage are assumed to be released directly to the environment.

For both cases, the licensee assumed that the primary-to-secondary leak rate is apportioned equally between the SGs at the rate of 0.5 gpm total with 0.25 gpm to any one SG. This is in accordance with the accident induced leakage performance criteria of the Steam Generator Program as described in TS Section 6.8.4.1. This accident induced leakage performance criteria continues to maintain margin to the operational leakage limit specified in the TSs. The SG tube leakage TS limit is 150 gallons per day per SG which is roughly equivalent to 0.1 gpm.

For the break outside containment, the licensee assumed that the primary-to-secondary leakage into the faulted SG is released directly to the atmosphere. For the break inside containment, the licensee assumed that the faulted SG primary-to-secondary leakage is released into containment. The licensee assumed that all primary-to secondary leakage continues until the faulted SG is completely isolated at 12.4 hours.

The licensee followed the guidance as described in RG 1.183, Appendix E, and Regulatory Position 5 in all aspects of the transport analysis for the MSLB. RG 1.183, Appendix E, Regulatory Position 5.2, states that, "The density used in converting volumetric leak rates (e.g., gpm) to mass leak rates (e.g., lbm/hr) should be consistent with the basis of the parameter being converted. The alternate repair criteria (ARC) leak rate correlations are generally based on the collection of cooled liquid. Surveillance tests and facility instrumentation used to show compliance with leak rate technical specifications are typically based on cooled liquid. In most cases, the density should be assumed to be 1.0 gm/cc (62.4 lbm/ft<sup>3</sup>).” The density used by the licensee in converting volumetric leak rates to mass leak rates is based upon RCS conditions, which is consistent with the plant design basis. The licensee used a RCS fluid density to convert the primary-to-secondary leakage from a volumetric flow rate to a mass flow rate, which is consistent with the RCS cooldown rate applied in the generation of the secondary steam releases. This methodology follows the guidance of RG 1.183 and is, therefore, acceptable to the NRC staff.

RG 1.183, Appendix E, Regulatory Position 5.3, states that, "The primary to secondary leakage should be assumed to continue until the primary system pressure is less than the secondary system pressure, or until the temperature of the leakage is less than 100 °C (212 °F). The release of radioactivity from unaffected SGs should be assumed to continue until shutdown cooling is in operation and releases from the SGs have been terminated.” In accordance with RG 1.183, the licensee assumed that the primary-to-secondary leakage is assumed to continue until after shutdown cooling has been placed in service and the temperature of the RCS is cooled to less than 212 °F.

In accordance with RG 1.183, the licensee assumed that all noble gas radionuclides released from the primary system are released to the environment without reduction or mitigation. Following the guidance from RG 1.183, Appendix E, Regulatory Positions 5.5.1, 5.5.2 and 5.5.3, the licensee assumed that all of the primary-to-secondary leakage into the faulted SG will flash to vapor, and be released to the environment or to the containment with no mitigation. For the unaffected SG that is used for plant cooldown, the licensee assumed that a portion of the leakage would flash to vapor based on the thermodynamic conditions in the reactor and secondary immediately following a plant trip when tube uncover is postulated. The licensee assumed that the primary-to-secondary leakage would mix with the secondary water without flashing during periods of total tube submergence.

The licensee assumed that the postulated leakage that immediately flashes to vapor would rise through the bulk water of the SG into the steam space and be immediately released to the environment or to the containment with no mitigation. For conservatism, the licensee did not credit any reduction for scrubbing within the SG bulk water. RG 1.183, Appendix E, Regulatory Position 5.5.4, states that, "The radioactivity in the bulk water is assumed to become vapor at a rate that is the function of the steaming rate and the partition coefficient. A partition coefficient for iodine of 100 may be assumed. The retention of particulate radionuclides in the steam generators is limited by the moisture carryover from the steam generators.” Accordingly, the licensee assumed that the radioactivity in the bulk water of the unaffected SG becomes vapor at

a rate that is a function of the steaming rate and the partition coefficient. The licensee used a partition coefficient of 100 for elemental iodine and other particulate radionuclides released from the intact SG.

In accordance with RG 1.183, Appendix E, Regulatory Position 5.6, the licensee evaluated the potential for SG tube bundle uncover and determined that tube bundle uncover is postulated to occur in the intact SG for up to 1 hour following a reactor trip for St. Lucie 1. During this period, the licensee assumed that the fraction of primary-to secondary leakage that flashes to vapor would rise through the bulk water of the SG into the steam space and be immediately released to the environment or the containment with no mitigation. The licensee determined the flashing fraction based on the thermodynamic conditions in the reactor and secondary coolant. The licensee assumed that the leakage that does not flash would mix with the bulk water in the SG.

The licensee assumed that operator action would be taken to restore water level above the top of the tubes in the unaffected SG within 1 hour following a reactor trip. The NRC staff considers that crediting operator action to restore water level above the top of the tubes in the unaffected SG within one hour following a reactor trip to be a conservative and acceptable assumption.

The licensee assumed that all secondary releases would occur from the ADV with the most limiting atmospheric dispersion factors. For the MSLB inside containment, the licensee assumed that releases from containment through the SBVS are released from the plant stack with a filter efficiency of 99 percent for particulates and 95 percent for both elemental iodine and organic iodide. The licensee assumed that 9.6 percent of the containment leakage is assumed to bypass the SBVS filters and is released unfiltered to the environment as a ground-level release from containment. The licensee assumed an initial leak rate from the containment of 0.5 percent of the containment air per day. In accordance with applicable guidance, the licensee reduced this leak rate by 50 percent after 24 hours to 0.25 percent per day. The licensee credited natural deposition of the radionuclides consistent with the LOCA methodology as discussed previously in this SE. The licensee did not credit containment sprays for the MSLB analysis.

#### 2.9.2.3.2.3 CR Ventilation Assumptions for the MSLB

In order to evaluate the CR habitability for the postulated design basis MSLB, the licensee assumed three modes of operation for the CR ventilation system. During the normal mode of operation prior to CR isolation, there is an even, unfiltered air flow from dual air intakes to the CR at a rate conservatively assumed to be 920 cfm with an assumed value of 460 cfm for unfiltered inleakage. After the radiation monitors activate the emergency signal, both the north and south CR intakes are closed simultaneously. This occurs approximately 50 seconds into the postulated MSLB event. Accordingly, the air flow distribution during this post CR isolation mode consists of 0 cfm of outside makeup flow, 460 cfm of assumed unfiltered inleakage, and 1760 cfm of filtered recirculation flow.

After 90 minutes from the onset of the accident, operator action is credited to open the more favorable CR air intake based on the output of the radiation monitors, maintaining positive pressure and initiating filtered air makeup into the CR. Air flow during this period consists of up to 504 cfm filtered makeup flow, an assumed 460 cfm of unfiltered inleakage, and 1256 cfm of filtered recirculation flow. This filtered air makeup continues throughout the remainder of the 30-day accident evaluation period. The licensee assumed CREVS filtration efficiencies, as

applied to both the filtered makeup flow and the recirculation flow, of 99 percent for particulate activity, 95 percent for elemental iodine, and 95 percent for organic iodide. The CR parameters used in the EPU analyses are shown in Table 4 of this SE.

#### 2.9.2.3.3 Conclusion

The licensee evaluated the radiological consequences resulting from the postulated MSLB accident and concluded that the radiological consequences at the EAB, LPZ, and CR comply with the reference values and the CR dose criterion provided in 10 CFR 50.67 and the accident specific dose guidelines specified in SRP Section 15.0.1 and RG 1.183. The NRC staff's review found that the licensee used analysis, assumptions, and inputs consistent with applicable regulatory guidance identified in Section 2.0 of this SE. The assumptions found acceptable to the NRC staff are presented in Table 7 and the licensee's calculated dose results are given in Table 1. The NRC staff finds, with reasonable assurance, that the licensee's estimates of the dose consequences of a design basis MSLB will comply with the requirements of 10 CFR 50.67 and the guidelines of RG 1.183, and are, therefore, acceptable.

#### 2.9.2.4 Steam Generator Tube Rupture (SGTR) Accident

##### 2.9.2.4.1 Description of Event

The SGTR event is described in Section 15.4.4 of the St. Lucie 1 FSAR. The SGTR accident is evaluated based on the assumption of an instantaneous and complete severance of a single SG tube. At normal operating conditions, the leak rate through the double-ended rupture of one tube is greater than the maximum flow available from the charging pumps. For leaks that exceed the capacity of the charging pumps, pressurizer water level and pressurizer pressure decrease and an automatic reactor trip results. The turbine then trips and the main steam dump and bypass valves open, discharging steam directly into the condenser.

The postulated break allows primary coolant liquid to leak to the secondary side of the ruptured SG. Integrity of the barrier between the RCS and the main steam system is significant from a radiological release standpoint. The radioactivity from the ruptured SG tube mixes with the shell side water in the affected SG. As stated in the FSAR, detection of reactor coolant leakage to the steam system is facilitated by radiation monitors in the SG blowdown lines, in the condenser air ejector discharge lines and in the main steam line radiation monitors. These monitors initiate alarms in the CR and alert operators of abnormal activity levels and that corrective action is required.

For the SGTR DBA radiological consequence analysis, a LOOP is assumed to occur shortly after the reactor trip signal. With a LOOP, the cessation of circulating water through the condenser would eventually result in the loss of condenser vacuum, thereby causing steam relief directly to the atmosphere from the ADVs. The licensee assumed that this direct steam relief continues until the ruptured SG is isolated at 45 minutes. This credited operator action after 45 minutes represents a conservative increase in the assumed time for this manual action over the time credited in the current licensing basis SGTR accident.

#### 2.9.2.4.2 Analysis Parameters and Assumptions

##### 2.9.2.4.2.1 SGTR Source Term

Appendix F of RG 1.183 identifies acceptable radiological analysis assumptions for an SGTR accident. If a licensee demonstrates that no or minimal fuel damage is postulated for the limiting event, the activity released should be the maximum coolant activity allowed by TSs. Two radioiodine spiking cases are considered. The first case is referred to as a pre-accident iodine spike and assumes that a reactor transient has occurred prior to the postulated SGTR that has raised the primary coolant iodine concentration to the maximum value permitted by the TS for a spiking condition. For St. Lucie 1, the maximum iodine concentration allowed by TS as a result of an iodine spike is 60  $\mu\text{Ci/gm DEI}$ .

The second case assumes that the primary system transient associated with the SGTR causes an iodine spike in the primary system. This case is referred to as an accident-induced iodine spike or a concurrent iodine spike. Initially, the plant is assumed to be operating with the RCS iodine activity at the TS limit for normal operation. For St. Lucie 1, the RCS TS limit for normal operation is 1.0  $\mu\text{Ci/gm DEI}$ . The increase in primary coolant iodine concentration for the concurrent iodine spike case is estimated using a spiking model that assumes that as a result of the accident, iodine is released from the fuel rods to the primary coolant at a rate that is 335 times greater than the iodine equilibrium release rate corresponding to the iodine concentration at the TS limit for normal operation. The iodine release rate at equilibrium is equal to the rate at which iodine is lost due to radioactive decay, RCS purification, and RCS leakage. The iodine release rate is also referred to as the iodine appearance rate. The concurrent iodine spike is assumed to persist for a period of 8 hours.

The licensee's evaluation indicates that no fuel damage is predicted as a result of an SGTR accident. Therefore, consistent with the CLB and regulatory guidance, the licensee performed the SGTR accident analyses for the pre accident iodine spike case and the concurrent accident iodine spike case. In accordance with regulatory guidance, the licensee assumed that the activity released from the iodine spiking mixes instantaneously and homogeneously throughout the primary coolant system. In accordance with regulatory guidance, the licensee assumed that the iodine releases from the SGs to the environment consist of 97 percent elemental iodine and 3 percent organic iodide.

For the SGTR accident, the licensee evaluated the radiological dose contribution from the release of secondary coolant iodine activity at the TS limit of 0.1  $\mu\text{Ci/gm DEI}$ .

##### 2.9.2.4.2.2 Transport

The licensee followed the guidance as described in RG 1.183, Appendix F, Regulatory Position 5, in all other aspects of the transport analysis for the SGTR dose consequence analysis.

In addition to the primary coolant released into the ruptured SG by the tube rupture, the licensee apportioned the primary-to-secondary leak rate between the SGs as specified by TS 6.8.4.1, which is 0.5 gpm total and 0.25 gpm to any one SG.

RG 1.183, Appendix F, Regulatory Position 5.2, states that, "The density used in converting volumetric leak rates (e.g., gpm) to mass leak rates (e.g., lbm/hr) should be consistent with the

basis of surveillance tests used to show compliance with leak rate technical specifications.” The density used by the licensee in converting volumetric leak rates to mass leak rates is based upon RCS conditions, which is consistent with the plant design basis. The licensee used an RCS fluid density to convert the primary-to-secondary leakage from a volumetric flow rate to a mass flow rate, which is consistent with the RCS cooldown rate applied in the generation of the secondary steam releases. This methodology follows the guidance of RG 1.183 and is therefore acceptable to the NRC staff.

RG 1.183, Appendix F, Regulatory Position 5.3, states that, “The primary to secondary leakage should be assumed to continue until the primary system pressure is less than the secondary system pressure, or until the temperature of the leakage is less than 100 °C (212 °F). The release of radioactivity from the unaffected SGs should be assumed to continue until shutdown cooling is in operation and releases from the SGs have been terminated.” For the EPU analysis, the isolation of the affected SG by operator action is assumed to occur in 45 minutes. Isolation of the affected SG terminates releases from the ruptured SG, while primary-to-secondary leakage continues to provide activity for release from the unaffected SG.

The licensee assumed that a portion of the primary-to-secondary ruptured tube flow or break flow through the SGTR will flash to vapor based on the thermodynamic conditions in the RCS and the secondary system. For the unaffected SG used for plant cooldown, the licensee assumed that flashing would occur immediately following the reactor trip when tube uncover is postulated. The licensee credited operator action to restore water level above the top of the tubes in the unaffected SG within a conservative time of 1 hour following a reactor trip. The licensee assumed that primary-to-secondary leakage would mix with the secondary water without flashing during periods of total tube submergence.

The licensee assumed that the source term resulting from the radionuclides in the primary system coolant, including the contribution from iodine spiking, is transported to the ruptured SG by the break flow. A portion of the break flow is assumed to flash to steam because of the higher enthalpy in the RCS relative to the secondary system. The licensee assumed that the flashed portion of the break flow will ascend through bulk water of the SG, enter the steam space of the affected generator, and be immediately available for release to the environment with no credit taken for scrubbing. Although RG 1.183 allows the use of the methodologies described in NUREG-0409 to determine the amount of scrubbing credit applied to the flashed portion of the break flow, the licensee conservatively did not credit scrubbing of the activity in the break flow in the ruptured SG.

During the first 0.131 hours (472.7 seconds) of the event, prior to the reactor trip and the assumed concurrent LOOP, the licensee assumed that all of the SG flow is routed to the condenser. After 0.131 hours, the condenser is no longer available due to the assumed LOOP. The iodine and other non-noble gas isotopes in the non-flashed portion of the break flow are assumed to mix uniformly with the SG liquid mass and be released to the environment in direct proportion to the steaming rate and in inverse proportion to the applicable partition coefficient. In accordance with the guidance in RG 1.183, the licensee assumed a partition coefficient of 100 for iodine. The licensee assumed that the retention of particulate radionuclides in the SGs is limited by the moisture carryover from the SGs. The licensee assumed the same partition coefficient of 100, as used for iodine, for other particulate radionuclides. This assumption is consistent with the SG carryover rate of less than 1 percent.



In accordance with RG 1.183, Appendix E, Regulatory Position 5.6, the licensee evaluated the potential for SG tube bundle uncover and determined that tube bundle uncover is postulated to occur in the intact SG for up to 1 hour following a reactor trip for St. Lucie 1. During this period, the licensee assumed that the fraction of primary-to secondary leakage that flashes to vapor would rise through the bulk water of the SG into the steam space and be immediately released to the environment or the containment with no mitigation. The licensee determined the flashing fraction based on the thermodynamic conditions in the reactor and secondary coolant. The licensee assumed that the leakage which does not flash would mix with the bulk water in the SG.

#### 2.9.2.4.2.3 CR Ventilation Assumptions for the SGTR

In order to evaluate the CR habitability for the postulated design basis SGTR, the licensee assumed three modes of operation for the CR ventilation system. During the normal mode of operation prior to CR isolation, there is an even, unfiltered air flow from dual air intakes to the CR at a rate conservatively assumed to be 920 cfm with an additional assumed unfiltered inleakage of 460 cfm. After the radiation monitors activate the emergency signal, both the north and south CR intakes are closed simultaneously. For the SGTR event, the licensee conservatively assumed that the CR isolation signal would be delayed until the release from the ADVs is initiated at 472.7 seconds. The licensee included an additional 50-second delay to account for the diesel generator start time, fan start, and damper actuation time. Therefore, for the SGTR analysis, the licensee assumed that CR isolation would occur approximately 522.7 seconds after initiation of the postulated SGTR event. After isolation, the air flow distribution consists of 0 cfm of outside makeup flow, an assumed 460 cfm of unfiltered inleakage, and 1760 cfm of filtered recirculation flow.

After 90 minutes from the onset of the accident, operator action is credited to open the more favorable CR air intake based on the output of the radiation monitors, maintaining positive pressure and initiating filtered air makeup into the CR. Air flow during this period consists of up to 504 cfm filtered makeup flow, an assumed 460 cfm of unfiltered inleakage, and 1256 cfm of filtered recirculation flow. This filtered air makeup continues throughout the remainder of the 30-day accident evaluation period. The licensee assumed CREVS filtration efficiencies, as applied to both the filtered makeup flow and the recirculation flow, of 99 percent for particulate activity, 95 percent for elemental iodine, and 95 percent for organic iodide. The CR parameters used in the AST analyses are shown in Table 4 of this SE.

#### 2.9.2.4.3 Conclusion

The licensee evaluated the radiological consequences resulting from the postulated SGTR accident and concluded that the radiological consequences at the EAB, LPZ, and CR comply with the reference values and CR dose criterion provided in 10 CFR 50.67 and the accident specific dose guidelines specified in SRP Section 15.0.1 and RG 1.183. The NRC staff's review has found that the licensee used analyses, assumptions, and inputs consistent with applicable regulatory guidance identified in Section 2.0 of this SE. The assumptions found acceptable to the NRC staff are presented in Table 8 and the licensee's calculated dose results are given in Table 1. The NRC staff finds, with reasonable assurance, that the licensee's estimates of the dose consequences of a design basis SGTR will comply with the requirements of 10 CFR 50.67 and the guidelines of RG 1.183, and are therefore acceptable.

## 2.9.2.5 Reactor Coolant Pump Shaft Seizure (Locked Rotor) Accident

### 2.9.2.5.1 Description of Event

Section 15.3.4 of the FSAR for St. Lucie 1 describes the locked rotor accident as an event in which the instantaneous seizure of a single RCP shaft occurs due to mechanical failure. The principal purpose of the RCP is to provide forced coolant flow through the core of the reactor. As a result of the mechanical failure, flow through the affected primary-to-secondary loop is rapidly reduced; ultimately, causing a three-pump system of reactor coolant flow through the core versus a four-pump system. The postulated sequence of events following a locked rotor accident is a reactor trip due to the low coolant flow rate, stored heat transferred to the primary coolant, rapid temperature increase in primary RCS, probable fuel damage due to a decrease of initial DNB margin, and SG tube leakage due to a significant pressure differential between the primary and secondary systems. Fission products from the damaged fuel in the St. Lucie 1 reactor core are assumed to mix instantaneously and homogeneously in the primary coolant. Primary coolant activity transfers to the secondary system via SG tube leakage. Primary coolant activity from SG tube leakage together with secondary activity is postulated to be released to the environment via the ADVs.

The licensee evaluated the locked rotor accident using the accident source term pursuant to guidance provided in RG 1.183, Appendix G. The licensee followed the regulatory positions noted in RG 1.183 to define the assumptions, parameters, and inputs used in calculating new values for the dose assessment of the postulated locked rotor accident.

### 2.9.2.5.2 Analysis Parameters and Assumptions

#### 2.9.2.5.2.1 Locked Rotor Accident Source Term

For the EPU analysis, the licensee assumed that 19 percent of fuel assemblies that will experience DNB as a result of the locked rotor accident. The licensee incorporated the release fractions from Appendix G of RG 1.183 with an increase of 4.608 percent to account for high burnup fuel and a radial peaking factor of 1.65. In accordance with RG 1.183, Appendix G, the licensee assumed that all activity released from the breached fuel assemblies mixes both instantaneously and homogeneously throughout the primary coolant system. This activity is assumed to be released to the secondary system via SG tube leakage.

In accordance with RG 1.183, Appendix G, Regulatory Position 4, the licensee assumed that the chemical form of radioiodine released from the breached fuel assemblies consists of 95 percent CsI, 4.85 percent elemental iodine, and 0.15 percent organic iodide. The licensee also assumed that the chemical form of radioiodine released from the SGs to the environmental atmosphere consists of 97 percent elemental iodine and 3 percent organic iodide. This speciation is applicable to both the iodine released as a result of fuel damage and the iodine released from the pre-accident equilibrium iodine concentrations in the RCS and in the secondary coolant system. Additionally, the licensee accounted for the TS limited RCS and secondary activity in the calculations.

#### 2.9.2.5.2.2 Transport

Pursuant to guidance provided in RG 1.183, Appendix G, the licensee analyzed the primary-to-secondary release path, with subsequent secondary release to the atmosphere via steaming

from the ADVs without scrubbing. The released activity consists of the RCS TS equilibrium activity in addition to activity released from the breached fuel. The licensee assumed that the release of noble gases occurs without mitigation or reduction. In accordance with RG 1.183, if the temperature of the leakage exceeds 212 °F, the fraction of total iodine in the liquid that becomes airborne should be assumed equal to the fraction of the leakage that flashes to vapor. For the locked rotor accident analysis, the licensee assumed that 5 percent of the primary-to-secondary leakage will flash to steam during the assumed 1-hour period of tube uncover.

Consistent with Regulatory Positions 5.5.1, 5.5.2, and 5.5.3 of RG 1.183, Appendix E, the licensee assumed that all of the primary-to-secondary leakage that does not flash mixes with the bulk water in the SGs. Additionally, in agreement with Regulatory Position 5.5.4, the licensee assumed that the radioactivity in the bulk water of both SGs becomes vapor at a rate that is a function of the steaming rate and the partition coefficient of 100 for iodine and other particulate radionuclides.

#### 2.9.2.5.2.3 CR Ventilation Assumptions for the LRA

In order to evaluate the CR habitability for the postulated design basis locked rotor accident, the licensee assumed three modes of operation for the CR. During normal mode of operation, there is an even, unfiltered air flow from dual air intakes to the CR at a rate conservatively adjusted to 920 cfm. After the radiation monitors activate the emergency signal, both north and south CR intakes are closed simultaneously. This occurs approximately 50 seconds into the postulated locked rotor accident. Accordingly, the air flow distribution during this post CR isolation mode consists of 0 cfm of outside makeup flow, 460 cfm of assumed unfiltered inleakage, and 1760 cfm of filtered recirculation flow. After 90 minutes from the onset of the accident, operator action is credited to open the more favorable CR air intake based on the output of the radiation monitors, maintaining a positive pressure by initiating filtered air makeup into the CR. Air flow during this period consists of up to 504 cfm filtered makeup flow, 460 cfm of assumed unfiltered inleakage, and 1256 cfm of filtered recirculation flow. This filtered air makeup continues throughout the remainder of the 30-day accident analysis period. The licensee considered CREVS filtration efficiencies, as applied to both the filtered makeup flow and the recirculation flow, of 99 percent for particulate activity, 95 percent for elemental iodine, and 95 percent for organic iodide.

#### 2.9.2.5.3 Conclusion

The licensee evaluated the radiological consequences resulting from a postulated locked rotor accident at St. Lucie 1 and concluded that the radiological consequences at the EAB, outer boundary of the LPZ, and CR are within the reference values and CR dose criterion provided in 10 CFR 50.67 and accident specific dose guidelines specified in SRP 15.0.1. The staff's review has found that the licensee used analysis, assumptions, and inputs consistent with applicable regulatory guidance identified in Section 2.0 of this SE. The assumptions found acceptable to the staff are presented in Table 9 and the licensee's calculated dose results are given in Table 1. The staff finds that the doses estimated by the licensee for the St. Lucie 1 LRA will comply with the requirements of 10 CFR 50.67 and the guidelines of RG 1.183, and are therefore acceptable.

## 2.9.2.6 Control Element Assembly Ejection Accident

### 2.9.2.6.1 Description of Event

Section 15.4.5 of the FSAR for St. Lucie 1 describes the CEA ejection accident as the mechanical failure of a CEA and drive shaft resulting in a rapid withdrawal of a single CEA from the reactor core. This uncontrolled ejection of a CEA is caused by a sudden circumferential break of either the CEDM pressure housing or the CEDM nozzle of the reactor vessel head. As a result, the pressure of the RCS acts to fully eject a CEA. The primary consequence of the described mechanical failure is a rapid reactivity insertion together with an adverse core power distribution (leading to a reactor trip and possible fuel rod damage). The licensee evaluated two independent release paths in the event of a CEA accident. The first release path assumes an instantaneous and homogeneous release of fission products from the damaged fuel in the reactor core to the containment atmosphere with successive release to the environment via containment leakage. The second release pathway assumes that all of the activity that is released from the damaged fuel is fully dispersed in the primary coolant and subsequently released to the secondary system via SG tube leakage. Activity is subsequently released from the secondary side to the environment via steaming from the ADVs.

The licensee evaluated the CEA event using the accident source term pursuant to guidance provided in RG 1.183, Appendix H. The licensee followed the regulatory positions noted in RG 1.183 to define the assumptions, parameters, and inputs used in calculating the dose assessment of the CEA accident.

### 2.9.2.6.2 Analysis Parameters and Assumptions

#### 2.9.2.6.2.1 CEA Ejection Accident Source Term

For the purpose of this EPU analysis, the licensee assumed in both release scenarios that 9.5 percent of the fuel rods experience DNB and 0.5 percent of the fuel will experience FCM as a result of the CEA ejection from the reactor core. The licensee incorporated the release fractions from Appendix H of RG 1.183 with an increase of 4.608 percent to account for high burnup fuel and a radial peaking factor of 1.65. In deriving the source term for the CEA event, the licensee made assumptions consistent with Regulatory Position 1 of RG 1.183, Appendix H. Per this guidance, the licensee assumed the following conditions for the two release paths analyzed in the provided AST analysis:

For the containment leakage release pathway, it is assumed that in the event of a CEA accident, 100 percent of the noble gases and 25 percent of the iodine contained in the assumed fraction of melted fuel are available for release via containment leakage. In addition, the release from the breached fuel is based on the estimate of the number of fuel rods breached and the assumption that 10 percent of the core inventory of the noble gases and iodines resides in the fuel gap. All of the activity released as a result of clad damage and core centerline melting is assumed to be released both instantaneously and homogeneously throughout the containment atmosphere.

For the secondary system release pathway, it is assumed that in the event of a CEA, accident, 100 percent of the noble gases and 50 percent of the iodine contained in the assumed fraction of melted fuel are released to the RCS. In

addition, the release from the breached fuel is based on the estimate of the number of fuel rods breached and the assumption that 10 percent of the core inventory of the noble gases and iodines resides in the fuel gap. All of the activity released as a result of clad damage and core centerline melting is assumed to be released both instantaneously and homogeneously throughout the primary coolant system and to be available for release to the secondary system via SG tube leakage.

In accordance with RG 1.183, Appendix H, Regulatory Position 4, the licensee assumed that the chemical form of radioiodine released to the containment atmosphere consists of 95 percent CsI, 4.85 percent elemental iodine, and 0.15 percent organic iodide. The licensee credits effective controls to limit the pH in the containment sump to 7.0 or higher. In agreement with Regulatory Position 5 of RG 1.183, Appendix H, the licensee assumed that the chemical form of radioiodine released from the SGs to the environment consists of 97 percent elemental iodine and 3 percent organic iodide.

Additionally, the licensee accounted for the TS limited RCS and secondary system activity in the calculations.

#### 2.9.2.6.2.2 Transport

Pursuant to guidance provided in RG 1.183, Appendix H, the licensee analyzed two release cases. The first case is based on the assumption that all of the fission products released from the damaged fuel in the reactor core are instantaneously and homogeneously mixed throughout the atmosphere of the containment. The licensee analyzed releases from the containment to the environment that are filtered via the SBVS and the released activity that bypasses the SBVS. The SBVS is assumed to remove 99 percent of the particulate activity and 95 percent of both the elemental iodine and organic iodide activity. The licensee assumed 9.6 percent of the activity leaked from the containment will bypass the SBVS filters in the CEA accident analysis.

The second case assumes that all of the fission products released from the damaged fuel in the reactor core are completely dissolved in the primary coolant system and are transferred to the secondary system via SG tube leakage. The activity in the secondary system is subsequently released to the environment via the ADVs without credit for SG scrubbing.

The licensee utilized the plant stack as the point of release for the containment scenario crediting SBVS filtration. This release was considered as a ground-level release per guidance provided in RG 1.145, discussed in more detail in Section 3.2.3, "Offsite Atmospheric Dispersion Factors" of this SE. A ground-level release mode was also used for the containment releases that bypass the SBVS and for the secondary release scenario.

#### 2.9.2.6.2.3 Transport from Containment

For containment releases of the CEA accident, the licensee assumed that all activity from the breached fuel would release to and mix instantaneously and homogeneously in the containment volume. As specified in TS 3.6.1.1 limit, this activity was modeled to leak from the containment to the environment at an initial rate of 0.50 weight % per day for the first 24 hours, followed by a rate of 0.25 weight % per day for the remaining 29 days of the 30-day CEA accident analysis period. This assumption is consistent with Regulatory Position 6.2 of RG 1.183, Appendix H.

The licensee credited natural deposition of the released activity inside the containment. This credit was applied to the radionuclides released using a removal coefficient of 0.10 per hour for aerosols and 2.89 per hour for elemental iodine. No credit was applied to the natural deposition of organic iodide or for the removal of activity via containment sprays.

#### 2.9.2.6.2.4 Transport from the Secondary System

For secondary releases of the CEA accident, the licensee assumed that all activity from the breached and melted fuel would release to and completely mix in the primary coolant system. Subsequently, the released activity is assumed to transfer to the secondary coolant system as a result of SG tube leakage. Releases to the environment occur as a result of steaming via the ADVs. The release of noble gases is assumed to occur without mitigation or reduction. The activity released from the primary-to-secondary system is assumed to occur at a leak rate of 0.25 gpm per SG for a total of 0.50 gpm. For both cases, the licensee assumed that the primary-to-secondary leak rate is apportioned equally between the SGs at the rate of 0.5 gpm total with 0.25 gpm to any one SG. The 0.50 gpm total primary-to-secondary leakage rate is assumed to continue until the SG is fully isolated. The time needed to achieve these conditions is assumed to be 12.4 hours.

If the temperature of the leakage exceeds 212 °F, the fraction of total iodine in the liquid that becomes airborne should be assumed equal to the fraction of the leakage that flashes to vapor. The licensee has determined that the tube bundle in the intact SGs may become uncovered for up to 45 minutes following a reactor trip and that less than 5 percent of the primary-to-secondary leakage will flash to steam while the tube bundle is uncovered. For the CEA analysis, the licensee conservatively assumed that 5 percent of the primary-to-secondary leakage will flash to steam for a 1-hour period of tube uncover.

Consistent with Regulatory Positions 5.5.1, 5.5.2, and 5.5.3 of RG 1.183, Appendix E, the licensee assumed that all of the primary-to-secondary leakage that does not flash mixes with the bulk water in the SGs. Additionally, in agreement with Regulatory Position 5.5.4 of this guidance, it is assumed that the radioactivity in the bulk water of both SGs becomes vapor at a rate that is a function of the steaming rate and the partition coefficient of 100 for iodine and other particulate radionuclides.

#### 2.9.2.6.2.5 CR Ventilation Assumptions for the CEA Ejection Accident

In order to evaluate the CR habitability for the postulated design basis CEA ejection accident, the licensee assumed three modes of operation for the CR. During normal mode of operation (i.e., prior to CR isolation), there is an even, unfiltered air flow from dual air intakes to the CR at a rate conservatively adjusted to 920 cfm. After the radiation monitors activate the emergency signal, both north and south CR intakes are closed simultaneously. This occurs approximately 50 seconds into the postulated CEA accident. Accordingly, the air flow distribution during this post CR isolation mode consists of 0 cfm of outside makeup flow, 460 cfm of assumed unfiltered inleakage, and 1760 cfm of filtered recirculation flow. After 90 minutes from the onset of the accident, operator action is credited to open the more favorable CR air intake based on the output of the radiation monitors, maintaining a positive pressure by initiating filtered air makeup into the CR. Air flow during this period consists of up to 504 cfm filtered makeup flow, 460 cfm of assumed unfiltered inleakage, and 1256 cfm of filtered recirculation flow. This filtered air makeup continues throughout the remainder of the 30-day accident analysis period. This process is discussed in more detail in Section 3.2.2, "Control Room Atmospheric Dispersion

Factors” of this SE. The licensee considered CREVS filtration efficiencies, as applied to both the filtered makeup flow and the recirculation flow, of 99 percent for particulate activity, 95 percent for elemental iodine, and 95 percent for organic iodide.

#### 2.9.2.6.3 Conclusion

The licensee evaluated the radiological consequences resulting from a postulated CEA accident at St. Lucie 1 and concluded that the radiological consequences at the EAB, outer boundary of the LPZ, and CR are within the reference values and the CR dose criterion provided in 10 CFR 50.67 and the accident specific dose guidelines specified in SRP 15.0.1. The staff’s review has found that the licensee used analysis, assumptions, and inputs consistent with applicable regulatory guidance identified in Section 2.0 of this SE. The assumptions found acceptable to the staff are presented in Table 10 and the licensee’s calculated dose results are given in Table 1. The staff finds that the doses estimated by the licensee for the St. Lucie 1 CEA ejection accident will comply with the requirements of 10 CFR 50.67 and the guidelines of RG 1.183, and are therefore acceptable.

#### 2.9.2.7 Inadvertent Opening of a Main Steam Safety Valve (IOMSSV)

##### 2.9.2.7.1 Description of Event

This event is caused by the inadvertent opening of a SG MSSV. Due to the pressure differential between the primary and secondary systems and assumed SG tube leakage, fission products contained in the primary coolant before the accident are discharged from the primary into the secondary system. The licensee assumed that the SG tubes do not remain covered and therefore, no credit is taken for scrubbing in the SG. In addition, the licensee did not credit a flashing fraction for the primary leakage into the SGs. As a result, the licensee assumed that the entire leaked RCS radioactivity is released to the outside atmosphere from the secondary coolant system through the SG MSSVs. The licensee assumed that all of the activity initially present in the SGs would be released to the environment over a 2-hour period. The IOMSSV event is described in Section 15.2.11 of the FSAR.

##### 2.9.2.7.2 Analysis Parameters and Assumptions

###### 2.9.2.7.2.1 IOMSSV Source term

Regulatory Guide 1.183 does not provide specific guidance for an inadvertent opening of a SG MSSV. Therefore to analyze this event, the licensee referred to the guidance in RG 1.183, Appendix G, for a PWR locked rotor accident, which the licensee judged and the NRC staff agrees, to be closely applicable to the conditions of an inadvertent opening of an MSSV.

The licensee has determined that no fuel damage is postulated to occur for this event. Therefore, the source term for this event is the initial RCS and secondary side activity present at the beginning of the event. The licensee assumed the activity from the fuel to be released instantaneously and homogeneously through the primary coolant.

The licensee assumed the initial RCS activity to be at the TS limit of 1.0  $\mu\text{Ci/gm}$  DEI and 518.9  $\mu\text{Ci/gm}$  DE Xe-133. The licensee assumed the initial SG secondary side activity to be at the TS 3.7.1.4 limit of 0.1  $\mu\text{Ci/gm}$  DEI. The licensee conservatively assumed that the entire contents of both SGs are assumed to be released to the environment over a 2-hour period.

#### 2.9.2.7.2.2 Transport

Following NRC guidance, the licensee assumed that the iodine releases from the SGs to the environment would consist of 97 percent elemental iodine and 3 percent organic iodide. The licensee assumed that the primary-to-secondary leak rate is apportioned equally between the SGs as specified by TS 6.8.4.1 to 0.5 gpm total and 0.25 gpm to any one SG. The licensee determined the density used in converting volumetric leak rates to mass leak rates upon RCS conditions, consistent with the plant design basis.

The licensee assumed that the primary-to-secondary leakage would continue until after SDC has been placed in service and the temperature of the RCS is less than 212 °F. The licensee's analysis assumes a coincident LOOP and that all noble gas radionuclides released from the primary system are released to the environment without reduction or mitigation.

The licensee assumed that the SG tubes do not remain covered throughout this event for St. Lucie 1. Therefore, the iodine and transport model for release from the SGs assumes that both SGs discharge all of their contents. As a result of this assumption, all of the primary-to-secondary leakage is assumed to flash to steam and be released to the environment with no mitigation and all the radioactivity within the bulk water in the SGs is assumed to be released directly to the environment over a 2-hour period.

#### 2.9.2.7.2.3 CR Ventilation Assumptions for the IOMSSV

In order to evaluate the CR habitability for the postulated design basis IOMSSV, the licensee assumed three modes of operation for the control room ventilation system. During the normal mode of operation prior to CR isolation, there is an even, unfiltered air flow from dual air intakes to the CR at a rate conservatively assumed to be 920 cfm. After the radiation monitors activate the emergency signal, both the north and south CR intakes are closed simultaneously. This occurs approximately 50 seconds into the postulated IOMSSV event. Accordingly, the air flow distribution during this post CR isolation mode consists of 0 cfm of outside makeup flow, 460 cfm of assumed unfiltered inleakage, and 1760 cfm of filtered recirculation flow.

After 90 minutes from the onset of the accident, operator action is credited to open the more favorable CR air intake based on the output of the radiation monitors, maintaining positive pressure and initiating filtered air makeup into the CR. Air flow during this period consists of up to 504 cfm filtered makeup flow, an assumed 460 cfm of unfiltered inleakage, and 1256 cfm of filtered recirculation flow. This filtered air makeup continues throughout the remainder of the 30-day accident evaluation period. The licensee assumed CREVS filtration efficiencies, as applied to both the filtered makeup flow and the recirculation flow, of 99 percent for particulate activity, 95 percent for elemental iodine, and 95 percent for organic iodide. The CR parameters used in the AST analyses are shown in Table 4 of this SE.

#### 2.9.2.7.3 Conclusion

The licensee evaluated the radiological consequences resulting from the postulated IOMSSV accident and concluded that the radiological consequences at the EAB, LPZ, and CR comply with the reference values provided in 10 CFR 50.67 and the accident specific dose guidelines specified in SRP Section 15.0.1 and RG 1.183. The NRC staff's review has found that the licensee used analysis, assumptions, and inputs consistent with the most applicable regulatory



guidance identified in Section 2.0 of this SE. In the absence of directly applicable guidance, the licensee used conservative assumptions to evaluate this event which are found to be acceptable to the NRC staff. The assumptions found acceptable to the NRC staff are presented in Table 11 and the licensee's calculated dose results are given in Table 1. The NRC staff finds, with reasonable assurance, that the licensee's estimates of the dose consequences of a design basis IOMSSV will comply with the requirements of 10 CFR 50.67 and the guidelines of RG 1.183, and are therefore acceptable.

### Conclusion

The NRC staff has evaluated the licensee's revised accident analyses performed in support of the proposed EPU and concludes that the licensee has adequately accounted for the effects of the proposed EPU. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of postulated DBAs since, as set forth above, the calculated TEDE at the EAB, at the LPZ outer boundary, and in the control room meet the exposure guideline values specified in 10 CFR 50.67 and GDC 19, as well as applicable acceptance criteria denoted in SRP 15.0.1. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to the radiological consequences of DBAs.

**Table 1**  
**St. Lucie 1 Radiological Consequences Expressed as TEDE <sup>(1)</sup>**  
**(rem)**

Design Basis Accidents	EAB <sup>(2)</sup>	LPZ <sup>(3)</sup>	CR <sup>(4)</sup>
LOCA	1.1E+00	2.5E+00	4.8E+00
MSLB – Outside containment (1.2% DNB)	2.7E-01	7.7E-01	4.6E+00
MSLB – Outside containment (0.29% FCM)	3.0E-01	8.1E-01	4.7E+00
MSLB – Inside containment (21% DNB)	4.1E-01	8.7E-01	4.7E+00
MSLB – Inside containment (4.5% FCM)	6.3E-01	1.2E+00	4.6E+00
SGTR Pre-accident spike	3.7E-01	3.7E-01	4.7E+00
Dose acceptance criteria	2.5E+01	2.5E+01	5.0E+00
SGTR Concurrent iodine spike	1.8E-01	2.8E-01	2.2E+00
Locked Rotor Accident (19% DNB)	3.7E-01	8.7E-01	4.4E+00
IOMSSV	3E-02	3E-02	3.9E-01
Dose acceptance criteria	2.5E+00	2.5E+00	5.0E+00
FHA - Containment	5.6E-01	5.8E-01	1.4E+00
FHA – Fuel Handling Building	5.6E-01	5.5E-01	3.5E+00
CEA Ejection Containment Release <sup>(5)</sup> (9.5% DNB, 0.5% FCM)	2.8E-01	5.5E-01	3.3E+00
CEA Ejection Secondary Side Release <sup>(5)</sup> (9.5% DNB, 0.5% FCM)	2.9E-01	7.1E-01	3.3E+00
Dose acceptance criteria	6.3E+00	6.3E+00	5.0E+00

<sup>(1)</sup> Total effective dose equivalent

<sup>(2)</sup> Exclusion area boundary - worst 2-hour dose

<sup>(3)</sup> Low population zone - Integrated 30 day dose

<sup>(4)</sup> CR - Integrated 30 day dose - assumed unfiltered inleakage of 460 cfm

<sup>(5)</sup> Assumes 9.5% DNB and 0.5% FCM

**Note:** Licensee's dose results are expressed to a limit of two significant figures.

**Table 2 (Page 1 of 8)**

**St. Lucie 1  
Control Room (CR) Atmospheric Dispersion Factors ( $\chi/Q$  Values)**

**A. Loss-of-Coolant Accident (LOCA): Containment Leakage - Shield Building Ventilation System (SBVS) and Containment Purge / H<sub>2</sub> Purge**

Operation Mode	Release/ Receptor Pair	$\chi/Q$ Values (sec/m <sup>3</sup> )				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
<b>Prior to CR Isolation</b>	Stack Vent / North CR Intake*	2.39E-03	---	---	---	---
<b>During CR Isolation</b>	Stack Vent / Midpoint CR Intake*	3.91E-03	---	---	---	---
<b>After Initiation of Filtered Make-up</b>	Stack Vent / South CR Intake*	6.93E-04	4.88E-04	2.19E-04	1.46E-04	1.28E-04

\* Credit for dilution was taken in this case.

**B. Loss-of-Coolant Accident (LOCA): Containment Leakage – Shield Building Ventilation System (SBVS) Bypass**

Operation Mode	Release/ Receptor Pair	$\chi/Q$ Values (sec/m <sup>3</sup> )				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
<b>Prior to CR Isolation</b>	Closest FW Line Point / North CR Intake	7.29E-03	---	---	---	---
<b>During CR Isolation</b>	Closest FW Line Point / Midpoint CR Intake	3.17E-03	---	---	---	---
<b>After Initiation of Filtered Make-up</b>	Closest FW Line Point/ South CR Intake	1.76E-03	1.41E-03	5.72E-04	4.29E-04	3.57E-04

**Table 2 (Page 2 of 8)**

**St. Lucie 1**

**Control Room (CR) Atmospheric Dispersion Factors ( $\chi/Q$  Values)**

**C. Loss-of-Coolant Accident (LOCA): Emergency Core Cooling System (ECCS) Leakage**

Operation Mode	Release/ Receptor Pair	$\chi/Q$ Values (sec/m <sup>3</sup> )				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
<b>Prior to CR Isolation</b>	Aux. Bldg. Louver L-7B / North CR Intake	4.80E-03	---	---	---	---
<b>During CR Isolation</b>	Aux. Bldg. Louver L-7A / Midpoint CR Intake	5.03E-03	---	---	---	---
<b>After Initiation of Filtered Make-up</b>	Aux. Bldg. Louver L-7A / South CR Intake	3.61E-03	2.87E-03	1.20E-03	9.07E-04	7.13E-04

**D. Loss-of-Coolant Accident (LOCA): Refueling Water Tank (RWT) Backleakage**

Operation Mode	Release/ Receptor Pair	$\chi/Q$ Values (sec/m <sup>3</sup> )				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
<b>Prior to CR Isolation</b>	RWT / North CR Intake	1.37E-03	---	---	---	---
<b>During CR Isolation</b>	RWT / Midpoint CR Intake	1.34E-03	---	---	---	---
<b>After Initiation of Filtered Make-up</b>	RWT / South CR Intake	1.12E-03	9.10E-04	3.84E-04	2.93E-04	2.37E-04

**Table 2 (Page 3 of 8)**

**St. Lucie 1  
Control Room (CR) Atmospheric Dispersion Factors ( $\chi/Q$  Values)**

**E. Fuel Handling Accident (FHA): Containment Release**

Operation Mode	Release/ Receptor Pair	$\chi/Q$ Values (sec/m <sup>3</sup> )				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
<b>Prior to CR Isolation</b>	Containment Maintenance Hatch / North CR Intake	1.90E-03	---	---	---	---
<b>During CR Isolation</b>	Containment Maintenance Hatch / Midpoint CR Intake	1.21E-03	---	---	---	---
<b>After Initiation of Filtered Make-up</b>	Containment Maintenance Hatch / South CR Intake	8.22E-04	6.57E-04	2.87E-04	1.92E-04	1.74E-04

**F. Fuel Handling Accident (FHA): Fuel Handling Building (FHB) Release**

Operation Mode	Release/ Receptor Pair	$\chi/Q$ Values (sec/m <sup>3</sup> )				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
<b>Prior to CR Isolation</b>	FHB Closest Wall Point / North CR Intake	4.99E-03	---	---	---	---
<b>During CR Isolation</b>	FHB Closest Wall Point / Midpoint CR Intake	3.27E-03	---	---	---	---
<b>After Initiation of Filtered Make-up</b>	FHB Closest Wall Point / South CR Intake	2.01E-03	1.44E-03	6.25E-04	4.34E-04	3.33E-04

**Table 2 (Page 4 of 8)**

**St. Lucie 1  
Control Room (CR) Atmospheric Dispersion Factors ( $\chi/Q$  Values)**

**G. Main Steam Line Break (MSLB): Release from Outside Containment**

Operation Mode	Release/ Receptor Pair	$\chi/Q$ Values (sec/m <sup>3</sup> )				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
<b>Prior to CR Isolation</b>	Closest ADV / North CR Intake	6.30E-03	---	---	---	---
<b>During CR Isolation</b>	Closest ADV / Midpoint CR Intake	2.84E-03	---	---	---	---
<b>After Initiation of Filtered Make-up</b>	Closest ADV / South CR Intake	1.62E-03	1.32E-03	5.06E-04	3.88E-04	3.30E-04

**H. Main Steam Line Break (MSLB): Release from Inside Containment – Shield Building Ventilation System (SBVS)**

Operation Mode	Release/ Receptor Pair	$\chi/Q$ Values (sec/m <sup>3</sup> )				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
<b>Prior to CR Isolation</b>	Stack Vent / North CR Intake*	2.39E-03	---	---	---	---
<b>During CR Isolation</b>	Stack Vent / Midpoint CR Intake*	3.91E-03	---	---	---	---
<b>After Initiation of Filtered Make-up</b>	Stack Vent / South CR Intake*	6.93E-04	4.88E-04	2.19E-04	1.46E-04	1.28E-04

\* Credit for dilution was taken in this case.

Table 2 (Page 5 of 8)

**St. Lucie 1**  
**Control Room (CR) Atmospheric Dispersion Factors ( $\chi/Q$  Values)**

**I. Main Steam Line Break (MSLB): Release from Inside Containment – Shield Building Ventilation System (SBVS) Bypass**

Operation Mode	Release/ Receptor Pair	$\chi/Q$ Values (sec/m <sup>3</sup> )				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
<b>Prior to CR Isolation</b>	Closest FW Line Point / North CR Intake	7.29E-03	---	---	---	---
<b>During CR Isolation</b>	Closest FW Line Point / Midpoint CR Intake	3.17E-03	---	---	---	---
<b>After Initiation of Filtered Make-up</b>	Closest FW Line Point/ South CR Intake	1.76E-03	1.41E-03	5.72E-04	4.29E-04	3.57E-04

**J. Steam Generator Tube Rupture (SGTR)**

Operation Mode	Release/ Receptor Pair	$\chi/Q$ Values (sec/m <sup>3</sup> )				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
<b>Prior to CR Isolation</b>	<b><u>Prior to Turbine Trip</u></b> Steam Jet Air Ejector/ North CR Intake	3.02E-03	---	---	---	---
	<b><u>After Turbine Trip</u></b> Closest ADV / North CR Intake	6.30E-03	---	---	---	---
<b>During CR Isolation</b>	Closest ADV / Midpoint CR Intake	2.84E-03	---	---	---	---
<b>After Initiation of Filtered Make-up</b>	Closest ADV / South CR Intake	1.62E-03	1.32E-03	5.06E-04	3.88E-04	3.30E-04

**Table 2 (Page 6 of 8)**

**St. Lucie 1  
Control Room (CR) Atmospheric Dispersion Factors ( $\chi/Q$  Values)**

**K. Locked Rotor**

<b>Operation Mode</b>	<b>Release/ Receptor Pair</b>	<b><math>\chi/Q</math> Values (sec/m<sup>3</sup>)</b>				
		<b>0 to 2 Hours</b>	<b>2 to 8 Hours</b>	<b>8 to 24 Hours</b>	<b>24 to 96 Hours</b>	<b>96 to 720 Hours</b>
<b>Prior to CR Isolation</b>	Closest ADV / North CR Intake	6.30E-03	---	---	---	---
<b>During CR Isolation</b>	Closest ADV / Midpoint CR Intake	2.84E-03	---	---	---	---
<b>After Initiation of Filtered Make-up</b>	Closest ADV / South CR Intake	1.62E-03	1.32E-03	5.06E-04	3.88E-04	3.30E-04

**L. Control Element Assembly (CEA) Ejection: Secondary Release**

<b>Operation Mode</b>	<b>Release/ Receptor Pair</b>	<b><math>\chi/Q</math> Values (sec/m<sup>3</sup>)</b>				
		<b>0 to 2 Hours</b>	<b>2 to 8 Hours</b>	<b>8 to 24 Hours</b>	<b>24 to 96 Hours</b>	<b>96 to 720 Hours</b>
<b>Prior to CR Isolation</b>	Closest ADV / North CR Intake	6.30E-03	---	---	---	---
<b>During CR Isolation</b>	Closest ADV / Midpoint CR Intake	2.84E-03	---	---	---	---
<b>After Initiation of Filtered Make-up</b>	Closest ADV / South CR Intake	1.62E-03	1.32E-03	5.06E-04	3.88E-04	3.30E-04



**Table 2 (Page 7 of 8)**

**St. Lucie 1  
Control Room (CR) Atmospheric Dispersion Factors ( $\chi/Q$  Values)**

M. Control Element Assembly (CEA) Ejection: Inside Containment Leakage - Shield Building Ventilation System (SBVS)

Operation Mode	Release/ Receptor Pair	$\chi/Q$ Values (sec/m <sup>3</sup> )				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
<b>Prior to CR Isolation</b>	Stack Vent / North CR Intake*	2.39E-03	---	---	---	---
<b>During CR Isolation</b>	Stack Vent / Midpoint CR Intake*	3.91E-03	---	---	---	---
<b>After Initiation of Filtered Make-up</b>	Stack Vent / South CR Intake*	6.93E-04	4.88E-04	2.19E-04	1.46E-04	1.28E-04

\* Credit for dilution was taken in this case.

N. Control Element Assembly (CEA) Ejection: Inside Containment Leakage - Shield Building Ventilation System (SBVS) Bypass

Operation Mode	Release/ Receptor Pair	$\chi/Q$ Values (sec/m <sup>3</sup> )				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
<b>Prior to CR Isolation</b>	Closest FW Line Point / North CR Intake	7.29E-03	---	---	---	---
<b>During CR Isolation</b>	Closest FW Line Point / Midpoint CR Intake	3.17E-03	---	---	---	---
<b>After Initiation of Filtered Make-up</b>	Closest FW Line Point/ South CR Intake	1.76E-03	1.41E-03	5.72E-04	4.29E-04	3.57E-04

**Table 2 (Page 8 of 8)**

**St. Lucie 1  
Control Room (CR) Atmospheric Dispersion Factors ( $\chi/Q$  Values)**

O. Inadvertent Opening of a Main Steam Safety Valve (IOMSSV)

Operation Mode	Release/ Receptor Pair	$\chi/Q$ Values (sec/m <sup>3</sup> )				
		0 to 2 Hours	2 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
<b>Prior to CR Isolation</b>	Closest ADV / North CR Intake	6.30E-03	---	---	---	---
<b>During CR Isolation</b>	Closest ADV / Midpoint CR Intake	2.84E-03	---	---	---	---
<b>After Initiation of Filtered Make-up</b>	Closest ADV / South CR Intake	1.62E-03	1.32E-03	5.06E-04	3.88E-04	3.30E-04

**Table 3**

**St. Lucie 1  
Offsite Atmospheric Dispersion Factors ( $\chi/Q$  Values)**

Offsite Dose Location		$\chi/Q$ Values* (sec/m <sup>3</sup> )				
		0 to 2 Hours	0 to 8 Hours	8 to 24 Hours	24 to 96 Hours	96 to 720 Hours
<b>Ground Release</b>	<b>EAB</b>	9.84E-05	5.53E-05	4.15E-05	2.22E-05	9.06E-06
	<b>LPZ</b>	9.56E-05	5.34E-05	3.99E-05	2.12E-05	8.55E-06

\*Note that all releases are assumed to be ground-level pursuant to RG. 1.145. The 0-2 hour EAB  $\chi/Q$  value was used throughout the entire design-basis accident (DBA).

**Note:** Licensee's  $\chi/Q$  results are expressed to a limit of three significant figures.

**Table 4**  
**St. Lucie 1 Control Room Data and Assumptions and Direct Shine Results**

Control Room Volume (Includes TSC)	96,228 ft <sup>3</sup>
<b>Normal Operation</b>	
Filtered Make-up Flow Rate	0 cfm
Filtered Recirculation Flow Rate	0 cfm
Unfiltered Make-up Flow Rate	920 cfm
Assumed unfiltered Inleakage	460 cfm
<b>Emergency</b>	
Isolation Mode:	
Filtered Make-up Flow Rate	0 cfm
Filtered Recirculation Flow Rate	1760 cfm <sup>(1)</sup>
Unfiltered Make-up Flow Rate	0 cfm
Assumed unfiltered Inleakage	460 cfm
Filtered Make-up Mode:	
Filtered Make-up Flow Rate	504 cfm <sup>(1)</sup>
Filtered Recirculation Flow Rate	1256 cfm <sup>(1)</sup>
Unfiltered Make-up Flow Rate	0 cfm
Assumed unfiltered Inleakage	460 cfm
Filter Efficiencies	
Particulates	99%
Elemental iodine	95%
Organic iodide	95%
CR operator breathing rate	
0 - 720 hours	3.5E-04 m <sup>3</sup> /sec
CR occupancy factors	
0 - 24 hours	1.0
24 - 96 hours	0.6
96 - 720 hours	0.4
LOCA CR Direct Shine Dose	
Containment	0.027 rem
Filters	0.094 rem
External Cloud	0.078 rem
<b>Total</b>	<b>0.20 rem</b>

1. Control room emergency ventilation flow rates conservatively consider over/under frequency/voltage of the emergency diesel generators, as well as tolerance in the control room ventilation flow rate test acceptance criteria.

**Table 5 (Page 1 of 3)**

**St. Lucie 1 Data and Assumptions for the LOCA**

Core Power level	3030 MWt (~3020 +0.3%)	
Core Average Fuel Burnup	49,000 MWd/MTU	
Fuel Enrichment	1.5 – 5.0 weight %	
Initial RCS Equilibrium Activity in coolant blowdown	1.0 $\mu\text{Ci/gm DEI}$	
	518.9 $\mu\text{Ci/gm DE Xe-133}$	
Volumetric flow rate for Hydrogen purge release	500 cfm	
Duration of Hydrogen purge release	30 seconds	
Primary containment leak rate		
0 - 24 hours	0.5% (by weight)/day	
24 - 720 hours	0.25% (by weight)/day	
Containment spray initiation time	80.0 seconds (0.022 hours)	
Containment spray termination time	8 hours	
Elemental iodine wall deposition coefficient (0-720 hours)	2.89 $\text{hr}^{-1}$	
Particulate natural deposition removal coefficient	Unsprayed	Sprayed region
0 - 8 hours	0.1 $\text{hr}^{-1}$	0 $\text{hr}^{-1}$
8 - 720 hours	0.1 $\text{hr}^{-1}$	0.1 $\text{hr}^{-1}$
Primary containment volume sprayed region	2,155,160 $\text{ft}^3$	
Primary containment volume unsprayed region	350,840 $\text{ft}^3$	
Flow rate between sprayed and unsprayed regions		
During spray operation	23,389 cfm	
After sprays are secured	11,695 cfm	
Elemental iodine spray removal coefficients		
0.022 – 2.331 hours	20 $\text{hr}^{-1}$	
2.331 - 720 hours	0 $\text{hr}^{-1}$	
Particulate spray removal coefficients		
0.022 – 2.334 hours	6.07 $\text{hr}^{-1}$	
2.334 - 8 hours	0.607 $\text{hr}^{-1}$	
8 - 720 hours	0 $\text{hr}^{-1}$	
Volume of water in containment sump (minimum)	67,394 $\text{ft}^3$	
ECCS Leakage to RAB (2 times allowed limit)	4750 cc/hr	
ECCS Flashing fraction		
Calculated	5.5%	
Used for dose determination	10%	
Chemical form of released iodine from ECCS leakage		
Particulate	0%	
Elemental iodine	97%	
Organic iodide	3%	

**Table 5 (Page 2 of 3)**

**St. Lucie 1 Data and Assumptions for the LOCA**

ECCS area filter efficiencies		
Elemental iodine		95%
Organic iodide		95%
Particulate		99%
Sump volume at time of recirculation		67,394 ft <sup>3</sup>
Initial RWT liquid inventory (minimum)		44,147 gallons
ECCS leakage into RWT (2 times allowed value)		2 gpm
Flashing fraction for leakage into RWT		0 %
Release from RWT vapor space to environment		1.07 cfm
Time dependent RWT pH values		
Selected times in hours		RWT pH
0.00		4.500
10.0		4.511
25.0		4.528
100.0		4.604
720.00		4.968
Time dependent RWT iodine concentration (gm-atom/liter)		
Selected times in hours	Total Iodine	Elemental Iodine
0.00	0.00E+00	0.000E+00
10.0	1.56E-06	2.487E-08
25.00	3.85E-06	1.320E-07
100.0	1.31E-05	9.771E-07
720.00	4.07E-05	2.532E-06
Time dependent RWT elemental iodine fraction		
Selected times in hours		Elemental iodine fraction
0.00		0.000E+00
10.0		3.181E-02
25.0		6.650E-02
100.0		1.492E-01
720.00		1.245E-01
RWT partition coefficient (PC)		
Time in hours		Elemental iodine PC
0.00 – 720.0		41.18

**Table 5 (Page 3 of 3)**

**St. Lucie 1 Data and Assumptions for the LOCA**

LOCA Release Rate from Sump to RWT Vapor Space	
Time (hours)	Adjusted Iodine Release Rate (cfm)
0.0	0.0
0.4	7.973E-07
10.0	8.637E-06
25.0	4.886E-05
75.0	1.545E-04
125.0	2.636E-04
200.0	3.895E-04
300.0	4.995E-04
450.0	5.563E-04
600.0	5.687E-04
Secondary containment filter efficiency	
Particulate	99%
Elemental iodine	95%
Organic iodide	95%
Secondary containment drawdown time	310 seconds
Secondary containment bypass fraction	9.6%
Containment purge filtration efficiency	0%
Transport assumptions	
Secondary containment prior to drawdown	Nearest containment penetration to CR
Secondary containment after drawdown	Plant stack
Secondary containment bypass leakage	Nearest containment penetration to CR
	Ventilation intake
ECCS leakage	ECCS exhaust louver
RWT backleakage	RWT
Containment purge	Plant stack
Control Room Ventilation System	
Time of automatic CR Isolation	50 seconds
Time of manual CR intake opening	1.5 hrs

**Table 6**  
**St. Lucie 1 Data and Assumptions for the FHA**

Core thermal power level	3030 MWt (~3020 + 0.3%)
Core average fuel burnup	49,000 MWd/MTU
Discharged fuel assembly burnup	45,000 – 62,000 MWd/MTU
Fuel enrichment	1.5 – 5.0 w/o
Maximum radial peaking factor	1.65
Number of fuel assemblies in the core	217
Number of fuel assemblies damaged	1
Minimum post shutdown fuel handling time (decay time)	72 hours
High burnup fuel adjustment factor	2.0
Minimum pool water depth	23 feet
Fuel clad damage gap release fractions (2 times RG 1.183, Table 3)	
I-131	16%
Remainder of halogens	10%
Kr-85	20%
Remainder of noble gases	10%
Alkali metals	24% (remains in pool water)
Pool DF	
Noble gases and organic iodide	1
Aerosols	Infinite
Elemental iodine (23 ft of water cover)	285
Overall iodine (23 ft of water cover)	200 (effective DF)
Chemical form of iodine in pool	
Elemental iodine	99.85%
Organic iodide	0.15%
Chemical form of iodine above pool surface	
Elemental iodine	70%
Organic iodide	30%
Duration of release to the environment	2 hour release
Control room ventilation assumptions	
Isolation time	50 seconds
Filtered makeup flow time	1.5 hours
Assumed unfiltered inleakage	460 cfm

**Table 7 (Page 1 of 2)**

**St. Lucie 1 Data and Assumptions for the MSLB Accident**

Core Power level	3030 MWt (~3020 + 0.3%)
Core Average Fuel Burnup	49,000 MWd/MTU
Fuel Enrichment	1.5 – 5.0 w/o
Maximum radial peaking factor	1.65
Percent DNB for MSLB outside containment	1.2%
Percent DNB for MSLB inside containment	21%
Percent FCM for MSLB outside containment	0.29%
Percent FCM for MSLB inside containment	4.5%
Initial RCS Equilibrium Activity	1.0 $\mu$ Ci/gm DEI
	518.9 $\mu$ Ci/gm DE Xe-133
Secondary coolant iodine activity	0.1 $\mu$ Ci/gm DEI
High burnup fuel adjustment factor	1.04608
Primary to secondary leak rates	0.25 gpm per SG
Time to terminate SG tube leakage	12.4 hours
RCS mass	406,715 lbm (minimum)
SG secondary side mass assumptions	
Intact SG	120,724.1 lbm (minimum)
Faulted SG	226,800 lbm (maximum)
Time to reach 212 °F terminating steam release	12.4 hours
Intact SG steam release rate in lbm/min for time interval in hours	
0.00 – 0.50	5225
0.50 – 0.75	2687
0.75 – 1.39	2687
1.39 – 2.00	2687
2.00 – 4.00	2711
4.00 – 6.00	2711
6.00 – 8.00	2711
8.00 – 10.50	2711
10.5 – 12.4	2711
12.4 - 720	0
SG secondary side iodine partition coefficients	
Intact SG	100
Faulted SG	1(none)
Chemical form of iodine released from the secondary side	
Particulate	0%
Elemental iodine	97%
Organic iodide	3%



**Table 7 (Page 2 of 2)**

**St. Lucie 1 Data and Assumptions for the MSLB Accident**

Credit for scrubbing within the SG bulk water	None
Intact SG tube uncover following reactor trip	
Time until tube recovery	1 hour
Flashing fraction	6 %
Containment volume	2.506E+06 ft <sup>3</sup>
Containment leakage rate	
0 to 24 hours	0.5% (by weight)/day
24 – 720 hours	0.25% (by weight)/day
Credit for containment sprays	None
Containment natural deposition coefficients	
Aerosols	0.1 hr <sup>-1</sup>
Elemental iodine	2.89 hr <sup>-1</sup>
Organic iodide	None
Secondary containment filter efficiency	
Particulate	99%
Elemental iodine	95%
Organic iodide	95%
Secondary containment drawdown time	310 seconds
Secondary containment bypass fraction	9.6%
Control room ventilation assumptions	
Isolation time	50 seconds
Filtered makeup flow time	1.5 hours
Assumed unfiltered inleakage	460 cfm

MSLB SG Tube Leakage (lbm/min)		
Time (hours)	Intact SG	Faulted SG
0.00 – 0.50	1.552	2.006
0.50 – 0.75	1.680	2.006
0.75 – 1.39	1.768	2.006
1.39 – 2.00	1.783	2.006
2.00 – 4.00	1.828	2.006
4.00 – 6.00	1.878	2.006
6.00 – 8.00	1.923	2.006
8.00 – 10.50	1.973	2.006
10.5 – 12.4	2.006	2.006
12.4 - 720	0	0

**Table 8**

### St. Lucie 1 Data and Assumptions for the SGTR Accident

Core power level	3030 MWt (~3020 + 0.3%)
Initial RCS equilibrium activity	1.0 $\mu\text{Ci/gm DEI}$
	518.9 $\mu\text{Ci/gm DE Xe-133}$
Initial secondary side equilibrium activity	0.1 $\mu\text{Ci/gm DEI}$
Initial maximum RCS equilibrium activity	1.0 $\mu\text{Ci/gm DEI}$
Maximum pre-accident spike iodine concentration	60 $\mu\text{Ci/gm DEI}$
Accident initiated iodine spike appearance rate	335 times equilibrium rate
Duration of accident initiated spike	8 hours
Break flow flashing fraction	
Prior to reactor trip	17%
Following reactor trip	6%
Time to terminate break flow	45 minutes
Primary to secondary SG tube leakage rate	0.25 gpm per SG
Time to terminate SG tube leakage	12 hours
Time to recover intact SG tubes	1 hour
SG secondary side iodine partition coefficients	
Flashed tube flow	None
Non-flashed tube flow	100
Time to reach 212 °F and terminate steam release	12.4 hours
RCS mass	
Pre-accident iodine spike	406,715 lbm
Concurrent iodine spike	474,951 lbm
Secondary coolant system mass	
Minimum for SG tube leakage	120,724 lbm
Maximum for secondary side release	226,800 lbm

### SGTR Break Flow and Steam Releases in lbm/min

Time (hr)	Event Description	Break flow	Steam Release to Atmosphere	
			Ruptured SG	Intact SG
0	SGTR	2544.83	11100	110730
0.131	Rx Trip	1724.28	4920	100
0.75	Ruptured SG Isolated	0	130	3760
1.0	Intact SG Re-covered	26.0	0	3760
1.5	Realign CR Intakes	39.0	0	3760
2.0	RSG PORV BV closed	39.0	0	3760
8.0	Flashing in RSG ends	39.0	0	2320
12.4	Termination of releases	0	0	0

RCS Iodine Inventory (Ci) for 8-hr concurrent spike with an appearance rate factor of 335

Isotope	Appearance rate (Ci/min)	8 hour total (Ci)
I-131	170.8	82,006
I-132	94.7	45,478
I-133	207.8	99,767
I-134	88.8	42,629
I-135	127.7	61,275

RCS Iodine concentrations for SGTR pre-existing spike of 60  $\mu$ Ci/gm DEI

I-131	50.6
I-132	10.1
I-133	52.3
I-134	4.6
I-135	23.6

SG secondary side iodine partition coefficients

Flashed tube flow	None
Non-flashed tube flow	100

Chemical form of iodine released from SGs

Particulate	0%
Elemental iodine	97%
Organic iodide	3%

Control room ventilation assumptions

Isolation time (total)	522.7 seconds
Start of release from ADVs	472.7 seconds
Delay for DG start, fan start and dampers	50 seconds
Filtered makeup flow time	1.5 hours
Assumed unfiltered inleakage	460 cfm

**Table 9**

**St. Lucie 1 Data and Assumptions for the Locked Rotor Accident**

Core Power level	3030 MWt (3020 + 0.3%)
Core Average Fuel Burnup	49,000 MWd/MTU
Fuel Enrichment	1.5 – 5.0 weight %
Maximum radial peaking factor	1.65
Percent of fuel rods in DNB	19%
High burnup fuel adjustment factor	1.04068
Initial RCS equilibrium activity	1.0 $\mu$ Ci/gm DEI
	518.9 $\mu$ Ci/gm DE Xe-133
Initial secondary side equilibrium activity	0.1 $\mu$ Ci/gm DEI
Total primary to secondary leak rate	0.5 gpm
Time to terminate SG tube leakage	12.4 hours
Time to recover SG tubes following Rx trip	1 hour
Flashing fraction	5%
Time to reach 212 °F terminating steam release	12.4 hours
RCS mass – minimum used to maximize dose	406,715 lbm
SG secondary side mass	
Minimum for SG leakage	120,724 lbm/SG
Maximum for secondary side release	226,800 lbm/SG
SG secondary side iodine partition coefficients	
Flashed tube flow	1(none)
Non-flashed tube flow	100

**LRA steam release rates and SG Tube leakage (lbm/min)**

Time (Hours)	Steam Release	Single SG leakage	Total SG Leakage
0.00 – 0.5	5486.15	1.552	3.103
0.5 – 0.75	2820.86	1.680	3.361
0.75 – 1.0	2820.86	1.714	3.428
1.0 – 1.39	2820.86	1.768	3.536
1.39 – 2.0	2820.86	1.783	3.565
2.0 – 4.0	2846.36	1.828	3.657
4.0 – 8.0	2846.36	1.878	3.756
8.0 – 10.5	2846.36	1.973	3.945
10.5 – 12.4	2846.36	2.006	4.012
12.4 - 720	0.0	0.0	0.0

Control room ventilation assumptions

Isolation time	50 seconds
Filtered makeup flow time	1.5 hours
Assumed unfiltered inleakage	460 cfm

**Table 10**  
**St. Lucie 1 Data and Assumptions for the CEA Ejection Accident**

Core Power level	3030 MWt (3020 + 0.3%)
Core Average Fuel Burnup	49,000 MWd/MTU
Fuel Enrichment	1.5 – 5.0 weight %
Maximum radial peaking factor	1.65
Percent of fuel rods in DNB	9.5%
Percent of fuel rods with FCM	0.5%
Initial RCS equilibrium activity	1.0 $\mu$ Ci/gm DEI
	518.9 $\mu$ Ci/gm DE Xe-133
Initial secondary side equilibrium activity	0.1 $\mu$ Ci/gm DEI
High burnup fuel adjustment factor	1.04068 (10 fuel assemblies)
Total primary to secondary leak rate	0.5 gpm
Time to terminate SG tube leakage	12.4 hours
Time to recover SG tubes following reactor trip	1 hour
Flashing fraction	5%
SG secondary side iodine partition coefficients	
Flashed tube flow	1(none)
Non-flashed tube flow	100
Time to reach 212 °F terminating steam release	12.4 hours
RCS mass – minimum used to maximize dose	406,715 lbm
SG secondary side mass	
Minimum for SG leakage	120,724 lbm/SG
Maximum for secondary side release	226,800 lbm/SG
Chemical form of iodine released to containment	
Particulate	95%
Elemental iodine	4.85%
Organic iodide	0.15%
Chemical form of iodine released from SGs	
Particulate	0%
Elemental iodine	97%
Organic iodide	3%
Control room ventilation assumptions	
Isolation time	50 seconds

Filtered makeup flow time	1.5 hours
Assumed unfiltered inleakage	460 cfm
Containment volume	2.506E+06 ft <sup>3</sup>
Containment leakage rate	
0 to 24 hours	0.5% (by weight)/day
24 – 720 hours	0.25% (by weight)/day
Secondary containment filter efficiency	
Particulate	99%
Elemental iodine	95%
Organic iodide	95%
Secondary containment drawdown time	310 seconds
Secondary containment bypass fraction	9.6%
Containment natural deposition coefficients	
Aerosols	0.1 hr <sup>-1</sup>
Elemental iodine	2.89 hr <sup>-1</sup>
Organic iodide	None
Credit for containment sprays	None

**Table 11**  
**St. Lucie 1 Data and Assumptions for the IOMSSV**

Core Power level	3030 MWt (3020 + 0.3%)
Initial RCS equilibrium activity	1.0 µCi/gm DEI
	518.9 µCi/gm DE Xe-133
Initial secondary side equilibrium activity	0.1 µCi/gm DEI
Total primary to secondary leak rate	0.5 gpm
Time to terminate SG tube leakage	12.4 hours
Secondary side mass release to environment	Entire inventory in 2 hours
SG secondary side iodine partition coefficients	1(none)
Maximum secondary side mass	226,800 lbm/SG
Control room ventilation assumptions	
Isolation time	50 seconds
Filtered makeup flow time	1.5 hours
Assumed unfiltered inleakage	460 cfm

### 2.9.3 Radiological Consequences of Gas Decay Tank Ruptures

#### Regulatory Evaluation

The license performed an analysis of the radiological consequences of the rupture of a waste gas decay tank (WGDT). The analysis was conducted to verify the adequacy of design and of operation of the gaseous waste management system with respect to the change in source term caused by EPU conditions. The NRC Staff reviewed the radiological consequences of the WGDT rupture to ensure compliance with:

- BTP 11-5, Rev. 3 from the Standard Review Plan, NUREG-0800, insofar as it established specific analysis and acceptance criteria for licensee evaluations of this event.
- 10 CFR 50.67, insofar as it establishes requirements for AST licensed plants that radiological doses from postulated accidents to individuals offsite and control room operators will be below established guidelines.

#### Technical Evaluation

##### 2.9.3.1 Description of Event

The licensee evaluated the WGDT rupture under EPU conditions assuming that a single WGDT fails catastrophically, instantaneously releasing the entire inventory of stored gaseous activity to the environment at ground level.

##### 2.9.3.2 Acceptance Criteria

BTP 11-5 allows for a dose acceptance criterion of 2.5 rem TEDE for systems designed to withstand explosions and earthquakes. For systems not designed to withstand explosions and earthquakes, BTP 11-5 imposes a significantly lower acceptance criterion of 0.1 rem TEDE. As described in FSAR Section 11.3, the licensee's gaseous waste management system is designed to prevent an explosive gas mixture and the WGDTs are seismically designed. Notwithstanding the fact that the licensee's gaseous waste management system meets the criteria for the higher acceptance criterion, the licensee has chosen the more restrictive criterion of 0.1 rem to establish the proposed TS limit for the contents of the WGDTs. The offsite dose acceptance criterion for a WGDT rupture accident of 0.1 rem TEDE applies to receptors located at the EAB and the outer boundary of the LPZ. In accordance with 10 CFR 50.67, the licensee evaluated the WGDT rupture using a CR dose acceptance criterion of 5.0 rem TEDE.

##### 2.9.3.3 Applicable Regulatory Guidance

The licensee analyzed the WGDT rupture accident using NRC guidance given in Regulatory Issue Summary RIS-2006-04, "Experience with Implementation of Alternative Source Terms", regarding application of the AST to WGDT events. RIS-2006-04 guidance specifically endorses BTP 11-5, Rev. 3 from the SRP, NUREG-0800.

##### 2.9.3.4 Source Term and Dose Models, Assumptions, and Parameters

In accordance with BTP 11-5 Position 1.B, "Source Term", the licensee developed the design basis source term based on an assumption that one percent of the operating fission product

inventory in the core is released to the RCS. BTP 11-5 Position 1.B specifies that typical operation of equipment should be assumed to remove gases from the coolant, and to process and treat them. The licensee's design basis RCS inventory is based on an extended full power operation period with 1 percent failed fuel releasing fission product gases into the RCS.

The licensee conservatively assumed that the entire RCS noble gas inventory is instantaneously transferred into one WGDT following reactor shutdown. The WGDT rupture is modeled based on an assumption that the entire WGDT inventory of noble gases is released instantaneously to the environment at ground level with no credit for decay or for isolation of the release path.

The licensee modeled the CR using assumptions consistent with other design basis events even though filtration will have no impact on the WGDT noble gas source term. The licensee assumed that unfiltered CR leakage continues at 460 cfm throughout the 30-day event and that normal CR ventilation mode unfiltered makeup air continues for 50 seconds, until CR isolation is assumed to occur. The licensee confirmed that the WGDT rupture will generate sufficient airborne activity to initiate automatic CR isolation well within the 50-second assumption. Consistent with other design bases events, the licensee assumed that after 1.5 hours CR operators identify the most favorable CR intake and implement pressurization mode through air make up and recirculation operations of the ventilation system. The licensee considered several different release points and CR intake locations to generate atmospheric dispersion factors (X/Qs) in order to bound all possible release-receptor pairs for both St. Lucie units.

#### 2.9.3.5 Results

The licensee's calculated offsite radiological doses for the design basis WGDT rupture source term of 90,921 DE curies Xe-133 are approximately 50 percent of the BTP 11-5 specified limit of 0.1 rem TEDE and the calculated CR dose is less than 10 percent of the CR dose guideline of 5 rem TEDE as stated in of 10 CFR 50.67. In addition the licensee derived the proposed TS limit of 165,000 curies of DE Xe-133 by increasing the dose equivalent source term proportionately to yield a predicted EAB dose very close to the dose limit of 0.1 rem TEDE.

#### Conclusion

The licensee analyzed the radiological consequences of releases from an accidental WGDT rupture accounting for the effects of the proposed EPU. The licensee has determined that the calculated total effective dose equivalents at the EAB and the LPZ outer boundary from a postulated WGDT rupture are below the dose guidelines of BTP 11-5. In addition, the licensee has determined that the CR dose will continue to meet its current licensing basis with respect to the dose criterion of 10 CFR 50.67. The NRC staff conducted a confirmatory calculation and determined that the licensee's TS limit is acceptable. The staff's review also found that the licensee used analyses, assumptions, and inputs consistent with applicable regulatory guidance identified in this safety evaluation. Therefore, based on consistency with applicable guidance and engineering judgment, the NRC staff finds the proposed EPU acceptable with respect to the radiological consequences of an accidental WGDT release.



## 2.10 Health Physics

### 2.10.1 Occupational and Public Radiation Doses

#### Regulatory Evaluation

The NRC staff conducted its review in this area to ascertain what overall effects the proposed EPU will have on both occupational and public radiation doses and to determine that the licensee has taken the necessary steps to ensure that any dose increases will be maintained within applicable regulatory limits and ALARA. The NRC staff's review included an evaluation of any increases in radiation sources and how this may affect plant area dose rates, plant radiation zones, and plant area accessibility. The NRC staff evaluated how personnel doses needed to access plant vital areas following an accident are affected. The NRC staff also considered the effects of the proposed EPU on plant effluent levels and any effect this increase may have on radiation doses at the site boundary. The NRC's acceptance criteria for occupational and public radiation doses are based on 10 CFR Part 20, and 10 CFR Part 50, Appendix I. Specific review criteria are contained in SRP Sections 12.2, 12.3, 12.4, and 12.5, NUREG-0737, Item II.B.2, and other guidance provided in Matrix 10 of RS-001.

#### Technical Evaluation

##### *Radiation Sources*

The original plant shielding design for St. Lucie was based on a core power level of 2700 MWt with 1 percent fuel defects and a 1-year fuel-cycle length. Currently Unit 1 is operating at 2700 MWt and an 18-month cycle. The licensee is proposing new core power level of 3020 MWt on an 18-month fuel cycle. This represents an approximate 11.85-percent increase in power level from the original (and the current) licensed power. For purposes of evaluating the impact of the EPU, the licensee evaluated the EPU based on 3030 MWt to account for a 0.3 percent power uncertainty margin. This represents an approximate 12.2-percent increase in power level from the original (and the current) licensed power. In general, the production of radiation and radioactive material (either fission or activation products) in the reactor core is directly dependent on the neutron flux and power level of the reactor. Therefore, an approximate 12.2-percent increase in power level is expected to result in a proportional increase in the direct (i.e. from the reactor fuel) and indirect (i.e., from the reactor coolant) radiation source terms.

The proposed EPU will require an increase in the nuclear fission rate, which will lead to an increase in the nuclear flux in the reactor core. The increased flux will cause an increase in neutron activation products in the RCS, control rod assemblies, reactor internals, and the pressure vessel as well as an increase in the fission product inventory in the core and spent fuel. The increased flux will also result in an increase in neutron and gamma flux leakage out of the RV. The increased inventory of fission products in the core will increase the activity concentration in the reactor coolant due to fuel defects. In the event of primary-to-secondary leakage in the SGs, the activity concentration in the secondary system will also increase relative to pre-EPU conditions. The increase in radioactivity levels in the core and RCS will result in an increase in radiation levels in the containment building, RAB, and other locations subject to direct shine from radiation sources contained in these buildings.

### *Radiation Levels*

As stated earlier, the approximate 12.2-percent increase in power level associated with the proposed EPU is expected to result in a proportional increase in the direct and indirect radiation source terms. The licensee has utilized scaling techniques to determine the impact of the EPU on plant radiation levels in the major plant areas affected by this proposed power increase. The licensee's evaluation takes credit for conservatism in existing shielding analyses, the TSs limits on reactor coolant activity, and the site's ALARA program to demonstrate continued adequacy of current plant shielding to ensure compliance with the occupational dose limits of 10 CFR Part 20.

The radiation dose rates near the RV are determined by the neutron and gamma leakage flux from the RV during operation and by the gamma fluxes in the core and the activation activities in the RV internals, pressure vessel, and primary system piping walls during shutdown. The primary purpose of the reinforced concrete primary shield wall surrounding the RV is to attenuate the neutron and gamma fluxes leaking out of the RV. The licensee estimates that the normal operation radiation levels near the RV will increase by a factor of approximately 12.2 percent due to the increased neutron and gamma flux leakage resulting from the proposed EPU. However, in performing new design calculations to support the proposed EPU, the licensee has determined that the combination of the following 3 items will offset the anticipated 12.2-percent increase in radiation levels:

1. the conservatism in the original analysis of the shielding design
2. the conservatism in the pre-EPU design basis source term used to establish the radiation zones
3. the more restrictive reactor coolant radionuclide concentrations required by the EPU change to TS 3.4.8 which significantly reduces the design basis source term

The licensee has determined, by shielding calculations, that the current neutron and gamma leakage from the RV is significantly less than the leakage conservatively estimated in the original design basis calculations. Although the neutron and gamma flux levels will increase by 12.2 percent as a result of the EPU, increases in radiation levels near the reactor vessel will not be substantially greater than the radiation levels previously estimated and approved in the original design basis analyses.

The radiation dose rates in containment areas adjacent to the RCS during operation are determined primarily by the N-16 levels in the reactor coolant. The shutdown dose rates in these areas are determined primarily by the deposited corrosion product activity and the cobalt impurities in the RCS and the SG components. The licensee estimates that, following EPU, both the N-16 and corrosion product source terms will increase by approximately 12.2 percent, resulting in operating and shutdown radiation levels in these areas increasing by the same percentage. The primary function of the secondary shielding which surrounds the RCS and the SGs is to attenuate the radiation levels from the N-16 source to those areas of containment outside of this secondary shield. The licensee stated that the increase in radiation levels due to the EPU will not affect the plant radiation zoning.

In most areas outside containment, the radiation sources are fission products and corrosion products in the primary coolant or down-stream sources originating from the primary coolant activity. The licensee estimates that, following EPU, both the fission products and the activated corrosion products will increase by approximately 12.2 percent, resulting in an approximate

12.2-percent increase in radiation levels in these areas. For example, the radiation levels in the auxiliary building near systems and components containing RCS fluids are expected to increase by approximately 12.2 percent. The radiation levels near the condensate polishing system may increase. The licensee indicates no additional personnel access controls will be required in this area other than continued use of existing plant ALARA procedures. The NRC finds a potential increase of 12.2 percent in dose rates in the area outside of containment will have no significant impact on compliance with 10 CFR Part 20 limits. Additionally, the NRC finds the anticipated increase in dose rates near the condensate polishers will have no significant impact on compliance with 10 CFR Part 20 limits since the current dose rates at the condensate polishers are so low (e.g., in the range of 0.1 mrem/hr or less).

As described above, the normal operation radiation levels in most of the plant area are expected to increase by approximately 12.2 percent. The licensee has stated that this expected increase in radiation levels will not affect radiation zoning, occupancy limits, or shielding requirements because of the conservatism in the licensee's shielding analyses and the TS limits on reactor coolant concentrations. The NRC finds that the licensee's established radiation protection program is sufficient to assure that all radiation areas are properly designated, posted, and controlled, in a timely manner, as required by 10 CFR Part 20 and TSs.

The licensee indicates the exposure to plant personnel and to the offsite public is also expected to increase approximately 12.2 percent. The NRC Occupational Exposure data base indicates that during the 3 years from 2008 to 2010, the annual collective dose at St. Lucie was greater than the national average for PWRs. The licensee estimates that the annual collective dose at St. Lucie will increase by approximately 12.2 percent as a result of implementing the proposed EPU. Assuming that the annual collective dose at St. Lucie does increase by approximately 12.2 percent following EPU, the resulting annual collective dose at St. Lucie should still be less than half the occupational dose of the NRC licensed PWR reporting the highest 3-year average. These occupational doses are well within those allowed by 10 CFR Part 20. The licensee indicates doses to members of the public offsite, resulting from effluent releases, are also expected to increase by 12.2 percent. The NRC finds that effluents from St. Lucie 1 are approximately one to two orders of magnitude below the 10 CFR Part 50 Appendix I design objectives, and are two to three orders of magnitude below the limits of 10 CFR Part 20. As a result, an anticipated increase of 12.2 percent will not challenge the 10 CFR Part 50 design objectives or the 10 CFR Part 20 dose limits for members of the public.

Compliance with Item II.B.2 ensures that operators can access and perform required duties and actions in designated vital areas. Item II.B.2 of NUREG 0737 requires licensees to demonstrate that during a design basis accident, access to areas of the plant needed to operate equipment vital to mitigating the consequences of that accident (vital areas), can be achieved within the dose criteria of GDC 19. GDC 19 requires that adequate radiation protection be provided such that the dose to personnel shall not exceed 5 rem whole body, or its equivalent, to any part of the body for the duration of the accident, or alternatively, not to exceed 5 rem TEDE for licensees that have adopted the AST under 10 CFR 50.67. St. Lucie 1 has been approved for use of AST for post-accident dose assessments associated with onsite locations that require continuous occupancy such as the CR, and the TSC. The licensee indicates the CR and the TSC share the same CRHE and will meet the same radiological habitability criteria. The licensee's calculations indicate that the dose to the CR would be 4.97 rem TEDE or less when employing alternate source term and making changes consistent with EPU conditions.

In the amendment request, the licensee stated vital areas are addressed in FSAR Table 12.1-11. Table 12.1-11 indicates the only vital areas are the CR and the TSC. The adequacy of the control room and TSC habitability envelope to meet the GDC 19 dose criteria (as required by NUREG-0737 II.B.2) is addressed in the Design Basis Consequence Analysis of this safety evaluation.

#### *Public and Offsite Radiation Exposures*

The liquid radioactive waste system is designed to operate such that the doses to members of the public in the unrestricted area are within the design objectives of 10 CFR Part 50, Appendix I. These design objectives have been incorporated into St. Lucie's TSs.

At the original rated power, the doses from radioactive liquid effluents were a small fraction of the TS limits. The licensee estimates that the radioactivity content of the liquid releases will increase by a maximum of 12.2 percent for tritium and long-lived radionuclides, with an expected increase of 12.3 percent for I-131 as a result of the EPU. The licensee evaluated historical liquid effluent data that indicated a 12.2 percent increase in effluent activity for tritium and long-lived nuclides – including a 12.3 percent increase for iodine – would still ensure compliance with the TSs limits. The NRC staff evaluated liquid effluent data from Annual Radioactive Effluent Release Reports submitted by the licensee and found that the dose from liquid effluents was less than 1 percent of the 10 CFR Part 50 design objectives. As a result, NRC staff concludes a 12.2-percent increase in activity (or 12.3-percent increase for I-131) would allow the licensee to meet the design objectives in 10 CFR Part 50, Appendix I.

The gaseous radioactive waste system is designed to operate such that the doses to members of the public in the unrestricted area are within the design objectives of 10 CFR Part 50, Appendix I. These design objectives have been incorporated into St. Lucie's TSs.

At the original rated power, the doses from radioactive gaseous effluents were a small fraction of the TS limits. The licensee estimates that the radioactivity content of the gaseous releases of noble gases will increase by a maximum of 12.9 percent, with an expected increase of 13.2 percent for short-lived gaseous radionuclides, and an increase of 12.2 percent for tritium as a result of the EPU. The licensee indicates increases in iodines will be 12.2 percent in the reactor coolant and will increase 22.2 percent in secondary steam in the event of primary to secondary leakage. The increases from gaseous effluents are due to the large increase in moisture carryover as a result of the EPU. The licensee indicates that even though I-131 will increase by the largest fraction, it will not be the dose-controlling radionuclide from a dose perspective since tritium will continue to be the controlling nuclide. NRC staff reviewed gas release data from Annual Radioactive Effluent Release Reports submitted by the licensee and found that the dose from gaseous effluents was less than 1 percent of the 10 CFR 50 design objectives. The NRC has evaluated this information and agrees that moisture carryover will increase radionuclide transport but only during episodes of primary-to-secondary leakage. NRC review of St. Lucie 1 gaseous radwaste historical data indicates a 12.2-percent to 13.2-percent increase in gaseous radwaste following EPU will still allow the licensee to meet the NRC design objectives in 10 CFR Part 50, Appendix I. Additionally, during times of primary-to-secondary leakage, the secondary system activity limits in TSs and the radioactive effluent control program will provide additional assurance that the projected doses from gaseous effluents following EPU will still be significantly below the 10 CFR Part 50, Appendix I design objectives.

The licensee estimates the activity contained in (and the dose rate from) the solid waste following EPU is estimated to be bounded by an increase of 14.2 percent, which is the product of the expected 12.2 percent increase normalized to a unit power capacity factor of 100 percent. Although there are no regulations on the amounts of solid radioactive waste generated, the direct shine from solid radioactive waste stored onsite could affect the offsite radiation dose. 40 CFR Part 190 limits the annual whole body dose to an actual member of the public to 25 mrem to the whole body from all pathways (e.g., from liquid releases, gaseous releases, and direct radiation from the facility). The licensee evaluated the direct shine dose rates based on results of previous Annual Radioactive Effluent Release and those reports indicated a 14.2-percent increase in the direct shine dose rates from storage of solid radwaste would not challenge the 25 mrem whole body standard of 40 CFR Part 190. The licensee stated that the procedures and controls in the Offsite Dose Calculation Manual would monitor the direct shine component of the offsite dose and the licensee would limit the offsite dose to ensure continued compliance with the 40 CFR Part 190 dose limits through storage, and administrative controls. The NRC finds the licensee's estimate of an increase of 14.2 percent in solid waste volume/curies to be reasonable since the EPU is expected to increase in liquid and gaseous waste generated by 12.2 percent. Furthermore, normalizing the value to 14.2 percent to adjust the solid waste generation to a 100-percent power capacity factor is a conservative assumption that provides a reasonable bounding estimate of increases in solid waste generation. The NRC has reviewed the information presented by the licensee in the LAR, and the NRC has also reviewed previous Annual Radiological Environmental Operating Reports that indicate the total dose from liquid effluents, gaseous effluents, and direct radiation is less than 2 mrem per year, and concludes a 14.2-percent increase in direct radiation will not challenge the 40 CFR Part 190 dose limits. The NRC staff concludes the licensee has provided sufficient information to demonstrate the expected increase in solid waste generation will allow the licensee to continue to comply with the dose limits of 40 CFR Part 190.

On the basis of information contained in the licensee's submittal regarding public and offsite radiation exposures, any increase in offsite doses due to EPU will be well within the TS dose limits and below the limits of 10 CFR Part 20, 40 CFR Part 190, and the Design Objectives of 10 CFR Part 50, Appendix I, during normal operations and anticipated operational occurrences.

#### *Ensuring that Occupational and Public Radiation Exposures are ALARA*

The Radiation Protection Program at St. Lucie 1 ensures that internal and external radiation exposures to station personnel, contractor personnel, and the general population resulting from station operation will be within applicable limits and will be ALARA. Design features currently in place to support St. Lucie's commitment to ALARA exposures include shielding to reduce levels of radiation, ventilation arranged to control the flow of potentially contaminated air, an installed radiation monitoring system used to measure levels of radiation in potentially occupied areas and measure airborne radioactivity throughout the plant, and respiratory protection equipment that is used as prescribed by the Radiation Protection Program. Compliance with the requirements of the Offsite Dose Calculation Manual ensures that radioactive discharges and public exposures are ALARA. The design features currently in place at St. Lucie 1 will be able to compensate for the anticipated increases in dose rates associated with the EPU. Therefore, the increased radiation sources resulting from this proposed EPU will not adversely impact the licensee's ability to maintain occupational and public radiation doses resulting from plant operation to within the applicable limits in 10 CFR Part 20, the Design Objectives of 10 CFR Part 50, Appendix I, and ALARA.

## Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on radiation source terms and plant radiation levels. The NRC staff concludes that the licensee has taken the necessary steps to ensure that any increases in radiation doses will be maintained as low as is reasonably achievable. The NRC staff further concludes that the proposed EPU meets the requirements of 10 CFR Part 20, and 10 CFR Part 50, Appendix I and meets the guidelines contained in Item II.B.2 of NUREG-0737. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to radiation protection and ensuring that occupational radiation exposures will be maintained as low as is reasonably achievable.

### 2.11 Human Performance

#### 2.11.1 Human Factors

##### Regulatory Evaluation

The area of human factors deals with programs, procedures, training, and plant design features related to operator performance during normal and accident conditions. The NRC staff's human factors evaluation was conducted to ensure that operator performance is not adversely affected as a result of system changes made to implement the proposed EPU. The NRC staff's review covered changes to operator actions, human-system interfaces, and procedures and training needed for the proposed EPU. The NRC's acceptance criteria for human factors are based on GDC 19, 10 CFR 50.120, 10 CFR Part 55, and the guidance in GL 82-33. Specific review criteria are contained in SRP Sections 13.2.1, 13.2.2, 13.5.2.1, and 18.0.

##### Technical Evaluation

The NRC staff has developed a standard set of topics for the human factors assessment of EPU's (i.e., RS-001, Review Standard for Extended Power Uprates, Section 3.2 for BWRs or Section 3.3 for PWRs, Insert 11 (Reference 1)). FPL has addressed these topics in its submittals. The following are FPL's description of these topics and the staff's evaluation.

#### Emergency and Abnormal Operating Procedures

This section includes a summary of the licensee's assessment of how the proposed EPU will change the plant emergency and abnormal operating procedures, and the staff's evaluation of that assessment.

The licensee performed a review of the EOPs and abnormal operating procedures or ONPs, as they are called at St. Lucie 1, to identify any changes that are required to support the EPU project. In addition, the licensee conducted a review of the operator actions and times credited in the plant's FSAR Chapter 15 safety analyses, to determine if there is any impact to those analyses as a result of EPU.

On the basis of the above reviews, the licensee concluded that the EPU will require revisions to EOPs and ONPs to address changes in a variety of setpoints, alarms, and physical plant changes that are needed to support the EPU. The most significant changes are listed below:

- Boric acid makeup tank requirements will be revised due to increased volume and boron concentration requirements for EPU. These changes will result in revising the curves in various ONPs.
- CST level requirements are being revised to achieve SDC entry conditions in a timelier manner. This will affect the EOP figures. The time duration and the time by which shutdown cooling entry conditions are achieved will be revised.
- Various EPU modifications will affect the ONP electrical load list. Procedures will be revised to include the new electrical loads.
- MFW pump suction pressure alarm and automatic trip setpoints are affected as a result of the replacement of the MFW pumps to support EPU.
- Turbine drain valves cycle on cross over steam pressure (from high pressure to low pressure turbines). Due to changes in MWt power level and condenser backpressure values, this cycling setpoint will change.
- Containment pressure normal operating TS limit will be decreased. Because the EOP setpoint is based on the normal operating containment pressure TS limit, the normal high containment pressure alarm setpoint and normal expected containment pressures may be lowered as a result of the change to the Containment pressure normal operating TS limit.
- Procedure changes will be required to update RCS sub-cooling, post-accident P-T curves. These curves provide a range of limiting conditions to help verify adequate core cooling, during various plant conditions. These changes are required in support of the LTOP.
- The existing setpoint for loop delta T will be increased. This setpoint is used, in conjunction with other indications, to assess the status of single-phase liquid, natural circulation flow in at least one RCS loop.
- The licensee performed boric acid precipitation analysis and determined that increases to flowrates are required to the minimum simultaneous hot leg and cold leg injection to preclude boric acid precipitation. The auxiliary spray flow path is being modified to meet the EPU hot leg injection flow requirements. The accident analysis assumptions for the minimum HPSI, maximum LPSI, and CS flow rates will be revised. Associated flow delivery curves in procedures will be revised consistent with the assumptions of the accident analysis.
- As a result of the EPU, the increase in decay heat in the core following a trip from a higher RTP will cause the time to boil to decrease affecting the timing and sequence of several procedures.
- The time for boiloff after shutdown will decrease as a result of the increased decay heat in the core as a result of the higher RTP. Therefore, RCS makeup flow will be increased, affecting several procedures.

- The SIT pressure will increase to support the SBLOCA analysis. Tank pressure will be raised to support injection at an earlier time. Associated setpoints for venting, draining and isolating the SITs will be revised, as required.
- The turbine back pressure alarm setpoint be increased as a result of higher condenser back pressure at EPU conditions.

Affected procedures will be revised to reflect the above changes, and other more minor changes, such as insignificant setpoint changes, prior to start up after St. Lucie 1, EPU implementation. The procedure development and revision processes used at St. Lucie, as described by the licensee, are comprehensive and rigorous, and include verification of technical accuracy and written correctness, as well as validation by means of simulation, walkdown, and operator tabletop discussions. Detailed information about the St. Lucie 1 change processes from the Human Factors perspective may be found in the following site procedures:

- Q1-5-PR-PSL-3, Verification Guide for Emergency Operating Procedures
- Q1-5-PR-PSL-4, Validation Guide for Emergency Operating Procedures
- Q1-5-PR-PSL-6, Requirements for Development and Revision of Emergency Operating Procedures [Procedures Generation Package]
- ADM-09-02, EOP Plant-Specific Technical Guidelines
- ADM-11-09, Emergency and Off-normal Operating Procedures Writers' Guide

Based on these factors, the staff finds the licensee's identification and resolution of EOP and abnormal operating procedure impact due to EPU acceptable.

#### Operator Actions Sensitive to Power Uprate

The licensee stated in its LAR that any new operator actions or changes in current operator actions needed as a result of the EPU will be addressed in accordance with plant procedures, which provide guidance to ensure that control room modifications conform to the human factors criteria established in NUREG-0700, as well as site-specific guidelines. These processes also ensure that each change is fully reviewed and approved by station and operations personnel prior to implementation. These licensee processes provide increased confidence that operator actions that are sensitive to power uprate will be of high quality regarding their human factors characteristics. Additionally, as described above in section 3.1, changes that involve EOPs are subjected to the verification and validation processes of the licensee's quality assurance program.

The licensee reviewed operator actions in the FSAR Chapter 15 safety analyses for changes in the timing, sequence, or existence of credited EOP operator actions. The licensee identified the following changes:

- In the event of an SBO, operators are required to secure SG blowdown within 30 minutes. In an SBO, the air operated SG blowdown valves will close on the loss of instrument air. This action is currently included in the EOPs and will continue to be a



verification action for EPU. The new time limit provides inventory conservation with the higher decay heat loads at EPU conditions.

- In the event of an SBO, operators must ensure there is a continuous source of FW, and start one charging pump within 60 minutes. These actions are included in the existing EOPs, only the timing has changed.
- In the event of a total loss of FW (TLOFW), a new step sequence is being implemented. Currently, two RCPs are tripped early in the event and the remaining two RCPs are secured later in the event. No credit is taken for securing the remaining two RCPs in the accident analysis. After EPU implementation, all four RCPs will be secured early in the TLOFW event to conserve SG inventory. Modular Accident Analysis Program (MAAP) analysis showed that this action, in conjunction with the proposed change in the narrow range SG low level reactor trip setpoint from 20.5 percent to 35 percent, will provide an additional 7 minutes to establish once-through-cooling and an additional 15 minutes for operators to restore FW.
- The boric acid precipitation analysis determined that increases are required to the minimum simultaneous hot leg and cold leg injection flow rates to preclude boric acid precipitation. The auxiliary spray flow path is being modified to meet EPU hot leg injection flow requirements.
- The containment hydrogen purge system will be upgraded to provide capability for online venting. This includes upgrading the manual containment isolation valves to provide remote-manual control capability. Additionally, the valves will automatically close on a CIAS. Valve position indication (open/close) will be provided in the control room. In the event of a CIAS; a new action is required to verify the containment hydrogen purge valves closed.
- In the event of a SGTR; the current analysis requires isolation of the affected SG and opening of the ADV associated with the affected SG within 30 minutes. The EPU analysis supports a revised action time of 45 minutes.

The licensee stated that there are no operator workarounds being created by the EPU or that affect timely execution of EPU-related actions, and that there are no operator actions that are being automated or changed from automatic to manual, as a result of EPU.

The NRC concurs with the licensee's conclusion that the additions, deletions, and changes in the sequence or timing of operator actions sensitive to EPU are not significant in terms of overall mitigation strategy, and that the licensee's established change processes will ensure that required revisions are technically adequate, correctly written, and within the abilities of St. Lucie 1 operators to perform within the time constraints established by analyses.

#### Changes to Control Room Controls, Displays, and Alarms

This section includes the licensee's assessment of any changes that the proposed EPU will have on the operator interfaces for control room controls, displays, and alarms, and the staff's evaluation of the licensee's assessment.

FPL stated in its LAR that changes to the St. Lucie 1 control room controls, displays, and alarms would not be extensive and will generally include calibration and/or rescaling loops for identified instrumentation. The licensee states that the following instrumentation is affected by EPU:

1. Leading Edge Flowmeter (LEFM)

The Cameron LEFM CheckPlus™ system, previously installed and NRC-approved at several nuclear stations, will be installed as part of the EPU to provide accurate determination of main FW flow.

2. The following instrument loops are affected by the EPU (calibration range, setpoint transmitter changes and/or scaling):

- a. FW flow – The range of the various FW flow channels will be increased to accommodate the higher EPU flow rates. Associated indicators, recorders, computer points, and alarm setpoints will be rescaled, as necessary.
- b. Main steam flow – The range of the various main steam flow channels will be increased to accommodate the higher EPU flow rates. Associated indicators, recorders, computer points, and alarm setpoints will be rescaled, as necessary.
- c. Turbine first stage pressure – turbine first stage pressure is changing. Associated control systems [digital electro-hydraulic and reactor regulating system] will be rescaled, as necessary.
- d. FW pump suction – Low suction pressure alarm and pump trip setpoints will be revised, as necessary, to reflect EPU operating conditions and requirements for the replacement main FW pumps.

3. Annunciator setpoint changes and annunciator response procedures will be revised as necessary to reflect affected operating parameters and instrument channel rescaling.

4. Plant computer setpoints will be revised as necessary to reflect affected operating parameters and instrument channel rescaling.

5. Changes to controls and control systems:

- a. FW Control System changes will include range changes for main steam and FW flow, scaling changes to reflect replacement FW pump performance and FW control valve curves, and improvements to transition logic between main FW control valves and low power control valves designed to minimize loss of SG inventory following a turbine trip.
- b. SBCS changes will include range changes for steam header pressure input signal, scaling changes for revised valve capacities, changes to the sequential valve position versus master controller demand to reflect linearization of valve trim, changes to quick open logic to improve system response during transition back to modulation control.

c. Containment Venting:

The containment hydrogen purge system will be upgraded to provide capability for online venting, which will support a decreased TS LCO for allowable containment pressure. The existing containment hydrogen purge system manual containment isolation valves will be upgraded to provide remote-manual control capability, and they will automatically close on a CIAS. Open/close valve position indication will be provided in the control room.

d. Turbine Controls:

Turbine governor valve control will be changed from partial arc (sequential valve) to full arc (single valve), with other modes of operation (speed, MW, and turbine impulse pressure) remaining the same as existing. As part of the turbine controls modification, the existing computer will be replaced with a more modern computer and operator interface panels will be replaced with dedicated touch-screen panels.

e. MSR and FW Heater 5A/B level controls:

The existing pneumatic controls for MSR and high pressure FW heater 5 level control are being replaced with electronic instruments. The existing backup level switch control functions will not be changing.

The above control room modifications have been or will be assessed for potential Human Factors Engineering (HFE) impact using plant administrative procedure NE-AA-205-1100, Design Change Packages and EC Form-250, Human Factors Engineering Checklist. Those modifications identified as having HFE impact will be further reviewed for compliance with NUREG-0700 and site-specific HFE guidance. Based on the licensee's use of accepted HFE standards and guidelines, and the minor nature of the identified changes, the staff finds the licensee's approach to controlling HFE design changes to the St. Lucie 1 CR acceptable. Application of these administrative controls should result in effective and useable controls, displays, and alarms.

### Changes on the Safety Parameter Display System

This section includes the review of the changes to the SPDS resulting from the proposed EPU and how the licensee will make the operators aware of the proposed SPDS changes.

In its LAR, FPL stated that no significant SPDS changes are anticipated as a result of the proposed EPU. Critical safety function status trees will be reviewed and revised as necessary for related changes to setpoints and decision points. Any changes identified to the safety parameter display system will be captured through the normal update process, modification process, and interdepartmental reviews.

The staff finds the proposed approach to changes in the design of SPDS acceptable.

## Control Room Plant Reference Simulator and Operator Training

This section includes the review of changes to the operator training program and the plant referenced CR simulator resulting from the proposed EPU and the implementation schedule for making the changes.

FPL stated in its LAR that FPL will ensure that adequate training is provided prior to EPU implementation per its normal training program. The proposed training will focus on the TS changes, procedure changes and plant modifications, and will take place during the training cycle prior to the outage implementing the EPU modifications. Training related to the EPU modifications and resulting control board and procedure changes will be provided to the operators. The operators will also be provided station modification review packages as well as classroom and simulator training where appropriate. The staff finds these actions to be acceptable.

### Conclusion

The NRC staff has reviewed the changes to operator actions, human-system interfaces, procedures, and training required for the proposed EPU and concludes that the licensee has (1) appropriately accounted for the effects of the proposed EPU on the available time for operator actions and (2) taken appropriate actions to ensure that operator performance is not adversely affected by the proposed EPU. The NRC staff further concludes that the licensee will continue to meet the requirements of GDC 19, 10 CFR 50.120, and 10 CFR Part 55 following implementation of the proposed EPU. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to the human factors aspects of the required system changes.

## 2.12 Power Ascension and Testing Plan

### 2.12.1 Approach to EPU Power Level and Test Plan

#### Regulatory Evaluation

The purpose of the EPU test program is to demonstrate that SSCs will perform satisfactorily inservice at the proposed EPU power level. The test program also provides additional assurance that the plant will continue to operate in accordance with design criteria at EPU conditions. The NRC staff's review included an evaluation of: (1) plans for the initial approach to the proposed maximum licensed thermal power level, including verification of adequate plant performance; (2) transient testing necessary to demonstrate that plant equipment will perform satisfactorily at the proposed increased maximum licensed thermal power level; and (3) the test program's conformance with applicable regulations.

The NRC's acceptance criteria for the proposed EPU test program are based, in part, on 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," which requires establishment of a test program to demonstrate that SSCs will perform satisfactorily in service; NRC RG 1.68, Appendix A, Section 5, "Power Ascension Tests," which describes tests that demonstrate that the facility operates in accordance with design both during normal steady-state conditions, and, to the extent practical, during and following AOOs; and specific review criteria contained in Section III, "Review Procedures," of SRP 14.2.1. Other guidance is also provided in Section 2 and Insert 12 for Section 3.3, "PWR Template Safety Evaluation" of RS-001, Revision 0.

## Technical Evaluation

### 2.12.1.1 SRP 14.2.1, Section III.A, Comparison of Proposed EPU Test Program to the Initial Plant Test Program

Section 14.2.1 of the SRP specifies the guidance and acceptance criteria that the licensee should use to compare the proposed EPU testing program to the original power-ascension test program performed during initial plant licensing. The scope of this comparison should include: (1) all initial power-ascension tests performed at a power level of equal to or greater than 80-percent original licensed thermal power (OLTP) level; and (2) initial test program tests performed at lower power levels if the EPU would invalidate the test results. The licensee shall either repeat initial power-ascension tests within the scope of this comparison or adequately justify proposed test deviations. The following specific criteria should be identified in the EPU test program:

- All power-ascension tests initially performed at a power level of equal to or greater than 80-percent of the OLTP level,
- All initial test program tests performed at power levels lower than 80-percent of the OLTP level that would be invalidated by the EPU, and
- Differences between the proposed EPU power-ascension test program and the portions of the initial test program identified by the previous criteria.

The NRC staff reviewed EPU test plan information provided by the licensee to verify that the initial EPU application, including supplemental information, addressed the specific criteria for an adequate EPU test program as described above. The staff reviewed Attachment 5, "Licensing Report," of the LAR which discusses the analyses and evaluations performed to demonstrate that the proposed increase in power can be safely achieved with no adverse impact on the health and safety of the public. The staff also reviewed Licensing Report Table 2.12-3, "Post-Modification Testing," of Attachment 5 to the LAR, for a list of planned modifications necessary to support power operation at the proposed uprated core thermal power, and the associated post-modification testing planned for these modifications. The planned modifications listed in the table constitute planned actions on the part of the licensee and do not constitute regulatory commitments. The modifications will be implemented in accordance with the requirements of 10 CFR 50.59 and will provide functional and operational post modification testing for each modification to verify satisfactory installation and performance.

The staff also found that transient tests described in the initial startup test program were listed in Table 2.12-2, "Comparison of Proposed EPU Tests to Original Startup Tests," of Attachment 5. The Table provided a summary of the original startup testing performed in accordance with FSAR Sections 14.2.12.2-4, and also included the initial startup test objectives, a brief comparison with the proposed power ascension and testing plan (PATP), and a justification for not repeating certain of the original tests during the proposed EPU test plan. Table 2.12-1, "EPU Power Ascension Test Plan," of Attachment 5, provided a listing of power ascension startup tests to be performed at EPU power levels through 100-percent RTP of 3020 MWt. The licensee stated in the LAR that analyses were performed for EPU using the CENTS computer code for certain operating transients and that the results were used, in part, as the basis for the justification of the elimination of certain transient testing included in the original startup testing program.

FPL stated in the LAR that the EPU testing program will also draw on the results of the original startup and test program and applicable industry experience as a means of ensuring safe operation at the new core thermal power level. Comparisons will be made between pre-determined acceptance criteria and the data that will be gathered during the uprate testing to ensure that the results are reasonable. Additionally, FPL stated that St. Lucie 1 has significant operating experience at its current operating conditions such that system interactions are well known. FPL also stated that Arkansas Nuclear One, Unit 2 (ANO-2) and Waterford 3 have uprated to a core thermal power level that is nearly identical to that requested for St. Lucie 1 (3026 MWt and 3020 MWt, respectively); and that both have operated successfully at the new power level for 7 and 4 years, respectively. Both ANO-2 and Waterford 3 are CE-designed NSSS plants.

As stated in the LAR, the St. Lucie 1 PATP is primarily an initial power ascension test plan in which power will be increased in a slow and deliberate manner, stopping at pre-determined power plateaus for steady-state data gathering and formal parameter evaluation. The program consists of a combination of normal startup and surveillance testing, post-modification testing, and power ascension testing deemed necessary to support acceptance of the proposed EPU. At approximately 89-percent EPU power (2700 MWt), power will be slowly and deliberately increased through four additional test plateaus, and each differing by approximately 3 percent of the EPU RTP. Both dynamic performance during the ascension and steady-state performance for each test plateau will be monitored, documented and evaluated against predetermined acceptance criteria and expected values.

The staff concludes through comparison of the documents referenced above, including a review of the initial startup tests and planned EPU testing described in Attachment 5 to the LAR, the proposed power ascension test program conforms to the NRC's acceptance criteria of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," including specific review criteria contained in Section III.A. of SRP 14.2.1, and other staff guidance provided in RS-001. Therefore, the proposed power ascension and testing plan is acceptable.

2.12.1.2 SRP 14.2.1, Section III.B, Post Modification Testing Requirements for Functions Important to Safety Impacted by EPU-Related Plant Modifications

This Section of the SRP specifies the guidance and acceptance criteria, which the licensee should use to assess the aggregate impact of EPU plant modifications, setpoint adjustments, and parameter changes that could adversely impact the dynamic response of the plant to an AOO. AOOs include those conditions of normal operation that are expected to occur one or more times during the life of the plant and include events such as LOOP, tripping of the main turbine generator set, and loss of power to all RCPs. The EPU test program should adequately demonstrate the performance of SSCs important to safety that meet all of the following criteria: (1) the performance of the SSC is impacted by EPU-related modifications; (2) the SSC is used to mitigate an AOO described in the plant-specific design basis; and, (3) involves the integrated response of multiple SSCs.

The staff reviewed Attachment 5 to the LAR which discusses the planned modifications scheduled to be performed prior to operation at EPU conditions. Modifications necessary to allow operation at EPU conditions are scheduled to be implemented during refueling outage SL1-24 (spring 2012). A list of significant plant modifications planned to improve overall plant

operating margin and support the proposed EPU is provided in Attachment 5, Table 2.12-3 "Post-Modification Testing." Some of the key modifications planned prior to operation at EPU conditions include, but are not limited to, upgrading condensate and FW system components; controls and instrumentation; main generator upgrade; main steam, FW and condensate systems instrumentation; and replacement of MFW pumps and heaters. Functional and operational post-modification testing will be performed for each modification to verify satisfactory installation and performance.

The NRC staff also reviewed the licensee's approach relative to assessing the aggregate impact of the proposed equipment modifications. In Section 2.12.1.2.6, "Transient Analytical Methodology," of the LAR, the licensee stated that analyses and evaluations had been performed for the Condition I, II, III, and IV operating transients to assess the aggregate impact of the equipment modifications and setpoint changes for EPU conditions. Condition I, II, III, and IV refers to the following four classifications of plant conditions established by ANS: normal operation and operational transients, incidents of moderate frequency, infrequent incidents, and limiting faults, respectively, in accordance with the anticipated frequencies of occurrence and potential radiological consequences. Analysis inputs and models were updated as appropriate to incorporate the EPU equipment modifications and setpoint changes as well as the EPU operating conditions. The licensee stated that in terms of transient response, the most significant hardware modifications are those for the SBCS and the FW system; and that the aggregate impact of the hardware changes on dynamic plant response is addressed through CENTS analyses for Condition I initiating events and Condition II trip tests.

The licensee stated that transient accident analyses evaluations were performed using the NRC-approved CENTS computer code acceptable for analyzing operational transients for CE-designed PWRs which include Waterford 3; San Onofre Nuclear Generating Station (SONGS), Units 2 and 3; ANO-2; and the Palo Verde Nuclear Generating Station (PVNGS), Units 1-3. The CENTS code is described in Westinghouse Owners Group Topical Report WCAP-15996-P-A, Revision 1, "Technical Description Manual for the CENTS Code," March 2005. The CENTS code was used for the analysis of design basis transients at EPU conditions and incorporated the applicable EPU equipment modifications and setpoint changes as well as the EPU operating conditions. The NSSS transients evaluated for EPU using the CENTS code are shown in Table 2.12-4 of LAR Attachment 5, and include reactor trip from 100-percent power and step load changes. The code has been used for many years for accident evaluations for safety analysis reports and for control system performance and has also been used for the Waterford 3 and ANO-2 EPU applications. As documented in the CENTS Topical Report CENPD-282-P-A, the NRC SE for the code concluded that CENTS is "acceptable for referencing in licensing actions with respect to the calculation of non-LOCA transient behavior in [PWRs]."

The NRC staff concludes that the licensee's proposed EPU PATP demonstrates that EPU related modifications will be adequately implemented. Specifically, the staff concludes that based on a review of the listing of completed and planned modifications, the proposed EPU test program should adequately demonstrate the performance of SSCs, and complies with the criteria established in Section III.B of SRP 14.2.1.

2.12.1.3 SRP 14.2.1, Section III.C, Use of Evaluation to Justify Elimination of Power-Ascension Tests

This Section of the SRP specifies the guidance and acceptance criteria the licensee should use to provide justification for a test program that does not include all of the power-ascension testing that would normally be performed, provided that proposed exceptions are adequately justified in accordance with the criteria provided in Section III.C.2. The proposed EPU test program shall be sufficient to demonstrate that SSCs will perform satisfactorily in service. The following factors should be considered, as applicable, when justifying elimination of power-ascension tests:

- Previous operating experience,
- Introduction of new thermal-hydraulic phenomena or identified system interactions,
- Facility conformance to limitations associated with analytical analysis methods,
- Plant staff familiarization with facility operation and trial use of operating and EOPs,
- Margin reduction in safety analysis results for AOOs,
- Guidance contained in vendor topical reports, and
- Risk implications.

The staff's review is intended to provide reasonable assurance that the performance of plant equipment important to safety that could be affected by integrated plant operation or transient conditions is adequately demonstrated prior to extended operation at the requested EPU power level. The staff recognized that the licensee may propose a test program that does not include all of the power-ascension testing referred to in Sections III.A and III.B of SRP 14.2.1 that would normally be performed, provided that proposed exceptions are adequately justified in accordance with the criteria provided in SRP Section III.C.2. If the licensee proposes to omit certain original startup tests from the EPU testing program based on favorable operating experience, the applicability of the operating experience to the specific plant must be demonstrated. Plant design details such as configuration, modifications, and relative changes in setpoints and parameters, equipment specifications, operating power level, test specifications and methods, engineering operating procedures, and adverse operating experience from previous EPUs, should be considered and addressed.

The EPU PATP is relied upon as a quality check to confirm that analyses and any modifications and adjustments that are necessary for proposed EPUs have been properly implemented, and to benchmark the analyses against the actual integrated performance of the plant. This is consistent with 10 CFR Part 50, Appendix B, which states that design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate calculation methods, or by the performance of a suitable testing program; and requires that design changes be subject to design control measures commensurate with those applied to the original plant design, which includes power ascension testing. SRP 14.2.1 specifies that the EPU test program should include steady-state and transient performance testing sufficient to demonstrate that SSCs will perform satisfactorily at the requested power level and that EPU-related modifications have been properly implemented. The SRP provides guidance to the staff in assessing the adequacy of the licensee's evaluation of the aggregate impact of EPU plant modifications, setpoint adjustments, and parameter changes that could adversely impact the dynamic response of the plant to AOOs.



The St. Lucie 1 EPU PATP is comprised of power ascension monitoring, post-modification testing and analytical evaluation with no large load transient testing planned as part of the EPU PATP. The PATP does not include all the power ascension testing that would typically be performed during initial startup of a new plant. The PATP is based, in part, on plant-specific experience, industry PWR EPU operating experience, St. Lucie 1 Startup Test Reports, outputs of various system and integrated plant analyses performed in support of the EPU, FSAR Chapter 14, and review of planned EPU modifications which FPL has used in the formulation of expected system interactions, design of EPU modifications, determination of control system settings and setpoints, and development of post-modification and power ascension test plans.

The staff reviewed the licensee's justification for not performing certain large load transient tests that were originally performed as part of the startup test program. These large load transient tests are listed and discussed in Table 2.12-2 of Attachment 5 to the LAR. The tests, originally performed at various OLTP levels, include an Automatic Control System Checkout and Load Swing Test (originally performed from 50 to 100-percent OLTP); Generator Trip Test (originally performed at 100-percent OLTP); and Natural Circulation Test (originally performed at hot standby conditions). The justification for not performing these tests was presented in Section 2.12.1.2.7, "Justification for Exception to Transient Testing," of Attachment 5 to the LAR, which provides a discussion of the PATP covering power ascension up to the full EPU power level of 3020 MWt to verify acceptable performance.

The licensee's basis for not performing certain original startup tests, including large transient tests, as part of the proposed EPU PATP primarily relies on an analytical justification using the NRC-approved computer code CENTS to evaluate plant responses to Condition I and II initiating events at EPU conditions. As stated in the LAR, the CENTS code is acceptable for analyzing operational transients for CE designed PWRs and has been used on other CE designs including Waterford 3; ANO-2; SONGS, Units 2 and 3; and the PVNGS, Units 1, 2, and 3. The licensee also stated in the LAR that additional justification for not performing certain original startup tests included performance of post-modification testing of EPU-related plant modifications to ensure proper installation; performance of system surveillance tests as required to verify that the planned modifications meet applicable performance criteria; performance of integrated plant analyses to define the performance criteria of the various plant modifications necessary to accommodate the uprated power; review of the original startup test program; St. Lucie 1 plant-specific operating experience at greater than OLTP power levels; and industry experience at other previously uprated PWRs. The licensee stated that the analysis results and the evaluation of plant data acquired during power ascension are used, in part, in lieu of performing large transient testing to verify that the plant systems are capable of performing safely in the uprated condition.

The licensee presented a comparison of the proposed EPU tests to those performed during original plant startup in Table 2.12-2 of Attachment 5 to the LAR to address the staff's review criteria in Section III.C.2 of SRP 14.2.1. The licensee concluded that no large load transient tests are required to be performed as part of the St. Lucie 1 EPU PATP since such tests would not confirm any new or significant aspect of performance not already demonstrated through analysis, by previous operating experience, or routinely through plant operations.

### *Industry PWR Transient Operating Experience at Up-rated Power Levels*

With respect to the review criteria established in SRP Section III.C.2, the licensee stated in the LAR that satisfactory post-EPU industry operating experience has been demonstrated at greater than original power levels at two other PWRs of similar design to St. Lucie 1. Section 2.12.1.2.2 of Attachment 5 to the LAR states, in part, that applicable industry operating experience comes from Waterford 3 and ANO-2 plants, which are similar in design to that of St. Lucie 1. In April 2005, the staff approved an 8-percent EPU for Waterford to 3716 MWt; and in April 2002, approved a 7.5-percent uprate for ANO-2 to 3026 MWt. Both are CE designs and nearly identical to that of St. Lucie 1. In November 2005, Waterford 3 experienced a manual reactor trip from 100-percent power (approximately 109.5-percent of OLTP) due to a total loss of circulating water. According to the LAR and further supported by Licensee Event Report 2005-005, the integrated plant control systems operated satisfactorily in automatic to stabilize the plant post-trip and safety systems responded as designed. In December 2002, ANO-2 experienced an unplanned post-EPU reactor trip. The LAR stated that a review of the data from the trip indicated that plant performance had been adequately predicted by the calculation method used for control systems and integrated plant transient response evaluation for EPU. In accordance with RS-001, industry operating experience may be used by the licensee to support the basis for not performing certain original startup tests, including large transient tests, as part of the proposed EPU PATP.

### *St. Lucie 1 Plant-Specific Transient Experience at Up-rated Power Level*

Another factor used by the staff in its review of the licensee's justification for not performing large transient testing as part of the proposed EPU PATP were actual plant transient events experienced at St. Lucie. The licensee provided information in the LAR regarding one trip from full power in the past decade. The licensee stated that during the trip, safety equipment operated per design, and the unit was safely brought to Mode 3. The trip occurred at 100-percent CLTP (2700 MWt), which translates to approximately 105.5-percent OLTP, since the NRC approved a 5.5-percent stretch power uprate for both Units 1 and 2 on November 23, 1981. FPL stated in the LAR that CENTS analyses showed similar results for trips from 2700 MWt and EPU requested power level of 3020 MWt.

The staff reviewed the licensee's justification for not performing certain original startup tests against the review criteria established in SRP 14.2.1. In justifying test eliminations or deviations, St. Lucie 1 addressed several factors discussed in SRP Section III.C.2. These factors included industry operating experience at previously uprated PWRs, plant response to actual reactor trips for other similar PWRs, and experience gained from actual plant-specific events. Additionally, the FPL referenced the use of the NRC-approved WCAP-15996-P-A, Revision 1, which describes use of the CENTS computer code to analyze operational transients for CE designed PWRs. Based on the review, the staff concludes that the St. Lucie 1 EPU PATP provides reasonable assurance that plant SSCs that are affected by the proposed EPU will perform satisfactorily in service at the proposed power uprate level, and that the program complies with the quality assurance requirements of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," including specific review criteria contained in Section III.C.2 of SRP 14.2.1 and other staff guidance provided in RS-001. Therefore, the proposed power ascension and test plan is acceptable.

2.12.1.4 SRP 14.2.1, Section III.D, Evaluate the Adequacy of Proposed Transient Testing Plans

This Section specifies the guidance and acceptance criteria the licensee should use to include plans for the initial approach to the increased EPU power level and testing that should be used to verify that the reactor plant operates within the values of EPU design parameters. The test plan should assure that the test objectives, test methods, and the acceptance criteria are acceptable and consistent with the design basis for the facility. During testing, safety-related SSCs relied upon during operation shall be verified to be operable in accordance with existing TS and quality assurance program requirements. The following should be identified in the EPU test program:

- The method in which initial approach to the uprated EPU power level is performed in an incremental manner including steady-state power hold points to evaluate plant performance above the original full-power level,
- Appropriate testing and acceptance criteria to ensure that the plant responds within design predictions including development of predicted responses using real or expected values of items such as beginning-of-life core reactivity coefficients, flows, pressures, temperatures, response times of equipment, and the actual status of the plant, not the values or plant conditions used for conservative evaluations of postulated accidents,
- Contingency plans if the predicted plant response is not obtained, and
- A test schedule and sequence to minimize the time untested SSCs important to safety are relied upon during operation above the original licensed full-power level.

The licensee stated in the LAR that during the EPU startup, power will be increased in a slow and deliberate manner, stopping at pre-determined power levels (test plateaus) for steady-state data gathering and formal parameter evaluation, consistent with the PATP. A summary of the St. Luce 1 PATP is provided in Table 2.12-1, "EPU Power Ascension Test Plan," of the LAR. The typical post-refueling power plateaus will be used until the current full power condition (2700 MWt) is attained at approximately 89 percent of the EPU full power level (3020 MWt), with additional equipment and post-modification testing performed to verify satisfactory performance of the modification in accordance with the design. Prior to exceeding the current licensed core thermal power of 2700 MWt, the data gathered at the pre-determined power plateaus will allow verification of the performance of the EPU modifications. By comparison of the plant data with pre-determined acceptance criteria, the test plan will verify that expected interactions between the various modifications have occurred such that integrated plant performance is demonstrated to be within design predictions.

Once at approximately 89 percent (2700 MWt) of EPU power, power will be slowly and deliberately increased through four additional test plateaus, each differing by approximately 3 percent of the EPU RTP. Both dynamic performance during the ascension and steady-state performance for each test plateau will be monitored, documented and evaluated against pre-determined acceptance criteria and expected values. In addition to the steady-state parameter data gathered and evaluated at each test condition. The PATP consists of a combination of normal startup and surveillance testing, post-modification testing, and power ascension testing deemed necessary to support the proposed EPU.

The staff concluded that the proposed test plan will adequately assure that the test objectives, test methods, and test acceptance criteria are consistent with the design basis for the facility; and that the test schedule would be performed in an incremental manner with appropriate hold points for evaluation.

### Conclusion

The staff has reviewed the licensee's EPU power ascension and testing program, including plans for the initial approach to the proposed maximum licensed thermal power level, transient testing necessary to demonstrate that plant equipment will perform satisfactorily at the proposed increased maximum licensed thermal power level, and the test program's conformance with applicable regulations. The licensee's test program includes primarily power ascension monitoring, post-modification testing and analytical evaluation, using the NRC-approved transient analysis code CENTS, with no large transient testing proposed. The staff reviewed the licensee's justification for not performing large transient testing as discussed in Attachment 5 to the LAR. Such justification included industry operating experience from previously uprated PWRs, St. Lucie 1 plant-specific operating experience at power level greater than OLTP, and analytical evaluations and analysis of transient events.

Based on the review, the staff concludes that the licensee's proposed EPU test program provides adequate assurance that the plant will perform as expected and that SSCs affected by the proposed EPU, or modified to support the proposed power increase, will perform satisfactorily in service; and satisfies the requirements of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," including the staff guidance and review criteria in SRP 14.2.1 and other guidance provided in RS-001. Therefore, the staff finds the proposed EPU acceptable with respect to the power ascension and test program.

#### 2.12.2 Power Ascension and Testing Plan (BOP systems consideration)

The NRC staff's review of EPU test plans for BOP considerations focuses on modifications to BOP systems and the integrated response of the modified BOP systems to transients initiated from the full EPU power level. The staff evaluates the licensee's proposed EPU testing program to assure that, in conjunction with plant operating experience, computer modeling, and analyses, SSCs important to safety will perform satisfactorily in service at the requested increased plant power level. For most design basis accidents, the BOP systems are not essential to mitigate the event. However, the reliability of BOP systems affects the frequency of certain design basis events and the frequency of challenges to certain safety-related components. Therefore, consistent with the guidelines of Section 14.2.1, "Generic Guidelines for Extended Power Uprate Testing Programs," of the NRC Standard Review Plan (SRP) (NUREG-0800), the staff verifies that the proposed EPU test program adequately demonstrates the performance of SSCs important to safety that meet any of the following criteria: (1) the performance of the SSC is impacted by EPU-related modifications, (2) the SSC is used to mitigate an anticipated operational occurrence described in the plant-specific design basis, and (3) performance of the SSC can be affected by integrated plant operation or transient conditions.

The staff reviewed the information provided in Section 2.12 of the St. Lucie 1 EPU licensing report against the considerations discussed in SRP Section 14.2.1 with respect to the BOP area of review. In addition to setpoint, pressure, and flow changes associated with the EPU, significant EPU modifications to BOP systems include replacement of the heater drain pumps,

replacement of the high-pressure FW heaters and moisture-separator/reheaters, modifications to other FW heaters and controls, replacement of the main FW pumps, modification of the FW control valves, modification of the steam bypass control system, and replacement of the main high-pressure and low-pressure turbines.

The staff reviewed the scope of integrated plant testing proposed for evaluation of physical modifications associated with the power uprate. In many instances, the staff considers system and component level testing adequate to assure that the modified systems and components would perform acceptably in service, but integrated testing may be necessary where new or complicated system interactions exist. The licensee proposed to modify the steam bypass control system such that it would retain the capacity to pass the same fraction of rated steam flow at EPU conditions as the current system passes at current licensed thermal power. The licensee listed proposed post-modification testing of the steam bypass control system in Table 2.12-3, "Post-Modification testing," of the EPU licensing report and specified performance of dynamic system testing to verify adequate performance of the modified system, in addition to channel calibrations and functional stroke testing. The staff reviewed this test plan and concluded testing of the steam bypass control system would provide reasonable assurance of the important to safety function of relieving steam to the main condenser to control SG pressure and remove residual heat. Because the licensee is proposing neither to modify nor to credit additional capacity for the atmospheric steam dump valves, the staff concluded that integrated plant transient testing for the purpose of demonstrating the capacities of the atmospheric steam dump valves is not necessary. Adequate operation of the replacement main high pressure and low-pressure turbine would not require integrated testing because testing of the overspeed protection system provides reasonable assurance that the important to safety function of preventing turbine missile generation would be satisfied. Therefore, the staff concluded that integrated plant testing of these modifications would not be necessary. However, integrated testing and evaluation of the FW system modifications would provide the greatest assurance the system will perform its important to safety function of heat removal from the RCS during normal operation, including moderate transient conditions.

The licensee provided a comparison of the original plant start-up testing to the EPU power ascension test plan in Table 2.12-2, "Comparison of EPU Tests to Original Startup Tests," of the EPU licensing report. This table addressed testing involving integrated plant control system response, and indicated that large transient testing was not necessary to demonstrate acceptable performance of equipment important to safety at EPU operating conditions. The licensee specified performance of minor transient testing associated with routine power ascension and provided justification for exceptions to larger transient testing in Section 2.12.1.2.7 of the EPU licensing report. In this section, the licensee described that the limited testing and measurements included in the power ascension test plan would provide an indication that no unanticipated interactions had been introduced and the FW control system would operate properly at EPU conditions. The licensee presented details of the power ascension test plan in Table 2.12-1, "EPU Power Ascension Test Plan." In addition, the licensee described operating experience applicable to St. Lucie 1 and system-level modeling of plant response to larger transients using the CENTS code.

Section 2.12.1.2.6.1, "Transient Analytical Methodology," of the EPU licensing report described how the licensee used the CENTS computer code to evaluate the plant transient response. With respect to BOP system performance, the transients evaluated for normal operation, including anticipated operational occurrences, are most relevant because the BOP systems would be expected to operate throughout many these transients. The licensee listed the

specific transient events evaluated using the CENTS code in Table 2.12-3, "NSSS Transients Evaluated for EPU with the CENTS Code." These transients included a turbine trip, a reactor trip, and a variety of step load changes of various magnitudes from varying initial power levels. The licensee benchmarked the CENTS code to the following St. Lucie transients to refine the EPU model:

- Unit 1 100 percent power automatic reactor trip from RCP 1A2 trip on June 5, 2001
- Unit 1 100 percent to 68 percent power ramp on August 20, 2008
- Unit 1 42 percent to 83 percent power ramp on March 14, 2008
- Unit 2 manual reactor trip from 100 percent power on June 4, 2008, following a loss of a main FW pump
- Unit 2 manual reactor trip from 100 percent power on June 7, 2008, following a condensate pump trip

In the response to a request for additional information provided by letter dated June 22, 2011, the licensee stated that agreement between the CENTS model results and the actual plant response during the benchmarking process and the incorporation of FW system equipment in the CENTS model provided confidence that CENTS cases adequately model plant response at EPU conditions.

The licensee described that the FW control system would be monitored during the EPU power ascension to ensure the FW controls are operating correctly and that SG level is automatically controlled within operating limits. This monitoring in combination with completed analyses and operating experience would provide reasonable assurance that the FW system and associated control systems would operate properly at the proposed uprated power level.

The NRC staff assessed the licensee's power ascension test plan against the guidance of SRP Section 14.2.1. The staff considered the proposed modifications to the steam bypass control system, main turbine, and FW systems to be of limited scope. Operating experience indicated that similar limited scope modifications have been successfully implemented at other units, including Combustion Engineering reactors comparable to St. Lucie 1. The licensee modeled the transient response of plant systems to provide reasonable assurance that the plant would continue to respond to transients at the EPU power level consistent with its design basis. Detailed plant modeling demonstrated that the condensate and FW systems, with EPU modifications in place, would have ample margin to respond as assumed in the transient analysis. Therefore, the NRC staff determined that, for the limited scope of BOP modifications, demonstration of acceptable BOP performance during the planned power ascension test program combined with the described computer modeling of postulated transients would provide reasonable assurance that BOP systems will function as designed for EPU operation.

## 2.13 Risk Evaluation

### Regulatory Evaluation

The licensee did not request the relaxation of any deterministic requirements for their proposed power uprate, and the staff's approval is primarily based on the licensee meeting the current deterministic engineering requirements. As discussed in RS-001, Section 13, a risk evaluation is conducted to determine if "special circumstances" are created by the proposed EPU. As described in Appendix D of SRP Chapter 19.2, special circumstances are any issues that would potentially rebut the presumption of adequate protection provided by the licensee meeting the

currently specified regulatory requirements. Specific review guidance is contained in Matrix 13 of RS-001 and its attachments. Further guidance on how to make a determination of special circumstances is provided in Appendix D to SRP Chapter 19.2.

The staff's review addresses the risk associated with operating at EPU conditions (10 percent greater than the currently licensed power level) in terms of changes in CDF and LERF from internal events, external events, and shutdown operations. In addition, the NRC staff's review addresses the quality of the risk analyses used by the licensee to support the application for the proposed EPU. This includes a review of licensee actions to address issues or weaknesses that may have been raised in previous staff reviews of the licensee's IPE, IPEEE, or by industry peer reviews. The staff used the guidance provided in RG 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," to focus the review of this nonrisk-informed submittal.

### Technical Evaluation

The staff reviewed the risk evaluation submitted for St. Lucie Plant 1 by FPL, as supplemented by responses to the staff's request for additional information. The licensee has provided an estimate of the increase in risk (CDF and LERF) assuming EPU conditions. A combination of quantitative and qualitative methods was used to assess the risk impact of the proposed EPU. The following sections provide the staff's technical evaluation of the risk information provided by the licensee. The staff's evaluation did not involve an in-depth review of the licensee's risk evaluation.

### Probabilistic Risk Assessment (PRA) Model Quality

The quality of the licensee's PRA used to support a license application needs to be commensurate with the role the PRA results play in the decision-making process. The staff's approval is based on the licensee meeting the current deterministic requirements, with the risk assessment providing confirmatory insights and ensuring that the EPU creates no new vulnerabilities.

### IPE/IPEEE

The licensee submitted the St. Lucie 1 IPE, which is based on a full scope level 2 PRA performed in fulfillment of GL 88-20. The NRC issued a SER stating that the licensee did not identify any severe accident vulnerabilities associated with either core damage or containment failure. The IPE submittal identified changes to the plant, procedures, and training as part of the IPE process.

The licensee submitted the St. Lucie 1 IPEEE to the NRC in response to Supplement 4 of GL 88-20. The NRC issued an SER that concluded that the licensee's IPEEE identifies most likely severe accidents and severe accident vulnerabilities from external events.

In its submittal, the licensee states that all vulnerabilities identified in the IPE and IPEEE have been resolved and no new vulnerabilities are introduced as a result of the EPU.

## PRA Peer Review

In July 2002, CEOG performed a peer review of the St. Lucie 1 PRA. The review followed a process that was adopted from industry reference NEI-00-02, Rev A3. The review identified ten A level Facts and Observations (F&Os) and 34 B level F&Os. A-Level F&Os are defined as being extremely important and necessary to address in order to assure the technical adequacy of the PRA, while B-level F&Os are defined as being important and necessary to address, but may be deferred until the next PRA update. The licensee provided a summary of the A-Level and B-Level F&Os and their resolutions.

Additionally, in July 2009, a focused peer review was conducted for LERF and common cause failures (CCFs). The LERF review resulted in closure of all LERF related F&Os. No open items and no EPU impacts were identified. The CCF review closed all risk-significant open items. New F&Os generated during that review were determined to not impact the EPU PRA risk assessment.

The staff finds that all F&O findings were properly assessed and dispositioned in regard to this application.

## Conclusions Regarding the Quality of the St. Lucie PRA

The NRC staff's evaluation of the licensee's submittal focused on the capability of the licensee's PRA and other risk evaluations (e.g., for external events) to analyze the risks stemming from pre- and post-EPU plant operations and conditions. The NRC staff's evaluation did not involve an in-depth review of the licensee's PRA; instead, it involved an evaluation of the information provided by the licensee in its submittal; considered the review findings for the St. Lucie IPE and IPEEE; and reviewed the CEOG peer review open F&Os and their dispositions for this application.

Based on its evaluation, the NRC staff finds that the St. Lucie 1 PRA models used to support the risk evaluation for this application have sufficient scope, level of detail, and technical adequacy to support the evaluation of the EPU.

## *Internal Events Risk Evaluation*

The licensee assessed the risk impacts from internal events resulting from the proposed EPU by reviewing the changes in plant design and operations resulting from the proposed EPU, mapping these changes onto appropriate PRA elements, modifying affected PRA elements as needed to capture the risk impacts of the proposed EPU, and requantifying the St. Lucie 1 PRA to determine the CDF and LERF of the post-EPU plant.

## Initiating Event Frequencies

The St. Lucie 1 PRA model includes initiating event categories that include transient initiating events, LOOP, LOCA initiators, SGTR initiators, ATWS initiators, and internal flooding initiators.

*Transients* – The licensee stated that the evaluation of the plant conditions and procedural changes for EPU conditions do not result in any new transient initiators, nor directly impact transient initiator frequencies significantly. Sensitivity calculations were performed that increased the transient initiator frequency to bound the various challenges to the plant from



transients resulting from loss of electrical busses, reactor trip, PORV challenges, and increased flow accelerated corrosion.

*LOOP* – The licensee states in its submittal that several plant modifications will be undertaken to ensure the plant, at EPU conditions, is more robust to external LOOP. Conditional LOOP likelihood is also expected to decrease as a result of a modification to rearrange post-trip safety injection actuation signal non-safety loads. As a consequence, increases in switchyard, plant centered or grid LOOP frequency are not expected. Sensitivity calculations were performed to show negligible risk increase due to increase in LOOP frequency.

*Support System* – The licensee states that no significant changes to support systems are planned in support of the EPU and no significant impact on support system initiating event frequencies due to the EPU are postulated.

*LOCA* – The licensee did not identify any impact on LOCA or interfacing system LOCA frequencies resulting from the EPU. A sensitivity study concluded that increasing the transient induced PORV challenge frequency by 50 percent resulted in a CDF increase of 1E-9 per year.

*SGTR* – The licensee states that as changes to the SG operating conditions are minimal, the existing PRA modeling for SGTR events is considered applicable to EPU conditions.

*ATWS* – The significance of the ATWS event is evaluated in terms of unfavorable exposure times, which reflect the fraction of cycle the plant would have to wait before the MTC is sufficiently negative such that ATWS events could be mitigated with charging pumps and other resources. St. Lucie 1 analyses indicate that the EPU ATWS frequency is approximately 3.4E-7 per year. This results in a delta CDF of about 4.7E-08 per year. This analysis conservatively assumes that core damage results when RCS pressurizes to above 3700 psia. While EPU ATWS events do increase slightly, their significance is low due to the low frequency of failure of rods to insert.

*Internal Flooding* – The licensee states that other than the pipe break initiators discussed, there are no substantive changes to other systems that might induce internal flooding; therefore, the flooding impacts and initiator frequencies remain unchanged.

#### Overall EPU Impact on Initiating Events

The staff finds the licensee adequately addressed internal initiating event frequencies based on the licensee properly implementing the equipment modifications and replacements it identified in its license amendment submittal. Furthermore, based on the licensee's sensitivity calculation, any short-term risk impact from break-in failures caused by the numerous BOP equipment changes is expected to be very small. Finally, the staff notes that any changes observed in the future in initiating event frequencies will be identified and tracked under the plant's existing performance monitoring programs and processes and will be reflected in future updates of the PRA, based on actual plant operating experience.

The NRC staff has not identified any issues associated with the licensee's evaluation of internal initiating event frequencies that would significantly alter the overall risk results or conclusions for this license amendment. Therefore, the staff concludes that there are no issues with the evaluation of internal initiating event frequencies associated with the St. Lucie 1 internal events

PRA that would rebut the presumption of adequate protection or warrant denial of this license amendment.

### Component Failure Rates

The licensee concluded in its submittal that the EPU would not significantly impact long-term equipment reliability due to the replacement/modification of plant components. The majority of hardware changes in support of the EPU may be characterized as either replacement of components or upgrade of existing components. The licensee described no planned operational modifications as part of the EPU that involve operating equipment beyond design ratings. Sensitivity studies were performed on selected components or systems where changes due to EPU had the potential to impact plant performance.

The staff finds that the licensee adequately addressed equipment reliability based on the licensee properly implementing the equipment modifications and replacements it identified in its license amendment submittal. Further, any short-term risk impact of the numerous BOP equipment changes, due to break-in failures, is expected to be very small. Finally, the staff notes that the licensee's component monitoring programs, including equipment modifications and/or replacement are being relied upon to maintain the current reliability of the equipment.

The staff has not identified any issues associated with licensee's evaluation of component reliability that would significantly alter the overall results or conclusions for this license amendment. Therefore, the staff concludes that there are no issues with component reliabilities/failure rates modeled in the St. Lucie 1 internal events PRA that would rebut the presumption of adequate protection or warrant denial of this license amendment and that the expectation is that there will be no change in component reliability as a result of the EPU.

### Accident Sequence Delineation and Success Criteria

Success criteria specify the performance requirements on plant systems performing critical safety functions. The licensee performed a review to assess the effect of the increase in thermal power level on success criteria. Safety functions, and related EPU impacts on success criteria considered by the licensee, are discussed in this section.

Increased decay heat due to EPU results in a more rapid depletion of inventory in the SG and degrades the once-through cooling (OTC) heat removal capability. Should FW not be recoverable, the increased core decay power and the associated decreased boil-off time impacts operator timing and equipment required for successful implementation of OTC. To address this potential loss of capability, the licensee increased the SG low level reactor trip setpoint and made changes to the plant EOPs. These changes are:

1. Increase the narrow range SG low level reactor trip setpoint from 20.5 percent to 35 percent
2. Modify Emergency Operating Procedure 1-EOP-01, Standard Post Trip Actions procedures to trip all RCPs upon indication of a TLOFW

The intent of these actions is to increase the inventory in the SG following TLOFW events to increase the time available for operator to implement OTC. MAAP analyses show that implementation of these actions following a TLOFW with a reactor trip on SG low level will

increase the time to successfully implement OTC from 30 minutes under current conditions to 37 minutes at EPU conditions. These changes also provide an additional 15 minutes to restore FW. In addition, to reduce the potential for AFW unavailability during an event, St. Lucie 1 is modifying surveillance procedures to reduce potential pre-initiator human failure events associated with mispositioning of the AFW discharge valves. Combined, these EPU plant improvements will provide a safety benefit.

There are no changes in reactivity control methods or effectiveness due to EPU. However, the increased power level results in a longer period of unfavorable MTC during ATWS events. As the frequency of ATWS is low, the impact on risk is small.

EPU associated conditions reduce the time to reach boron solubility limits in the core for medium and large LOCAs from 10 hours to 6.5 hours. This condition can result in boron precipitation on the fuel assemblies, which reduces heat transfer rates, and may lead to core damage. To preclude this occurrence, the licensee will revise the associated EOPs to direct the operators to reestablish hot leg/cold leg injection no later than 6 hours following the initiation of safety injection in the cold leg. The only potential impact on risk is from an increase in the probability of the operators failing to reinitiate safety injection within this time period. This reduction in time was considered in developing the operator action for initiating hot leg injection. Based on human reliability analysis evaluation, the licensee notes that operator recovery times from the point of the cue to enter hot leg injection are unchanged, thus HEPs remain unchanged and impact on the plant risk is negligible.

As a result of the EPU, St. Lucie is also planning to modify the pressurizer level control program since the level is estimated to have larger variation for EPU. The pressurizer level control system maintains the pressurizer level within a programmed band consistent with measured  $T_{avg}$ . The programmed level is designed to maintain a sufficient margin above the low level alarm where the heaters turn off while maintaining the level low enough that a sufficient steam volume is maintained to ensure the pressurizer does not go solid during accidents and transient conditions. Since  $T_{avg}$  temperature program has changed for EPU, the nominal pressurizer level program temperatures for the low and high level limits have changed for EPU. The low limit  $T_{avg}$  setpoint is at 15 percent power; temperature of  $T_{avg}$  538.7 °F. The high limit  $T_{avg}$  setpoint is at 90 percent power;  $T_{avg}$  temperature of 572 °F. The level control program is linear between 15 percent power and the high limit  $T_{avg}$ . For measured  $T_{avg}$  below 15 percent load, the level program is constant at the low limit. For measured  $T_{avg}$  above the high limit  $T_{avg}$  setpoint, the level program is constant at the high limit. The pressurizer level program low limit and high limit in terms of level do not change for EPU. Currently, the pressurizer level varies from 33.09 percent at 15 percent power to 65.6 percent at 100 percent power. After EPU, the pressurizer level will be 33.09 percent at 15 percent power to 65.6 percent at 90 percent power and maintain that level through 100 percent. Since it is possible that the higher water level could lead to increased PORV challenges and less pressurizer steam volume to react to pressure changes, the licensee investigated this impact within the initiating event frequency analysis by increasing the fraction of reactor trip events due to pressurizer level control problems resulting in a PORV challenge by 50 percent. The staff expects that any increase in PORV challenges following implementation of the proposed EPU would be identified under the licensee's performance monitoring programs and processes and incorporated into future model updates.

The staff finds that the licensee's assessment of the impact of the proposed EPU on success criteria appears to be reasonable and that there are no issues related to the St. Lucie 1 success

criteria that would rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

#### Operator Actions

*Human Reliability Analysis (HRA)* – EPU has the general effect of reducing the time available for the operators to complete recovery actions, because of the higher decay heat level after EPU implementation. The plant is dependent on operating crew actions for successful accident mitigation. The success of these actions is, in turn, dependent on a number of performance shaping factors and that the performance shaping factor that is principally influenced by the EPU is the time available within which to detect, diagnose, and perform required actions. The higher power levels normally result in reduced time available for some operator actions.

The licensee states that the St. Lucie HRA was developed in a manner to conform to RG 1.200. Each operator action was evaluated using the EPRI HRA Calculator, and where appropriate, response time windows were evaluated using plant specific MAAP 4.0.7 accident analysis simulations. The Human Cognitive Correlation/Operator Reliability and Cause Based Decision Tree Methodology methodologies were applied to all of the human error events, and for each event, the greater of the calculated HEPs from the two methodologies was used in the PRA model. In addition, the licensee utilized the accident sequence evaluation program for pre-initiator human failure events to identify and increase surveillance frequencies for EPU risk significant valves, thereby decreasing CDF by  $5.5\text{E-}07$  per year and LERF by approximately  $1.0\text{E-}07$  per year.

EPU has no impact on estimated operator recovery actions for approximately one half of the operator actions included in the PRA. For several HEPs, the SG low-level setpoint change and the modified 1-EOP-1 to trip all RCPs on indication of a TLOFW resulted in a significant benefit. The increased time window improves the reliability of three basic operator actions following an instantaneous TLOFW: (1) restoration of MFW, (2) restoration of AFW and (3) implementation of OTC.

An assessment of the net risk impact of the current plant and EPU HRA were performed. This analysis consisted of estimating the plant risks as monitored by CDF and LERF. Results of these analyses indicate that by implementing a revised risk-informed TLOFW response strategy, the impact of EPU on HEPs is limited to  $6.67\text{E-}08$  per year CDF and  $1.25\text{E-}08$  per year LERF.

#### Overall EPU Impact on Operator Actions

Based on the licensee's submitted information, the NRC staff finds that it is reasonable to expect that the main impact of the EPU is to reduce the time available for some operator actions, which will increase the associated HEPs. However, these increased HEPs are not expected to create significant impacts, unless a number of critical operator actions cannot be performed at the increased power levels. The NRC staff has not identified any issues associated with the licensee's evaluation of operator actions that would significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff concludes that there are no issues with the operator actions evaluation associated with the St. Lucie internal events PRA that would rebut the presumption of adequate protection or warrant denial of this license amendment.

## Internal Events Risk Results

Level 1 PRA estimates the frequency of core damage for different initiating events that have the potential to occur at the plant. The impact of increases in initiating event frequencies was presented as sensitivity studies in the application and the outcome of these studies show negligible increases in core damage frequency.

Level 2 PRA calculates the containment response under postulated severe accident conditions and provides an assessment of the containment adequacy. The simplified Level 2 evaluation calculates the LERF using CDF accident sequences and bins that result in LERF, intact containment, late containment failure and small early release end states. The licensee states that the calculations considered all relevant severe accident phenomenology.

Table 1: Internal Events CDF and LERF Risk Metrics

	Pre-EPU	Post-EPU	Delta Change	Percent decrease
CDF	$5.96 \times 10^{-6}/\text{year}$	$5.60 \times 10^{-6}/\text{year}$	$-3.6 \times 10^{-7}$	6.0
LERF	$4.06 \times 10^{-7}/\text{year}$	$3.23 \times 10^{-7}/\text{year}$	$-8.3 \times 10^{-8}$	20.4

The above results are consistent with RG 1.174, since this application represents decreases in internal events CDF and LERF. The application does not raise concerns of adequate protection.

The staff finds the licensee's evaluation of the impact of the proposed EPU on at-power risk from internal events is reasonable and concludes that the base risk due to the proposed EPU is acceptable and that there are no issues that rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

## *External Events Risk Evaluation*

The licensee does not have fire or seismic PRA models. The IPEEE studies used the EPRI Fire Induced Vulnerability Evaluation (FIVE) methodology to address external risk from fire sources. For the Seismic IPEEE process, the licensee used a site-specific seismic program associated with unresolved safety issue (USI) A-46, "Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors," to address the seismic aspects of the IPEEE. High winds, external flooding, and other external events (e.g., transportation and nearby facility accidents) were addressed by reviewing the plant environs against regulatory requirements. The licensee provided a qualitative assessment of the impact of EPU implementation on external event risk, which is discussed below.

## Internal Fire Risk

For the IPEEE fire analysis, St. Lucie implemented the EPRI FIVE. The IPEEE staff evaluation notes the licensee analyzed all fire areas and compartments using a reasonable screening methodology. A qualitative evaluation of EPU modifications was performed with respect to fire risk. The evaluation included an assessment of the impact of EPU on the initial IPEEE fire screening, and a reassessment of the three non-screened fire areas: main control room, cable

spreading room and switchgear room. The evaluation concluded that EPU changes would not impact the initial plant fire screening.

The combined fire risk estimates for the main control room, cable spreading room, and switchgear room are on the order of  $4\text{E-}06$  per year for each room. An assessment of the impact of planned EPU changes on the fire risk for these compartments indicates the impact to be negligible as fire risk for these rooms did not credit operator actions.

Fire frequencies and fire mitigation (e.g., fire suppression, fire brigade response) are not related to reactor power level, therefore the staff does not expect the post-EPU risk to significantly increase due to fire and create the "special circumstances" described in Appendix D of SRP Chapter 19.2 for a non-risk-informed application.

### Seismic Risk

In the seismic IPEEE, the site-specific program for seismic adequacy evaluations for St. Lucie 1 addresses only a subset of the elements specified in NUREG-1407 as recommended items that should be considered in the seismic IPEEE of a reduced-scope plant. St. Lucie's scaled-back site-specific seismic adequacy program was approved, in concept, by the NRC for the purpose of addressing USI A-46. The justifications cited by St. Lucie for performing a scaled-back analysis include: (a) very low probability of having an earthquake at the SSE level; and (b) very low values of potential offsite releases and potential risk reductions given the postulated accident scenarios and seismic hazards. St. Lucie's approach to seismic evaluation relied primarily on plant walkdowns and on the use of seismic review team judgment, supplemented with calculations, as needed, for resolving outliers.

EPU systems modifications were reviewed for their impact on safe shutdown. Through the review, it was concluded that none of the planned EPU plant modifications have any significant potential impact on seismic vulnerability. Therefore, the licensee judged the impact of EPU plant modifications on safe shutdown and associated plant risk due to seismic events to be negligible. Furthermore, the licensee states that all structural plant modifications and anchoring of all replacement components (safety and non-safety) for EPU will have the same or greater seismic capability than the current design basis.

Seismic risk was not quantified either for the current plant or for EPU implementation. However, in order to provide additional insight with respect to the effect of EPU on seismic risk, a focused seismic estimate was established. The primary purpose of the evaluation was to provide a risk estimate of the impact of operator actions following a seismic event. The analyzed event was a seismic initiated LOOP that occurs during ground accelerations with a magnitude between the operating basis earthquake ( $0.05g$ ) and the beyond design basis earthquake ( $0.1g$ ). This evaluation indicated that both current and EPU CDF estimates were very close to  $9\text{E-}08$  per year. Similarly, LERF estimates were on the order of  $1.3\text{E-}08$  per year.

The staff finds that the licensee's characterization of the seismic risk at St. Lucie 1 is not complete and that the steps undertaken during the seismic IPEEE process leads to an inconclusive risk estimate. In the IPEEE seismic evaluation, the NRC staff notes that there are several weaknesses in the licensee's seismic submittal; however, the staff indicates that the process used to address seismic risk was capable of identifying the most likely severe accidents and severe accident vulnerabilities. Based on a simplified approach to estimate the core damage frequency from a seismic margins approach and using the latest published United

States Geological Survey seismic hazards information, the staff estimates the St. Lucie seismic CDF is about or below  $5E-5$  per year. Since all structural plant modifications and anchoring of all replacement components (safety and non-safety) for EPU will have the same or greater seismic capability than the current design basis, and new vulnerabilities to a seismic event due to implementation of the EPU are negligible, the staff finds the delta seismic risk associated with the EPU to be insignificant. As such, the staff does not expect the seismic risk associated with the plant to rebut the presumption of adequate protection. For a risk-informed submittal, the staff would have investigated further the impact of seismic risk; however, for a non-risk-informed submittal, the staff does not expect the post-EPU risk to significantly increase due to seismicity and create the "special circumstances" described in Appendix D of SRP Chapter 19.2.

#### Other External Events Risk

The St. Lucie IPEEE addresses events other than seismic and fires, including high winds, external floods, and transportation and nearby facility accidents. Consistent with the IPEEE guidance, the licensee reviewed the plant environs against regulatory requirements regarding these hazards and concluded that St. Lucie meets the applicable NRC SRP requirements and, therefore, has an acceptably low risk with respect to these hazards.

#### External Events Risk Conclusion

The staff has not identified any issues associated with the licensee's evaluation of the risks related to external events that would significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff concludes that there are no issues with the external events risk evaluation that would rebut the presumption of adequate protection or warrant denial of this license amendment. The expectation is that the risk impact from external events resulting from the proposed EPU will be very small, based on the licensee's current risk evaluations.

#### *Shutdown Risk Evaluation*

The primary impact of the EPU on risk during shutdown operations is associated with the decrease in allowable operator action times in response to events. Reductions in available time for operators to take compensatory or mitigating actions could vary from several to 10 or more minutes, dependent on the shutdown condition. A licensee safety evaluation demonstrates that the shorter available time window under EPU would not adversely impact safety consequences. As the shutdown operation related procedures are condition driven, no significant risk impacts to the shutdown operations procedures are anticipated for EPU.

The staff has not identified any issues associated with the licensee's evaluation of shutdown risks that would significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff concludes that there are no issues with the shutdown operations risk evaluation that would rebut the presumption of adequate protection or warrant denial of this license amendment. The expectation is that the impact on shutdown risk resulting from the proposed EPU will be negligibly small, based on the licensee's current shutdown risk management process.

## Conclusion

The NRC staff has reviewed the licensee's assessment of the risk implications associated with the implementation of the proposed EPU and concludes that the licensee has adequately modeled and/or addressed the potential impacts associated with the implementation of the proposed EPU. The NRC staff further concludes that the results of the licensee's risk analysis indicate that the risks associated with the proposed EPU are acceptable and do not create the "special circumstances" described in Appendix D of SRP Chapter 19. Therefore, the NRC staff finds the risk implications of the proposed EPU acceptable.

### 3.0 FACILITY OPERATING LICENSE AND TECHNICAL SPECIFICATION CHANGES

To achieve the EPU, the licensee proposed the following changes to the Facility Operating License and TSs for St. Lucie 1. The bases of the NRC's acceptance of those changes are discussed above in Section 2 of this SE. Based on that review of the effect of the EPU on the changes below, the NRC staff found the proposed changes acceptable.

#### 3.1 LICENSE CONDITION 3.A - MAXIMUM POWER LEVEL

- The maximum reactor core power level is revised from "2700 megawatts (thermal)" to "3020 megawatts (thermal)."

#### 3.2 LICENSE CONDITION 3.I – RODEX2 Safety Analyses

RODEX2 has been specifically approved for use for St. Lucie Unit 1 licensing basis analyses. Upon NRC approval of a generic supplement to the RODEX2 code and associated methods that account for thermal conductivity degradation (TCD), FPL will, within six months:

- a. Demonstrate that the St Lucie Unit 1 safety analyses remain conservatively bounded in licensing basis analyses when compared to the NRC-approved generic supplement to the RODEX2 methodology, or
- b. Provide a schedule for re-analysis using the NRC-approved generic supplement to the RODEX2 methodology for any of the affected licensing basis analyses.

#### 3.3 INDEX

##### DEFINITIONS

- "1.11 E Average Disintegration Energy" is changed to "1.11 Dose Equivalent Xe-133" and
- "1.16 Low Temperature RCS Overpressure Protection Range" is changed to "1.16 Deleted."

##### LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

- "3/4.1.2 Borated Water Sources – Operating" page number is changed from "3/4 1-18" to "3/4 1-17",
- "3/4.9.7 Crane Travel – Spent Fuel Storage Pool Building" is changed to "3/4.9.7 DELETED",



- “3/4.9.13 Spent Fuel Storage Cask Crane” is changed to “3/4.9.13 DELETED”, and
- “3/4.9.14 Decay Time - Storage Pool” is changed to “3/4.9.14 DELETED.”

### 3.4 TS 1.11, DEFINITIONS - E AVERAGE DISINTEGRATION ENERGY

- The definition “E - AVERAGE DISINTEGRATION ENERGY” is deleted and replaced with the definition “DOSE EQUIVALENT XE-133” provided below:

DOSE EQUIVALENT XE-133 shall be that concentration of Xe-133 ( $\mu\text{Ci/gram}$ ) that alone would produce the same acute dose to the whole body as the combined activities of noble gas nuclides Kr-85m, Kr-85, Kr-87, Kr-88, Xe-131m, Xe-133m, Xe-133, Xe-135m, Xe-135, and Xe-138 actually present. If a specific noble gas nuclide is not detected, it should be assumed to be present at the minimum detectable activity. The determination of DOSE EQUIVALENT XE-133 shall be performed using effective dose conversion factors for air submersion listed in Table III.1 of EPA Federal Guidance Report No. 12, 1993, “External Exposure to Radionuclides in Air, Water, and Soil.”

### 3.5 TS 1.16, DEFINITIONS - LOW TEMPERATURE RCS OVERPRESSURE PROTECTION RANGE

- The definition “LOW TEMPERATURE RCS OVERPRESSURE PROTECTION RANGE” is deleted.

### 3.6 TS 1.25, DEFINITIONS - RATED THERMAL POWER

- The RATED THERMAL POWER (RTP) is revised from “2700 MWt” to “3020 MWt.”

### 3.7 TS 2.1, SAFETY LIMITS – FIGURE 2.1-1: REACTOR CORE THERMAL MARGIN SAFETY LIMIT – FOUR REACTOR COOLANT PUMPS OPERATING

- Replacement for FIGURE 2.1-1 REACTOR CORE THERMAL MARGIN SAFETY LIMIT – FOUR REACTOR COOLANT PUMPS OPERATING, and

- The “VESSEL FLOW LESS MEASUREMENT UNCERTAINTIES – 365,000 GPM” is changed to “–REACTOR COOLANT SYSTEM TOTAL FLOW RATE – SPECIFIED IN LCO 3.2.5” in the replacement figure.

### 3.8 TS 2.2, LIMITING SAFETY SYSTEM SETTINGS – TABLE 2.2-1 – REACTOR PROTECTIVE INSTRUMENTATION TRIP SETPOINTS LIMITS

- Table 2.2-1, Trip Setpoint for reactor coolant flow-low, four reactor coolant pumps operating in Table 2.2-1 is changed from “ $\geq 95\%$  of design reactor coolant flow with 4 pumps operating” to “ $\geq 95\%$  of minimum reactor coolant flow with 4 pumps operating\*”
- Table 2.2-1, Trip Setpoint for “7. Steam Generator Water Level – Low” in Table 2.2-1 is changed from “ $\geq 20.5\%$  Water Level – each steam generator” to “ $\geq 35.0\%$  Water Level – each steam generator”,

- Table 2.2-1, Allowable Value for “7. Steam Generator Water Level – Low” in Table 2.2-1 is changed from “≥ 19.5% Water Level – each steam generator” to “≥ 35.0% Water Level – each steam generator”,

- Table 2.2-1, the current footnote is changed from “\* Design reactor coolant flow with 4 pumps operating is 365,000 gpm.” to “\* For minimum reactor coolant flow with 4 pumps operating, refer to Technical Specification LCO 3.2.5”,

### 3.9 TS 3/4.1.1.1, BORATION CONTROL – SHUTDOWN MARGIN – $T_{avg} > 200^{\circ}\text{F}$

- ACTION, The minimum boron concentration is changed from “...greater than or equal to 1720 ppm boron or equivalent...” to “...greater than or equal to 1900 ppm boron or equivalent...”

### 3.10 TS 3/4.1.1.2, BORATION CONTROL – SHUTDOWN MARGIN – $T_{avg} \leq 200^{\circ}\text{F}$

- ACTION, The minimum boron concentration is changed from “...greater than or equal to 1720 ppm boron or equivalent...” to “...greater than or equal to 1900 ppm boron or equivalent...”

### 3.11 TS 3/4.1.2.1, REACTIVITY CONTROL SYSTEMS – FLOW PATHS – SHUTDOWN

- LCO 3.1.2.1b contains a footnote designated by an asterisk (\*). The second sentence of this footnote which starts, “In the latter case:...” is being revised as follows:

- “In the latter case: 1) all ... their power removed:” is changed to “In the latter case, all charging pumps shall be disabled.”, and

- The list of valves in footnote (\*) is deleted.

- Figure 3.1-1b is deleted.

### 3.12 TS 3/4.1.2.2, REACTIVITY CONTROL SYSTEMS – FLOW PATHS – OPERATING

- LCO 3.1.2.2 The second set of requirements after the “OR” currently numbered “a., b., and c.” are renumbered to “d., e., and f.”

### 3.13 TS 3/4.1.2.3, REACTIVITY CONTROL SYSTEMS – CHARGING PUMPS – SHUTDOWN

- LCO 3.1.2.3 contains a footnote designated by an asterisk (\*). The second sentence of this footnote which starts, “In the latter case:...” is being revised as follows:

- “In the latter case: 1) all ... their power removed:” is changed to “In the latter case, all charging pumps shall be disabled”, and

- The list of valves in footnote (\*) is deleted.

3.14 TS 3/4.1.2.7, REACTIVITY CONTROL SYSTEMS – BORATED WATER SOURCES - SHUTDOWN

- LCO 3.1.2.7.a. The boric acid makeup tank parameters are changed from “a minimum borated water volume of 3650 gallons of 2.5 to 3.5 weight percent boric acid (4371 to 6119 ppm boron).” to “a minimum borated water volume of 3650 gallons of 3.0 to 3.5 weight percent boric acid (5245 to 6119 ppm boron)”,
- LCO 3.1.2.7.b.2. The RWT minimum boron concentration is changed from “1720 ppm” to “1900 ppm”,

3.15 TS FIGURE 3.1-1, ST. LUCIE 1 MIN BAMT VOLUME VS STORED BAMT CONCENTRATION

– This figure is replaced with new TS Figure 3.1-1, entitled “FIGURE 3.1-1, ST. LUCIE 1 MIN BAMT VOLUME VS STORED BAMT CONCENTRATION (Modes 1, 2, 3 and 4)”, and

- TS Figure 3.1-1 is relocated from TS 3/4.1.2.7 to TS 3/4.1.2.8.

3.16 TS 3/4.1.2.8, REACTIVITY CONTROL SYSTEMS – BORATED WATER SOURCES - OPERATING

- LCO 3.1.2.8.d.2. The RWT minimum boron concentration is changed from “1720 ppm” to “1900 ppm”,
- Pages 3/4.1-17, 3/4.1-18, and 3/4.1-19 are renumbered to reflect the relocation of Figure 3.1-1 to TS 3/4.1.2.8.

3.17 TS 3/4.2.5, POWER DISTRIBUTION LIMITS – DNB PARAMETERS

- LCO 3.2.5 is revised as follows to refer to the limits in COLR Table 3.2-1 and COLR Figure 3.2-4, while adding a footnote:

“The following DNB related parameters shall be maintained within the limits:

- a. Cold Leg Temperature as shown on Table 3.2-1 of the COLR,
- b. Pressurizer Pressure\* as shown on Table 3.2-1 of the COLR,
- c. Reactor Coolant System Total Flow Rate - greater than or equal to 375,000 gpm, and
- d. AXIAL SHAPE INDEX as shown on Figure 3.2-4 of the COLR.”

- SURVEILLANCE REQUIREMENT 4.2.5.1 is changed from “Each of the parameters of Table 3.2-1 shall be ...” to “Each of the DNB related parameters shall be ...”,

- SURVEILLANCE REQUIREMENT 4.2.5.2, is changed from “...within its limit by measurement\* at least ...” to “...within its limit by measurement\*\* at least ...” to shift the related footnote designation below the footnote that is added for LCO 3.2.5.b,

- The footnote originally at the bottom of Table 3.2-1 is added to the bottom of the page as “\* Limit not applicable during either a THERMAL POWER ramp increase in excess of 5% per minute of RATED THERMAL POWER or a THERMAL POWER step increase of greater than 10% of RATED THERMAL POWER.”, with “per minute” added for additional clarity,
- The current footnote at the bottom on the page is revised from “\*” to “\*\*”, and
- Table 3.2-1 “DNB MARGIN LIMITS” is deleted from TS and relocated to the COLR.

### 3.18 TS 3/4.3.1, REACTOR PROTECTIVE INSTRUMENTATION

Table 4.3-1, Channel Functional Test in the Table for “7. Steam Generator Water Level – Low” is changed to “M(6,7)” to include two new notes as described below.

Table 4.3-1, two new notes are added below Table 4.3-1 that read

- (6) If the as-found channel setpoint is either outside its predefined as-found acceptance criteria band or is not conservative with respect to the Allowable Value, then the channel shall be declared inoperable and shall be evaluated to verify that it is functioning as required before returning the channel to service.
- (7) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance of the Field Trip Setpoint, otherwise that channel shall not be returned to OPERABLE status. The Field Trip Setpoint and the methodology used to determine the Field Trip Setpoint, the as-found acceptance criteria band, and the as-left acceptance criteria are specified in the UFSAR Section 7.2.

### 3.19 TS 3/4.4.8, REACTOR COOLANT SYSTEM – SPECIFIC ACTIVITY

- LCO 3.4.8.b, is changed from “ $\leq 100/E$   $\mu\text{Ci}/\text{gram}$ .” to “ $\leq 518.9$   $\mu\text{Ci}/\text{gram}$  DOSE EQUIVALENT XE-133.”,
- APPLICABILITY is changed from “1, 2, 3, 4, and 5” to “1, 2, 3, and 4”,
- ACTION: All ACTIONS, associated APPLICABILITY statements, footnote, and TS Figure 3.4-1 are deleted and replaced with the following ACTIONS:
  - a. With the specific activity of the primary coolant  $> 1.0$   $\mu\text{Ci}/\text{gram}$  DOSE EQUIVALENT I-131, verify DOSE EQUIVALENT I-131 is  $\leq 60.0$   $\mu\text{Ci}/\text{gram}$  once per four hours.
  - b. With the specific activity of the primary coolant  $> 1.0$   $\mu\text{Ci}/\text{gram}$  DOSE EQUIVALENT I-131, but  $\leq 60.0$   $\mu\text{Ci}/\text{gram}$  DOSE EQUIVALENT I-131, operation may continue for up to 48 hours while efforts are made to restore DOSE EQUIVALENT I-131 to within the 1.0  $\mu\text{Ci}/\text{gram}$  limit. Specification 3.0.4 is not applicable.
  - c. With the specific activity of the primary coolant  $> 1.0$   $\mu\text{Ci}/\text{gram}$  DOSE EQUIVALENT I-131 for greater than 48 hours during one continuous time interval, or  $> 60.0$   $\mu\text{Ci}/\text{gram}$  DOSE EQUIVALENT I-131, be in HOT STANDBY within 6 hours and COLD SHUTDOWN within the following 30 hours.

- d. With the specific activity of the primary coolant > 518.9  $\mu\text{Ci/gram}$  DOSE EQUIVALENT XE-133, operation may continue for up to 48 hours while efforts are made to restore DOSE EQUIVALENT XE-133 to within the 518.9  $\mu\text{Ci/gram}$  DOSE EQUIVALENT XE-133 limit. Specification 3.0.4 is not applicable.
- e. With the specific activity of the primary coolant > 518.9  $\mu\text{Ci/gram}$  DOSE EQUIVALENT XE-133 for greater than 48 hours during one continuous time interval, be in HOT STANDBY within 6 hours and COLD SHUTDOWN within the following 30 hours.

• TABLE 4.4-4, PRIMARY COOLANT SPECIFIC ACTIVITY SAMPLE AND ANALYSIS PROGRAM, Item 1 is changed as follows:

- TYPE OF MEASUREMENT AND ANALYSIS is changed from "Gross Activity Determination" to "DOSE EQUIVALENT XE-133 Determination."

- MINIMUM FREQUENCY is changed from "3 times per 7 days with a maximum time of 72 hours between samples" to "1 per 7 days,"

• TABLE 4.4-4, Item 3 and its associated footnote \* are deleted, and

• TABLE 4.4-4, Item 4 is changed as follows:

- Item "4" is changed to Item "3",

- TYPE OF MEASUREMENT AND ANALYSIS is changed from "...Including I-131, I-133, and I-135" to "...Including, I-131, I-132, I-133, I-134, and I-135."

- MODES IN WHICH SAMPLE AND ANALYSIS REQUIRED is changed from "1#, 2#, 3#, 4# and 5#" to "1#, 2#, 3# and 4#",

### 3.20 TS 3/4.4.9.1, REACTOR COOLANT SYSTEM – PRESSURE/TEMPERATURE LIMITS

• TS 3.4.9.1 LCO is changed from "...Figures 3.4-2a, 3.4-2b and 3.4-3 ..." to "... Figure 3.4-2a and Figure 3.4-2b ...",

• APPLICABILITY: is changed from "At all times. \*#" to "At all times. \*",

• TS 3.4.9.1 ACTION is changed from "...Figures 3.4-2b and 3.4-3." to Figure 3.4-2b.",

• The current asterisk (\*) footnote related to APPLICABILITY is deleted,

• The current (#) footnote related to APPLICABILITY is retained but changed to (\*),

• Current SURVEILLANCE REQUIREMENT 4.4.9.1.c "...Figures 3.4-2a, 3.4-2b and 3.4-3." is changed to "...Figures 3.4-2a and 3.4-2b.",

- 3.21 TS Figure 3.4-2a, ST. LUCIE UNIT 1 P/T LIMITS, 35 EFPY - HEATUP AND CORE CRITICAL is replaced with TS Figure 3.4-2a, ST. LUCIE UNIT 1 P/T LIMITS, 54 EFPY - HEATUP AND CORE CRITICAL.
- 3.22 TS Figure 3.4-2b, ST. LUCIE UNIT 1 P/T LIMITS, 35 EFPY - COOLDOWN AND INSERVICE TEST is replaced with TS Figure 3.4-2b, ST. LUCIE UNIT 1 P/T LIMITS, 54 EFPY - COOLDOWN AND INSERVICE TEST
- 3.23 TS Figure 3.4-3, ST. LUCIE UNIT 1 P/T LIMITS, 35 EFPY – MAXIMUM ALLOWABLE COOLDOWN RATES is deleted.
- 3.24 TS 3/4.4.13, REACTOR COOLANT SYSTEM – POWER OPERATED RELIEF VALVES

- LCO 3.4.13.a is changed to delete the colon after “selected” and add “during heatup, cooldown and isothermal conditions when the temperature of any RCS cold leg is less than or equal to 200°F.”,
- LCO 3.4.13.a.1. is deleted,
- LCO 3.4.13.a.2. is deleted,
- LCO 3.4.13.b is changed to delete the colon after “selected” and add “during heatup, cooldown and isothermal conditions when the temperature of any RCS cold leg is greater than 200°F and less than or equal to 300°F.”,
- LCO 3.4.13.b.1. is deleted,
- LCO 3.4.13.b.2. is deleted, and
- LCO APPLICABILITY is changed from “...RCS cold leg is less than or equal to 304°F,...” to “...RCS cold leg is less than or equal to 300°F,...”.

- 3.25 TS 3/4.4.14, REACTOR COOLANT SYSTEM – REACTOR COOLANT PUMP STARTING

- LCO 3.4.14 Note “#” at the bottom of page is changed from “# Reactor Coolant System Cold Leg Temperature is less than 304°F.” to “# Reactor Coolant System Cold Leg Temperature is less than 300°F.”

- 3.26 TS 3/4.5.1, EMERGENCY CORE COOLING SYSTEMS (ECCS) – SAFETY INJECTION TANKS (SIT)

- LCO 3.5.1.c. The SIT minimum boron concentration is changed from “1720 PPM” to “1900 ppm”, and
- LCO 3.5.1.d. The SIT nitrogen cover-pressure is changed from “between 200 and 250 psig” to “between 230 and 280 psig.”

3.27 TS 3/4.5.2, EMERGENCY CORE COOLING SYSTEMS (ECCS) – OPERATING

- LCO 3.5.2.b. The word “and” is deleted from the end of this LCO requirement,
- LCO 3.5.2.c. The end of this LCO is revised to delete the period and add “, and”,
- LCO 3.5.2.d. This is a new requirement stating “One OPERABLE charging pump\*.”,
- APPLICABILITY is changed from “MODES 1, 2 and 3\*” to “MODES 1, 2 and 3\*\*”.
- Footnote “\* With pressurizer pressure  $\geq$  1750 psia.” is changed to “\*\* With pressurizer pressure  $\geq$  1750 psia.”
- A new Footnote \* is added stating “\* One ECCS subsystem charging pump shall satisfy the flow path requirements of Specification 3.1.2.2.a or 3.1.2.2.d. The second ECCS subsystem charging pump shall satisfy the flow path requirements of Specification 3.1.2.2.b or 3.1.2.2.e.”
- Surveillance Requirement 4.5.2.e.1. is revised from “... valve in the flow path actuates ...” to “... valve in the flow paths actuates ...”,
- Surveillance Requirement 4.5.2.e.2.a. is revised from “High-Pressure Safety Injection Pump.” to “High-Pressure Safety Injection Pumps.”,
- Surveillance Requirement 4.5.2.e.2.b. is revised from “Low-Pressure Safety Injection Pump.” to “Low-Pressure Safety Injection Pumps.”,
- A new Surveillance Requirement 4.5.2.e.2.c. “Charging Pumps.” is added,
- Surveillance Requirement 4.5.2.f. an underline “\_” is deleted.

3.28 TS 3/4.5.4, EMERGENCY CORE COOLING SYSTEMS – REFUELING WATER TANK

- LCO 3.5.4.b. The RWT minimum boron concentration is changed from “1720 ppm” to “1900 ppm.”

3.29 TS 3/4.6.1.4, CONTAINMENT SYSTEMS – INTERNAL PRESSURE

- LCO 3.6.1.4 The primary containment internal pressure upper limit is changed from “2.4 PSIG” to “+ 0.5 psig.”

3.30 TS 3/4.7.1.1 PLANT SYSTEMS – TURBINE CYCLE – SAFETY VALVES

- Table 3.7-1 MAXIMUM ALLOWABLE POWER LEVEL-HIGH TRIP SETPOINT WITH INOPERABLE STEAM LINE SAFETY VALVES DURING OPERATION WITH BOTH STEAM GENERATORS

- Change allowable power level-high trip setpoint for 1 inoperable safety valve from “93.2” to “88.5.”

- Table 4.7-1 STEAM LINE SAFETY VALVES PER LOOP

- Change column header from "LIFT SETTING (+1% to -3%) to "LIFT SETTING \*\*",
- Change the upper limit for valves 8201, 8202, 8203, 8204, 8205, 8206, 8207, and 8208 from " $\leq 995.3$  psig" to " $\leq 1015.3$  psig", and
- Change the upper limit for valves 8209, 8210, 8211, 8212, 8213, 8214, 8215, and 8216 from " $\leq 1035.7$  psig" to " $\leq 1046.1$  psig".
- A new Footnote is added to read, "\*\* +/- 3% for valves a through d and +2%/-3% for valves e through h".

### 3.31 TS 3/4.7.1.3 PLANT SYSTEMS – CONDENSATE STORAGE TANK

- LCO 3.7.1.3. The condensate storage tank minimum contained volume is changed from "116,000 gallons" to "153,400 gallons."

### 3.32 TS 3/4.8.1, ELECTRICAL POWER SYSTEM – AC SOURCES – OPERATING

- LCO 3.8.1.1.b.2. The minimum fuel storage is changed from "... 16,450 gallons ..." to "... 19,000 gallons ...",
- Surveillance Requirement 4.8.1.1.2.e.3.b) The voltage is changed from "...4160  $\pm$  420..." to "...4160  $\pm$  210...", and the frequency is changed from "...60  $\pm$  1.2 Hz..." to "... 60  $\pm$  0.6 Hz...",
- Surveillance Requirement 4.8.1.1.2.e.4. This requirement is rewritten as indicated below:
  4. Verifying that on an ESF actuation test signal (without loss-of-offsite power) the diesel generator starts\*\*\*\* on the auto-start signal, and:
    - a) Within 10 seconds, generator voltage and frequency shall be 4160  $\pm$  420 volts and 60  $\pm$  1.2 Hz.
    - b) Operates on standby for greater than or equal to 5 minutes.
    - c) Steady-state generator voltage and frequency shall be 4160  $\pm$  210 volts and 60  $\pm$  0.6 Hz and shall be maintained throughout this test.,

- Surveillance Requirement 4.8.1.1.2.e.5.b) The voltage is changed from "...4160  $\pm$  420..." to "...4160  $\pm$  210...", and the frequency is changed from "...60  $\pm$  1.2 Hz..." to "... 60  $\pm$  0.6 Hz...", and

### 3.33 TS 3/4.8.1.2 ELECTRICAL POWER SYSTEM – AC SOURCES – SHUTDOWN

- LCO 3.8.1.2.b.2. The minimum fuel storage is changed from "... 16,450 gallons ..." to "...19,000 gallons ..."



3.34 TS 3/4.9.1, REFUELING OPERATIONS – BORON CONCENTRATION

- ACTION: The ACTION requirement is changed from "...greater than or equal to 1720 ppm boron..." to "...greater than or equal to 1900 ppm boron..."

3.35 TS 3/4.9.11, REFUELING OPERATIONS – SPENT FUEL STORAGE POOL

- LCO 3.9.11.b. is changed from "...greater than or equal to 1720 ppm" to "...greater than or equal to 1900 ppm."

3.36 TS 3/4.9.14, REFUELING OPERATIONS – DECAY TIME – STORAGE POOL

- TS 3/4.9.14, This specification is deleted.

3.37 TS 3/4.10.1, SPECIAL TEST EXCEPTIONS – SHUTDOWN MARGIN

- ACTION a. is changed from "...continue boration at  $\geq 40$  gpm of  $\geq 1720$  ppm boric acid solution..." to "...continue boration at  $\geq 40$  gpm of  $\geq 1900$  ppm boric acid solution...", and
- ACTION b. is changed from "...continue boration at  $\geq 40$  gpm of  $\geq 1720$  ppm boric acid solution..." to "...continue boration at  $\geq 40$  gpm of  $\geq 1900$  ppm boric acid solution..."

3.38 TS 3/4.11.2.6, RADIOACTIVE EFFLUENTS – GAS STORAGE TANKS

- LCO 3.11.2.6 is changed from "...less than or equal to 285,000 curies noble gases..." to "...less than or equal to 165,000 curies noble gases...", and
- Surveillance Requirement 4.11.2.6 is changed from "...when reactor coolant system activity exceeds 100/E" to "...when reactor coolant system activity exceeds 518.9  $\mu\text{Ci}/\text{gram}$  DOSE EQUIVALENT XE-133."

3.39 TS 5.3, DESIGN FEATURES – REACTOR CORE – FUEL ASSEMBLIES

- TS 5.3.1, Fuel Assemblies, the entire paragraph is replaced with the following:

The reactor shall contain 217 fuel assemblies. Each assembly shall consist of a matrix of Zircaloy clad fuel rods and/or poison rods, with fuel rods having an initial composition of natural or slightly enriched uranium dioxide ( $\text{UO}_2$ ) as fuel material. Limited substitutions of zirconium alloy or stainless steel filler rods for fuel rods, in accordance with approved applications of fuel rod configurations, may be used. Fuel assemblies shall be limited to those fuel designs that have been analyzed with applicable NRC staff approved codes and methods and shown by tests or analyses to comply with all fuel safety design bases. A limited number of lead test assemblies that have not completed representative testing may be placed in non-limiting core regions.

3.40 TS 5.4.2, DESIGN FEATURES – REACTOR COOLANT SYSTEM – VOLUME

- TS 5.4.2 This specification is deleted.

3.41 TS 5.6, DESIGN FEATURES – FUEL STORAGE - CRITICALITY

- TS 5.6.1.a.4. is changed from "... Criteria 1 and 3." to "... Criteria in 5.6.1.a.1 and 5.6.1.a.3."
- TS 5.6.1.a.6. is changed from "... Criteria 1 and 3." to "... Criteria in 5.6.1.a.1 and 5.6.1.a.3."
- TS 5.6.1.c. is changed from "... Criteria 2 and 3." to "... Criteria in 5.6.1.c.2, 5.6.1.c.3, 5.6.1.c.5 and 5.6.1.c.6."
- TS 5.6.1.c.1 is changed from "...less than or equal to 4.5 weight percent." to "...less than or equal to 4.6 weight percent."
- TS 5.6.1.c.2 is changed from "... Table 5.6-1 and Table 5.6-2." to "...Table 5.6-1."
- TS 5.6.1.c.3 is changed from "... Table 5.6-1 and Table 5.6-2." to "...Table 5.6-1."
- New TS 5.6.1.c.5 is added: "The same directional orientation for Metamic inserts is required for contiguous groups of 2x2 arrays where Metamic inserts are required."
- New TS 5.6.1.c.6 is added: "Any 2x2 array of Region 2 storage cells that interface with Region 1 shall comply with the rules of Figure 5.6-3. The allowed special arrangement in Region 2 as shown in Figure 5.6-2 shall not be placed adjacent to Region 1."
- TS 5.6.1.d is changed from "...having a U-235 enrichment less than or equal to 4.5 weight percent..." to "...having a maximum planar average U-235 enrichment less than or equal to 4.6 weight percent..."
- Figure 5.6-1 "Allowable Region 1 Storage Patterns and Fuel Alignments" is replaced with a new figure titled, "Allowable Region 1 Storage Patterns and Fuel Arrangements."
- Figure 5.6-2, "Allowable Region 2 Storage Patterns and Arrangements" is replaced with a new figure titled, "Allowable Region 2 Storage Patterns and Fuel Arrangements."
- New Figure 5.6-3, "Region 2 Interface requirements with Region 1" is added.
- The title of Table 5.6-1, "Minimum Burnup as a Function of Enrichment for Non-Blanketed Assemblies" is revised to "Minimum Burnup as a Function of Enrichment."
- In Table 5.6-1, the columns entitled "Minimum Burnup (GWd/MTU) for Initial Enrichment" are deleted and the entries in the "Fuel Type", "Cooling Time" and "Coefficients" columns are revised.
- Table 5.6-1, NOTE 1 is deleted.

- Table 5.6-1, NOTE 2 is renumbered as NOTE 1 and the phrase “given in the table” in the first sentence is deleted.

- The formula in Table 5.6-1, NOTE 1 (formerly NOTE 2) is revised from:

$$BU = A \cdot E^2 + B \cdot E + C$$

to

$$BU = A + B \cdot E + C \cdot E^2$$

- Table 5.6-1, NOTE 3 is renumbered as NOTE 2.

- Table 5.6-2, “Minimum Burnup as a Function of Enrichment for Blanketed Assemblies” is deleted.”

### 3.42 TS 6.8.4, ADMINISTRATIVE CONTROLS – PROGRAMS

- TS 6.8.4.h. Containment Leakage Rate Testing Program is changed from “The peak calculated containment internal pressure for the design basis loss-of-coolant accident Pa, is 39.6 psig.” to “The peak calculated containment internal pressure for the design basis loss-of-coolant accident Pa, is 42.8 psig.”

### 3.43 TS 6.9.11, ADMINISTRATIVE CONTROLS – CORE OPERATING LIMITS REPORT (COLR)

- TS 6.9.11.b The references for the COLR are revised to address the revised analyses for EPU. The following references are deleted and replaced with “DELETED”:

4. ANF-84-73(P)(A), “Advanced Nuclear Fuels Methodology for Pressurized Water Reactors: Analysis of Chapter 15 Events”,

6. EMF-84-093(P)(A), “Steam Line Break Methodology for PWRs”,

8. XN-NF-82-49(P)(A), “Exxon Nuclear Company Evaluation Model Revised EXEM PWR Small Break Model”,

11. EMF-2087(P)(A), “SEM/PWR-98: ECCS Evaluation Model for PWR LBLOCA Applications”, and

15. ANF-89-151(P)(A), “ANF-RELAP Methodology for Pressurized Water Reactors Analysis of Non-LOCA Chapter 15 Events.”

- TS 6.9.11.b The following references are being revised:

21. EMF-2310(P)(A), “SRP Chapter 15 Non-LOCA Methodology for Pressurized Water Reactors,” Revision 1, as supplemented by ANP-3000(P), “St. Lucie Unit 1 EPU - Information to Support License Amendment Request,” Revision 0.

22. EMF-2328(P)(A), “PWR Small Break LOCA Evaluation Model, S-RELAP5 Based,” Revision 0, as supplemented by ANP-3000(P), “St. Lucie Unit 1 EPU - Information to Support License Amendment Request,” Revision 0.

- TS 6.9.11.b The following reference is being added:

23. EMF-2103(P)(A), "Realistic Large Break LOCA Methodology for Pressurized Water Reactors," Revision 0, as supplemented by ANP-2903(P), "St. Lucie Nuclear Plant Unit 1 EPU Cycle Realistic Large Break LOCA Summary Report with Zr-4 Fuel Cladding," Revision 1.

#### 4.0 REGULATORY COMMITMENTS

The licensee has made the following regulatory commitment(s):

1. Update the Inservice Testing Program to reflect changes to plant pumps and valves under EPU conditions.
2. Provide operator training to account for increased EPU power level and resultant plant changes.
3. Implement modifications to provide radiation shielding for reactor auxiliary building heating, ventilation, and air conditioning (HVAC) components identified in LAR Attachment 5, Section 2.3.1, Environmental Qualification of Electrical Equipment.
4. Implement modification(s) to increase safety injection tank design pressure for EPU conditions described in LAR Attachment 5, Section 2.8.5.6.3, Emergency Core Cooling System and Loss-of-Coolant Accidents.
5. Implement modification(s) necessary to accommodate the simultaneous hot and cold leg injection requirements for EPU conditions as described in LAR Attachment 5, Section 2.8.5.6.3, Emergency Core Cooling System and Loss-of-Coolant Accidents.
6. Implement modification(s) to install a leading edge flow meter (LEFM) as described in LAR Attachment 5, Section 2.4.4, Measurement Uncertainty Recapture Power Uprate, and update FSAR Section 13.8, Licensee-Controlled Technical Specification Requirements, to include Limiting Conditions for Operation (LCO) and Action Statements for the LEFM system.
7. Implement modification(s) to the ac electrical busses as described in LAR Attachment 5, Section 2.3.3, AC Onsite Power System.
8. Revise the administrative controls for the main containment purge isolation valves such that they are maintained closed in MODES 1, 2, 3 and 4.
9. Implement modification(s) to pipe supports for systems impacted by loads due to EPU conditions, as described in LAR Attachment 5, Section 2.2.2.2, Balance of Plant Piping, Components, and Supports.
10. Revise applicable procedures to accommodate operator actions during station blackout at EPU conditions, as described in LAR Attachment 5, Section 2.11, Human Factors.
11. Implement a Metamic<sup>TM</sup> insert surveillance program as described in LAR Attachment 5, Section 2.8.6.2, Spent Fuel Storage, and update the UFSAR to include the program requirements.
12. Adopt MRP-227-A during the period of extended operation in place of the existing Reactor Vessel Internals Inspection Program.
13. Final verification of the site-specific uncertainty analyses occurs as part of the LEFM CheckPlus<sup>TM</sup> system commissioning process. The commissioning process provides final positive confirmation that actual performance in the field meets the uncertainty

bounds established for the instrumentation as described in Cameron engineering report ER-733 (page 2.4.4-5, paragraph 2 of Attachment 5 to the LAR, Reference 1).

The NRC staff finds that reasonable controls for the implementation and for subsequent evaluation of proposed changes pertaining to the above regulatory commitment(s) are best provided by the licensee's administrative processes, including its commitment management program. The above regulatory commitments do not warrant the creation of regulatory requirements (items requiring prior NRC approval of subsequent changes).

## 5.0 STATE CONSULTATION

Based upon a letter dated May 2, 2003, from Michael N. Stephens of the Florida Department of Health, Bureau of Radiation Control, to Brenda L. Mozafari, Senior Project Manager, U.S. Nuclear Regulatory Commission, the State of Florida does not desire notification of issuance of license amendments.

## 6.0 ENVIRONMENTAL CONSIDERATION

Pursuant to 10 CFR 51.21, 51.32, 51.33, and 51.35, a draft Environmental Assessment and finding of no significant impact was prepared and published in the *Federal Register* on January 6, 2012 (77 FR 813). The draft Environmental Assessment provided a 30-day opportunity for public comment. The NRC staff received comments which were addressed in the final environmental assessment. The final Environmental Assessment was published in the *Federal Register* on July 6, 2012 (77 FR 40092). Accordingly, based upon the environmental assessment, the Commission has determined that the issuance of this amendment will not have a significant effect on the quality of the human environment.

## 7.0 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.

## 8.0 REFERENCES

1. RS-001, Revision 0, "Review Standard for Extended Power Uprates". December 2003.
2. Licensing Report, Attachment 5 to Letter from Richard L. Anderson to NRC Re: St. Lucie Plant Unit 1, Docket No. 50-335, Renewed License No. DPR-67, License Amendment Request for an Extended Power Uprate, FPL Letter No. L-2010-259. November 22, 2010. ADAMS Accession No. ML103560429.
3. WCAP-17197-NP Revision 0, St. Lucie Unit 1 RCS Pressure and Temperature Limits and Low-Temperature Overpressure Protection Report For 54 Effective Full Power Years, Appendix G to the EPU Licensing Report for Saint Lucie, Unit 1. February 28, 2010. ADAMS Accession No. ML103560511.

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5. *FPL Letter L-97-223, "St. Lucie Units 1 and 2 Docket Nos. 50-335 and 50-389 NRC Reactor Vessel Integrity Generic Letter 92-01 Revision 1 Updated Information"*. August 28, 1997. ADAMS Accession No. 9709040378.
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7. *WCAP-15770, Revision 2, "Beaver Valley Unit 1 Heatup and Cooldown Limit Curves for Normal Operation"*. s.l. : Westinghouse Electric Co., April 2001. ADAMS Accession No. ML011870482.
8. *FPL Letter L-2011-178 from R. L. Anderson to NRC, "Response to NRC Vessels & Internals Integrity Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request"*. May 17, 2011. ADAMS Accession No. ML11139A167.
9. *Technical Methodology Paper Comparing ABB/CE PT Curve to ASME Section III, Appendix G (063-PENG-ER-096, Revision 00)*. January 22, 1998. ADAMS Accession No. ML100500515.
10. *FPL Letter L-2011-075 from R. L. Anderson to NRC, "Response to NRC Request for Additional Information (RAI) Regarding Extended Power Uprate License Amendment Request"*. March 3, 2011. ADAMS Accession No. ML110660300.
11. *FPL Letter L-2011-076 from R. L. Anderson to NRC, "Response to NRC Request for Additional Information (RAI) Regarding Extended Power Uprate License Amendment Request"*. February 25, 2011. ADAMS Accession Nos. ML110600706 and ML110600707.
12. *NUREG-1779, "Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 & 2"*. September 30, 2003. ADAMS Accession No. ML032940205.
13. *Enclosure to Letter from J. A. Stall (FPL) to NRC, "Application for Renewed Operating Licenses, St. Lucie Units 1 & 2"*. November 29, 2001. ADAMS Accession No. ML013400292.
14. *EPRI Product No. 1016596, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-Revision 0)"*. s.l. : Electric Power Research Institute, January 12, 2009. ADAMS Accession No. ML090160204.
15. *Letter from R. A. Nelson (NRC) to N. Wilmshurst (EPRI), "Final Safety Evaluation of EPRI Report, Materials Reliability Program Report 1016596 (MRP-227), Revision 0, 'Pressurized Water Reactor (PWR) Internals Inspection and Evaluation Guidelines'"*. June 22, 2011. ADAMS Accession No. ML111600498.
16. *FPL Letter L-2011-512 from R. L. Anderson to NRC, "Response to NRC Mechanical and Civil Branch Request for Additional Information RAI EMCB-1; Regarding Extended Power*

*Uprate License Amendment Request*". November 23, 2011. ADAMS Accession No. ML11333A373.

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32. XN-NF-573, "RAMPEX Pellet-Clad Interaction Evaluation Code for Power Ramps". May 1982.
33. XN-NF-82-21(P)(A), Revision 1, "Application of Exxon Nuclear Company PWR Thermal Margin Methodology to Mixed Core Configurations". s.l. : Exxon Nuclear Company, September 1983.
34. ANP-3026(P) Revision 0, "St. Lucie Plant Unit EPU RAIs – Nuclear Performance & Code (SNPB)". s.l. : AREVA NP, Inc., August 2011.
35. BAW-10231P-A, Revision 1, "COPERNIC Fuel Rod Design Computer Code". s.l. : AREVA NP, Inc., January 2004.
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53. *FPL Letter L-2011-311 from R. L. Anderson to NRC, "Information Regarding Steam Generator Tube Rupture Steam Release and Margin to Overfill Provided in Support of the Extended Power Update License Amendment Request"*. August 18, 2011. ADAMS Accession No. ML11231A946.
54. *FPL Letter L-2012-082 from R. L. Anderson to NRC, "Response to NRC Reactor Systems Branch (SRXB) Request for Additional Information Regarding Extended Power Update License Amendment Request"*. February 29, 2012. ADAMS Accession No. ML12061A261.
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56. *FPL Letter L-2012-207 from R. L. Anderson to NRC, "St. Lucie Plant Unit 1, Response to NRC Reactor Systems Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request."*. May 3, 2012. ADAMS Accession No. ML12129A373.

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66. FPL Letter L-2011-556 from R.L. Anderson to NRC, "St. Lucie, Unit 2 - Response to NRC Vessels & Internals Integrity Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request". December 20, 2011. ADAMS Accession No. ML11362A382.

Attachment:

1. List of Application Supplements
2. List of Acronyms

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Date: July 9, 2012

## Attachment 1

### LIST OF APPLICATION SUPPLEMENTS

ADAMS Accession No.	Document Date	Availability	Title
ML110600706	2/25/2011	Publicly Available	St. Lucie, Unit 1 - Response to NRC Request for Additional Information (RAI) Regarding Extended Power Uprate License Amendment Request.
ML110600707	2/25/2011	Non-Publicly Available	Attachment 1 to L-2011-076 - Stress Intensity Factors.
ML110660300	3/3/2011	Publicly Available	St. Lucie, Unit 1 - Response to NRC Request for Additional Information (RAI) regarding Extended Power Uprate License Amendment Request.
ML110750025	3/14/2011	Publicly Available	St. Lucie Plant, Unit 1 - Response to NRC Request for Additional Information (RAI) Regarding Extended Power Uprate License Amendment Request.
ML110840043	3/22/2011	Publicly Available	St. Lucie, Unit 1 - Response to NRC Instrumentation & Controls Branch Request For Additional Information Regarding Extended Power Uprate License Amendment Request.
ML110950058	4/1/2011	Publicly Available	St. Lucie, Unit 1, Response To NRC Instrumentation & Controls Branch Request For Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11112A079	4/21/2011	Publicly Available	St. Lucie Plant Unit 1, License Amendment Request for Extended Power Uprate.
ML11139A167	5/17/2011	Publicly Available	St. Lucie, Unit 1, Response to NRC Vessels & Internals Integrity Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11145A087	5/18/2011	Publicly Available	St. Lucie, Unit 1, Response to NRC Containment and Ventilation Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11145A084	5/19/2011	Publicly Available	St. Lucie Plant Unit 1, Response to NRC PRA Licensing Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.

ADAMS Accession No.	Document Date	Availability	Title
ML11144A008	5/19/2011	Publicly Available	St. Lucie, Unit 1 - Response to NRC Steam Generator Tube Integrity and Chemical Engineering Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11144A009	5/19/2011	Publicly Available	St. Lucie Plant Unit 1 - Response to NRC Health Physics and Human Performance Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11147A027	5/24/2011	Non-Publicly Available	St. Lucie Plant, Unit 1 - Response to NRC Fire Protection Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11153A048	5/27/2011	Publicly Available	St. Lucie Plant, Unit 1 - Information Regarding Areva LOCA and Non-LOCA Methodologies Provided in Support of the License Amendment Request for Extended Power Uprate.
ML11153A049	5/31/2011	Publicly Available	ANP-3000(NP), Rev. 0, "St. Lucie Nuclear, Unit 1 - EPU-Information to Support License Amendment Request," Attachment 6.
ML11153A050	5/31/2011	Publicly Available	ANP-2903(NP), Revision 1, "St. Lucie Nuclear Plant, Unit 1 - EPU Cycle Realistic Large Break LOCA Summary Report With ZR-4 Fuel Cladding," Attachment 7.
ML11171A656	6/16/2011	Publicly Available	St. Lucie, Unit 1, Response to NRC Electrical Engineering Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11188A193	6/22/2011	Publicly Available	St. Lucie, Unit 1, Response to NRC Balance-of-Plant Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11189A007	7/5/2011	Publicly Available	St. Lucie, Unit 1, Information Requested by the Nuclear Performance & Code Review Branch in Support of Extended Power Uprate License Amendment Request.

ADAMS Accession No.	Document Date	Availability	Title
ML11194A016	7/8/2011	Publicly Available	St. Lucie, Unit 1, Response to NRC Vessels & Internals Integrity Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11207A459	7/22/2011	Publicly Available	St. Lucie Plant Unit 1, Information Regarding Anticipated Transients Without Scram (ATWS) Provided in Support of the Extended Power Uprate License Amendment Request.
ML11284A221	8/5/2011	Non-Publicly Available	Calculation HI-2094346, Revision 3, "Criticality Safety Evaluation of the St. Lucie, Unit 1 New Fuel Storage Vault".
ML11222A021	8/8/2011	Publicly Available	St. Lucie, Unit 1, Response to NRC Reactor Systems Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11234A283	8/12/2011	Publicly Available	St. Lucie Plant Unit 1, Response to NRC Accident Dose Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11231A946	8/18/2011	Publicly Available	St. Lucie, Unit 1 - Information Regarding Steam Generator Tube Rupture Steam Release and Margin to Overfill Provided in Support of the Extended Power Uprate License Amendment Request.
ML11242A147	8/25/2011	Non-Publicly Available	Attachment 4 to L-2011-341, Calculation CN-TAS-08-36, Rev 1, "Setpoint Uncertainties and Operability Limits for the Steam Generator Level RPS and AFAS Functions for St. Lucie, Unit 1".
ML11242A150	8/25/2011	Non-Publicly Available	St. Lucie, Unit 1 - Response to NRC Instrumentation & Controls Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11242A142	8/25/2011	Publicly Available	St. Lucie, Unit 1 - Response to Nuclear Performance and Code Review Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.

ADAMS Accession No.	Document Date	Availability	Title
ML11242A143	8/31/2011	Publicly Available	ANP-3028(NP), Revision 0, "St. Lucie Plant, Unit 1 EPU RAIs - Nuclear Performance & Code (SNPB)".
ML11231A947	8/31/2011	Publicly Available	ANP-3019NP, Revision 0, "St. Lucie Unit 1 EPU - Information to Support NRC Review of Steam Generator Tube Rupture," Attachment 2.
ML11251A159	9/2/2011	Publicly Available	St. Lucie Plant Unit 1, Response to NRC Accident Dose Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11251A158	9/2/2011	Publicly Available	St. Lucie, Unit 1, Response to Containment & Ventilation Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11256A047	9/8/2011	Non-Publicly Available	St. Lucie, Unit 1 - Response to NRC Electrical Engineering Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11256A014	9/8/2011	Publicly Available	St. Lucie, Unit 1 - Response to NRC Containment and Ventilation Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11269A221	9/22/2011	Publicly Available	St. Lucie Plant, Unit 1 - Response to NRC Reactor Systems Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11271A030	9/23/2011	Publicly Available	St. Lucie Plant Unit 1, Response to NRC Mechanical and Civil Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11271A031	9/23/2011	Non-Publicly Available	Response to NRC Mechanical and Civil Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.

ADAMS Accession No.	Document Date	Availability	Title
ML11277A239	9/27/2011	Publicly Available	Material to Support St. Lucie Nuclear Power Plant, Unit 1, Extended Power Uprate (EPU) License Application.
ML11284A184	9/29/2011	Publicly Available	St. Lucie, Unit 1 - Submittal of Attachment 2, Response to NRC Reactor Systems Branch Request for Additional Information re Extended Power Uprate License Amendment Request.
ML11305A087	9/30/2011	Publicly Available	St. Lucie, Unit 1, Response to NRC Reactor Systems Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11305A088	9/30/2011	Publicly Available	ANP-2903Q1(NP), Revision 0, "St. Lucie Nuclear Plant Unit 1 EPU Cycle Realistic Large Break LOCA Summary Report with Zr-4 Fuel Cladding."
ML11305A125	9/30/2011	Non-Publicly Available	St. Lucie, Unit 1, Response to NRC Reactor Systems Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11285A045	10/10/2011	Publicly Available	St. Lucie Plant, Unit 1 - Supplemental Information Regarding Extended Power Uprate License Amendment Request - Revision to EPU LAR Proposed Technical Specifications.
ML11291A035	10/14/2011	Publicly Available	St. Lucie, Unit 1, Revision to Extended Power Uprate License Amendment Request Proposed Technical Specification Regarding Fuel Loading Curve and Areal Density Criteria for Metamic Inserts.
ML11291A036	10/14/2011	Non-Publicly Available	HI-2104714, Rev. 2, "St. Lucie Unit 1 Criticality Analysis for EPU and Non-EPU Fuel."
ML11297A198	10/20/2011	Publicly Available	St. Lucie Plant, Unit 1, Response to NRC Nuclear Performance and Code Review Branch Request for Additional Information Regarding Extended Power Uprated License Amendment Request.



ADAMS Accession No.	Document Date	Availability	Title
ML11299A006	10/21/2011	Publicly Available	St. Lucie, Unit 1, Response to NRC Mechanical and Civil Branch Request for Additional Information Number 23: Regarding Extended Power Uprate License Amendment Request.
ML11304A185	10/27/2011	Publicly Available	St. Lucie, Unit 1 - Response to NRC Mechanical and Civil Branch Request for Additional Information RAI EMCB-1; Regarding Extended Power Uprate License Amendment Request.
ML11307A213	10/31/2011	Publicly Available	St. Lucie Plant Unit 1, Response to NRC Containment and Ventilation Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11306A014	10/31/2011	Publicly Available	St. Lucie, Unit 1, Information Regarding CVCS Malfunction Provided in Support of the Extended Power Uprate License Amendment Request.
ML11306A015	10/31/2011	Publicly Available	ANP-3057(NP), Revision 0, "St. Lucie Unit 1 EPU - Responses to NRC Questions SRXB-58, SRXB-59, and SRXB-60."
ML11306A016	10/31/2011	Non-Publicly Available	ANP-3057(P), Revision 0, "St. Lucie Unit 1 EPU - Responses to NRC Questions SRXB-58, SRXB-59, and SRXB-60."
ML11307A335	10/31/2011	Non-Publicly Available	Response to NRC Reactor Systems Branch and Nuclear Performance and Code Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11307A338	10/31/2011	Non-Publicly Available	St. Lucie Plant Unit 1, Response to NRC Reactor Systems Branch and Nuclear Performance Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11306A014	10/31/2011	Publicly Available	St. Lucie, Unit 1, Information Regarding CVCS Malfunction Provided in Support of the Extended Power Uprate License Amendment Request.

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ML11306A015	10/31/2011	Publicly Available	ANP-3057(NP), Revision 0, "St. Lucie Unit 1 EPU - Responses to NRC Questions SRXB-58, SRXB-59, and SRXB-60."
ML11307A335	10/31/2011	Non-Publicly Available	Response to NRC Reactor Systems Branch and Nuclear Performance and Code Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11307A338	10/31/2011	Publicly Available	St. Lucie Plant Unit 1, Response to NRC Reactor Systems Branch and Nuclear Performance Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11308B353	11/1/2011	Publicly Available	St. Lucie Plant, Unit 1 - Response to NRC Instrumentation & Controls Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11333A373	11/23/2011	Publicly Available	St. Lucie Plant, Unit 1, Response to NRC Mechanical and Civil Branch Request for Additional Information RAI EMCB-1: Regarding Extended Power Uprate License Amendment Request.
ML11335A170	11/29/2011	Publicly Available	St. Lucie, Unit 1, Response to NRC Reactor Systems Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML11340A029	12/1/2011	Publicly Available	St. Lucie, Unit 1 - Impact of Containment Spray System Modification on Extended Power Uprate License Amendment Request.
ML11340A079	12/2/2011	Publicly Available	Information to Support Licensing Submittal for St. Lucie Plant Unit 1.
ML11354A236	12/14/2011	Publicly Available	St. Lucie, Unit 1, Response to Balance-of-Plant Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.

ADAMS Accession No.	Document Date	Availability	Title
ML11364A044	12/27/2011	Publicly Available	St. Lucie Plant Unit 1 - Response to NRC Steam Generator Tube Integrity and Chemistry Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12005A209	1/2/2012	Publicly Available	St. Lucie Plant Unit 1 - Response to NRC Reactor Systems Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12012A217	1/10/2012	Publicly Available	St. Lucie Plant Unit 1 - Response to NRC Question Regarding Report Referenced in the Extended Power Uprate License Amendment Request.
ML12019A066	1/14/2012	Non-Publicly Available	St. Lucie, Unit 1, Attachment 2 - Calculation CN-TAS-08-36, Rev. 3, "Setpoint Uncertainties and Operability Limits for the Steam Generator Level RPS and AFAS Functions for St. Lucie Unit 1."
ML12019A076	1/14/2012	Publicly Available	St. Lucie, Unit 1, Response to NRC Instrumentation & Controls Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12030A079	1/25/2012	Non-Publicly Available	St. Lucie Plant, Unit 1, Response to NRC Mechanical and Civil Engineering Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12046A012	02/11/2012	Publicly Available	St. Lucie Plant Unit 1, Information Regarding Fuel Thermal Conductivity Degradation Provided in Support of the Extended Power Uprate License Amendment Request.
ML12055A047	02/21/2012	Publicly Available	St. Lucie, Unit 1, Response to NRC Mechanical and Civil Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request RAI EMCB-1.
ML12061A250	02/29/2012	Publicly Available	ANP-2903Q2(NP), Rev 0, St. Lucie, Unit 1 - EPU Cycle Realistic Large Break LOCA Summary Report with Zr-4 Fuel Cladding, Attachment 3.

ADAMS Accession No.	Document Date	Availability	Title
ML12061A262	02/29/2012	Publicly Available	St. Lucie Plant Unit 1, Supplemental Information for the Extended Power Uprate License Amendment Request Related to the Post-Loss of Coolant Accident (LOCA) Boric Acid Precipitation Analysis.
ML12061A261	02/29/2012	Publicly Available	St. Lucie Plant Unit 1, Response to NRC Reactor Systems Branch (SRXB) Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12061A248	02/29/2012	Publicly Available	St. Lucie, Unit 1 - Response to Request for Additional Information Identified During Audit of the Safety Analyses Calculations for the Extended Power Uprate License Amendment Request.
ML12061A249	02/29/2012	Publicly Available	ANP-3067, Rev. 1, St. Lucie, Unit 1 EPU - Information to Support NRC Review of RCS Depressurization With Pressurizer Overfill.
ML12061A251	02/29/2012	Non-Publicly Available	ANP-2903Q2(P), Revision 0, St. Lucie, Unit 1 - EPU Cycle Realistic Large Break LOCA Summary Report with Zr-4 Fuel Cladding, Attachment 4.
ML12068A369	03/06/2012	Publicly Available	St. Lucie, Unit 1 - Response to NRC Reactor Systems Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12068A371	03/06/2012	Publicly Available	St. Lucie, Unit 1 - Response To Request For Additional Information Identified During Audit Of The Safety Analyses Calculations for the Extended Power Uprate License Amendment Request.
ML12072A038	03/08/2012	Publicly Available	St. Lucie, Unit 1 - Response to NRC Steam Generator Tube Integrity and Chemistry Branch (CSGB) Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12079A012	03/15/2012	Publicly Available	St. Lucie, Unit 1, Response to Nuclear Performance and Code Review Branch Request for Additional Information Identified During an Audit of Analyses Supporting the Extended Power Uprate License Amendment Request.

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ML12079A179	03/16/2012	Publicly Available	St. Lucie, Unit 1 - Response to NRC Reactor Systems Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request.
ML12086A202	03/22/2012	Publicly Available	St. Lucie, Unit 1 - Supplemental Information for Extended Power Uprate License Amendment Request (LAR) Sections 2.1.7 (Protective Coating Systems) and 2.8.7.2 (Natural Circulation Cooldown).
ML12086A042	3/26/2012	Non-Publicly Available	St. Lucie Unit 1- Safety Evaluation of the Metamic Surveillance Program Related to the Licensee's Extended Power Uprate License Amendment (TAC ME5091).

## Attachment 2

### LIST OF ACRONYMS

AAC	alternate ac sources
AC or ac	alternating current
ADAMS	Agencywide Documents Access and Management System
ADV	atmospheric dump valve
AEC	Atomic Energy Commission
AFT	as-found tolerance
AFW	auxiliary feedwater
AFWS	auxiliary feedwater system
AIF	Atomic Industrial Forum
AISC	American Institute of Steel Construction
ALARA	as low as reasonably achievable
ALT	as-left tolerance
AMP	aging management program
AMSAC	ATWS [anticipated transient without scram] mitigating system actuation circuitry
ANO-2	Arkansas Nuclear One, Unit 2
ANS	American Nuclear Society
ANSI	American National Standards Institute
AOO	anticipated operational occurrence
AOR	analysis on record
AOT	allowed outage time
AOV	air operated valve
APCF	actual pressure correction factors
ARAVS	auxiliary and radwaste area ventilation system
ARI	alternate rod insertion
ART	adjusted reference temperature
ASGT	asymmetric steam generator transient
ASME	American Society of Mechanical Engineers
AST	alternative source term
ASTM	American society for Testing and Materials
ATWS	anticipated transient without scram
B&PV	boiler and pressure vessel
B&W	Babcock & Wilcox
BL	bulletin
BOC	beginning of cycle

BOL	beginning of life
BOP	balance-of-plant
BRS	boron recovery system
BTP	branch technical position
BWR	boiling-water reactor
BWRVIP	Boiling Water Reactor Vessel and Internals Project
C	Celsius
cal/gm	calories per gram
CASS	cast austenitic stainless steel
CCF	common cause failure
CCW	component cooling water
CDF	core damage frequency
CE	Combustion Engineering
CEA	control element assembly
CEDE	committed effective dose equivalent
CEDM	control element drive mechanism
CEOG	Combustion Engineering Owners Group
CF	chemistry factor
Cfm	cubic feet per minute
CFR	<i>Code of Federal Regulations</i>
CFS	condensate and feedwater system
CHF	critical heat flux
Ci/gm	Curie per gram
CIAS	containment isolation actuation signal
CLB	current licensing basis
CLTP	current licensed thermal power
CPU	central processing unit
CR	control room
CRAVS	control room area ventilation system
CRDA	control rod drop accident
CRDM	control rod drive mechanism
CRDS	control rod drive system
CREVS	control room emergency ventilation system
CRHE	control room habitability envelope

CS	containment spray
CSB	core support barrel
Csl	cesium iodide
CST	condensate storage tank
CUF	cumulative usage factor
CVCS	chemical and volume control system
CWS	circulating water system
DAFAS	diverse auxiliary feedwater actuation system
DBA	design-basis accident
DBLOCA	design-basis loss-of-coolant accident
DC or dc	direct current
DCF	dose conversion factor
DCS	distributed control system
DE	dose equivalent
DEHLS	double-ended hot leg slot
DEI	dose-equivalent iodine
DF	decontamination factor
DG	draft guide
DNB	departure from nucleate boiling
DP	differential pressure
DSS	diverse scram system
DTT	diverse turbine trip
EAB	exclusion area boundary
ECCS	emergency core cooling system
EDE	effective dose equivalent
EDG	Emergency diesel generator
EEQ	electrical equipment qualification
EFDS	equipment and floor drainage system
EFPY	effective full-power year
EM	evaluation model
EOC	end of cycle
EOL	end of life
EOP	emergency operating procedure
EPG	emergency procedure guideline
EPRI	Electric Power Research Institute



EPU	extended power uprate
EQ	environmental qualification
ESF	engineered safety feature
ESFAS	engineered safety feature actuation system
ESFVS	engineered safety feature ventilation system
F	Fahrenheit
F&O	fact and observation
FAC	flow-accelerated corrosion
FGR	Federal Guidance Report
FCM	fuel centerline melt
FEM	finite element method
FHA	fuel-handling accident
FHB	fuel-handling building
FIV	flow-induced vibration
FIVE	Fire Induced Vulnerability Evaluation
FMP	fatigue monitoring program
FPL	Florida Power & Light Company
FPP	fire protection program
FPS	fire protection system
F <sub>Q</sub>	total peaking factor
FSAR	Final Safety Analysis Report
FTSP	field trip setpoint
FW	feedwater
FWLB	feedwater line break
GALL	General Aging Lessons Learned
GDC	general design criterion (or criteria)
GL	generic letter
gm-atom	gram-atom
gpm	gallons per minute
GSI	generic safety issue
GWd/MTU	gigawatt days per metric ton of uranium
GWMS	gaseous waste management system
HELB	high-energy line break
HEP	human error probability
HEPA	high-efficiency particulate air

HFE	human factors engineering
HFP	hot full power
HI	Hydraulic Institute
hp	horse power
HP	high pressure
HPSI	high-pressure safety injection
HRA	human reliability analysis
HTP	high thermal power
HX	heat exchanger
Hz	Hertz
HZP	hot zero power
I&C	instrumentation and controls
IASCC	irradiation-assisted stress-corrosion cracking
ICW	intake cooling water
ID	inside diameter
IEEE	Institute of Electrical and Electronics Engineers
IGSCC	intergranular stress-corrosion cracking
IN	information notice
INPO	Institute for Nuclear Power Operations
IOMSSV	inadvertent opening of a main steam safety valve
IPB	isolated phase bus
IPCF	indicated pressure correction factors
IPE	individual plant examination
IPEEE	individual plant examination of external events
ISA	Instrument Society of America
ISG	interim staff guidance
ISI	inservice inspection
IST	inservice testing
JFD	joint frequency distribution
kA	kilo Ampere
$k_{\text{eff}}$	effective neutron multiplication factor
kV	kilo Volt
kW	kilo Watt
LAR	license amendment request
LBB	leak before break

LBLOCA	large-break loss-of-coolant accident
lbm/sec (or /hr)	pounds mass per second (or per hour)
LCO	limiting condition for operation
LEFM	leading-edge flow meter
LERF	large early release frequency
LHR	linear heat rate
LLHS	light load handling system
LOCA	loss-of-coolant accident
LOCF	loss of normal coolant flow
LOEL	loss of external load
LONF	loss of normal FW
LOOP	loss of offsite power
LPD	local power density
LPSI	low-pressure safety injection
LPZ	low population zone
LRA	license renewal application
LR/SB	locked rotor or shaft break
LSSS	limiting safety system setting
LST	lowest service temperature
LTOP	low-temperature overpressure protection
LWMS	liquid waste management system
M&E	mass and energy
MAAP	Modular Accident Analysis Program
MBtu	million british thermal units
MC	main condenser
MCC	motor control center
MCES	main condenser evacuation system
MDNBR	minimum departure from nucleate boiling ratio
MEDP	maximum expected differential pressure
MFW	main feedwater
MOV	motor-operated valve
MRP	Materials Reliability Program
MSIS	main steam isolation signal
MSIV	main steam isolation valve

MSIVLCS	main steam isolation valve leakage control system
MSLB	main steamline break
MSR	moisture separator reheater
MSSS	main steam supply system
MSSV	main steam safety valve
MT	main transformer
MTC	moderator temperature coefficient
MTO	margin-to-overfill
MUR	measurement uncertainty recapture
MVA	megavolt ampere
MW	megawatt
MWd/MTU	megawatt days per metric ton of uranium
MWe	megawatt electric
MWt	megawatt thermal
NAI	Numerical Applications, Inc.
NEI	Nuclear Energy Institute
NFV	new fuel storage vault
NPSH	net positive suction head
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NRS	narrow range span
NSSS	nuclear steam supply system
NTSP	nominal trip setpoint
O&M	operations and maintenance
OD	outside diameter
OL	operability limit
OLTP	original licensed thermal power
OMS	overpressure mitigation system
ONP	off-normal operating procedures
OOS	out of service
OTC	once through cooling
P-T	pressure-temperature
PAOT	post-accident operability time
PATP	power ascension and testing plan
pcm	percent millirho

PCT	peak cladding temperature
PORV	power-operated relief valve
ppm	parts per million
PRA	probabilistic risk assessment
PRT	pressurizer relief tank
PSHT	preservice hydrostatic test
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PT	potential transformer
PTS	pressurized thermal shock
PVNGS	Palo Verde Nuclear Generating Station
PWR	pressurized-water reactor
PWSCC	primary water stress-corrosion cracking
QT	quench tank
R	Rankine
RAB	reactor auxiliary building
RAI	request for additional information
RCB	reactor containment building
RCIC	reactor core isolation cooling
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RG	regulatory guide
RHR	residual heat removal
RIS	Regulatory Issue Summary
RLBLOCA	realistic large break loss-of-coolant accident
rpm	revolutions per minute
RPS	reactor protection system
RPV	reactor pressure vessel
RS	review standard
RSG	replacement steam generator
RT	radiography techniques
RTP	rated thermal power
RV	reactor vessel

RVI	reactor vessel internals
RVID	Reactor Vessel Integrity Database
RWCS	reactor water cleanup system
RWT	refueling water tank
SAFDL	specified acceptable fuel design limit
SAG	severe accident guideline
SAR	Safety Analysis Report
SBLOCA	small break loss of-coolant accident
SBO	station blackout
SBCS	steam bypass control system
SBVS	shield building ventilation system
SCC	stress-corrosion cracking
SDC	shutdown cooling
SDCS	shutdown cooling system
SE	safety evaluation
SER	Safety Evaluation Report
SFP	spent fuel pool
SFPAVS	spent fuel pool area ventilation system
SG	steam generator
SGBS	steam generator blowdown system
SGTR	steam generator tube rupture
SGTS	standby gas treatment system
SIAS	safety injection actuation signal
SIT	safety injection tank
SLCS	standby liquid control system
SONGS	San Onofre Nuclear Generating Station
SPDS	safety parameter display system
SR	Surveillance Requirement
SRP	Standard Review Plan
SRV	safety relief valve
SSC	structure, system, and component
SSE	safe-shutdown earthquake
SST	service station transformer
ST	setting tolerance
SUT	startup transformers

SWMS	solid waste management system
SWS	service water system
TAVS	turbine area ventilation system
TBS	turbine bypass system
TCS	turbine control system
TCV	turbine control valve
TDAFW	turbine driven auxiliary feedwater
TEDE	total effective dose equivalent
TGSCC	transgranular stress corrosion cracking
TID	total integrated dose
TLAA	time-limited aging analysis
TLOFW	total loss of feedwater
TLU	total loop uncertainty
TM/LP	thermal margin/low pressure
TLOFW	total loss of feedwater
TS	technical specification
TSC	technical support center
UAT	unit auxiliary transformer
UHS	ultimate heat sink
USE	upper shelf energy
USI	unresolved safety issue
UT	ultrasonic testing
V	volt
VCT	volume control tank
VHPT	Variable high power trip
<u>W</u> CAP	Westinghouse Commercial Atomic Power (report)
WGDT	waste gas decay tank
χ/Q	atmospheric dispersion factor

M. Nazar

- 2 -

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/

Tracy J. Orf, Project Manager  
Plant Licensing Branch II-2  
Division of Operator Reactor Licensing  
Office of Nuclear Reactor Regulation

Docket No. 50-335

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1. Amendment No. 213 to DPR-67
2. Safety Evaluation

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Letter & Amendment ML12156A208

Technical Specifications ML12191A236

Proprietary Safety Evaluation ML12191A238

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