

**ATTACHMENT 5
LICENSE AMENDMENT REQUEST
EXTENDED POWER UPRATES**

LICENSING REPORT

**FLORIDA POWER & LIGHT
ST. LUCIE NUCLEAR PLANT, UNIT 2**

This coversheet plus 1686 pages

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1.0 Introduction To The St. Lucie Plant Unit 2 Extended Power Uprate Licensing Report

General Overview of the St. Lucie Unit No. 2 Extended Power Uprate Licensing Report

Florida Power and Light (FPL) is proposing an extended power uprate (EPU) that would increase the St. Lucie Unit 2 current licensed core power from 2700 megawatts thermal (MWt) to 3020 MWt. This represents a net increase in licensed thermal power of approximately 11.85 percent and includes a 10.0 percent power uprate and a 1.7 percent measurement uncertainty recapture (MUR). The net increase is calculated as follows:

$$2700 \text{ MWt} \times 1.10 \times 1.017 \cong 3020 \text{ MWt}$$

$$[(3020 \text{ MWt} - 2700 \text{ MWt}) / 2700 \text{ MWt}] \times 100 \cong 11.85 \text{ percent.}$$

Unless specified otherwise, the acronym “EPU” as used in this submittal refers to the combined reactor core and MUR power uprates.

The licensing report (LR) is Attachment 5 to the EPU license amendment request (LAR). The LR demonstrates that the EPU can be safely achieved, and that the increase will not be inimical to the common defense and security or to the health and safety of the public. The LR provides the details supporting the requested power uprate, and works in concert with the other attachments to the LAR to provide a comprehensive evaluation of the effects of the EPU. The changes necessary to support the power uprate and those made to improve operating margin based on risk-informed insights are summarized below.

The LR follows the guidance of RS-001, Review Standard for Extended Power Uprates, Revision 0. The LR summarizes the evaluations necessary to implement the EPU with sufficient detail to permit the Nuclear Regulatory Commission (NRC) staff to reach an informed determination regarding the technical basis, and the consistency, quality, and completeness of the evaluation. To that end, the technical evaluations discuss the effects of the EPU on plant operating limits, functional performance requirements and impact on the current licensing basis, including the methods used in reaching the conclusions documented in the report.

FPL added information to the LR beyond the guidance of RS-001, e.g., this Section 1.0, Introduction to the St. Lucie Plant Unit 2 Extended Power Uprate Licensing Report, when doing so would facilitate understanding the effects of the EPU on St. Lucie Unit 2. These additions are identified in the following pages.

LR **Section 2.4.4**, Measurement Uncertainty Recapture Power Uprate, describes the MUR portion of the requested power uprate and follows the guidelines in NRC Regulatory Issue Summary, (RIS) 2002-03, Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications.

Table 1.0-1 provides a list of the key plant changes required to support operation at the uprate power level. **Table 1.0-2** provides a list of key changes to the current licensing basis that are in addition to those included in the scope of LAR Attachment 1, Descriptions and Technical Justifications for the Renewed Facility Operating License, Technical Specifications, and Licensing Basis Changes.

Table 1.0-3 provides a list of new and re-sequenced key emergency operating procedure (EOP) operator actions credited in the accident analyses. **Table 1.0-4** provides a list of key changes to

the EOPs and Off-Normal Procedures (ONPs). The existing procedures provide adequate guidance to cover the spectrum of anticipated events. The EPU will result in changes to EOPs and ONPs to enhance operator response times and address changes in setpoints, alarm response setpoints and physical plant changes.

Summary of Significant Plant Modifications and Schedule

Plant changes necessary to achieve the EPU are planned to be implemented no later than the spring 2012 refueling outage. Power ascension to the EPU power level is planned to commence following NRC approval of the EPU and the completion of the spring 2012 refueling outage. The following discussion summarizes the key physical plant changes.

Reactor System

Reactor Core and Fuel Design

For the EPU, the St. Lucie Unit No. 2 fuel design will remain the 16x16 CE HID-1L fuel assembly design (High Impact Design). The 16x16 CE HID-1L fuel rod is currently licensed to a peak pin burnup of 60,000 MWD/MTU by the NRC.

Evaluations of the fuel rod design criteria for the 16x16 CE HID-1L fuel assembly design demonstrated that all fuel rod design criteria can be satisfied for the EPU conditions. Continued compliance with fuel rod design criteria for the 16x16 CE HID-1L fuel will be confirmed for each reload cycle design. Refer to LR [Section 2.8.1](#), Fuel System Design, for details.

Reactor Coolant System (RCS)

There are no physical modifications planned to the RCS or reactor vessel internals; however, RCS operating temperatures will change for the uprate. The limiting reactor vessel inlet temperature (T_{cold}) at 3020 MWt core power will be increased from 549°F to 551°F. The coolant temperature across the core will increase in proportion to the increase in uprate power. With the higher reactor vessel inlet temperature, the reactor outlet temperature (T_{hot}) will increase to approximately 608°F, based on RCS thermal design flow. The RCS no-load temperature will remain at the current value of 532°F. LR [Section 1.1](#), Nuclear Steam Supply System Parameters, lists the primary and secondary side system conditions (thermal power, temperatures, pressures, and flows) that serve as the basis for the nuclear steam supply system (NSSS) analyses and evaluations.

Minor changes will be made to the pressurizer level control program function of the reactor regulating system to accommodate the higher reactor coolant system average temperature. Refer to LR [Section 2.4.1](#), Reactor Protection, Safety Features Actuation, and Control Systems, for additional details. Additionally, the pressurizer safety valve as-found lift setting tolerance specified in TS 3.4.2.2 is being changed from “ ≥ 2435.3 psig and ≤ 2535.3 psig” to “ ≥ 2410.3 psig and ≤ 2560.3 psig.” Discussion of this change is provided in LR [Section 2.8.4.2](#), Overpressure Protection During Power Operation.

Reactor Protection System (RPS)

Except as noted below, current RPS instrumentation and setpoints will be maintained and will continue to satisfy specified design functions at EPU conditions. Refer to LR [Section 2.4.1](#), Reactor Protection, Safety Features Actuation, and Control Systems, for details. In order to

maintain current risk levels, as supported by probabilistic risk analyses (PRA), the steam generator low-level narrow range trip setpoint will be changed from 20.5 percent to 35 percent. Refer to LR [Section 2.13](#), Risk Evaluation, for details.

Accident Mitigation Systems

Several modifications will be completed prior to implementation of the EPU. Consistent with the proposed TS change, the minimum boron concentration in the safety injection tanks, boric acid makeup tanks, and refueling water tank will be increased. Modifications will be made to increase the component cooling water system heat removal margin. Refer to LR [Section 2.5.4.3](#), Reactor Auxiliary Cooling Water Systems, for additional details. Components will be upgraded as needed to maintain compliance with environmental qualification requirements, as described in LR [Section 2.3.1](#), Environmental Qualification of Electrical Equipment. Additionally, component cooling water pipe supports will be upgraded as necessary to accommodate generally higher temperatures, pressures and flows. Refer to LR [Section 2.2.2.2](#), Balance of Plant Piping, Components and Supports.

Current engineered safety features actuation system instrumentation and setpoints will be maintained and will continue to satisfy specified design functions at EPU conditions. Refer to LR [Section 2.4.1](#), Reactor Protection, Safety Features Actuation, and Control Systems, for details.

Steam and Power Conversion System

The steam and power conversion system piping has been analyzed for applicable uprate loading conditions and piping structural limits are maintained. Piping supports are being modified as required. Refer to LR [Section 2.2.2.2](#), Balance of Plant Piping, Components, and Supports, for details. In addition, current steam and power conversion system instrumentation and setpoints will be upgraded to satisfy specified design functions at EPU conditions. Refer to LR [Section 2.4.2](#), Plant Operability, for details.

Steam Generator (SG)

The SG steam outlet pressure for the uprate will be approximately 895 psia. The main steam flow from the SGs will increase to accommodate the increased core thermal power level. Structural limits for the SG components will be maintained at uprate conditions. The SG moisture separator design will maintain the steam moisture carryover content below 0.10 percent. The SG tube bundles are designed and supported such that flow induced vibration and fretting wear limits are not exceeded at uprate conditions. In summary, all calculated thermal hydraulic parameters are projected to be within acceptable ranges for operation at EPU conditions, with tube plugging levels of up to 10 percent. Refer to LR [Section 2.2.2.5](#), Steam Generators and Supports, for details.

Main Steam (MS) System

Evaluations performed for the main steam system are documented in LR [Section 2.5.5.1](#), Main Steam, and confirm that the current main steam safety valves (MSSVs) are acceptable at EPU without modification. The nominal lift settings of the MSSVs remain unchanged for the EPU. The main steam system design pressure and temperature of 985 psig (1000 psia) and 550°F bound the maximum EPU operating conditions. The as-found tolerances on the MSSVs listed in TS Table 3.7-2 will be changed for operational flexibility to ± 3 percent for the eight MSSVs at the

985 psig setpoint, and + 2 percent / -3 percent for the eight MSSVs at the 1025 psig setpoint. The moisture separator reheaters are being replaced as a part of the uprate project and will be designed to accommodate uprate steam conditions.

The atmospheric dump valves (ADVs), which are located upstream of the main steam isolation valves (MSIVs) and MSSVs, provide a means for decay heat removal and plant cooldown by discharging main steam to the atmosphere. Analyses performed for the uprate confirm that the existing ADVs, in conjunction with the auxiliary feedwater (AFW) system, are sized to permit the plant to be cooled down to shutdown cooling entry conditions.

The main steam piping has been analyzed for applicable uprate loading conditions and piping structural limits are maintained. Piping supports are being modified as required. Refer to LR [Section 2.2.2.2](#), Balance of Plant Piping, Components and Supports, for details.

Steam Bypass Control System (SBCS)

The SBCS flow capacity to the main condenser will be increased 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. Refer to LR [Section 2.4.2](#), Plant Operability, and LR [Section 2.5.5.3](#), Turbine Bypass, for details.

Main Turbine

The high pressure and low pressure turbine steam paths will be replaced in order to pass the additional volumetric steam flow for the uprate. The existing high pressure turbine control valves and inlet piping are sized for the uprate main steam conditions. The turbine control system has been evaluated under uprate operating conditions. The turbine electro-hydraulic control system will be replaced to gain the risk benefit resulting from a lower frequency of spurious trip. The replacement system will have built-in redundancy, diagnostics and on-line testability features that will result in higher reliability. Refer to LR [Section 2.5.1.2.2](#), Turbine Generator, for details.

Main Condenser and Circulating Water

EPU conditions will result in higher steam flows to the condensers and modifications are planned to support these conditions. The higher main steam flow will reduce the main condenser vacuum and increase the temperature of the circulating water discharged to the Atlantic Ocean. However, St. Lucie Unit 2 will continue to operate within the limits imposed by the State Pollution Discharge Elimination System permit issued by the State of Florida. Refer to LR [Sections 2.5.1.1.3](#), Circulating Water System, and [2.5.5.2](#), Main Condenser, for details.

Feedwater System

The feedwater flow rates will increase at the uprate power conditions. Refer to LR [Section 2.5.5.4](#), Condensate and Feedwater, for details. The main feedwater pumps will be replaced with pumps with higher rated flow to accommodate the increased feedwater flow and increased system pressure drops. The existing feedwater pump motors are suitable for the increased pump brake horsepower and will not be replaced. The main feedwater regulating valves will be modified with a valve configuration having a higher flow coefficient to accommodate the increased feedwater flow and pressure drop. Due to the increase in operating

flows and pressures of the feedwater system, the No. 5 high pressure feedwater heaters will be replaced.

To achieve an MUR power uprate of 1.7 percent, the Cameron CheckPlus™ Leading Edge Flow Meter (LEFM) ultrasonic flow measurement instrumentation will be installed to improve feedwater flow measurement accuracy. The technical justification is provided in LR [Sections 2.4.4](#), Measurement Uncertainty Recapture Power Uprate.

Condensate System

Condensate flow rates will increase at the uprate power conditions. The condensate pumps and some supporting components require replacement to improve internal hydraulic performance and increase reliability. The existing motors are adequate to provide sufficient motive force for pump operation at EPU conditions. The existing condensate pump recirculation system provides sufficient flow for condensate pump protection and supplies the minimum flow required by the steam jet air ejector condensers and the turbine gland steam condenser. Refer to LR [Section 2.5.5.4](#), Condensate and Feedwater, for details.

Heater Drains

Heater drain flow rates will increase at the uprate power conditions. Replacement heater drain pumps will be installed that provide the operating characteristics necessary to meet the uprate hydraulic requirements. The existing heater drain pump motors are suitable for the increased pump brake horsepower and will not be replaced. Specific heater drain valves will also require modification to address the uprate operating conditions. Refer to LR [Section 2.5.5.4](#), Condensate and Feedwater, for details.

Auxiliary Feedwater (AFW)

The increase in core thermal power and decay heat associated with the uprate increases the heat removal requirements of the AFW system. Analyses performed at the increased uprate power level conclude that the existing AFW system is sized to remove the increased sensible and decay heat for all design basis events.

The condensate storage tank (CST) provides the safety-related water source for the AFW system. The condensate storage tank analysis has demonstrated that there is sufficient inventory within the CST to provide a back-up water supply for Unit 1 and enough usable water volume to meet the cooldown requirements. Refer to LR [Section 2.5.4.5](#), Auxiliary Feedwater System, for details.

AC Power Block

Main Generator

The main generator electrical output will increase with the proposed uprate. The main generator will be modified to increase the rating from 1000 to 1200 MVA with a power factor of 0.90. Improvements include a stator rewind and replacement of the generator rotor, bushings, current transformers, and installation of a power system stabilizer. The power system stabilizer will enhance the dynamic response of the main generator to grid oscillatory transients by working in conjunction with the generator control system.

To accommodate the main generator rating increase, the generator hydrogen pressure will be increased from 60 psig to 75 psig. The generator hydrogen and the generator exciter air coolers will be replaced with coolers that can accommodate the increased cooling loads. Refer to LR [Section 2.3.3](#), AC Onsite Power System, for details. In addition, the existing turbine cooling water system heat exchangers will be replaced to provide additional cooling capability and operating margin. Refer to LR [Section 2.5.4.2](#), Station Service Water System, for details.

Isolated Phase Bus Ducts/Main Transformers

To transfer the power from the main generator to the grid at uprate conditions, the continuous rating of the isolated phase bus duct system will be increased. This will be accomplished by increasing the isolated phase bus duct cooling system capacity. The two three-phase main transformers will be replaced to achieve a design rating of 635 MVA, which envelopes the anticipated uprate loading condition. Refer to LR [Section 2.3.3](#), AC Onsite Power System, for details.

AC Electrical Busses

The EPU increases electrical loading on the AC electrical busses. Modifications will be implemented to compensate for this increase for scenarios that include degraded grid voltage conditions. These modifications shed nonessential loads from AC electrical buses on receipt of a safety injection actuation signal. As a result, increased operating margin is provided for components powered by the associated electrical buses. Refer to LR [Section 2.3.3](#), AC Onsite Power System, for details.

Transmission Grid

The planned dual unit uprate requires an increase in the rating of the three St. Lucie-Midway transmission lines from 2380A to 2790A. Modifications will also be made to improve reliability of the grid system. Refer to LR [Section 2.3.2](#), Offsite Power System, for details.

Risk Evaluation

An objective for the EPU is to maintain or improve overall plant reliability and risk. This objective will be achieved by implementing the plant changes shown in [Table 1.0-1](#). As evaluated in LR [Section 2.13](#), Risk Evaluation, for internal events the EPU is estimated to result in a small risk benefit, once plant changes are implemented. Several actions have been taken by FPL to compensate for adverse impacts associated with the EPU. To reduce the overall change in core damage frequency and large early release frequency values following implementation of the uprate, the following plant changes will be implemented in conjunction with the uprate:

- The SG low-level reactor trip setpoint will be increased to provide greater inventory for total loss of feedwater flow events.
- Plant procedures will be changed to enhance mitigation of total loss of feedwater flow events:
 - Surveillance frequencies will be increased to ensure key valve alignments, and
 - Critical operator action steps will be re-sequenced to conserve SG inventory.

Key physical plant changes planned to improve overall plant operating margin are identified in [Table 1.0-1](#).

Regarding external events, no new fire, seismic, wind, or external flooding vulnerabilities are introduced due to the EPU. Although no new vulnerabilities are introduced, the time available for operator actions has decreased slightly; however, the impact on plant risk will be small. St. Lucie Unit 2 shutdown procedures will continue to control shutdown operations. The risk assessment also shows that the power uprate does not create the “special circumstances” described in Appendix D of the NRC’s Standard Review Plan, Chapter 19.

Current Licensing Basis

The St. Lucie Unit 2 current licensing basis (CLB) is presented in the Updated Final Safety Analysis Report (UFSAR) and other docketed material. The CLB addresses the NRC’s general design criteria (GDC), which were issued in 1971 by the Atomic Energy Commission (AEC) as issued 10 CFR 50, Appendix A, General Design Criteria (36FR03255, 2/20/71), and subsequently amended July 7, 1971 and February 12, 1976. The GDC are intended to establish minimum requirements for the plant’s principal design standards.

In addition to the changes identified in LAR Attachment 1, Descriptions and Technical Justifications for the Renewed Facility Operating License, Technical Specifications, and Licensing Basis Changes, key changes to the current licensing basis as a result of the EPU are listed in [Table 1.0-2](#).

Treatment of Issues Related to the Renewed Operating License

By letter dated November 29, 2001, FPL submitted to the NRC an application requesting the NRC to renew the St. Lucie Unit 2 Operating License for 20 additional years. The NRC reviewed the application in accordance with 10 CFR 54, Requirements for Renewal of Operating Licenses for Nuclear Power Plants, utilizing the guidance of NUREG-1800, Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants. The NRC completed its review and approved the license renewal application to extend the expiration date from April 6, 2023 to April 6, 2043, as documented in NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, in September 2003.

In the safety evaluation report, SSCs subject to aging management review are discussed in Sections 2.3 through 2.5. For those identified SSCs, the specific applicable aging management programs are discussed in Sections 3.1 through 3.6.

The requirements for renewal of nuclear power plant operating licenses are contained in 10 CFR 54, which provides the criteria for determining plant SSCs that are within the scope of the rule (10 CFR 54.21), as well as requirements for performing aging management reviews of those SSCs. Additionally, the rule requires an evaluation of time-limited aging analyses (TLAAs) to account for the effects of aging on the intended functions of structures, systems, and components (SSCs) that are not subject to replacement based on a qualified life or specified time period. The TLAAs are intended to ensure that the effects of aging on the intended function(s) will be managed for the period of extended operation.

The operating conditions associated with the EPU affect certain operating parameters, such as pressure, temperature, flow, and radiation compared to current operating conditions. In addition, the EPU introduces the possibility that components not currently within the scope of the rule

(either currently installed in the plant or added as the result of the EPU) may meet the scoping inclusionary criteria.

As discussed in each section of this LR that addresses specific SSCs, an evaluation of the impact of the EPU on the extended period of operation of the plant was performed. The purpose of this evaluation was to identify which, if any, SSCs warranted additional aging management action. These may include SSCs subject to new aging effects because of changes in the operating environment resulting from the EPU or the addition of, or modification to, components relied upon to satisfy EPU operating conditions.

The potential impact of the EPU on license renewal TLAAs was also evaluated. Specifically, the evaluation considered any new aging effects or increases in degradation rates potentially created by the new EPU operating parameters. In addition to the discussion contained in the individual LR section, the impact of the EPU on license renewal TLAAs is further discussed in LR **Section 2.14**, Impact of EPU on the Renewed Plant Operating License.

Sections Within the Licensing Report in Addition to Those Specified in RS-001

In order to provide a complete description of the analysis performed, the LR takes advantage of the provision in RS-001 to add additional sections (additional review areas). The following sections are in addition to the standard template:

1.0	Introduction to the St. Lucie Unit 2 Extended Power Uprate Licensing Report
1.1	Nuclear Steam Supply System (NSSS) Design Transients
2.2.6	NSSS Design Transients
2.4.2	Plant Operability
2.4.3	Pressurizer Component Sizing
2.4.4	Measurement Uncertainty Recapture Power Uprate
2.5.8.1	Circulating Water System
2.7.7	Other Ventilation Systems (Containment)
2.8.5.0	Accident and Transient Analyses
2.8.5.2.5	Asymmetric Steam Generator Transient
2.8.7.1	Loss of Decay Heat Removal at Mid-loop Operation
2.8.7.2	Natural Circulation Cooldown
2.9.3	Radiological Consequences of Gas Decay Tank Ruptures
2.14	Impact of EPU on the Renewed Plant Operating License
Appendix A	Safety Evaluation Report Compliance
Appendix B	Additional Codes and Methods
Appendix C	Grid Stability
Appendix D	List of Key Acronyms

Appendix E	Supplement to LR Section 2.4.1, Reactor Protection, Engineered Safety Features Actuation, and Control Systems
Appendix F	Cameron Ultrasonics Engineering Reports
Appendix G	HOLTEC Criticality Analysis Reports

Use of Industry Operating Experience

Both the regulators and the nuclear industry peer groups strongly advocate incorporating operating experience and lessons learned as basic input in design, maintenance, operating and licensing activities. The analysis and evaluations performed for the EPU took full advantage of past EPU experiences by:

- Review of previous power uprate applicant NRC requests for additional information (RAI). Pressurized water reactor RAIs issued over the past several years were reviewed and, where appropriate, the plant analysis or evaluations relating to the subject were reviewed.
- Review and incorporation of relevant EPU RAIs asked of other NextEra Energy fleet reactors (St. Lucie Unit 1 and Point Beach Units 1 and 2).
- Review of Institute of Nuclear Power Operations (INPO) communications relating to power uprates.

Treatment of Proprietary Information Referenced Within the Licensing Report

Two versions of the LR have been prepared; a proprietary version and a non-proprietary version. The non-proprietary version will be provided as a separate transmittal and is for placement in the public document room. The proprietary version is for use by the NRC staff.

Regulatory Commitments

Regulatory commitments are listed in Attachment 7 of this LAR.

**Table 1.0-1
Extended Power Uprate – Physical Plant Changes**

Description	Support EPU	Improve Operating Margin	LR Section
Reactor and Reactor Protection System			
Implement EPU fuel design	X		2.8.1
Raise reactor protection system steam generator low-level trip setpoint		X	2.4.1, 2.13
Rescale pressurizer level control program	X		2.4.1
Accident Mitigation Systems			
Increase component cooling water system heat removal margin	X	X	2.5.4.3
Maintain components' environmental qualification	X		2.3.1
Modify component cooling water system pipe supports	X		2.2.2.2
Spent Fuel Pool			
Add METAMIC TM inserts to spent fuel pool storage racks	X		2.8.6.2
Steam and Power Conversion System			
Replace moisture separator reheaters and upgrade related valves / controls	X		2.5.5.1
Increase steam bypass control system capacity and upgrade control system	X	X	2.4.2, 2.5.5.3
Replace high and low pressure turbine steam paths	X	X	2.5.1.2.2
Replace main turbine electro-hydraulic control system		X	2.5.1.2.2
Upgrade steam and power conversion system instruments	X		2.4.2
Modify piping supports	X		2.2.2.2
Condensate and Feedwater System			
Upgrade main condenser	X		2.5.5.2
Replace condensate pumps	X		2.5.5.4
Replace main feedwater pumps and modify steam generator flow control valves	X		2.5.5.4
Replace heater drain pumps	X		2.5.5.4
Upgrade heater drain valves	X	X	2.5.5.4
Replace No. 5 feedwater heaters and upgrade level controls	X		2.5.5.4

Table 1.0-1 (Continued)
Extended Power Uprate – Physical Plant Changes

Description	Support EPU	Improve Operating Margin	LR Section
Install leading edge flow meters	X		2.4.4
Upgrade feedwater controls and instrumentation	X	X	2.4.2
Modify piping supports	X		2.2.2.2
AC Power Block			
Replace main generator rotor and rewind stator	X		2.3.3
Replace main generator bushings, current transformers, and install power system stabilizer	X	X	2.3.3
Replace main generator hydrogen coolers	X		2.3.3
Replace turbine cooling water heat exchangers	X	X	2.5.4.2
Increase main generator hydrogen seal oil pressure	X		2.3.3
Replace main generator exciter coolers	X		2.3.3
Increase margin on AC electrical busses	X	X	2.3.3
Replace main transformers	X		2.3.3
Upgrade iso-phase bus duct cooling system and supports	X		2.3.3
Modify switchyard components	X	X	2.3.2

Table 1.0-2
Extended Power Uprate – Key Changes to Current Licensing Basis
(in addition to those discussed in LAR Attachment 1)

Description	LR Section
LR Appendix A summarizes NRC-approved codes and methods used in the 2.8.5 series of LRs.	App. A
LR Appendix B summarizes key codes and methods used in the LR that are in addition to those listed in LR Appendix A and not currently identified in the UFSAR.	App. B
The RETRAN code replaced the CESEC-III code to perform the station blackout analysis described in LR Section 2.3.5 , Station Blackout.	2.3.5
The IGOR code was used in addition to the RETRAN code to perform the loss of normal feedwater transient discussed in LR Section 2.5.4.5 , Auxiliary Feedwater.	2.5.4.5

Table 1.0-3
Extended Power Uprate – Key Changes to Credited EOP Operator Actions

Description	LR Section
In the event of a steam generator tube rupture, the CLB requires isolation of the affected steam generator and opening of the associated atmospheric dump valve within 30 minutes. The EPU analysis supports a revised action time of 45 minutes.	2.8.5.6.2, 2.9.2, 2.11.1

Table 1.0-4
Extended Power Uprate
Key Changes to Emergency (EOP) and Off-Normal Operating (ONP) Procedures

Description	LR Section
Boric acid makeup tank requirements are changing due to increased boron concentration requirements for EPU, resulting in changes to various ONP curves.	2.11.1
Condensate storage tank level requirements are increasing for cool down to shutdown cooling entry conditions, requiring changes to EOP figures and in the time until shutdown cooling entry conditions are reached.	2.11.1
Various instrumentation and control EPU modifications will affect the ONP load list. Procedure changes are required to include the revised electrical loads.	2.11.1
Due to changes in EPU power level and condenser backpressure values, the setpoint for the turbine drain valves to cycle on cross over steam pressure (from high pressure to low pressure turbines) is changing.	2.11.1
The existing setpoint for loop ΔT is increasing. This setpoint is used in conjunction with other indications to assess the status of single phase liquid natural circulation flow in at least one reactor coolant system loop.	2.11.1
Increases are required to the minimum simultaneous hot leg and cold leg injection flow rates to enhance mitigation of boric acid precipitation.	2.11.1
The EOP and ONP safety injection delivery curves require revision to reflect the high pressure safety injection (HPSI) accident analysis pressure reference point. The associated flow delivery curves will be revised consistent with the assumptions of the accident analysis.	2.11.1
The reactor coolant system makeup flow for boil-off versus time after shutdown will increase as a result of the EPU, due to the increased decay heat.	2.11.1
The replacement low pressure turbine rotors, which are heavier, will run hotter. ONP setpoints will change for turbine bearing temperature and turbine oil discharge temperature.	2.11.1

1.1 Nuclear Steam Supply System Parameters

The nuclear steam supply system (NSSS) design parameters are the fundamental parameters used as input in the NSSS analyses and evaluations. The NSSS design parameters provide the primary and secondary side system conditions (thermal power, temperatures, pressures, and flows) that serve as the basis for the NSSS analyses and evaluations.

The EPU represents a core power increase of approximately 12 percent above the current core power of 2700 MWt. The increase in core power will be accomplished by increasing the core temperature rise. As a result of the EPU, the NSSS design parameters have been revised as shown in LR [Table 1.1-1](#), NSSS PCWG Parameters for EPU. This table provides information for the current design bases conditions as well as for various cases representing operation following the EPU. These parameters have been incorporated, as required, into the applicable NSSS systems and components evaluations, as well as safety analyses, performed in support of the EPU. The specific NSSS design parameters assumed for each NSSS system, component, and safety evaluation are discussed in each individual LR section.

1.1.1 Input Parameters, Assumptions, and Acceptance Criteria

The NSSS design parameters, also referred to as the Performance Capability Working Group (PCWG) parameters, provide the reactor coolant system (RCS) and secondary system conditions (thermal power, temperatures, pressures, and flow) that are used as the basis for the design transients, systems, structures, components, accidents, and fuel analyses and evaluations.

The NSSSPlus computer code was used to generate a PCWG design sheet to support the EPU. There is no explicit NRC approval for the code since it is used to facilitate calculations that could be performed by hand to determine system parameters, including bounding analysis parameters, which would have to be complied with during EPU operation. The code and method used to calculate these values have been successfully used to license all previous similar power uprates for Westinghouse plants. They use basic thermal-hydraulic calculations, along with first principles of engineering, to generate the temperatures, pressures, and flows shown in LR [Table 1.1-1](#).

The major input parameters and assumptions used in the calculation of Cases 1 through 4 of the PCWG parameters established for the EPU are summarized below and in LR [Table 1.1-1](#).

1. Up-rated NSSS Power of 3050 MWt, which includes a reactor coolant pump (RCP) net heat input of 20 MWt;
2. Thermal design flow of 187,500 gpm/hot leg (each steam generator contains one hot leg and two cold legs);
3. Combustion Engineering 16x16 standard fuel;
4. Core bypass flow of 3.7 percent;
5. Feedwater temperature range of 409.0°F to 441.0°F;

6. Steam generator tube plugging (SGTP) levels of 0 percent and 10 percent average with a maximum asymmetry of +/-2 percent of the actual average value between steam generators and a maximum peak tube plugging level of 12 percent; and
7. Reactor vessel inlet temperature range of 535.0°F to 551.0°F.

Acceptance Criteria

The acceptance criteria for determining the NSSS design parameters were that the results of the EPU analyses and evaluations continue to comply with the industry and regulatory requirements applicable to St. Lucie Unit 2, and that they provide adequate flexibility and margin during plant operation.

1.1.2 Description of Analyses and Evaluation

LR [Table 1.1-1](#) provides the NSSS design parameter cases that were evaluated and serve as the basis for the EPU.

- The current design bases NSSS parameters are provided in the first column.
- EPU Cases 1 and 2 of LR [Table 1.1-1](#) represent parameters based on a reactor vessel inlet temperature of 535.0°F. Case 1 is based on 0 percent SGTP. Case 2 yielded the minimum secondary side steam generator pressure and temperature since it assumed an average of 10 percent SGTP. Note that all primary side temperatures were identical for these two cases. This is a result of defining the thermal design flow based on 10 percent SGTP and conservatively applying it to all cases.
- EPU Cases 3 and 4 of LR [Table 1.1-1](#) are based on a reactor vessel inlet temperature of 551.0°F. Case 3 yields the highest secondary side steam pressure performance conditions since it assumed 0 percent SGTP. Case 4 is based on an average of 10 percent SGTP. Note that all primary side temperatures were identical for these two cases. Note that for Case 3, for instances where an absolute upper limit steam generator outlet pressure is controlling, steam generator outlet temperature, pressure, and flow are increased above the values in LR [Table 1.1-1](#) (see LR [Table 1.1-1](#) footnote (6)). The higher values for steam generator outlet temperature, pressure, and steam flow result from assuming a fouling factor of zero.

Best-estimate calorimetric measurement-based performance predictions were also calculated for the EPU. These calorimetric measurement based calculations were performed to estimate the actual expected steam conditions at the steam generator outlet as opposed to the design conditions shown in LR [Table 1.1-1](#).

1.1.3 Best-Estimate RCS Flows

Best-estimate RCS flows were calculated to support the EPU to determine whether adequate flow margin exists for the thermal design flow and mechanical design flow values established for the EPU. The results of the best-estimate RCS flow calculations are as follows:

- Best-estimate RCS flow values of 200,378 gpm/loop at 0 percent SGTP and 195,769 gpm/loop at 10 percent SGTP

These calculated flows demonstrate that adequate flow margin exists for the thermal design flow and the mechanical design flow values. The current actual measured flows (0 percent SGTP) however show additional margin of ~2,000 gpm total to the predicted best estimate flows.

1.1.4 Conclusion

The resulting PCWG parameters presented in LR **Table 1.1-1** were used as the basis for the NSSS analytical efforts. The analyses and evaluations were based on the parameter sets that were most limiting, so that the analyses would support operation over the entire range of conditions specified.

Florida Power and Light concludes that the NSSS parameters established are suitable for use in the evaluation of NSSS systems, components, and accidents for the EPU.

**Table 1.1-1
NSSS PCWG Parameters for EPU**

Thermal Design Parameters	Current		EPU	
	Case 1	Case 2	Case 1	Case 2
NSSS Power (% current)	100	100	112	112
MWt	2720	2720	3050 ⁽⁵⁾	3050 ⁽⁵⁾
10 ⁶ Btu/hr	9,281	9,281	10,407	10,407
Reactor Power MWt	2700	2700	3030 ⁽⁴⁾	3030 ⁽⁴⁾
10 ⁶ Btu/hr	9,213	9,213	10,339	10,339
Thermal Design Flow, loop gpm	167,500	167,500	187,500 ⁽²⁾	187,500 ⁽²⁾
Reactor 10 ⁶ lb/hr	128.4	128.4	143.8	143.8
Reactor Coolant Pressure, psia	2250	2250	2250	2250
Core Bypass,%	3.7	3.7	3.7	3.7
Reactor Coolant Temperature, °F				
Core Outlet	592.9	592.9	593.0	593.0
Vessel Outlet	590.9	590.9	591.0	591.0
Core Average	564.9	564.9	565.0	565.0
Vessel Average	563.0	563.0	563.0	563.0
Vessel/Core Inlet	535.0	535.0	535.0	535.0
Steam Generator Outlet	534.6	534.6	534.6	534.6
Steam Generator				
Steam Outlet Temperature, °F	511.7	498.6	514.5	511.7
Steam Outlet Pressure, psia	755	672	775 ⁽¹⁾	756 ⁽¹⁾
Steam Outlet Flow, 10 ⁶ lb/hr total	11.82	11.79	12.79/13.36	12.78/13.35
Feed Temperature, °F	435	435	409.0/441.0	409.0/441.0
Steam Outlet Moisture,% max.	0.25	0.25	0.10	0.10
Design Fouling Factor, hr. sq. ft. °F/Btu	0.00017	0.00017	0.00005	0.00005
Tube Plugging Level (%)	0	30	0	10 ⁽⁷⁾
Zero Load Temperature, °F	532	532	532	532
Thermal Design Parameters	Current		EPU	
	Case 3	Case 4	Case 3	Case 4
NSSS Power (% current)	100	100	112	112
MWt	2720	2720	3050 ⁽⁵⁾	3050 ⁽⁵⁾
10 ⁶ Btu/hr	9,281	9,281	10,407	10,407

Table 1.1-1 (Continued)
NSSS PCWG Parameters for EPU

Reactor Power MWt	2700	2700	3030 ⁽⁴⁾	3030 ⁽⁴⁾
10 ⁶ Btu/hr	9,213	9,213	10,339	10,339
Thermal Design Flow, loop gpm	167,500	167,500	187,500 ⁽²⁾	187,500 ⁽²⁾
Reactor 10 ⁶ lb/hr	126.1	126.1	140.8	140.8
Reactor Coolant Pressure, psia	2250	2250	2250	2250
Core Bypass,%	3.7	3.7	3.7	3.7
Reactor Coolant Temperature, °F				
Core Outlet	605.9	605.9	607.9	607.9
Vessel Outlet	604.0	604.0	606.0	606.0
Core Average	578.6	578.6	580.7	580.7
Vessel Average	576.5	576.5	578.5	578.5
Vessel/Core Inlet	549.0	549.0	551.0	551.0
Steam Generator Outlet	548.6	548.6	550.6	550.6
Steam Generator				
Steam Outlet Temperature, °F	526.2	513.2	531.2 ⁽⁶⁾	528.4
Steam Outlet Pressure, psia	857	766	895 ^(1, 6)	873 ⁽¹⁾
Steam Outlet Flow, 10 ⁶ lb/hr total	11.87	11.83	12.84/13.42 ⁽⁶⁾	12.83/13.41
Feed Temperature, °F	435	435	409.0/441.0	409.0/441.0
Steam Outlet Moisture,% max.	0.25	0.25	0.10	0.10
Design Fouling Factor, hr. sq. ft. °F/Btu	0.00017	0.00017	0.00005	0.00005
Tube Plugging Level (%)	0	30	0	10 ⁽⁷⁾
Hydraulic Design Parameters	Current		EPU	
Reactor Coolant Pump Design Point, Flow (gpm)/Head (ft.)	87,750/296.75		87,750/296.75	
Mechanical Design Flow, total gpm	406,000		431,000	
Minimum Measured Flow, total gpm	349,500		390,000 ⁽³⁾	

Table 1.1-1 (Continued)
NSSS PCWG Parameters for EPU

Notes:

1. A 13 psi steam generator internal pressure drop is incorporated.
2. Thermal design flow of 187,500 gpm/hot leg (each steam generator contains one hot leg and two cold legs).
3. Minimum measured flow based on a 15,000 gpm flow measurement uncertainty.
4. Upper limit on core thermal power.
5. RCP net heat input of 20 MWt included in NSSS power.
6. If a high steam pressure is more limiting for analysis purposes, a greater steam pressure than that specified in the table should be assumed. This is to envelop the possibility that the plant could operate with better than expected steam generator performance.
7. SGTP of up to 10% average tube plugging with a maximum asymmetry of +/- 2% of the actual average value between steam generators and a maximum peak tube plugging level of up to 12%.

2.0 EVALUATION

2.1 Materials and Chemical Engineering

2.1.1 Reactor Vessel Materials Surveillance Program

2.1.1.1 Regulatory Evaluation

The reactor vessel material surveillance program provides a means for determining and monitoring the fracture toughness of the reactor vessel beltline materials to support analyses for ensuring the structural integrity of the ferritic components of the reactor vessel. The Florida Power and Light (FPL) review primarily focused on the effects of the proposed extended power uprate (EPU) on the reactor vessel surveillance capsule withdrawal schedule.

The NRC acceptance criteria are based on:

- General Design Criteria (GDC)-14, insofar as it 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 fracture;
- 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 non-brittle manner and the probability of a rapidly propagating fracture is minimized;
- 10 CFR 50 Appendix H, which provides for monitoring changes in the fracture toughness properties of materials in the reactor vessel beltline region; and,
- 10 CFR 50.60, which requires compliance with the requirements of 10 CFR 50 Appendix H.

Specific review criteria are contained in the Standard Review Plan (SRP), Section 5.3.1, and other guidance provided in Matrix 1 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design basis of St. Lucie Unit 2 conforms to the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971, and subsequently amended July 7, 1971, and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1

The specific GDC for the reactor vessel materials surveillance program are as follows:

- GDC-14 is described in UFSAR Section 3.1.14 Criterion 14 – Reactor Coolant Pressure Boundary.

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.

Reactor coolant system (RCS) components are designed to meet the requirements of the ASME Code, Section III. To establish operating pressure and temperature limitations during startup and shutdown of the RCS, the fracture toughness rules defined in Appendix G of the ASME Code,

Section III, are followed. Quality control, inspection, and testing as required by this standard and allowable reactor pressure-temperature operations ensure the integrity of the RCS.

The RCPB is designed to accommodate the system pressures and temperatures attained under all expected modes of unit operation, including all anticipated transients, and to maintain the stresses within applicable limits.

The pressure boundary has provisions for in-service inspection, in accordance with the requirements of ASME Code, Section XI, to ensure the structural and leak-tight integrity of the boundary (see also response to Criterion 32). For the reactor vessel, a material surveillance program conforming to the requirements of Appendix H of 10 CFR 50 is given in UFSAR Section 5.3.

- GDC-31 is described in UFSAR Section 3.1.31 Criterion 31 – Fracture Prevention of Reactor Coolant Pressure Boundary.

The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions (1) the boundary behaves in a non-brittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing and postulated accident conditions and the uncertainties in determining (1) material properties, (2) the effects of irradiation on material properties, (3) residual, steady-state and transient stresses, and (4) size of flaws.

Carbon and low-alloy steel materials that form part of the pressure boundary are tested for fracture toughness to the acceptance criteria and requirements of 10 CFR 50, Appendix G (see UFSAR Section 5.2).

UFSAR Section 5.3.1 describes reactor vessel materials and associated inspections.

The surveillance program is consistent with the objectives of ASTM E 185-82 (Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels) and 10 CFR 50, Appendix H to verify the initial predictions of the surveillance material response to the actual radiation environment and to determine the conditions under which the vessel can be operated with adequate margins of safety against fracture.

In addition to the licensing basis described in the UFSAR, the reactor vessel materials surveillance program was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.1 of the SER identifies that components of the reactor vessel materials surveillance program are within the scope of License Renewal. Programs used to manage the aging effects associated with the reactor vessel material surveillance program are discussed in SER Section 3.1.0.5 and Chapter 18 of the UFSAR.

2.1.1.2 Technical Evaluation

2.1.1.2.1 Introduction

The surveillance program is described in UFSAR Section 5.3.1.6, Materials Surveillance Program. The surveillance capsule withdrawal schedule is contained in UFSAR Section 5.3.1.6.6, Table 5.3-9. In addition, UFSAR Section 18.2.11 presents the existing programs utilized to manage reactor vessel material integrity. Those programs are 1) Reactor Vessel Surveillance Capsule Removal and Evaluation, 2) Fluence and Uncertainty Calculations, 3) Monitoring Effective Full Power Years (EFPY), and 4) Pressure-Temperature Limit Curves. The surveillance program is consistent with the objectives of ASTM E 185-82 (Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels) and 10 CFR 50, Appendix H. Those objectives are to verify the initial predictions of the surveillance material response to the actual radiation environment and to determine the conditions under which the vessel can be operated with adequate margins of safety against fracture. The post-irradiation evaluations conducted to date have been performed in accordance with ASTM E185-82 as contained in WCAP-15040, and the results have been submitted to the NRC (Reference 2). The surveillance capsule withdrawal schedule is maintained in the UFSAR and updated as necessary subsequent to each surveillance capsule evaluation. The current surveillance capsule withdrawal schedule given in LR Table 2.1.1-1 was designed to be consistent with ASTM E 185-82 and to provide for monitoring through 60 years of operation.

Reactor vessel integrity is impacted by any change in plant parameters that affect neutron fluence levels or temperature/pressure transients. The changes in neutron fluence resulting from the EPU have been evaluated to determine the impact on reactor vessel integrity. The assessment presented herein focuses on the reactor vessel surveillance program and the associated capsule withdrawal schedule.

2.1.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

EPU Fluence Projections

The EPU normally would result in an increase to the neutron fluence on the reactor pressure vessel. As shown in LR Table 2.1.1-2, there was actually a decrease of the projected 60-year vessel fluence because of the conservative basis for the pre-EPU fluence estimate. 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% factor of conservatism to the EPU fluence projections beginning with Cycle 23. The effect of this projected change on the reactor vessel surveillance capsule withdrawal schedule was evaluated. The surveillance capsule withdrawal schedule, shown in LR Table 2.1.1-1, is based on projections of vessel fluence to 60 years (approximately 55 EFPY) that made conservative allowance for the EPU. Vessel fluence projections to 60 years that did consider the EPU are compared to the previous values in LR Table 2.1.1-2 at the 0-degree azimuthal position. The 0° azimuth corresponds to the peak fluence locations for the base metal, weld and the axial welds. Both fluence values are judged sufficiently similar to warrant no change to the schedule in LR Table 2.1.1-1. Therefore, there is no impact of the EPU on the surveillance capsule withdrawal

schedule. Note that surveillance capsules that have previously been removed from the vessel and tested will not be impacted by the EPU.

The calculated fluence projections used in the EPU evaluation complied with Regulatory Guide (RG) 1.190 (Reference 1), including consideration of dosimetry measurements from the tested surveillance capsules. The EOL fluence values were used to calculate ART values as described in LR Section 2.1.2, Pressure-Temperature Limits and Upper Shelf Energy.

Chemistry Factor Values

Values of the chemistry factor (CF) for each of the beltline materials are determined and used with the projected neutron fluence factor to estimate the properties after irradiation. Associated with each surveillance capsule evaluation is a comparison between the CF values determined based on the measured changes for the surveillance materials and the CF values determined based on the copper and nickel content of those same materials. The results of the most recent assessment using the measurements in WCAP-15040 (Reference 2) are shown in LR Table 2.1.1-3. The effect of future measurements on the CF value calculations will be reassessed as part of each subsequent surveillance capsule evaluation to determine whether operation at higher power (EPU conditions) has resulted in any detectable changes to the surveillance program data.

Inlet Temperature

The reactor vessel core inlet temperature (T_{cold}) at full power is expected to change with the proposed EPU operating condition from 549°F to 551°F. The effect of this change is expected to slightly lower the rate of irradiation embrittlement. The effect will be assessed as described above for CF values.

Acceptance Criteria

The reactor vessel surveillance program is conducted in accordance with 10 CFR 50, Appendix H and the post-irradiation evaluation is performed following ASTM E 185-82. A sufficient number of surveillance capsules are provided in the reactor vessel to continue to monitor the vessel, including assessing the effects of the EPU, during the anticipated lifetime of the vessel.

The expected change to T_{cold} will result in vessel operating temperatures that are still within the range of temperature stipulated for the use of RG 1.99, Revision 2 (Reference 3), and 10 CFR 50.61. Reference 3 states, "The procedures are valid for a nominal irradiation temperature of 550°F. Irradiation below 525°F should be considered to produce greater embrittlement, and irradiation above 590°F may be considered to produce less embrittlement." Because the T_{cold} will continue to be within the range of 525°F to 590°F after the EPU, the equations and methodology of Reference 3 will remain valid.

2.1.1.2.3 Description of Analyses and Evaluations

The reactor vessel surveillance program was designed to monitor the condition of the reactor vessel materials under actual operating conditions. The surveillance capsule withdrawal schedule was developed to periodically remove capsules from the reactor vessel and to test the materials in accordance with ASTM E 185-82. The surveillance capsule withdrawal schedule

given in LR [Table 2.1.1-1](#) provides for monitoring through 60 years of operation. Two surveillance capsules have been removed and tested to date. Two more are scheduled for evaluation. There are two additional standby capsules in the vessel that would be available if additional monitoring becomes necessary.

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

As discussed above, the reactor vessel material surveillance program is within the scope of License Renewal. As described in LR [Section 2.1.1.2.3](#) above, the fluence projections for EPU have been incorporated into the surveillance capsule withdrawal schedule. This updated withdrawal schedule is documented in LR [Table 2.1.1-1](#). No changes are required to the capsule withdrawal schedule as a result of the EPU. Thus, no new aging effects requiring management are identified and no changes are necessary to any existing aging management programs. Furthermore, 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.

2.1.1.2.5 Results

Reactor vessel fluence projections and updated capsule fluence values were generated for the EPU following the guidance of RG 1.190 and are presented in LR [Table 2.1.1-1](#) and LR [Table 2.1.1-2](#). The pre-EPU vessel fluence projections are comparable because of the assumptions used (e.g., provision for an uprate). The updated fluence projections presented in LR [Table 2.1.1-1](#) for the two capsules scheduled for removal after 26 and 44 EFPY reflect the EPU conditions.

The surveillance capsule withdrawal schedule given in LR [Table 2.1.1-1](#) is consistent with ASTM E 185-82 and provides for monitoring through 60 years of operation. Note that the scheduled withdrawal of a capsule is adjusted to the vessel refueling outage nearest to the target fluence established for the particular surveillance capsule per ASTM E 185-82. Two capsules have been removed from the reactor vessel to date. The results are summarized in LR [Table 2.1.1-3](#).

The expected change to T_{cold} will result in vessel operating temperatures that are still within the range of temperature stipulated for the use of RG 1.99, Revision 2 and 10 CFR 50.61. As stated in [Reference 3](#), "The procedures are valid for a nominal irradiation temperature of 550°F. Irradiation below 525°F should be considered to produce greater embrittlement, and irradiation above 590°F may be considered to produce less embrittlement." Because T_{cold} will continue to be within the range of 525°F to 590°F after the EPU, the equations and methodology of RG 1.99, Revision 2 will remain valid.

Although the surveillance capsule withdrawal schedule is adequate for 60 years (55 EFPY) of operation including the EPU, the period of applicability for the pressure-temperature limits (discussed in [Section 2.1.2](#)) is limited to 47 EFPY after EPU implementation.

2.1.1.3 Conclusion

FPL has evaluated the effects of the proposed EPU on the reactor vessel surveillance withdrawal schedule and concludes that the withdrawal schedule adequately addresses changes in neutron fluence and their effects on the schedule. FPL further concludes that the reactor vessel capsule withdrawal schedule is appropriate to ensure that the material surveillance program will continue to meet its current licensing basis with respect to the requirements of GDC-14 and -31 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to the reactor vessel material surveillance program.

2.1.1.4 References

1. U.S. Nuclear Regulatory Commission. Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence. Regulatory Guide 1.190. March 2001.
2. Florida Power and Light Letter, L-98-119, transmitting Westinghouse Document, WCAP-15040, Rev. 0, Analysis of Capsule 263° from the Florida Power & Light Company St. Lucie Unit 2 Reactor Vessel Radiation Surveillance Program," April 28, 1998.
3. U.S. Nuclear Regulatory Commission. Radiation Embrittlement of Reactor Vessel Materials Regulatory Guide 1.99, Rev. 2. May 1988.

**Table 2.1.1-1
Surveillance Capsule Withdrawal Schedule for 60 Years**

Capsule Location	Capsule Lead Factor	Approximate Removal Time (EFPY)⁽¹⁾	Neutron Fluence (n/cm²)⁽¹⁾	Updated Neutron Fluence for EPU (n/cm²)
83°	1.33	1.1 ⁽²⁾	$1.779 \times 10^{18(2)}$	1.47×10^{18}
263°	1.34	11 ⁽²⁾	$1.244 \times 10^{19(2)}$	1.05×10^{19}
97°	1.33	26	2.70×10^{19}	2.3×10^{19}
277°	1.33	44 ⁽³⁾	$4.56 \times 10^{19(3)}$	4.5×10^{19}
104°	0.99	Standby ⁽⁴⁾	----	----
284°	0.99	Standby ⁽⁴⁾	----	----
Notes: 1. From UFSAR Table 5.3-9. Removal time is EFPY from plant startup. 2. Capsule evaluation completed in WCAP-15040 (Reference 2); fluence value updated for EPU. 3. Capsule 277° is projected to reach the 60-year vessel inside diameter (ID) fluence at approximately 44 EFPY; capsule to be available for testing. 4. Capsules 104° and 284° are designated as “standby” capsules.				

Table 2.1.1-2
Comparison of Peak (0° Azimuth) Vessel ID Fluence Values at 60 Years (55 EFPY)

Source	Azimuthal Location	Surface (n/cm², E > 1.0 MeV)
Pre-EPU	0°	4.48E+19
EPU Analysis	0°	4.42E+19

Table 2.1.1-3
Chemistry Factor Determination for Surveillance Plate and Weld Based on Updated Capsule Fluence

Capsule	Material	Measured Shift (°F)	Neutron Fluence (n/cm ²)	Fluence Factor (FF)	FF ²	Shift x FF	Best Fit CF ⁽¹⁾
83°	M-605-1 ⁽²⁾	30	1.47E+18	0.498325	0.248328	14.9	93.1 ⁽⁴⁾
83°	M-605-1 ⁽³⁾	45	1.47E+18	0.498325	0.248328	22.4	
263°	M-605-1 ⁽²⁾	103.1	1.05E+19	1.013650	1.027487	104.5	
83°	Weld	13.8	1.47E+18	0.498325	0.248328	6.9	26.0 ⁽⁵⁾
263°	Weld	26	1.05E+19	1.013650	1.027487	26.4	
Notes: 1. CF is Chemistry Factor. 2. Transverse plate orientation. 3. Longitudinal plate orientation. 4. Best Fit CF determined for plate M-605-1 (combined orientations). 5. Best Fit CF determined for surveillance weld.							

2.1.2 Pressure-Temperature Limits and Upper-Shelf Energy

2.1.2.1 Regulatory Evaluation

Pressure-temperature (P-T) limits are established to ensure the structural integrity of the ferritic components of the reactor coolant pressure boundary (RCPB) during any condition of normal operation, including anticipated operational occurrences and hydrostatic tests. The Florida Power and Light (FPL) review of P-T limits covered the P-T limits methodology and the calculations for the number of effective full-power years (EFPYs) specified for the proposed extended power uprate (EPU), considering neutron embrittlement effects and using linear elastic fracture mechanics.

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

- General Design Criteria (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 non-brittle manner and the probability of a rapidly propagating fracture is minimized,
- 10 CFR 50 Appendix G, which specifies fracture toughness requirements for ferritic components of the RCPB, and
- 10 CFR 50.60, which requires compliance with the requirements of 10 CFR 50, Appendix G.

Specific review criteria are contained in the Standard Review Plan (SRP), Section 5.3.2 and other guidance is provided in Matrix 1 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC GDC for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDC for the reactor vessel material surveillance program are as follows:

- GDC-14 is described in UFSAR Section 3.1.14 Criterion 14 – Reactor Coolant Pressure Boundary.

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.

Reactor coolant system (RCS) components are designed to meet the requirements of the ASME Code, Section III. To establish operating pressure and temperature limitations during startup and shutdown of the RCS, the fracture toughness rules defined in Appendix G of the ASME Code, Section III, are followed. Quality control, inspection, and testing as required by this standard and allowable reactor P-T operation ensure the integrity of the RCS.

- GDC-31 is described in UFSAR Section 3.1.31 Criterion 31 – Fracture Prevention of Reactor Coolant Pressure Boundary.

The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions (1) the boundary behaves in a non-brittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing and postulated accident conditions and the uncertainties in determining (1) material properties, (2) the effects of irradiation on material properties, (3) residual, steady-state and transient stresses, and (4) size of flaws.

RCPB components are designed and constructed in accordance with ASME Code Section III, and comply with the test and inspection requirements of this code. These test and inspection requirements assure that flaw sizes are limited so that the probability of failure by rapid propagation is extremely remote. Particular emphasis is placed on the quality control applied to the reactor vessel, on which tests and inspections exceeding ASME Code requirements are performed. The tests and inspections performed on the reactor vessel are summarized in UFSAR Sections 5.2 and 5.3.

Carbon and low-alloy steel materials that form part of the RCPB are tested for fracture toughness to the acceptance criteria and requirements of 10 CFR 50 Appendix G (see UFSAR Section 5.2).

10 CFR 50 Appendix G, Fracture Toughness Requirements are described in UFSAR Section 18.3.1.2 as follows:

The requirements on reactor vessel Charpy upper-shelf energy (USE) are included in 10 CFR 50 Appendix G. Specifically, 10 CFR 50, Appendix G requires licensees to submit an analysis at least 3 years prior to the time that the USE of any reactor vessel material is predicted to drop below 50 ft-lbs, as measured by Charpy V-notch specimen testing.

Components in the RCS are designed to withstand the effects of cyclic loads due to RCS temperature and pressure changes. These cyclic loads are introduced by normal unit load transients, reactor trips and startup and shutdown operations.

The maximum allowable RCS pressure at any temperature is based upon the stress limitations to prevent brittle fracture. These limitations are derived by using the rules contained in ASME Section III including Appendix G, Protection Against Nonductile Failure and the rules contained in 10 CFR 50 Appendix G, Fracture Toughness Requirements.

The ferritic pressure retaining materials used in the fabrication of the replacement reactor vessel closure head have been tested to demonstrate compliance with the fracture toughness requirements of 10 CFR 50 Appendix G as required by the ASME Code. The fracture toughness (impact) testing was performed in compliance with Subarticle NB-2200 and Subarticle NB-2300 of ASME Code Section III, Division 1, 1989 Edition No Addenda.

Technical Specification 3/4.4.9, Pressure/Temperature Limits, presents the P-T curves.

The provisions of 10 CFR 50.60, acceptance criteria for fracture prevention measures for light-water nuclear power reactors for normal operation, require compliance with the

requirements of 10 CFR 50 Appendices G and H. Alternatives to the requirements of these appendices may be proposed and an exemption granted by the NRC under 10 CFR 50.12. Relative to the requirements of 10 CFR 50.60, it is noted that the surveillance program is consistent with the objectives of ASTM E 185-82 Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels and 10 CFR 50 Appendix H to verify the initial predictions of the surveillance material response to the actual radiation environment and to determine the conditions under which the vessel can be operated with adequate margins of safety against fracture.

Compliance with the guidance presented in Regulatory Guide (RG) 1.99, Radiation Embrittlement of Reactor Vessel Materials, RG 1.190, Calculational and Dosimetry methods for Determining Pressure Vessel Neutron Fluence, and RG 1.161, Evaluation of Reactor Pressure Vessels with Charpy Upper Shelf Energy Less than 50 ft-lb, is discussed in LR [Section 2.1.2.2.2](#).

In addition to the licensing basis described in the UFSAR, the P-T limits and USE for the RCPB were evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. P-T limits and USE are time-limited aging analyses (TLAA) and are discussed in SER Section 4.2.3 and 4.2.1, respectively and Chapter 18 of the UFSAR. The purpose of the analysis is to confirm that the P-T limit curves meet the requirements of 10 CFR 50 Appendix G and 10 CFR 50.61.

2.1.2.2 Technical Evaluation

2.1.2.2.1 Introduction

Reactor vessel integrity is potentially impacted by any change in plant parameters that affect neutron fluence levels or P-T transients. The changes in neutron fluence resulting from the EPU were evaluated to determine the impact on reactor vessel integrity. The assessment presented herein focuses on the P-T limits and the end of license (EOL) USE.

2.1.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The EPU normally would result in an increase to the neutron fluence on the reactor pressure vessel. As shown in LR [Table 2.1.2-1](#), 60 Year Peak Vessel Fluence Values at Surface, 1/4T and 3/4T, there was actually a slight decrease of the projected 60-year vessel fluence because of the conservative basis for the pre-EPU fluence estimate. 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 23. The effect of the projected changes in operating conditions on reactor vessel integrity was evaluated. The vessel fluence projections for the reactor vessel are presented in LR [Table 2.1.2-1](#). The 0° azimuth corresponds to the peak fluence locations for the base metal, weld and the axial welds. Vessel fluence is provided for the vessel inside surface (clad-base metal interface) and for the 1/4 and 3/4 thickness (T) locations. The effect of this

projected change on the P-T limits and the EOL USE was evaluated. The P-T limits and USE projections described below were based on projections of vessel fluence to 60 years (approximately 55 EFPY) that made conservative allowance for the EPU. Vessel fluence projections to 60 years that did consider the EPU are compared to the previous values in LR [Table 2.1.2-1](#) at the 0° azimuthal position (peak location).

Neutron fluence values are used to calculate the EOL adjusted reference temperature (ART) and the EOL USE using the guidance from RG 1.99, Revision 2 ([Reference 1](#)). The projected fluence values at 55 EFPY levels are provided in LR [Table 2.1.2-1](#). The current P-T limit curves are applicable to 55 EFPY ([Reference 7](#)). The 60-year USE projections are based on the fluence at 55 EFPY. The neutron fluence was determined using an NRC approved methodology ([Reference 2](#)) that follows the guidance and meets the requirements of RG 1.190 ([Reference 3](#)), including consideration of dosimetry measurements from the tested surveillance capsules. The irradiation temperature for the reactor vessel beltline corresponds to the reactor vessel inlet temperature, T_{cold} . T_{cold} at full power will change from 549°F to 551°F for the EPU. Irradiation temperature affects the degree of material embrittlement; a higher temperature is expected to reduce the degree of embrittlement and a lower temperature is expected to increase the degree of embrittlement. The methodology of [Reference 1](#) is based on an irradiation temperature between 525°F and 590°F. The temperature will remain within the applicable range, and the net effect will be to slightly lower the degree of irradiation embrittlement. The overall effect of this temperature change on vessel integrity, therefore, is small but beneficial.

[Reference 1](#) uses values of chemistry factors (CF) and fluence factors (FF) to determine the transition temperature shift, ΔRT_{NDT} , for each of the beltline materials. The CF and initial RT_{NDT} values used in this evaluation are presented in LR [Table 2.1.2-2](#), Vessel Beltline Material Property Input for ART Projections. The initial RT_{NDT} values are the unirradiated reference temperature for each material, as reported in Reactor Vessel Integrity Database Version 2.0 (RVID-2) ([Reference 4](#)), and were used together with the ΔRT_{NDT} and margin to determine the EOL ART values at the 1/4T and 3/4T locations. The CF values were determined following Position 1.1 or 2.1 of [Reference 1](#). Position 1.1 uses the best-estimate copper and nickel contents for the beltline materials to determine the CF. The Position 1.1 CF values were reported in RVID-2 ([Reference 4](#)) and updated in [Reference 5](#). Position 2.1 determines CF values based on the reactor vessel surveillance capsule results. The post-irradiation measurements for the surveillance plate M-605-1 and the surveillance weld from [Reference 6](#) and the updated capsule fluence values are shown in LR [Table 2.1.2-3](#), Chemistry Factor Determination for Surveillance Plate and Weld. LR [Table 2.1.2-4](#), Chemistry Factors and Adjustments for Vessel Plates and Welds, shows the ratio analysis as prescribed in [Reference 1](#) for adjusting the post-irradiation surveillance results by the ratio of the chemistry factors to the vessel beltline plates M-605-1 and M-605-3.

The initial USE values for each beltline material were used as a baseline for determining the EOL USE. The initial USE and weight percent copper values for each of the beltline materials are presented in LR [Table 2.1.2-5](#), Best Estimate Cu Content and Initial USE Values for the Reactor Vessel. The chemistry values for weight percent copper were used along with the fluence to determine the percent decrease in USE at EOL.

Projected ART and USE values were determined for each of the reactor vessel beltline materials using a conservative estimate of neutron fluence at 60 years based on 55 EFPY. Each of the neutron fluence projections includes a 10 percent factor of conservatism beginning with Cycle 23 to accommodate future changes in core power distribution.

Acceptance Criteria

For the P-T limit curves acceptance criteria, the P-T limits are developed in accordance with 10 CFR 50 Appendix G. The period of applicability after implementation of the EPU is determined based on the EPU ART projections.

For USE, the acceptance criterion is that EOL values for all reactor beltline materials must meet the requirements of 10 CFR 50 Appendix G, which states that the USE must be maintained at or above 50 ft-lbs. As an alternative, an equivalent margins analysis may be performed to demonstrate that the vessel has an adequate margin.

For T_{cold} , the acceptance criteria are provided in RG 1.99, Revision 2 ([Reference 1](#)), and states: “The procedures are valid for a nominal irradiation temperature of 550°F. Irradiation below 525°F should be considered to produce greater embrittlement, and irradiation above 590°F may be considered to produce less embrittlement.” Thus, T_{cold} must be between 525°F and 590°F for the equations and methodology of 10 CFR 50.61 to remain valid. St. Lucie Unit 2 meets these acceptance criteria for temperature conditions as described above in the input parameters section.

2.1.2.2.3 Description of Analyses and Evaluations

Applicability of P-T Limit Curves

If the EPU ART projections exceed the values used for the current P-T limit curves, then a new applicability date for the pre-EPU P-T limit curves must be established using the EPU fluence projections. The current P-T limit curves ([Reference 7](#)) have been generated for operation to 60 years based on 55 EFPY fluence projection and Position 1.1 CF values.

The effect of the EPU on the applicability of the pre-EPU P-T limits curves was evaluated by comparing the ART values for the current licensing basis with the ART values after the EPU. The EPU fluence projections for the 1/4T and 3/4T locations in the vessel at the 0° azimuth are given in LR [Table 2.1.2-1](#). The Position 1.1 and 2.1 CF values in LR [Table 2.1.2-4](#), were used to compute ART values, and the higher value of ART was applied in the case where both Position 1.1 and 2.1 CF values were determined.

USE

In the assessment of the impact of the EPU on the USE, USE values were projected to EOL for all reactor vessel beltline materials using the EPU fluence projections for the 1/4T location in the vessel (LR [Table 2.1.2-1](#)) and Figure 2 of RG 1.99, Revision 2 ([Reference 1](#)). The calculated USE values were compared to the 50 ft-lbs acceptance criterion. If any of the materials had produced an EOL USE below 50 ft-lbs, then an equivalent margins analysis would have been required. If the materials are projected to have an EOL USE of 50 ft-lbs or higher, then no additional effort is required.

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

As discussed above, P-T Limits and USE are within the scope of License Renewal as a TLAA. Operation of the reactor vessel under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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, no changes are necessary to any existing aging management programs and the TLAA remains valid for EPU conditions as discussed in Results below.

2.1.2.2.5 Results

Applicability of Heatup and Cooldown P-T Limit Curves

LR [Table 2.1.2-6](#), Summary of Limiting ART Values for Reactor Vessel, contains the comparison of projected ART values under EPU conditions to the pre-EPU 55 EFPY bases ([Reference 7](#)). ART values were projected for 55 EFPY for the 1/4T and 3/4T locations. Those ART values reflect operation to 60 years. The ART values that form the basis for the pre-EPU P-T Limits are lower than the ART values projected for 55 EFPY that account for the effects of the EPU. That difference is the result of an increased CF value for the reactor vessel surveillance plate, M-605-1, obtained using revised surveillance capsule fluence values. The existing P-T limits are projected to remain valid for approximately 47 EFPY (i.e., the limits will bound the EPU limits through that time). This necessitates a change in the period of applicability for the P-T limit curves in the plant Technical Specifications. In accordance with the requirements of 10 CFR 50 Appendix H, it will be necessary to reassess the period of applicability in conjunction with the next reactor vessel surveillance capsule assessment.

USE

LR [Table 2.1.2-7](#), Projected 60 Year USE Values for the Beltline Region Materials, contains the results of the USE projections. These results were calculated using the EPU 1/4T fluence projections for 55 EFPY. All of the beltline materials are projected to have a USE value greater than 50 ft-lb through EOL (55 EFPY) in compliance with 10 CFR 50 Appendix G. As shown in LR [Table 2.1.2-7](#), the intermediate-to-lower shell girth weld, 101-171, has the lowest projected USE of 71 ft-lbs at 55 EFPY. Since USE values greater than 50 ft-lb were determined for EOL, it was not necessary to perform an equivalent margins analysis.

Inlet Temperature

The T_{cold} will be maintained at 551°F, which is within the acceptance limits of above 525°F and below 590°F.

2.1.2.3 Conclusion

FPL has evaluated the effects of the proposed EPU on the P-T limit curves and USE for St. Lucie Unit 2 and concludes that it has adequately addressed changes in neutron fluence and their

effects on P-T limits and USE. FPL further concludes that St. Lucie Unit 2 has demonstrated the validity of the P-T limits for operation under the proposed EPU conditions. Based on this, FPL concludes that the P-T limits will continue to meet the requirements of 10 CFR 50 Appendix G, and 10 CFR 50.60 and will enable St. Lucie Unit 2 to comply with GDC-14 and GDC-31 in this respect following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU is acceptable with respect to the P-T limits and USE.

2.1.2.4 References

1. U.S. Nuclear Regulatory Commission, Regulatory Guide 1.99, Rev. 2, Radiation Embrittlement of Reactor Vessel Materials, May 1988.
2. Westinghouse Document, WCAP-16083-NP-A, Rev. 0, Benchmark Testing of the FERRET Code for Least Squares Evaluation of Light Water Reactor Dosimetry, May 2006.
3. U.S. Nuclear Regulatory Commission, Regulatory Guide 1.190, Calculation and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence, March 2001.
4. NRC Reactor Vessel Integrity Database, Version 2.0.1 (RVID-2), July 6, 2000.
5. Florida Power and Light Letter, L-97-223, Rev. 0, 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.
6. Westinghouse Report, WCAP-15040, Rev. 0, Analysis of Capsule 263⁰ from the Florida Power & Light Company St. Lucie Unit 2 Reactor Vessel Radiation Surveillance Program, April 1998.
7. Florida Power and Light Letter, L-2007-198, Rev. 0, St. Lucie Unit 2 Docket No. 50-389 Proposed License Amendment Update PT Curve and LTOP for 55 EFPY, January 23, 2008.

Table 2.1.2-1
60 Year Peak Vessel Fluence Values at Surface, 1/4T and 3/4T

Basis	EFPY	Fluence at Clad-Base Metal Interface (n/cm², E > 1.0 MeV)	1/4 T Fluence (n/cm², E > 1.0 MeV)	3/4 T Fluence (n/cm², E > 1.0 MeV)
Pre-EPU	55	4.56E+19	2.72E+19	9.66E+18
EPU	55	4.42E+19	2.634E+19	9.358E+18

Table 2.1.2-2
Vessel Beltline Material Property Input for ART Projections

Beltline Materials	Code Number	Initial RT _{NDT}	Chemistry Factor	
			Position 1.1 ⁽¹⁾	Position 2.1 ⁽¹⁾
Intermediate shell plate	M-605-1	30°F	74.15	93.1
Intermediate shell plate	M-605-2	10°F	91.50	---
Intermediate shell plate	M-605-3	0°F	74.15	93.1 ⁽²⁾
Lower shell plate	M-4116-1	20°F	37.0	---
Lower shell plate	M-4116-2	20°F	44.0	---
Lower shell plate	M-4116-3	20°F	44.0	---
Intermediate to lower shell girth weld	101-171 (Heats 83637 & 3P7317)	-50°F	40.05	---
Intermediate shell axial weld	101-124 A/C (Heat 83642)	-56°F ⁽³⁾	36.35	---
Intermediate shell axial weld repair	101-124 C (Heat 83637)	-50°F	34.05	---
Lower shell axial weld	101-142 A/C (Heat 83637)	-50°F	34.05	---
Notes: 1. Position 1.1 and 2.1 values determined in accordance with Reference 1 . 2. M-605-3 is same heat as surveillance plate. 3. Generic value for CE welds.				

Table 2.1.2-3
Chemistry Factor Determination for Surveillance Plate and Weld

Capsule Location	Material and Orientation	Measured Shift (°F)	Neutron Fluence (n/cm²)	Fluence Factor	FF²	Shift x FF
83°	M-605-1 ⁽¹⁾	29.9	1.47E+18	0.498325	0.248328	14.9
83°	M-605-1 ⁽²⁾	45.11	1.47E+18	0.498325	0.248328	22.5
263°	M-605-1 ⁽¹⁾	103.12	1.05E+19	1.013650	1.027487	104.5
Best Fit CF for Plate M-605-1 = 93.1						
83°	Surveillance weld	13.8	1.47E+18	0.498325	0.248328	6.9
263°	Surveillance weld	26	1.05E+19	1.013650	1.027487	26.4
Best Fit CF for Surveillance Weld = 26.0						
Notes: 1. Transverse plate orientation. 2. Longitudinal plate orientation.						

Table 2.1.2-4
Chemistry Factors and Adjustments for Vessel Plates and Welds

Material	Copper and Nickel Content (%)	Chemistry Factor⁽¹⁾	Chemistry Factor Ratio	Chemistry Factor from Surveillance Data	Best Fit CF⁽²⁾
M-605-1	0.11, 0.61	74.15	1.0 ⁽³⁾	93.1 ⁽⁴⁾	93.1
M-605-2	0.13, 0.62	91.50	n/a	n/a	n/a
M-605-3	0.11, 0.61	74.15	1.0 ⁽³⁾	93.1 ⁽⁴⁾	93.1
M-4116-1	0.06, 0.57	37.0	n/a	n/a	n/a
M-4116-2	0.07, 0.60	44.0	n/a	n/a	n/a
M-4116-3	0.07, 0.60	44.0	n/a	n/a	n/a
101-124 A/C	0.05, 0.09	36.35	n/a	n/a	n/a
101-124 C Repair	0.05, 0.07	34.05	n/a	n/a	n/a
101-142 A/C	0.05, 0.07	34.05	n/a	n/a	n/a
Surveillance weld	0.05, 0.07 ⁽⁵⁾	n/a	1.0 ⁽³⁾	26.0 ⁽⁴⁾	26.0
101-171 weld	0.07, 0.07	40.05	n/a	n/a	n/a

Notes:

1. Values are from **Reference 4** and **5**.
2. The best fit of the CF is the product of the CF ratio and the CF from surveillance data.
3. Ratio is 1.0 based on equivalent copper and nickel.
4. Value is from **Table 2.1.2-3**.
5. Values are from **Reference 7**.

Table 2.1.2-5
Best Estimate Copper Content and Initial USE Values for the Reactor Vessel

Material Description	Material Heat Number	Copper (%)	Initial USE
Intermediate shell plate M-605-1	A-8490-2	0.11	105 ft-lb
Intermediate shell plate M-605-2	B-3416-2	0.13	113 ft-lb
Intermediate shell plate M-605-3	A-8490-1	0.11	113 ft-lb
Lower shell plate M-4116-1	B-8307-2	0.06	91 ft-lb
Lower shell plate M-4116-2	A-3131-1	0.07	105 ft-lb
Lower shell plate M-4116-3	A-3131-2	0.07	100 ft-lb
Intermediate-to-lower shell girth weld 101-171	83637 & 3P7317	0.07	96 ft-lb
Intermediate shell axial weld 101-124 A/C	83642	0.05	116 ft-lb
Intermediate shell axial weld 101-124 C Repair	83637	0.05	136 ft-lb
Lower shell axial weld 101-142 A/C	83637	0.05	136 ft-lb

Table 2.1.2-6
Summary of Limiting ART Values for Reactor Vessel

EFPY	1/4T Limiting ART	3/4T Limiting ART
Lower Shell Axial Welds, 3-203 A/C		
55 (EPU) ^(1,2)	164°F	138°F
55 (pre-EPU) ^(1,3)	160°F	137°F
Notes: 1. 55 EFPY (EPU) is the EPU-adjusted projection for a time corresponding approximately to 60 years. 55 (pre-EPU) is the pre-EPU projection for the existing P-T limit curves (Reference 7). 2. Limiting plate M-605-1 3. Limiting plates M-605-1 and M-605-2		

Table 2.1.2-7
Projected 60 Year USE Values for the Beltline Region Materials

Reactor Vessel Beltline Material	Copper Weight %	1/4T EOL Fluence (E+19 n/cm²)	Unirradiated USE (ft-lb)	Projected USE Decrease⁽¹⁾ (%)	Projected EOL USE (ft-lb)
M-605-1	0.11	2.634	105	25.2	79
M-605-2	0.13	2.634	113	27.6	82
M-605-3	0.11	2.634	113	25.2	85
M-4116-1	0.06	2.634	91	19.2	74
M-4116-2	0.07	2.634	105	20.4	84
M-4116-3	0.07	2.634	100	20.4	80
101-171	0.07	2.634	96	26.4	71
101-124 A/C	0.05	2.634	116	24	88
101-124 C repair	0.05	2.634	136	24	103
101-142 A/C	0.05	2.634	136	24	103
Note: 1. Calculated in accordance with RG 1.99, Revision 2, Position 1.2 (Reference 1).					

2.1.3 Pressurized Thermal Shock

2.1.3.1 Regulatory Evaluation

The pressurized thermal shock (PTS) evaluation provides a means for assessing the susceptibility of the reactor vessel beltline materials to PTS events to ensure that adequate fracture toughness is provided for supporting reactor operation. The Florida Power and Light (FPL) review covered the PTS methodology and the calculations for 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:

- General Design Criteria (GDC)-14, insofar as it requires that the reactor coolant pressure boundary (RCPB) be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture;
- 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 non-brittle manner and the probability of a rapidly propagating fracture is minimized; and
- 10 CFR 50.61, insofar as it sets fracture toughness criteria for protection against PTS events.

Specific review criteria are contained in the Standard Review Plan (SRP) Section 5.3.2, and other guidance is provided in Matrix 1 of Review Summary (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971, and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies these requirements and is in compliance with the General Design Criteria (GDC) as discussed in UFSAR Section 3.1.

The specific GDC for the reactor vessel material surveillance program are as follows:

- GDC-14 is described in UFSAR Section 3.1.14 Criterion 14 – Reactor Coolant Pressure Boundary.

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.

Reactor coolant system (RCS) components are designed to meet the requirements of the ASME Code, Section III. To establish operating pressure and temperature limitations during startup and shutdown of the RCS, the fracture toughness rules defined in Appendix G of the ASME Code, Section III, are followed. Quality control, inspection, and testing as required by this standard and allowable reactor pressure-temperature operation ensure the integrity of the RCS.

- GDC-31 is described in UFSAR Section 3.1.31 Criterion 31 – Fracture Prevention of Reactor Coolant Pressure Boundary.

The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions (1) the boundary behaves in a non-brittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing and postulated accident conditions and the uncertainties in determining (1) material properties, (2) the effects of irradiation on material properties, (3) residual, steady-state and transient stresses, and (4) size of flaws.

RCPB components are designed and constructed in accordance with ASME Code, Section III, and comply with the test and inspection requirements of this code. These test and inspection requirements assure that flaw sizes are limited so the probability of failure by rapid propagation is extremely small. Particular emphasis is placed on the quality control applied to the reactor vessel, specifically on which tests and inspections exceeding ASME Code requirements are performed. The tests and inspections performed on the reactor vessel are summarized in UFSAR Sections 5.2 and 5.3.

Carbon and low-alloy steel materials that form part of the RCPB are tested for fracture toughness to the acceptance criteria and requirements of 10 CFR 50 Appendix G (see UFSAR Section 5.2).

The requirements in 10 CFR 50.61 provide rules for protection against PTS events for pressurized water reactors. Licensees are required to perform an assessment of the projected values of the maximum nil ductility reference temperature (RT_{PTS}) whenever a significant change occurs in projected values of RT_{PTS} , or upon request for a change in the expiration date for the operation of the facility.

The calculated RT_{PTS} values that bound the 60-year period of operation for the reactor vessel are less than the 10 CFR 50.61(b)(2) screening criteria of 270°F for intermediate and lower shells and 300°F for the circumferential welds. Based upon the revised calculations, additional measures will not be required for the reactor vessel during the license renewal period.

The analysis associated with PTS has been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii). Compliance with the guidance presented in Regulatory Guides (RG) 1.154 Format and Content of Plant Specific Pressurized Thermal Shock Safety Analysis Reports for Pressurized Water Reactors and RG 1.190 Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence is discussed in LR [Section 2.1.3.2](#) below.

In addition to the licensing basis described in the UFSAR, PTS was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. PTS is a time-limited aging analysis (TLAA) and is discussed in SER Section 4.2.2 and Chapter 18 of the UFSAR. The analysis to confirm that the reactor vessel

beltline materials remain under the PTS screening criteria of 10 CFR 50.61 through the period of extended operation are discussed in SER Section 4.2.2.

2.1.3.2 Technical Evaluation

2.1.3.2.1 Introduction

PTS is discussed in UFSAR Section 18.3.1.1, Pressurized Thermal Shock and in the St. Lucie Units 1 and 2 License Renewal SER, NUREG-1779 Section 4.2.2, Pressurized Thermal Shock ([Reference 1](#)). In addition, UFSAR Section 18.2.11 describes the reactor vessel integrity program, designed to manage reactor vessel embrittlement, which encompasses the following sub-programs: (1) reactor vessel surveillance capsule removal and evaluation, (2) fluence and uncertainty calculations, (3) monitoring effective full power years (EFPY), and (4) pressure-temperature limit curves.

Reactor vessel integrity is potentially impacted by any change in plant parameters that affect neutron fluence levels or temperature/pressure transients. The changes in neutron fluence resulting from the EPU have been evaluated to determine the impact on reactor vessel integrity. The assessment presented herein focuses on the end-of-license (EOL) (60 years) PTS evaluation. The effect of the EPU on the reactor vessel surveillance program is discussed in LR [Section 2.1.1](#) Reactor Vessel Materials Surveillance Program, and the effect of the EPU on the reactor vessel pressure – temperature (P-T) limits and upper shelf energy (USE) is discussed in LR [Section 2.1.2](#) Pressure – Temperature Limits and Upper Shelf Energy.

2.1.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters

The EPU normally would result in an increase to the neutron fluence on the reactor pressure vessel. However, as shown in LR [Table 2.1.3-1](#), 60-Year Peak Vessel Fluence Values, there was actually a slight decrease of the projected 60-year vessel fluence because of the conservative basis for the current fluence estimate. The slight decrease occurred because the EPU fluence analysis used more recent core power histories that replaced conservative projections from the current 60-year fluence analysis, while adding a 10 percent factor of conservatism to the EPU fluence projections beginning with Cycle 23. The effect of the projected changes in operating conditions on reactor vessel integrity was evaluated. The vessel fluence projections for the reactor vessel are presented in LR [Table 2.1.3-1](#). The 0° azimuth corresponds to the peak fluence locations for the base metal, circumferential weld, and the axial welds. Vessel fluence is provided for the vessel inside surface (clad-base metal interface) location. The effect of the EPU on the EOL RT_{PTS} projection was evaluated. Vessel fluence projections to 60 years that consider the EPU are compared to the current values in LR [Table 2.1.3-1](#) at the peak location at the clad-base metal interface.

Neutron fluence values are used to calculate the EOL RT_{PTS} using the guidance from 10 CFR 50.61. The projected fluence values at 55 EFPY levels are provided in LR [Table 2.1.3-1](#). The neutron fluence was determined using an NRC approved methodology ([Reference 2](#)) that follows the guidance and meets the requirements of RG 1.190 ([Reference 3](#)), including consideration of dosimetry measurements from the tested surveillance capsules. The irradiation

temperature for the reactor vessel beltline corresponds to the reactor vessel inlet temperature, T_{cold} . T_{cold} at full power is expected to change from 549°F to 551°F for the EPU. Irradiation temperature affects the degree of material embrittlement; a higher temperature is expected to reduce the degree of embrittlement and a lower temperature is expected to increase the degree of embrittlement. The embrittlement prediction methodology of 10 CFR 50.61 is from RG 1.99 Radiation Embrittlement of Reactor Vessel Materials, Revision 2 (Reference 5), which is based on an irradiation temperature between 525°F and 590°F. The temperature will remain within the applicable range, and the net effect will be to slightly lower the degree of irradiation embrittlement. The overall effect of this temperature change on vessel integrity, therefore, is small but beneficial.

10 CFR 50.61 uses values of chemistry factors (CF) and fluence factors (FF) to determine the transition temperature shift, ΔRT_{PTS} , for each of the beltline materials. The Position 1.1 CF and initial RT_{NDT} values used in this evaluation are presented in LR Table 2.1.3-2, Vessel Beltline Material Property Input for RT_{PTS} Projections. The initial RT_{NDT} values are the unirradiated reference temperature for each material, as reported in Reactor Vessel Integrity Database Version 2.0 (RVID-2) (Reference 4), and were used together with the ΔRT_{PTS} and margin to determine the EOL RT_{PTS} . The CF values were determined following Position 1.1 or 2.1 of Reference 5. Position 1.1 uses the best-estimate copper and nickel contents for the beltline materials to determine the CF. The Position 1.1 CF values were reported in RVID-2 and updated in Reference 6. Position 2.1 determines CF values based on the reactor vessel surveillance capsule results. The post-irradiation measurements for the surveillance plate M-605-1 and the surveillance weld from Reference 7 and the updated capsule fluence values are shown in LR Table 2.1.3-3, Chemistry Factor Determination for Surveillance Plate and Weld. LR Table 2.1.3-4, Chemistry Factors and Adjustments for Vessel Plates and Welds shows the ratio analysis as prescribed in Reference 5 for adjusting the post-irradiation surveillance results by the ratio of the chemistry factors to the vessel beltline plates M-605-1 and M-605-3.

Assumptions

RT_{PTS} projections were based on vessel fluence values at 60 years (approximately 55 EFPY) that made conservative allowance for the EPU to accommodate future changes in core power distribution.

Acceptance Criteria

Acceptance criteria require that the RT_{PTS} values for all beltline materials projected based on the changes resulting from the EPU shall not exceed the PTS screening criteria as given in 10 CFR 50.61. Specifically, the RT_{PTS} values of the plates and axial welds shall not exceed 270°F, and the girth weld RT_{PTS} values shall not exceed 300°F for operation through 60 years (55 EFPY). St. Lucie Unit 2 meets these screening criteria.

For T_{cold} , the acceptance criteria are provided in RG 1.99, Revision 2, which is the basis for 10 CFR 50.61, and states: "The procedures are valid for a nominal irradiation temperature of 550°F. Irradiation below 525°F should be considered to produce greater embrittlement, and irradiation above 590°F may be considered to produce less embrittlement." Thus, T_{cold} must be between 525°F and 590°F for the equations and methodology of 10 CFR 50.61 to remain valid.

St. Lucie Unit 2 meets these acceptance criteria for temperature conditions as described above in the input parameters section.

2.1.3.2.3 Description of Analyses and Evaluations

PTS is a postulated event that can challenge reactor vessel integrity under one or more of the following conditions:

- Severe overcooling of the inside surface of the vessel wall followed by cold repressurization,
- Significant degradation of vessel material toughness caused by radiation embrittlement, and
- Presence of a critical-size defect in the vessel wall.

The vessel integrity concern arises if a transient is severe enough to initiate a crack in the beltline region of a reactor vessel where fracture resistance is reduced because of neutron irradiation, and there is sufficient driving force to cause the propagation of the crack through the vessel wall.

In 1985, the NRC issued a formal rule on PTS. It established screening criteria based on the projected degree of vessel embrittlement in terms of RT_{PTS} . The screening criteria values were set using conservative assumptions for beltline axial welds, plates, forgings, and circumferential weld seams. Licensees have been required to evaluate vessel embrittlement for all pressurized water reactor (PWR) vessels in accordance with the criteria through the end of life.

The NRC subsequently amended the procedure for calculating radiation embrittlement. The revised PTS rule was published in the Federal Register, December 19, 1995, with an effective date of January 18, 1996. This amendment made the procedure for calculating RT_{PTS} values consistent with the methods given in RG 1.99, Revision 2.

The PTS rule establishes the following requirements for all domestic, operating PWRs:

- For each PWR that has had an operating license issued, the licensee will have projected values of RT_{PTS} accepted by the NRC for each reactor vessel beltline material for the end of license fluence of the material.
- The assessment of RT_{PTS} must use the calculation procedures given in the PTS rule and must specify the bases for the projected value of RT_{PTS} for each beltline material. The report must specify the copper and nickel contents and the fluence values used in the calculation for each beltline material.
- This assessment must be updated whenever there is a significant change in projected values of RT_{PTS} , or upon the request for a change in the expiration date for operation of the facility. Changes to RT_{PTS} values are significant if either the previous value or the current value, or both values, exceed the screening criteria prior to the expiration of the operating license, including any license renewal term, if applicable for the plant.
- The RT_{PTS} screening criteria values for the beltline region are:
 - 270°F for plates, forgings, and axial weld materials, and
 - 300°F for circumferential weld materials.

- RT_{PTS} must be calculated for each vessel beltline material using a fluence value, f , which is the end of license fluence for the material. Equation 1 is used to calculate values of RT_{PTS} for each weld and plate or forging in the reactor vessel beltline.

$$RT_{PTS} = RT_{NDT(U)} + M + \Delta RT_{PTS} \quad \text{Equation 1}$$

Where,

$RT_{NDT(U)}$ = Reference temperature for a reactor vessel material in the pre-service or unirradiated condition

M = Margin to be added to account for uncertainties in the values of $RT_{NDT(U)}$, copper and nickel contents, fluence and calculational procedures.

M was determined using Equation 2.

$$M = 2\sqrt{\sigma_U^2 + \sigma_\Delta^2} \quad \text{Equation 2}$$

σ_U is the standard deviation for $RT_{NDT(U)}$.

σ_Δ is the standard deviation for ΔRT_{PTS} .

Where,

$\sigma_U = 0^\circ\text{F}$ when $RT_{NDT(U)}$ is a measured value

$\sigma_U = 17^\circ\text{F}$ when $RT_{NDT(U)}$ is based on a generic value of -56°F for CE welds

For plates and forgings:

$\sigma_\Delta = 17^\circ\text{F}$ when surveillance capsule data are not used

$\sigma_\Delta = 8.5^\circ\text{F}$ when surveillance capsule data are used

For welds:

$\sigma_\Delta = 28^\circ\text{F}$ when surveillance capsule data are not used

$\sigma_\Delta = 14^\circ\text{F}$ when surveillance capsule data are used

The value for σ_Δ does not have to exceed one-half of ΔRT_{NDT} .

ΔRT_{PTS} is the mean value of the transition temperature shift due to irradiation and was calculated using Equation 3.

$$\Delta RT_{PTS} = CF * f^{[0.28 - 0.1 \log(f)]} \quad \text{Equation 3}$$

CF ($^\circ\text{F}$) is the chemistry factor, a function of copper and nickel content determined from Tables 1 and 2 of 10 CFR 50.61. CF values determined in this way are identified in the tables as "Position 1.1 Chemistry Factor" using the nomenclature from Reference 5.

" f " is the calculated neutron fluence, in units of 10^{19} n/cm^2 ($E > 1.0 \text{ MeV}$), at the clad-base-metal interface on the inside surface of the vessel. This is the location where the

vessel material receives the highest fluence. The 55 EFPY (EOL) fluence projections were used in calculating the RT_{PTS} .

To verify that RT_{PTS} for each vessel beltline material is a bounding value for the specific reactor vessel, plant-specific information that could affect the level of embrittlement is considered. For the calculation, this information included, but was not limited to, the reactor vessel operating temperature and any related surveillance program results. Results from the plant-specific surveillance program are integrated into the RT_{PTS} estimate if the plant-specific surveillance data is deemed credible. Material-specific values of CF for surveillance materials are determined from Equation 4.

$$CF = \frac{\sum [A_i * f_i^{(0.28-0.10 \log f_i)}]}{\sum [f_i^{(0.56-0.20 \log f_i)}]}$$

Equation 4

In Equation 4, “ A_i ” is the measured value of ΔRT_{NDT} and “ f_i ” is the fluence for each surveillance data point. If there is clear evidence that the copper and nickel content of the surveillance weld differed from the vessel weld, i.e., differed from the average for the weld wire heat number associated with the vessel weld and the surveillance weld, the measured values of RT_{NDT} would be adjusted for differences in copper and nickel content by multiplying them by the ratio of the CF for the vessel material to that for the surveillance weld. CF values determined using Equation 4 are identified in LR Table 2.1.3-4 as “Best Fit CF” and in the text as “Position 2.1 Chemistry Factor.”

RT_{PTS} values calculated for the reactor vessel beltline materials at fluence values ($E > 1.0$ MeV) projected for 60 years (55 EFPY) are presented in LR Table 2.1.3-5, RT_{PTS} Calculations for Beltline Region Materials after 55 EFPY. The highest projected value of RT_{PTS} is 175°F and corresponds to the intermediate shell plate M-605-1.

As part of the PTS assessment, consideration was given to the reactor vessel surveillance data in the determination of the vessel beltline CF values for plates M-605-1 and M-605-3. The surveillance data were determined to be credible and were applied to the calculation of the RT_{PTS} values. The CF adjustments based on surveillance data are summarized in LR Tables 2.1.3-3 and 2.1.3-4.

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

As discussed above, P-T Limits and USE are within the scope of License Renewal as a TLAA. Operation of the reactor vessel under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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, no changes are necessary to any existing aging management programs and the TLAA remains valid for EPU conditions as discussed in Results below.

2.1.3.2.5 Results

An evaluation of the impact of the EPU on PTS was performed. RT_{PTS} projections were made for all the beltline materials of the reactor vessel under EPU conditions in accordance with 10 CFR 50.61. The results of these calculations are presented in LR [Table 2.1.3-5](#). The limiting material at 60 years (55 EFPY) is the intermediate shell plate M-605-1. The limiting value of RT_{PTS} is 175°F. This result is below the RT_{PTS} screening criterion of 270°F for axially-oriented welds and plates, and, therefore, the EPU will not have a significant effect on the projected RT_{PTS} . Based on these results, all RT_{PTS} values are projected to remain below the NRC screening criteria through 60 years (55 EFPY).

2.1.3.3 Conclusion

FPL has reviewed the evaluation of the effects of the proposed EPU on the PTS and concludes that it has adequately addressed changes in neutron fluence and their effects on PTS. FPL further concludes that it has demonstrated that it will continue to meet its current licensing basis with respect to the requirements of GDC-14, GDC-31, and 10 CFR 50.61 following implementation of the proposed EPU. In consideration of the results obtained, performing an analysis in accordance with the requirements of RG 1.154 is not applicable. Therefore, FPL finds the proposed EPU acceptable with respect to PTS.

2.1.3.4 References

1. U.S. Nuclear Regulatory Commission, NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2 Docket Nos. 50-335 and 50-389, September 2003.
2. Westinghouse WCAP-16083-NP-A, Rev. 0, Benchmark Testing of the FERRET Code for Least Squares Evaluation of Light Water Reactor Dosimetry, May 2006.
3. U.S. Nuclear Regulatory Commission, Regulatory Guide 1.190, Calculation and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence, March 2001.
4. NRC Reactor Vessel Integrity Database, Version 2.0.1 (RVID-2), July 6, 2000.
5. U.S. Nuclear Regulatory Commission, Regulatory Guide 1.99 Rev. 2, Radiation Embrittlement of Reactor Vessel Materials, May 1988.
6. Florida Power and Light Letter, L-97-223, Rev. 0, 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.
7. Westinghouse Report, WCAP-15040, Rev. 0, Analysis of Capsule 263⁰ from the Florida Power & Light Company St. Lucie Unit 2 Reactor Vessel Radiation Surveillance Program, April 1998.

8. Florida Power and Light Letter, L-2007-198, Rev. 0, St. Lucie Unit 2 Docket No. 50-389
Proposed License Amendment Update PT Curve and LTOP for 55 EFPY, January 23, 2008.

Table 2.1.3-1
60-Year Peak Vessel Fluence Values

Basis	EFPY	Fluence at Clad-Base Metal Interface (n/cm², E > 1.0 MeV)
Pre-EPU	55	4.56E+19
EPU	55	4.42E+19

Table 2.1.3-2
Vessel Beltline Material Property Input for RT_{PTS} Projections

Beltline Materials	Code Number	Initial RT_{NDT}	Position 1.1⁽¹⁾ Chemistry Factor	Position 2.1⁽¹⁾ Chemistry Factor
Intermediate shell plate	M-605-1	30°F	74.15	93.1
Intermediate shell plate	M-605-2	10°F	91.50	-
Intermediate shell plate	M-605-3	0°F	74.15	93.1
Lower shell plate	M-4116-1	20°F	37.0	-
Lower shell plate	M-4116-2	20°F	44.0	-
Lower shell plate	M-4116-3	20°F	44.0	-
Intermediate to lower shell girth weld	101-171 (Heats 83637 & 3P7317)	-50°F	40.05	-
Intermediate shell axial weld	101-124 A/C (Heat 83642)	-56°F ⁽²⁾	36.35	-
Intermediate shell axial weld repair	101-124 C (Heat 83637)	-50°F	34.05	-
Lower shell axial weld	101-142 A/C (Heat 83637)	-50°F	34.05	-
Notes: 1. Position 1.1 and 2.1 values determined in accordance with Reference 5 . 2. Generic value for CE welds.				

Table 2.1.3-3
Chemistry Factor Determination for Surveillance Plate and Weld

Capsule Location	Material and Orientation	Measured Shift (°F)	Neutron Fluence (n/cm²)	Fluence Factor	FF²	Shift x FF
83°	M-605-1 ⁽¹⁾	29.9	1.47E+18	0.498325	0.248328	14.9
83°	M-605-1 ⁽²⁾	45.11	1.47E+18	0.498325	0.248328	22.5
263°	M-605-1 ⁽¹⁾	103.12	1.05E+19	1.013650	1.027487	104.5
Best Fit CF for Plate M-605-1 = 93.1						
83°	Surveillance weld	13.8	1.47E+18	0.498325	0.248328	6.9
263°	Surveillance weld	26	1.05E+19	1.013650	1.027487	26.4
Best Fit CF for Surveillance Weld = 26.0						
Notes: 1. Transverse plate orientation. 2. Longitudinal plate orientation.						

Table 2.1.3-4
Chemistry Factors and Adjustments for Vessel Plates and Welds

Material	Copper and Nickel Content (%)	Chemistry Factor	Chemistry Factor Ratio	Chemistry Factor from Surveillance Data	Best Fit CF⁽¹⁾
M-605-1	0.11, 0.61	74.15 ⁽²⁾	1.0 ⁽³⁾	93.1 ⁽⁴⁾	93.1
M-605-2	0.13, 0.62	91.50 ⁽²⁾	-	-	-
M-605-3	0.11, 0.61	74.15 ⁽²⁾	1.0 ⁽³⁾	93.1 ⁽⁴⁾	93.1
M-4116-1	0.06, 0.57	37.0 ⁽²⁾	-	-	-
M-4116-2	0.07, 0.60	44.0 ⁽²⁾	-	-	-
M-4116-3	0.07, 0.60	44.0 ⁽²⁾	-	-	-
101-124 A/C	0.05, 0.09	36.35 ⁽²⁾	-	-	-
101-124 C Repair	0.05, 0.07	34.05 ⁽²⁾	-	-	-
101-142 A/C	0.05, 0.07	34.05 ⁽²⁾	-	-	-
Surveillance weld	0.05, 0.07 ⁽⁵⁾	-	1.0 ⁽³⁾	26.0 ⁽⁴⁾	26.0
101-171 weld	0.07, 0.07	40.05 ⁽²⁾	-	-	-
Notes: 1. The best fit of the CF is the product of the CF ratio and the CF from surveillance data. 2. Value is from Reference 4 and 6 . 3. Ratio is 1.0 based on equivalent copper and nickel. 4. Value is from LR Table 2.1.3-3 . 5. Values are from Reference 8 .					

Table 2.1.3-5
RT_{PTS} Values for Beltline Materials after 55 EFPY⁽¹⁾

Reactor Vessel Beltline Material	CF ⁽²⁾ (°F)	Fluence ⁽³⁾ (E19 n/cm ²)	FF	ΔRT _{PTS} (°F)	RT _{NDT} ⁽⁴⁾ (°F)	σ _U (°F)	σ _Δ (°F)	M ⁽⁵⁾ (°F)	RT _{PTS} ⁽⁶⁾ (°F)
M-605-1	93.1	4.42	1.377404	128	30	0	8.5	17	175
M-605-2	91.5	4.42	1.377404	126	10	0	17	34	170
M-605-3	93.1	4.42	1.377404	128	0	0	8.5	17	145
M-4116-1	37	4.42	1.377404	51	20	0	17	34	105
M-4116-2	44	4.42	1.377404	61	20	0	17	34	115
M-4116-3	44	4.42	1.377404	61	20	0	17	34	115
101-171	40.05	4.42	1.377404	55	-50	0	27.5	55	60
101-124 A/C	36.35	4.42	1.377404	50	-56	17	25	60.5	55
101-124 C	34.05	4.42	1.377404	47	-50	0	23.5	47	44
101-142 A/C	34.05	4.42	1.377404	47	-50	0	23.5	47	44

Note:

1. 60 years corresponds to approximately 55 EFPY.
2. Higher of "Chemistry Factor" and "Best Fit CF" value is from LR TTable 2.1.3-4.
3. From LR Table 2.1.3-1.
4. From LR Table 2.1.3-2.
5. Margin (M) from Equation 2.
6. From Equation 1.

2.1.4 Reactor Internal and Core Support Materials

2.1.4.1 Regulatory Evaluation

The reactor internals and core supports 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 reactor coolant system (RCS)). The Florida Power and Light (FPL) review covered the materials' specifications and mechanical properties, welds, weld controls, nondestructive examination procedures, corrosion resistance, and susceptibility to degradation.

The NRC's acceptance criteria for reactor internal and core support materials are based on General Design Criterion (GDC)-1 and 10 CFR 50.55a for material specifications, controls on welding, and inspection of reactor internals and core supports.

Specific review criteria are contained in Standard Review Plan (SRP) Section 4.5.2, and WCAP-14577, Rev. 1-A, License Renewal Evaluation: Aging Management for Reactor Internals ([Reference 1](#)). WCAP-14577 does not apply in its entirety to Combustion Engineering (CE) designed internals; therefore only the applicable criteria are applied to St. Lucie Unit 2.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conform with the NRC GDC for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDC for the reactor vessel internal (RVI) and core support structure materials is as follows:

- GDC-1 is described in UFSAR Section 3.1.1 Criterion 1 – Quality Standards and Records.

Structures, systems and components important to safety shall be designed, fabricated, erected and tested to quality standards commensurate with the importance of the safety functions to be performed. Where generally recognized codes and standards are used, they shall be identified and evaluated to determine their applicability, adequacy and sufficiency and shall be supplemented or modified as necessary to assure a quality product in keeping with the required safety function. A quality assurance program shall be established and implemented in order to provide adequate assurance that these structures, systems, and components will satisfactorily perform their safety functions. Appropriate records of the design, fabrication, erection and testing of structures, systems and components important to safety shall be maintained by or under the control of the nuclear power unit licensee throughout the life of the unit.

SSCs in the facility are classified according to their relative importance to safety. Those SSCs vital to safety such that their failure might cause or result in an uncontrolled release of an excessive amount of radioactive material are designated seismic Category I. These SSCs and SSCs of lesser importance to safety are designed, fabricated, erected and tested according to

the provisions of recognized codes and quality standards. Discussions of the applicable codes, standards, records and the quality assurance program used to implement and audit the construction and operation processes were originally presented in UFSAR Sections 17.1 and 17.2; however, this information is now provided in FPL Quality Assurance Topical Report FPL-1. A complete set of facility structural, arrangement and system drawings is maintained under the control of FPL throughout the life of the plant. Quality assurance written data and comprehensive test and operating procedures are likewise assembled and maintained by FPL. The classification of seismic Category I SSCs is discussed in UFSAR Section 3.2.

UFSAR Section 4.5.2.1 states that the materials used in fabrication of the reactor internal structures are primarily Type 304 stainless steel. Welded connections are used where feasible; however, in locations where mechanical connections are required, structural fasteners are used which are designed to remain captured in the event of a single failure. Structural fastener material is typically a high strength austenitic stainless steel; however, in the less critical applications, Type 316 stainless steel is employed. Hardfacing of Stellite material is used at wear points. The effect of irradiation on the properties of the materials is considered in the design of the reactor internal structures. Work hardening properties of austenitic stainless steels are not used.

The reactor vessel internals (RVI Inspection Program manages the aging effects of irradiation assisted stress corrosion cracking (IASCC), reduction in fracture toughness, loss of mechanical closure integrity of bolted joints, and dimensional changes due to void swelling.

WCAP-14577, Rev. 1-A presents additional information related to material specifications, weld control, NDE, corrosion resistance, and susceptibility to degradation. WCAP-14577 does not apply in its entirety to CE designed internals; therefore, only the applicable information was applied to St. Lucie Unit 2.

In addition to the licensing bases described in the UFSAR, the reactor internals and core support materials were evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.1.4 of the SER identifies that components of the RVI and core support materials are within the scope of License Renewal. Programs used to manage the aging effects associated with the RVI and core support materials are discussed in SER Sections 3.1.0.7 and 3.1.4 and Chapter 18 of the UFSAR.

2.1.4.2 Technical Evaluation

2.1.4.2.1 Introduction

This section summarizes the evaluations, and their results, of the potential materials degradation issues resulting from the effects of the EPU on the performance of the reactor internals and core support materials. UFSAR Section 4.5.2 describes the RVI structures and the materials used in their fabrication. The RVI components were primarily fabricated of wrought, cast, and welded

forms of austenitic stainless steels, with Type 304 being the most common grade. High-strength precipitation-hardening austenitic stainless steel and Type 316 stainless steel were used for the threaded structural fastener (TSF) applications. The number of fastener applications is limited because welded connections were used in the RVI components whenever possible. Stellite hardfacing was used at potential wear points in the RVIs, such as snubber spacer blocks on the core support barrel outside surface. A martensitic stainless steel, 13 percent chromium 4 percent nickel (13-4) was used for the upper internals holddown ring. There are no applications of nickel-base Alloy 600 or weld metals Alloys 82 or 182 in the RVI components. The flow skirt, which is Alloy 600, is welded to and considered part of the reactor vessel. There are no applications of high-strength, precipitation-hardening nickel-base alloys in the RVI components.

The primary objective of the RVI materials assessment was to ensure that the EPU conditions (primary coolant chemistry conditions, temperature, and neutron fluence) will not result in any new aging effects for the RVI component materials through the end of the current 60-year license period nor adversely impact how component aging will be managed by the aging management programs.

The relevant degradation (aging) mechanisms for the RVI and core support materials that were evaluated to assess the effects of the EPU were:

- A. Integrity of reactor vessel 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 TSFs.

An assessment of these aging mechanisms is provided in the following subsections.

2.1.4.2.2 Input Parameters, Assumptions, and Acceptance Criteria

EPU Service Conditions

A review of the EPU design parameters indicates the service conditions after EPU implementation will be as follows:

- The current RCS chemistry program coordinates boron and lithium concentrations during power operations to maintain a constant elevated temperature pH of approximately 7.2. The RCS lithium concentration is never allowed to exceed 4 parts per million (ppm).

- At the beginning of a cycle, pH is initially established at approximately 7.15. Lithium and boron are co-diluted during the start of the cycle until an equilibrium pH of 7.2 is established after approximately 4 effective full power days.
- For the EPU, materials were evaluated for the expected boron and lithium concentration ranges and a pH range of 6.9 to 7.4. The evaluated conditions bound plant operating conditions.
- A zinc injection program to reduce the radiation source term is currently in use. Soluble zinc is injected into the reactor coolant to maintain an RCS zinc concentration of 3 to 8 parts per billion (ppb) with a target value of 5 ppb.
- The concentration limits of hydrogen, dissolved oxygen, chlorides, sulfates, and other contaminants and dissolved solids will not be changed after EPU implementation.
- LR Table 2.1.4-1 shows an increase in the peak steady-state core outlet temperature to 607.9°F from the current temperature of 598°F, and the core inlet temperature increased to 551°F from the current value of 548.6°F.
- The maximum value of the long-term steady state temperature in the RVI components as the result of gamma heating is 735.8°F, which will be at a subsurface location in the horizontal plates of the core shroud near the mid-section of the core.
- A maximum neutron fluence after 60 years (54 effective full power years (EFPY)) at the inner surface of the core shroud will be 7.01×10^{22} n/cm² (E>1MeV). 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 end of 60-year license (54 EFPY) fluence will be 102 dpa. The EPU maximum fluence value for the 60-year EOL is presented in LR Table 2.1.4-2.

2.1.4.2.3 Description of Analyses and Evaluations

The effects of the EPU service conditions on the performance of the RVI component materials are discussed below.

Material Specifications, Weld Controls, and Nondestructive Testing (NDT) Inspections

The NRC staff's acceptance criteria for RVI and core support materials are based on GDC-1 and 10 CFR 50.55a for material specifications, controls on welding, and inspection of RVI and core supports. FPL's review covered the material specifications and mechanical properties, welds, weld controls, nondestructive examination procedures, corrosion resistance, and susceptibility to degradation. Specific review criteria are contained in SRP Section 4.5.2.

A. Fuel-Cladding Corrosion Effects

After EPU implementation, the reactor coolant chemistry program will continue to be coordinated as noted above. The chemistry limits are consistent with the guidance provided by the Electric Power Research Institute (EPRI) primary coolant guidelines (Reference 3). The EPRI guidelines were designed to prevent fuel-cladding corrosion effects, such as fuel deposit build-up and Alloy 600 primary water stress corrosion cracking (SCC); thus, there will not be an adverse effect

on fuel-cladding corrosion. Experience at operating pressurized water reactor (PWR) plants, as well as the **Reference 3** guidelines, indicates that an initial limit of 3.5 ppm lithium with controlled boron concentrations to maintain a pH of 6.9 to 7.4 has not produced undesirable material integrity issues in fuel cladding nor has zinc addition produced undesirable material integrity issues in fuel cladding. The slight increase in RCS temperatures will have an insignificant effect on corrosion.

B. Stress Corrosion Cracking (SCC)

Two degradation mechanisms that are operative in the austenitic stainless steel RVI and core support components are IGSCC and TGSCC. A sensitized microstructure and the presence of dissolved oxygen are required for the occurrence of IGSCC in austenitic stainless steels exposed to reactor coolant. TGSCC, which can occur in annealed stainless steels, requires the presence of halogens (e.g., chlorides) and dissolved oxygen. Both IGSCC and TGSCC in austenitic stainless steel are prevented by controlling the chemistry of the reactor coolant to ensure that the levels of contaminants present are below the levels required for IGSCC or TGSCC. The reactor coolant chemistry control program monitors the levels of contaminants in the coolant and ensures corrective actions are taken as required to minimize exposure to the contaminants. The EPU will not result in the introduction of any of the chemical contributors to IGSCC or TGSCC. In the absence of these chemical contributors to IGSCC or TGSCC, the minor increases in the core inlet and outlet temperatures resulting from the EPU will not affect the potential for IGSCC or TGSCC in the austenitic stainless steels in the RVI and core support components.

A high-strength, precipitation-hardening, austenitic stainless steel (A-286) is used for the TSFs in the RVI components. Although there have not been any occurrences of IGSCC in A-286 TSFs in CE plants, the potential for IGSCC at EPU conditions in A-286 was evaluated because of previous occurrences of SCC in A-286 fasteners in RVI applications. The available data indicated that the previous failures were the result of peak stresses, which were well above 100 ksi at the failure locations, and materials processing, which included significant cold-working during processing of the A-286 stainless steel fastener materials. The available data indicated that IGSCC is unlikely at peak stress levels of less than 100 ksi. The evaluation determined that peak stresses (operating stress times a stress concentration factor) in the A-286 TSFs are less than the reported threshold for A-286 stainless steel IGSCC in reactor coolant. The evaluation also determined that the potential for IGSCC in the A-286 stainless steel TSFs was further reduced by material fabrication processes with less cold-working than used in the A-286 fasteners (which failed in service) and the fastener fabrication processes that introduced beneficial compressive stresses in the areas with the maximum peak stresses. The small increase in core outlet temperature and the small increase in neutron fluences in the A-286 TSFs will not significantly increase the potential for IGSCC. However, SCC of the A-286 stainless steel TSFs will be managed in accordance with UFSAR Section 18.1.4, Reactor Vessel Internals Inspection Program.

C. Irradiation Embrittlement

Exposure of austenitic stainless steels to high levels of neutron irradiation results in an increase in strength and hardness and a decrease in fracture toughness and ductility. Irradiation

embrittlement is most relevant for those RVI materials that directly surround and are closest to the reactor core (core shroud materials). In austenitic stainless steel, irradiation-induced embrittlement (reductions in fracture toughness) results in reduced resistance to crack initiation and propagation. The degree of embrittlement is a function of irradiation temperature and neutron fluence. The irradiation temperature is determined by the reactor coolant temperature and gamma heating, which increases internal temperatures in those materials closest to the reactor core. In austenitic stainless steels, there is significant variation in the data describing the loss of fracture toughness with increasing fluence over the range of 0 to 0.2 dpa or approximately 1×10^{20} n/cm² (E>1 MeV). The scatter in the initial onset of irradiation embrittlement, which results from thermo-mechanical processing and heat-to-heat variability, makes definition of a threshold fluence difficult. Regardless of the fluence where changes in mechanical properties are detectable, the loss of toughness at less than 0.2 dpa is negligible. At fluences of 0.2 dpa to approximately 10 dpa (6.7×10^{21} n/cm² (E>1MeV)), fracture toughness decreases rapidly with increasing fluence. Above 10 dpa, toughness decreases more slowly, eventually reaching a constant value because of the saturation effect. Irradiation at fluences above about 40 dpa does not produce additional loss of fracture toughness. Although data on austenitic stainless steel weld metals (e.g., Type 308) are more limited than for wrought products, the decrease in fracture toughness with irradiation follows a similar pattern.

CASS exhibits a loss of fracture toughness which may be evident at lower fluences than for the wrought austenitic stainless steel because of the presence of the delta ferrite phase in CASS. The [Reference 4](#) screening criteria indicate that irradiation-induced loss of fracture toughness in CASS is negligible at fluences of less than 1×10^{17} n/cm² (E>1 MeV); however, recent evaluation of laboratory data indicate that loss of toughness is negligible below fluences of approximately 1 dpa (6.7×10^{20} n/cm² (E>1MeV)) for CASS materials.

The most limiting component with respect to irradiation-induced loss of fracture toughness is the core shroud, where peak fluences are in excess of the saturation level. The additional fluence resulting from EPU conditions will not cause significant additional decreases in fracture toughness in the Type 304 stainless steel plates and austenitic stainless steel weld metals in the core shroud. Other components that will receive sufficient neutron fluence at EPU conditions to cause significant changes in the mechanical properties, including fracture toughness, are:

- fuel alignment plate,
- upper guide structure support plate,
- control element assembly (CEA) shroud tubes,
- CEA flow channel parts,
- CEA shroud bolts and locking bars,
- core support barrel center cylinder,
- core support plate,
- fuel alignment pins, and
- core support columns, beams, and cylinder.

There will be negligible changes in the mechanical properties of the remaining RVI component materials because of the low fluences they will receive over the 60 year license period, including the effect of the EPU. At EPU, the most limiting component with respect to loss of fracture toughness will continue to be the core shroud. Any mechanical property changes in the other components listed above will be bounded by the core shroud material.

Although the available data indicate that the core shroud and other highly irradiated components may be embrittled, there have not been any reports of significant RVI component degradation (cracks, fractures, or broken parts) in PWRs attributed to radiation-induced embrittlement. The major effect of the loss of toughness (cracking or fracturing of components) requires the imposition of a significant tensile stress. In the absence of high tensile stress, or if the stresses are low, there will not be an effect due to the loss of fracture toughness. In-service inspections, in accordance with the ASME Code Section XI, Subsections IWB, IWC, IWD, and the RVI Inspection Program, provide a means to monitor and manage reductions in fracture toughness as the result of irradiation-induced embrittlement.

D. Irradiation-Assisted Stress Corrosion Cracking

IASCC is an age-related degradation mechanism in which materials, specifically austenitic stainless steels, experience SCC after long term exposure to neutron irradiation in an environment where they are not susceptible to SCC in the absence of radiation. To date, IASCC has not been an issue in PWR RVI, since IASCC has only been the suspected failure mechanism in a limited number of austenitic stainless steel baffle-former bolts and control rod cladding in several PWRs. St. Lucie Unit 2 does not have baffle-former or barrel-former bolts, and the TSF applications are not highly irradiated. IASCC has been more significant in boiling water reactors where the reactor coolant tends to have higher dissolved oxygen levels (more aggressive environment) than is the case for PWR reactor coolant. The more benign (lower oxygen) PWR environment has been considered to significantly delay but not prevent IASCC in PWR RVI components.

Analysis of IASCC occurrences in baffle-former bolts indicates a threshold in PWR environments ranging from approximately 2×10^{21} n/cm² (E>1MeV) to 1×10^{22} n/cm² (E>1MeV). The range indicates variability in the threshold for IASCC, which is likely the result of the following:

- Variations in stress levels,
- Variations in chemical composition (Type 304, Type 316, Type 308, etc.),
- Variations in metallurgical conditions (solution annealed, cold-worked, etc.), and
- Differing environmental conditions, including radiation temperature, coolant chemistry oxygen levels, and neutron spectra.

Based on a threshold fluence of 1×10^{21} n/cm² (E>1MeV), the following RVI components are potentially susceptible to IASCC:

- Core shroud plates, ribs, horizontal plates, and welds,
- Core support barrel, center section,
- Fuel alignment plate,

- Upper guide structure support plate,
- CEA shrouds, lower parts,
- CEA shroud bolts and locking bars,
- Core support plate in the lower internals, and
- Fuel alignment pins.

With the exception of the CEA shroud bolts, all of these components were fabricated from austenitic stainless steel wrought products (primarily plates) and weld metals. The CEA shroud bolts were fabricated from A-286 stainless steel, which is an austenitic, high-strength, precipitation-hardening grade. There is no laboratory data or relevant field experience in PWRs confirming that A-286 is susceptible to IASCC. A-286 has been in-service in CE plants for over 35 years without any reports of IASCC.

In summary, a number of RVI components will become susceptible to IASCC since their end-of-license (EOL) fluences will exceed the threshold values discussed above. However, the St. Lucie Unit 2 specific materials and service conditions, PWR experience and laboratory testing suggest that IASCC will not be a high potential age-related degradation mechanism. IASCC has not been a major issue in PWR RVI since IASCC has only been the failure mechanism in a limited number of austenitic SS baffle-former bolts and control rod cladding in several PWRs. However, there are not sufficient data to eliminate IASCC as an issue for the most highly irradiated components, currently or after the EPU is implemented. Additional data that further clarify the IASCC issue will be available in the future as the result of industry programs. Until such time, IASCC will be managed through in-service inspections conducted in accordance with Section XI of the ASME Code, Subsections IWB, IWC and IWD, the RVI Inspection program and the chemistry control program.

E. Void Swelling

Irradiation-induced void swelling is the gradual increase in size (physical dimensions) of RVI components as the result of exposure to high neutron fluences at elevated temperatures. Void swelling results from the formation and growth of vacancy clusters into voids during irradiation. Data from fast reactors and test reactors indicate that void swelling in austenitic stainless steel components can be significant, but the conditions under which most of the data were generated were significantly different in terms of neutron flux, spectra, and irradiation temperature from typical PWR conditions. The limited void swelling data for conditions representative of PWR conditions were obtained from austenitic stainless steel baffle-former bolts removed from several operating PWRs. These data indicate limited void swelling could occur at conditions present in PWR RVI components.

The evaluation included a review of the projected fluences at the end of the 60-year licensing period and temperatures in the RVI components at EPU conditions. If void swelling occurs in a PWR, it will be in the components that are closest to the fuel assemblies with the highest neutron fluences (i.e., the core shroud). In all other RVI components, the neutron fluences or the irradiation temperatures, or both, will be below thresholds required for void swelling. The areas of the core shroud that are most susceptible to void swelling will be behind the reentrant corners,

which are closest to the reactor core, and at the center of the core where the horizontal plate is thicker than the other horizontal plates. Gamma heating will produce the highest internal temperatures at locations below the surface of the core shroud. These pockets of elevated temperature are very localized and limited in number. At the next higher and lower horizontal plate locations, the plates are thinner so the temperatures are significantly lower, making significant void swelling less likely. In the core shroud panels (plates) near the horizontal plates, the temperatures at EPU conditions will be approximately the same as the local core coolant temperatures and void swelling will be non-existent or negligible because of the low internal temperatures.

Since the regions of higher temperatures are localized to very small volumes of the core shroud, the total amount of void swelling in the core shroud will be minor and void swelling of the core shroud will not be significant at the end of the 60-year license period. As noted above, void swelling has not been an issue to date in PWRs with the limited available data showing minor or no void swelling. [Reference 1](#) examined the effects of void swelling on PWR RVIs and concluded that any swelling that does occur will not prevent the RVIs from performing their intended functions. Void swelling can be managed through in-service inspections conducted in accordance with Section XI of the ASME Code, Subsections IWB, IWC, and IWD, the Reactor Vessel Internals Inspection Program, and the Chemistry Control Program.

F. Thermal Aging (Embrittlement)

CASS contains significant amounts of delta ferrite and, as a result, is susceptible to a thermal aging or embrittlement process that results in the precipitation of additional phases in the ferrite phase and the growth of existing carbides at the ferrite/austenite phase boundaries. The effects of the thermal aging process include increases in hardness and yield strength and decreases in ductility and fracture toughness. Long-term exposure to elevated temperatures can make CASS components susceptible to a low energy fracture that is characterized by cleavage of the ferrite phase and low energy grain boundary separation of the ferrite/austenite grain boundaries. Although most pronounced at temperatures near 885°F, thermal aging also occurs at lower temperatures although longer times are required to produce similar effects. Experimental data indicate that embrittlement may occur at temperatures near the maximum core inlet temperature at EPU conditions (551°F). CASS thermal embrittlement is dependent on exposure temperature and time, materials processing (casting method), and materials composition, including the amount and distribution of the ferrite phase and the amount of molybdenum.

The only components fabricated from CASS are the CEA shroud tubes and the flow bypass inserts. The temperature of the CEA shroud tubes at EPU conditions will be determined by the core outlet temperature (607.9°F) because the shroud tubes are sufficiently remote from the reactor core that gamma (internal) heating will be negligible. Similarly, the flow bypass inserts are in the upper internals assembly and will be exposed to primary coolant at core outlet temperatures with negligible gamma heating. Both applications use CASS with low molybdenum contents (< 0.5 percent), which are less susceptible to thermal aging than the high molybdenum grades. The CEA shroud tubes were fabricated from centrifugal castings and are not susceptible to thermal aging regardless of the delta ferrite content. The castings for the flow bypass inserts permitted either centrifugal or static castings. Static castings are more susceptible to thermal embrittlement.

The evaluation concluded that the EPU will result in small temperature increases of the CASS components. However, the service temperatures (551°F to 607.9°F) are relatively low and will not result in a significant loss of fracture toughness. The CEA shroud tubes are not susceptible to thermal embrittlement, based on the screening criteria of [Reference 4](#). Since the casting method and delta ferrite contents were not identified during the evaluation, the flow bypass inserts may be susceptible to thermal embrittlement. The lower bound fracture toughness of the CASS components will not be affected, although test data suggest that the lower bound value could be reached in a shorter time. Since the lower bound fracture toughness is not reduced, the small temperature increase will not affect the CASS RVI components. WCAP-14577, Rev. 1-A ([Reference 1](#)) concluded that the effects of thermal aging are insignificant for all of the RVI components.

Although, the CASS components are some distance from the reactor core, they may also receive significant neutron radiation. Reference 4 suggests the possibility of a synergistic effect between radiation induced and thermal embrittlement for those CASS components with a neutron fluence greater than 1×10^{17} n/cm² (E>1 MeV) and that are susceptible to thermal embrittlement, although this effect has not been confirmed by testing or by service experience. Centrifugally cast components with low molybdenum levels, such as the CEA shroud tubes, are not susceptible to thermal aging effects based on the criteria in [Reference 4](#), and thus would not experience additional decreases in fracture toughness as the result of this synergistic effect. The flow bypass inserts may be susceptible to this proposed synergistic effect because they experience neutron fluence in excess of the threshold and may have been statically cast. FPL has aging management programs, as described in Chapter 18 of the UFSAR, which address thermal aging of CASS components. The Reactor Vessel Internals Inspection Program and the Thermal Aging Embrittlement of CASS Program address the issue of embrittlement of CASS components.

G. Irradiation-Enhanced Stress Relaxation

The evaluation of the RVI components included an assessment of the effects of EPU conditions on stress relaxation, which is the time-dependent plastic deformation of materials that are stressed and exposed for long periods of time to elevated temperatures (thermal stress relaxation) and/or neutron irradiation. Stress relaxation is most significant to those components with significant preloads, such as TSFs or upper internals hold-down rings. Maintenance of preloads in these components is important to their function, since a significant loss of preload can result in cyclic loads being imposed on the TSFs, which would increase the potential for fatigue of the TSFs or result in fatigue or wear of the components. At PWR conditions, which include EPU conditions, thermal stress relaxation is relatively minor and is considered negligible.

Irradiation-enhanced stress relaxation is a more significant issue at relatively high neutron fluences. Irradiation-enhanced stress relaxation becomes significant for bolting applications at fluences above about 0.2 dpa (approximately 1×10^{20} n/cm² (E>1MeV). The only bolting applications receiving significant neutron fluences are the A-286 stainless steel CEA shroud bolts and guide lug insert bolts. There are no TSFs immediately adjacent to the reactor core; as a result, these TSFs receive significantly less radiation than the baffle-former bolts at other PWRs.

As noted above, the CEA shroud bolts and upper internals guide lug insert bolts are significantly above the reactor core and will receive relatively low fluences, although the fluences will be

above the threshold for irradiation-enhanced stress relaxation. The amount of stress relaxation will also be relatively small, especially when compared to the baffle-former bolts in other PWRs. There have not been any documented TSF failures in CE-designed PWRs attributed to stress relaxation nor any reports of any loose or missing TSFs as the result of stress relaxation. Some of the TSFs have been in service for over 35 years.

The small increases in temperature and neutron fluence projected for the current 60-year license period will not adversely affect the stress relaxation of the RVI TSFs. In addition, the RVI components are inspected in accordance with ASME Section XI, Subsections IWB, IWC, and IWD. This program manages the effects of the loss of preload.

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

As discussed above, the RVI and core support materials are within the scope of License Renewal. Operation of the RVI and core support materials under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.1.4.2.5 Results

The results of the RVI material degradation assessment determined that no new materials degradation issues will result from the EPU. Therefore, it is concluded that the new EPU environmental conditions (reactor coolant chemistry, temperature, and fluence) will not introduce any new aging effects on the RVI components during 60 years of operation, nor will the EPU change the manner in which RVI component aging will be managed by the aging management programs credited in the license renewal application and approved by the NRC in the SER (Reference 2).

2.1.4.3 Conclusion

FPL has reviewed the evaluation of the effects of the proposed EPU on the susceptibility of reactor internal and core support materials to known degradation mechanisms and concludes that it has identified appropriate degradation management programs to address the effects of changes in operating temperature and neutron fluence on the integrity of reactor internal and core support materials. FPL further concludes that it has demonstrated that the RVI and core support materials will continue to be acceptable and will continue to meet its current licensing basis with respect to the requirements of GDC-1 and 10 CFR 50.55a following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to reactor internal and core support materials.

2.1.4.4 References

1. WCAP-14577, Rev. 1-A, License Renewal Evaluation: Aging Management for Reactor Vessel Internals, March 2001.
2. U.S. Nuclear Regulatory Commission, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, NUREG-1779, September 2003.
3. Pressurized Water Reactor Primary Water Chemistry Guidelines: Volume 1, Revision 6, EPRI, Palo Alto, CA: 2007. 1014986.
4. U.S. Nuclear Regulatory Commission, Generic Aging Lessons Learned (GALL) Report Tabulation of Results. NUREG-1801, Vol. 2, Rev. 1. September 2005.
5. BAW-2248A, Demonstration of the Management of Aging Effects for the Reactor Vessel Internals, March 2000.

Table 2.1.4-1
Service Temperature Changes as the Result of EPU Conditions

Core Power Level (MWt)	Location	Temperature, Maximum (°F)⁽¹⁾	Maximum Change In Steady-State Temperature after EPU, (°F)
2700 (current)	Core Inlet	548.65	-
2700 (current)	Core Outlet	598.0	-
2700 (current)	Vessel Outlet	600.1	-
3020 (EPU)	Core Inlet	551.0	2.35
3020 (EPU)	Core Outlet	607.9	9.9
3020 (EPU)	Vessel Outlet	606.0	5.9
Note: 1. Temperature values were selected to maximize the apparent temperature increase associated with the EPU.			

Table 2.1.4-2
Peak Neutron Fluences at 60-Year EOL for EPU Conditions

Core Power Level (MWt)	n/cm², E>1 MeV	Displacements Per atom (dpa)
3020 (EPU)	7.01E+22 ⁽¹⁾	1.02E+02 ⁽¹⁾
Note: 1. Includes EPU conditions and 10% conservatism applied after Cycle 22		

2.1.5 Reactor Coolant Pressure Boundary Materials

2.1.5.1 Regulatory Evaluation

The reactor coolant pressure boundary (RCPB) defines the boundary of systems and components containing the high-pressure fluids circulated through the reactor. The Florida Power and Light Company (FPL) evaluation of RCPB materials addressed their specifications, compatibility with the reactor coolant, fabrication and processing, susceptibility to degradation, and degradation management programs.

The NRC's acceptance criteria for reactor coolant pressure boundary materials are based on:

- 10 CFR 50.55a and General Design Criterion (GDC)-1 insofar as they require that structures, systems, and components 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,
- GDC-4, insofar as it requires that structures, systems, and components 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,
- GDC-14, insofar as it requires that the reactor coolant pressure boundary be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture,
- GDC-31, insofar as it requires that the reactor coolant pressure boundary 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
- 10 CFR 50, Appendix G, which specifies fracture toughness requirements for ferritic components of the reactor coolant pressure boundary.

Specific review criteria are contained in Standard Review Plan (SRP) Section 5.2.3 and other guidance provided in Matrix 1 of Review Standard (RS)-001. Additional review guidance for primary water stress corrosion cracking of dissimilar metal welds and associated inspection programs is contained in Generic Letter (GL) 97-01, Information Notice (IN) 00-17, Bulletins 01-01, 02-01 and 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.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC GDC for Nuclear Power Plants as specified in Appendix A to Title 10 of the Code of Federal Regulations (10 CFR) Part 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific criteria for the RCPB materials are:

- 10 CFR 50.55a is described in UFSAR Section 5.2.1.1, Compliance with 10 CFR 50.55a.

RCS pressure boundary components are designed and fabricated in accordance with 10 CFR 50.55a. The actual addenda of the ASME B&PV Code applied in the original design of each component are listed in UFSAR Table 5.2-1.

- GDC-1 is described in UFSAR Section 3.1.1 Criterion 1 – Quality Standards and Records.

Structures, systems and components important to safety shall be designed, fabricated, erected and tested to quality standards commensurate with the importance of the safety functions to be performed. Where generally recognized codes and standards are used, they shall be identified and shall be supplemented or modified as necessary to assure a quality product in keeping with the required safety function. A quality assurance program shall be established and implemented in order to provide adequate assurance that these structures, systems, and components will satisfactorily perform their safety functions. Appropriate records of the design, fabrication, erection and testing of structures, systems and components important to safety shall be maintained by or under the control of the nuclear power unit licensee throughout the life of the unit.

Structures, systems and components (SSCs) of the facility are classified according to their relative importance to safety. Those items vital to safety such that their failure might cause or result in an uncontrolled release of an excessive amount of radioactive material are designated seismic Category I. They and items of lesser importance to safety are designed, fabricated, erected and tested according to the provisions of recognized codes and quality standards. Discussions of the applicable codes, standards, records and quality assurance program used to implement and audit the operation processes were originally presented in UFSAR Section 17.2; however, this information is now provided in FPL Quality Assurance Topical Report FPL-1. A complete set of facility structural, arrangement and system drawings is maintained under the control of FPL throughout the life of the plant. Quality assurance written data and comprehensive test and operating procedures are likewise assembled and maintained by FPL. The classification of seismic Category I structures and safety related systems and components is discussed in UFSAR Section 3.2.

- GDC-4 is described in UFSAR Section 3.1.4 Criterion 4 – Environmental and Missile Design Basis.

Structures, systems and components (SSCs) important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and approved by the Commission demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

- GDC-14 is described in UFSAR Section 3.1.14 Criterion 14 – Reactor Coolant Pressure Boundary.

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.

Reactor coolant system (RCS) components are designed to meet the requirements of the ASME Code, Section III. To establish operating pressure and temperature limitations during startup and shutdown of the RCS, the fracture toughness rules defined in Appendix G of the ASME Code, Section III, is followed. Quality control, inspection, and testing as required by this standard and allowable reactor pressure-temperature operations ensure the integrity of the RCS.

The RCPB is designed to accommodate the system pressures and temperatures attained under all expected modes of unit operation, including all anticipated transients, and to maintain the stresses within applicable limits.

The pressure boundary has provisions for inservice inspection in accordance with the requirements of ASME Code, Section XI, to ensure continuance of the structural and leaktight integrity of the boundary (see also response to Criterion 32). For the reactor vessel, a material surveillance program conforming with the requirements of Appendix H of 10 CFR 50 is given in UFSAR Section 5.3.

- GDC-31 is described in UFSAR Section 3.1.31 Criterion 31 – Fracture Prevention of Reactor Coolant Pressure Boundary.

The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions (1) the boundary behaves in a non-brittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing, and postulated accident conditions and the uncertainties in determining (1) material properties, (2) the effects of irradiation on material properties, (3) residual, steady-state and transient stresses, and (4) size of flaws.

RCPB components are designed and constructed in accordance with ASME Code Section III, and comply with the test and inspection requirements of this code. These test and inspection requirements assure that flaw sizes are limited so that the probability of failure by rapid propagation is extremely remote. Particular emphasis is placed on the quality control applied to the reactor vessel, on which tests and inspections exceeding ASME Code requirements are performed. The tests and inspections performed on the reactor vessel are summarized in UFSAR Sections 5.2 and 5.3.

Carbon and low-alloy steel materials that form part of the pressure boundary are tested for fracture toughness to the acceptance criteria and requirements of 10 CFR 50, Appendix G (see UFSAR Section 5.2).

The code class, edition, and addenda for the RCPB are listed in UFSAR Table 5.2-1 and are in accordance with the provisions of 10 CFR 50.55a.

Overpressure protection for the RCPB is provided by three spring-loaded ASME Code pressurizer safety valves connected to the top of the pressurizer. Two power operated relief valves are provided to minimize the opening of the pressurizer safety valves. The shutdown cooling suction relief valves are also credited for RCS overpressure protection during low temperature overpressure protection (LTOP) conditions.

- 10 CFR 50, Appendix G, Fracture Toughness Requirements, are described in UFSAR Sections 5.2 and 18.3.

The maximum allowable RCS pressure at any temperature is based upon the stress limitations to prevent brittle fracture. These limitations are derived by using the rules contained in ASME Section III including Appendix G, Protection Against Nonductile Failure and the rules contained in 10 CFR 50, Appendix G, Fracture Toughness Requirements.

The ferritic pressure retaining materials used in the fabrication of the reactor vessel closure head have been tested to demonstrate compliance with the fracture toughness requirements of 10 CFR 50, Appendix G as required by the Code. All aspects of the fracture toughness (impact) testing were performed in compliance with SUBARTICLE NB-2200 and SUBARTICLE NB-2300 of ASME Code Section III, Division 1, 1989 Edition No Addenda.

UFSAR Table 5.2-4 shows the specifications that are used for the principal pressure retaining ferritic and austenitic materials that form the reactor coolant pressure boundary.

Application of the additional review guidance for primary water stress corrosion cracking of dissimilar metal welds and associated inspection programs which is contained in GL 97-01, Information Notice (IN) 00-17, Bulletins 01-01, 02-01 and 02-02 are presented in LR [Section 2.1.5.2](#) below. Application of additional review guidance for thermal embrittlement of cast austenitic stainless steel components which is contained in a letter from C. Grimes, NRC, to D. Walters, Nuclear Energy Institute (NEI), dated May 19, 2000, is also presented in LR [Section 2.1.5.2](#).

In addition to the licensing basis described in the UFSAR, the RCPB was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.1 of the SER identifies that components of the RCPB are within the scope of License renewal. Programs used to manage the aging effects associated with the RCPB are discussed in SER Section 3.1.1 and Chapter 18 of the UFSAR.

2.1.5.2 Technical Evaluation

2.1.5.2.1 Introduction

This section of the report summarizes the evaluations, and their results, of the potential materials degradation issues arising from the effects of the EPU on the performance of the RCPB component materials. The RCPB materials are discussed in UFSAR Section 5.2.3 and are further identified in UFSAR Table 5.2-3 and UFSAR Table 5.2-4.

The EPU evaluation assessed the potential effects of changes in the RCS chemistry (impurities), pH conditions, and extended power uprate (EPU) service temperatures on the integrity of the primary pressure boundary component materials. The evaluation included:

- An assessment of the potential effect of the water chemistry changes on the i) general corrosion (wastage) of the carbon steel components, and ii) stress corrosion cracking (SCC) of austenitic stainless steel components, and the management strategy of any issues associated with these effects.
- An assessment of the effect of the increases in the service temperature on i) primary water stress corrosion cracking (PWSCC) of Alloys 600/182/82 nickel-base alloy components and ii) thermal aging of cast austenitic stainless steel (CASS) materials in primary system components, and the management strategy of any issues associated with these effects.

These evaluations are discussed in the following subsections.

2.1.5.2.2 Input Parameters, Assumptions, and Acceptance Criteria

EPU Service Conditions

A review of the EPU design parameters and current operating conditions indicates that the following service conditions will result from the EPU:

- The current RCS chemistry program coordinates boron and lithium concentration during power operations to maintain a constant elevated temperature pH of 7.2. The RCS lithium concentration is never allowed to exceed 4 parts per million (ppm).
- At the beginning of a cycle, pH is initially established at approximately 7.15 at 100 percent power (0 effective full power days, EFPD). Lithium and boron are co-diluted during the first few days of the cycle until an equilibrium pH of 7.20 is established after approximately 4 EFPD.
- For boron concentrations greater than 940 ppm, lithium concentration is maintained at 3.17 ppm to 3.50 ppm with a target concentration of 3.33 ppm. For boron concentrations equal to or less than 940 ppm, lithium and boron concentrations are coordinated to maintain pH.
- A zinc injection program to reduce the radiation source term is currently in use. Soluble zinc is injected to maintain an RCS zinc level of 3 to 8 parts per billion (ppb) with a target value of 5 ppb.
- The concentration limits of hydrogen, dissolved oxygen, chlorides, sulfates, and other contaminants and dissolved solids will not be changed after EPU implementation.
- **Table 2.1.5-1** indicates an increase in the peak steady-state service temperature at the reactor vessel outlet (hot leg) to 606.0°F (maximum ΔT of 5.9°F) and a maximum steady-state temperature at the reactor vessel inlet (cold-leg) of 551°F (maximum ΔT of 2.35°F).

2.1.5.2.3 Description of Analyses and Evaluations

The effect of changes in service conditions (temperature and water chemistry) resulting from the implementation of the EPU on the performance of the RCPB materials is discussed in the following paragraphs:

General Corrosion/Wastage of Carbon and Low Alloy Steel Components

After EPU implementation, the reactor coolant lithium/boron program will continue to be coordinated so that an elevated pH of 6.9 to 7.4 is maintained throughout the fuel cycle while maintaining the lithium level below 3.5 ppm, except for a short time at the beginning of the fuel cycle. Experience at operating plants and the primary coolant guidelines provided by the Electric Power Research Institute (EPRI) ([Reference 1](#)) indicate that increasing initial lithium concentrations of up to 3.5 ppm with controlled boron concentrations to maintain pH values between 6.9 and 7.4 does not produce undesirable material integrity issues. The inside surfaces of the carbon steel components of the RCPB (reactor vessel, steam generators, pressurizer, and RCS piping) are clad with austenitic stainless steels and will not be affected by changes in the reactor coolant chemistry. The EPU will not cause primary coolant chemistry changes which could increase the general corrosion of clad material. Similarly, the maximum increase in primary coolant temperature will not cause a significant increase in general corrosion rates of these materials.

The Boric Acid Wastage Surveillance Program manages the aging effects of the loss of material and loss of mechanical closure integrity as the result of aggressive chemical attack resulting from borated water leaks. Carbon steel components and structures are susceptible to aggressive chemical attack as the result of borated water leaks. The Program addresses the RCS and structures and components containing or exposed to borated water. The program is consistent with the ten attributes of aging management program XI.M10, "Boric Acid Corrosion" specified in NUREG-1801, Revision 1 ([Reference 2](#)). This program utilizes systematic inspections, leakage evaluations, and corrective actions to ensure that boric acid corrosion does not lead to degradation of the pressure boundary or the structural integrity of components, supports, or structures in proximity to borated water systems. This program includes commitments made in response to NRC GL 88-05, Boric Acid Corrosion of Carbon Steel Reactor Coolant Pressure Boundary Components in PWR Plants.

The NRC reviewed the boric acid corrosion control program as part of the license renewal application and found FPL's program acceptable since the program scope is consistent with NUREG-1801, Revision 1 (GALL Report) ([Reference 2](#)), incorporates lessons learned from Davis-Besse, and addresses NRC generic communications related to boric acid corrosion. On the basis of its review and audit findings, the NRC concluded ([Reference 3](#)) that FPL demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the current licensing basis (CLB) for the period of extended operation as required by 10 CFR 54.21(a)(3).

FPL replaced five hot leg Alloy 600 instrument and sampling nozzles and four Alloy 600 instrument nozzles in the pressurizer upper head with more PWSCC resistant Alloy 690 nozzles using the half-nozzle repair process. This process resulted in small areas of the carbon steel hot leg piping being permanently exposed to primary coolant. These are the only locations at where

carbon or low alloy steels are continuously exposed to primary coolant. There is no mechanism for boric acid to concentrate in the annular regions between the nozzles and hot leg piping. Thus, accelerated corrosion of the carbon steel will not occur. However, some minor corrosion may occur during plant operation and shutdowns. WCAP-15973-P-A, Low-Alloy Steel Component Corrosion Analysis Supporting Small-Diameter Alloy 600/690 Nozzle Repair/Replacement Programs, (Reference 4) addressed general corrosion of carbon steel pipe exposed to primary coolant as the result of small diameter Alloy 600 nozzle replacement or repair. The conditions for the most limiting pipe nozzles (nozzles with the minimum allowable corrosion before exceeding ASME Code criteria) in Combustion Engineering (CE) designed plants evaluated in WCAP-15973-P-A bound the EPU conditions, including temperature, of the repaired nozzles.

Therefore, the conclusions of the nozzle corrosion evaluation will remain valid after the EPU, thereby indicating that the EPU will not affect the calculated lifetimes of the hot leg nozzle repairs.

WCAP-15973-P-A (Reference 4) also provided bounding evaluations of the potential for fatigue or stress corrosion crack propagation after half-nozzle repairs in piping and concluded that cracks in the Alloy 600 nozzle remnants or Alloy 182 welds will not propagate into the carbon steel pipe material by stress corrosion cracking because of the low oxygen conditions present during plant operations. Similarly, fatigue crack propagation in the most limiting nozzle in CE plants will be minor, and the flaws at the end of plant life will continue to satisfy ASME Code criteria for emergency and faulted conditions. In addition, FPL has confirmed the assumptions of WCAP-15973-P-A relative to the specific configuration, materials, and operating conditions as required by the Conditions in the NRC SER for the WCAP. These assumptions will continue to be evaluated each inspection interval to support submittal of the relief requests (Reference 5). Since the current conditions evaluated bound the conditions for the EPU, the conclusions of WCAP-15973-P-A remain valid for the EPU.

SCC of Austenitic Stainless Steels

The two degradation mechanisms that are potentially operative in the austenitic stainless steels (base and weld metals) in the RCPB components are intergranular stress corrosion cracking (IGSCC) and transgranular stress corrosion cracking (TGSCC). A sensitized microstructure and the presence of dissolved oxygen are required for the occurrence of IGSCC in austenitic stainless steels. TGSCC, which may occur in annealed austenitic stainless steels, requires the introduction of halogens, such as chlorides, and the presence of dissolved oxygen. The chemistry changes resulting from the EPU will not introduce any of the chemical contributors to stress corrosion cracking. In the absence of these chemical contributors to IGSCC or TGSCC, the temperature increase resulting from the EPU (see Table 2.1.5-1) will not have an effect on material degradation of the austenitic stainless steels.

Alloy 600/82/182 Components

The major materials degradation mechanism affecting pressurized water reactors (PWR) is PWSCC of nickel-base alloys, such as Alloy 600 and weld metals Alloys 82 and 182. Various industry and regulatory programs require the evaluation of Alloy 600 and Alloy 82/182 weld metals and their potential for PWSCC based on their location throughout the primary system. GL 97-05, Information Notice IN-00-17, and Bulletins 01-01, 02-01, and 02-02 provide guidance

on evaluation and inspection of Alloy 600 and Alloys 82/182 weld metals in reactor vessel heads and hot leg piping. FPL has addressed the potential for PWSCC of Alloys 600/82/182 by replacing most of the original Alloy 600, as well as weld metals Alloys 82/182, in the RCPB with more PWSCC resistant Alloy 690 and weld metals Alloys 52/52M/152 and austenitic stainless steel, by covering Alloy 182 dissimilar metal welds between nozzles and safe-ends with structural weld overlays of Alloys 52 or 52M, or by performing mechanical stress improvement on Alloy 182 dissimilar metal welds. The following components in the RCPB still contain Alloys 600/82/182:

- Five hot-leg pipe weld pads used for the half-nozzle repairs of Alloy 600 instrument nozzles;
- Nozzle-to-safe-end dissimilar metal welds of the following cold-leg nozzles: letdown and drain, safety injection, charging inlet, spray, and RCP suction and discharge nozzles;
- Twelve cold-leg instrument nozzles and the welds connecting the nozzles to the RCS piping and connecting the nozzles to austenitic stainless steel safe-ends;
- Thirty pressurizer heater sleeves and the Alloy 182 in the partial penetration welds between the sleeves and pressurizer bottom head. The EPU will not result in an increase in the pressurizer operating temperature or in changes in the chemical conditions of the primary coolant in the pressurizer; thus, the potential for PWSCC of these parts and welds will not be affected by the EPU; and
- One pressurizer Alloy 690 replacement instrument nozzle has an Alloy 82 weld pad on the pressurizer OD surface.

Alloy 690/52/52M/152 Components

Laboratory testing and industry experience since 1989 indicate that nickel-base Alloy 690 and Alloys 52/52M/152 weld metals are resistant to PWSCC. As a result, many utilities have replaced or have mitigated (e.g., structural weld overlays) the components or locations which originally had Alloys 600/82/182. FPL has replaced most Alloy 600 applications determined by evaluation to be susceptible to PWSCC with Alloy 690 in the thermally treated condition and has replaced many of the Alloys 82/182 welds with Alloys 52/52M/152 welds that are more PWSCC resistant.

The following components contain Alloys 690/52/52M/152:

- The control element drive mechanism (CEDM) nozzles and adaptors, in-core instrumentation (ICI) nozzles, and vent line of the replacement reactor vessel closure head (RRVCH) are Alloy 690. The weld metals attaching the nozzles and vent line to the RRVCH and connecting the CEDM nozzles and adaptors and the ICI nozzles and adaptors are Alloys 52 or 152;
- The lower end fittings of the replacement CEDM housings are Alloy 690. The welds between the martensitic stainless steel motor sections and upper and lower end fittings are Alloy 52M;
- The seven replacement instrument nozzles in the pressurizer are Alloy 690. Six nozzles were attached to the pressurizer with Alloys 52/152 welds to Alloy 52 weld pads (one nozzle has an Alloy 82 weld pad);
- Nineteen hot leg replacement instrument and sampling nozzles are Alloy 690. The partial penetration welds between 14 of the nozzles and their weld pads as well as the weld pads on the OD surface of the pipe sections are Alloy 52;

- Structural weld overlays on the surge nozzle safe-end weld, drain nozzle safe-end welds, and the two shutdown cooling nozzles safe-end welds are Alloy 52M;
- The replacement steam generator heat transfer tubes are Alloy 690. The cladding on the primary side faces of the replacement steam generator tubesheet is Alloy 52.

PWSCC of Nickel Base Alloys 600/82/182

Extensive service experience and laboratory test data indicate that Alloy 600 and its compatible weld metals Alloys 82 and 182 are susceptible to IGSCC in high temperature water (PWSCC). Test data indicate that Alloy 600 PWSCC is a thermally activated process that can be represented by a typical Arrhenius relationship of:

$$1/t = A\sigma^n \text{Exp} (-Q/RT) \quad [\text{Reference 5}]$$

where:

1/t = initiation rate

t = time

A = material constant

σ = stress (combination of operating and residual stresses)

n = exponent on stress, which laboratory testing indicates is approximately 4

Q = activation energy (50 kcal/mole for PWSCC initiation)

R = gas constant (1.103×10^{-3} kcal/mole R)

T = absolute temperature, R ($^{\circ}\text{F} + 459.7^{\circ}$)

The above equation indicates that the maximum temperature after the EPU is implemented in the hot legs (606°F) will decrease the remaining lifetimes to PWSCC initiation of Alloys 600/82/182 containing components by approximately 21 percent compared to the pre-EPU temperature. The only Alloys 600/82/182 hot leg location that has not been replaced or mitigated is the drain nozzle safe-end weld. FPL has been visually inspecting this location at each refueling outage as part of the Alloy 600 inspection program. The above equation predicts that the maximum cold leg temperature at EPU conditions (551°F) will decrease the remaining lifetimes of Alloys 600/82/182 containing cold leg components by approximately 10 percent compared to the pre-EPU temperature.

Alloy 600 Management Program

FPL has a comprehensive Alloy 600 management plan to address the PWSCC issue. The program includes following industry experience, identifying and ranking Alloys 600/182/82 locations, developing and maintaining inspection plans, and development of mitigation/repair/replacement strategies for Alloys 600/182/82 components and welds. FPL plans to replace or mitigate the non-mitigated dissimilar metal safe-end welds in the hot leg drain nozzle and the safe-end welds of the cold-leg letdown and drain, safety injection, charging inlet, and spray nozzles at a future outage.

PWSCC of Alloy 690 and Alloys 52/52M/152 Weld Metal

FPL has addressed PWSCC of Alloy 600 by either replacing most of the Alloys 600/82/182 in components most susceptible to PWSCC (pressurizer, hot leg piping, reactor vessel closure head, and steam generators) with more PWSCC resistant materials (Alloys 690/52/52M/152 or stainless steel) or by covering Alloy 182 welds with structural weld overlays (SWOL) of Alloy 52 or 52M. An extensive laboratory database indicates that Alloy 690 (and its weld metals) is significantly more resistant to PWSCC than Alloy 600. The laboratory database is supported by extensive field experience that indicates there has not been any corrosion related degradation to date in Alloy 690 steam generator tubes, pressurizer instrument nozzles and heater sleeves, reactor vessel head nozzles, and hot leg instrument nozzles. Alloy 690 has been in-service in PWR applications for more than 20 years at temperatures of up to 653°F. Weld metal Alloy 52/52M/152 has been in-service in PWR RCPB components for approximately 15 years under the same conditions without any indications of PWSCC. Based on the laboratory data and service experience at temperatures above the maximum calculated hot-leg temperature for the EPU, the EPU will not increase the potential for PWSCC of Alloy 690 or weld metal Alloys 52/52M/152.

The RVCH was replaced in 2007. The RRVCH has Alloy 690 CEDM nozzles, ICI nozzles, and vent line with Alloys 52 or 152 welds.

To ensure safe management of the potential for PWSCC of Alloy 690 nozzles in replacement reactor vessel closure heads, the NRC has mandated the following inspection plan for replacement heads:

Licensees of PWRs shall augment their in-service inspection plans with ASME Code Case N-729-1 subject to the conditions specified in 10 CFR 50.55a paragraphs (g)(6)(ii)(D)(2) through 6. Code Case N-729-1 stipulates the following requirements for the inspection of replacement reactor vessel closure heads with nozzles and partial penetration welds of PWSCC resistant materials (Alloy 690 with Alloys 52/152 welds):

- An inspection of the closure head meeting the following requirements shall be completed every third refueling outage or every 5 years, whichever occurs first:

A bare metal visual examination of the entire outer surface of the head, including essentially 100 percent of the intersection of each nozzle with the head. If welded or bolted obstructions are present (i.e., mirror insulation, insulation support feet, shroud support ring/lug), the examination shall include 95 percent of the area in the region of the nozzles and the head surface uphill and downhill of the obstructions.

- An inspection of all nozzles and partial penetration welds in the head meeting the following requirements shall be completed every inspection interval (nominally 10 years):

A volumetric and/or surface examination of essentially 100 percent of the required volume or equivalent surfaces of the nozzle tubes, as identified in Code Case N-729-1. A demonstrated volumetric or surface leak path assessment through all J-groove welds shall be performed. If a surface examination is being substituted for a volumetric examination on a portion of a penetration nozzle that is below the toe of the J-groove weld, the surface examination shall

be of the inside and outside wetted surfaces of the penetration nozzle not examined volumetrically.

Thermal Aging (Embrittlement) of Cast Austenitic Stainless Steels (CASS)

Thermal aging (embrittlement) is a degradation mechanism occurring in CASSs that manifests itself as increases in hardness and yield strength and reductions in ductility and fracture toughness. CASS (Grade CF8M) is present in the pressurizer surge nozzle safe-end. In the hot leg piping, CASS (CF8M) is present in the safe-ends of the surge and shutdown cooling nozzles. CASS (CF8M) is also present in the surge line pipe and elbow. In the cold-leg, CASS (CF8M) is present in the reactor coolant pump (RCP) casings and covers, the safe-ends of pipe sections that connect to the RCP suction and discharge nozzles, and the safe-ends of the safety injection nozzles. Grade CF8M has a specified molybdenum content of 2 to 3 percent, which makes CF8M a high molybdenum grade for the evaluation of CASS thermal embrittlement using the screening criteria of NUREG-1801, Revision 1 ([Reference 2](#)). The screening criteria permit an initial assessment of whether specific heats of CASS are not susceptible to thermal embrittlement based on chemical composition (molybdenum content), casting method (static versus centrifugal) and calculated ferrite content. Available information from certified materials test reports (CMTRs) on the heats of CASS present in the RCPB components were compared to the screening criteria.

For RCP casings and valves that have CASS bodies, NUREG-1801, Revision 1 ([Reference 2](#)) does not require screening for susceptibility to thermal embrittlement because the results of a bounding analysis show that pump casings, pump covers, and valve bodies are resistant to failure caused by thermal embrittlement. As a result, the RCP casings, pump covers, and valve bodies fabricated from CASS do not have to be screened for susceptibility to thermal embrittlement.

An evaluation of CMTR data for CASS heats used in primary loop piping and nozzle safe-ends indicated that all heats used in the piping and piping safe-ends were centrifugally cast, had lower bound fracture toughness values at 550°F greater than the 1,450 in-lbs/in² criterion of NUREG-1801, and most heats had delta ferrite contents of less than 20 percent, indicating that they are not susceptible to thermal aging. However, several heats had calculated delta ferrite contents in excess of 20 percent and may be susceptible to thermal aging. The effects of aging for these CASS heats are managed in accordance with NUREG-1801, Revision 1 ([Reference 2](#)).

The increase in temperature resulting from EPU will not result in lower values for saturated fracture toughness; therefore, there will not be additional heats of CASS identified as potentially susceptible to aging. However, the saturated values of fracture toughness may be reached in shorter times as the result of the increased temperatures resulting from the EPU. Because some of the CASS components screen as potentially susceptible (because of calculated delta ferrite content), they will continue to require aging management in accordance with NUREG-1801. Temperature increases resulting from the EPU will not affect the current thermal aging management programs nor will the increased temperature require additional thermal aging management activities.

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

As discussed above, the RCPB is within the scope of License Renewal. Operation of the RCPB under EPU conditions has been evaluated to determine if there any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.1.5.2.5 Results

The assessment of the potential materials degradation issues associated with the EPU resulted in the following conclusions:

- There are no new materials degradation issues associated with boric acid corrosion of carbon steel RCPB components expected as a result of the EPU and primary coolant chemistry conditions after EPU implementation. The NRC review of the boric acid corrosion control program concluded that FPL's program was acceptable.
- Materials were evaluated for the expected boron, lithium, and zinc ranges and a pH of 6.9 to 7.4 in the primary coolant. The evaluated conditions bound the expected plant operating conditions after EPU implementation.
- A review of the effects of primary coolant on small areas of carbon steel pipe exposed to the coolant as the result of half-nozzle repairs of small-diameter Alloy 600 nozzles indicated the conditions of the current analysis bound the conditions expected after EPU implementation. Therefore, additional material degradation of these areas as a result of the EPU is not expected.
- The EPU will not introduce any of the contributors to SCC of austenitic stainless steels into the primary coolant. Therefore, material degradation is not expected in any of the stainless steel components as a result of the EPU.
- The increase in the primary coolant temperature will increase the potential for PWSCC of the Alloys 600/182/82 remaining in the RCPB components. However, most of the Alloys 600/182/82 at the most susceptible locations (hot leg piping and pressurizer) have been repaired or replaced by more PWSCC resistant materials or mitigated. As a result, the potential for future PWSCC of the remaining Alloys 600/182/82 is small. The aging of the remaining Alloy 600/182/82 will be managed in accordance with the Alloy 600 management program.
- Alloys 690/152/52 are present in the replacement RVCH, the replacement CEDM and RVLMS housings, the pressurizer instrument nozzles, replacement hot leg instrument and sampling nozzles, and in structural weld overlays. The risk for PWSCC of the

Alloys 690/152/52 is minimal based on industry experience with these materials. FPL continues to inspect the Alloy 690/52/152 components in accordance with ASME Code Case N-729-1 as required by the NRC and described previously in this LR section.

- The increase in temperature resulting from the EPU will not result in lower fracture toughness in RCPB components fabricated from CASS. The NRC review and approval of the Thermal Aging Embrittlement of CASS program concluded the program is acceptable for managing loss of toughness because of thermal aging in CASS components.
- The NRC's review (NUREG-1779) ([Reference 3](#)) concluded that FPL's Generic Aging Lessons Learned (GALL) process identified in the License Renewal Application (LRA) is consistent with the (NUREG-1801, Rev. 1 ([Reference 2](#))) and that FPL has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.21(a)(3).

The results of the RCPB material degradation evaluation concluded that no new material degradation issues will result from the EPU. On this basis, the conclusion is that the EPU environmental conditions will not introduce any new aging effects on RCPB components during 60 years of operation, nor will the EPU change the manner in which the component aging will be managed by the aging management program credited in the LRA and approved by the NRC in the SER NUREG-1779 ([Reference 3](#)).

2.1.5.3 Conclusion

FPL has reviewed the effects of the proposed EPU on the susceptibility of RCPB materials to known degradation mechanisms, and concludes that it has identified appropriate degradation management programs to address the effects of changes in the coolant chemistry and operating temperature due to EPU on the integrity of RCPB materials. FPL further concludes that it has demonstrated that the RCPB materials will continue to be acceptable following implementation of the proposed EPU and will continue to meet its current licensing basis with respect to the requirements of GDC-1, GDC-4, GDC-14, GDC-31, 10 CFR 50, Appendix G, and 10 CFR 50.55a. Therefore, FPL finds the proposed EPU acceptable with respect to reactor coolant pressure boundary materials.

2.1.5.4 References

1. Pressurized Water Reactor Primary Water Chemistry Guidelines: Volume 1 Revision 6, EPRI, Palo Alto, CA: 2007. 1002886.
2. U.S. Nuclear Regulatory Commission, Generic Aging Lessons Learned (GALL) Report Tabulation of Results, NUREG-1801, Vol. 2, Rev. 1, September 2005.
3. U. S. Nuclear Regulatory Commission, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, NUREG-1779, September 2003.
4. Westinghouse Report, WCAP-15973-P-A, Rev. 0, Low-Alloy Steel Component Corrosion Analysis Supporting Small-Diameter Alloy 600/690 Nozzle Repair/Replacement Programs, February 2005.

5. Rao, G. V., Methodologies to Address PWSCC Susceptibility of Primary Component Alloy 600 Locations in Pressurized Water Reactors, Proceedings of the Sixth International Symposium on Environmental Degradation of Materials in Nuclear Power Systems- Water Reactors, The Minerals, Metals and Materials Society, Warrendale, PA, 1993, pages 871-882.

Table 2.1.5-1
Service Temperature Changes in the Reactor Vessel and
RCS Piping as the Result of the EPU

Core Power Level (MWt)	Location	Temperature, Maximum (°F)	Maximum Change in Steady-State Temperature after EPU (°F)
2700 (current)	RV Outlet	600.1	-
2700 (current)	RV Inlet	548.65	-
3020	RV Outlet	606.0	5.9
3020	RV Inlet	551.0	2.35

2.1.6 Leak-Before-Break

2.1.6.1 Regulatory Evaluation

Leak-before-break (LBB) analyses provide a means for eliminating from the design basis the dynamic effects of postulated pipe ruptures for a piping system. 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 Florida Power and Light (FPL) review of LBB covered:

- direct pipe failure mechanisms (e.g., water hammer, creep damage, erosion, corrosion, fatigue, and environmental conditions),
- indirect pipe failure mechanisms (e.g., seismic events, system overpressurizations, fires, flooding, missiles, and failures of structures, systems, and components (SSCs) in close proximity to the piping), and
- deterministic fracture mechanics and leak detection methods.

The NRC's acceptance criteria for LBB are based on:

- General Design Criterion (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 Standard Review Plan (SRP) Section 3.6.3, Revision 1 and other guidance provided in Matrix 1 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC GDC for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDC for the LBB is as follows:

- GDC-4 compliance is described in UFSAR Section 3.1.4 Criterion 4 - Environmental and Missile Design Bases, and GDC-4 is stated as:

Structures, systems and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit.

However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analyses reviewed and approved by the

Commission demonstrates that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

SSCs important to safety are designed to accommodate the effects of and to be compatible with the pressure, temperature, humidity, and radiation conditions associated with normal operation, maintenance, testing, and postulated accidents, including a loss-of-coolant accident (LOCA), in the area in which they are located.

Due to the application of LBB methodology to the reactor coolant system (RCS) hot and cold leg piping, the dynamic effects of a LOCA do not have to be considered. A technical evaluation was performed to demonstrate that the probability or likelihood of large pipe breaks occurring in the primary coolant loops is sufficiently low that they need not be a design basis ([Reference 1](#)).

Seismic Category I piping is arranged or restrained such that in the event of rupture of a seismic Category I pipe which causes LOCA, resulting pipe movement will not result in loss of containment integrity or adequate engineered safety features systems operation.

The structures inside the containment vessel are designed to sustain dynamic loads which could result from failure of major equipment and piping, such as jet thrust, jet impingement and local pressure transients, where containment integrity is needed to cope with the conditions.

Refer to UFSAR Sections 3.5, 3.6, 3.7, and 3.11 for details on missile protection, pipe rupture and jet impingement protection, seismic design criteria and environmental qualification, respectively.

Circumferential (guillotine) and longitudinal (slot) breaks were postulated for the RCS hot and cold legs in the original plant design. Since then, however, the NRC revised GDC-4 to eliminate the consideration of dynamic effects of a LOCA from the plant design bases. The dynamic effects of a LOCA include the effects of missiles, pipe whipping, discharging fluid (i.e., jet impingement), decompression waves within the ruptured pipe and dynamic or nonstatic pressurization in cavities, compartments, and subcompartments. NUREG-1061 established criteria for existing plants to determine which systems were allowed exemption and the methodology that was applicable. The Combustion Engineering Owners Group (CEOG) Report CEN-367-A, Leak-Before-Break Evaluation of Primary Coolant Loop Piping in Combustion Engineering Designed Nuclear Steam Supply Systems ([Reference 1](#)) demonstrates that the primary loop piping meets all of the criteria for application of LBB presented in NUREG-1061, Volume 3. As a result, the mechanical/structural loads associated with dynamic effects of guillotine and slot breaks in RCS hot and cold legs are no longer considered a plant design basis.

As documented in a March 5, 1993, NRC letter to FPL, the NRC approved the St. Lucie LBB analysis. The NRC safety evaluation concluded that since the St. Lucie units are bounded by the CEOG analyses and the leakage detection systems are capable of detecting the specified leakage rate, the dynamic effects associated with postulated pipe breaks in the primary coolant system piping can be excluded from the licensing and design bases of the St. Lucie units.

In addition to the licensing basis described in the UFSAR, LBB was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an

aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. LBB is a time-limited aging analysis (TLAA) and is discussed in SER Section 4.6.1 and Chapter 18 of the UFSAR. The conclusion that the reactor coolant pressure boundary function remains valid through the period of extended operation is discussed in SER Section 4.6.1.4.

2.1.6.2 Technical Evaluation

2.1.6.2.1 Introduction

The original structural design basis of the RCS required consideration of dynamic effects resulting from postulated pipe breaks and the need to incorporate protective measures for such breaks into the design. Subsequent to the original design, an additional concern regarding asymmetric blowdown loads was raised as described in Unresolved Safety Issue A-2 (Asymmetric Blowdown Loads on the Reactor Coolant System) and Generic Letter 84-04. Westinghouse submitted the RCS asymmetric loads analysis results ([Reference 2](#)) to the NRC for their review. The [Reference 2](#) report applies to St. Lucie Unit 2 as well as those CEOG plants originally named in the report.

Subsequent research by the NRC and industry, coupled with operating experience, determined that safety could be negatively impacted by placement of pipe whip restraints on certain systems. As a result, NRC and industry initiatives resulted in demonstrating that LBB criteria can be applied to RCS piping based on fracture mechanics technology. SER-055 ([Reference 3](#)) accepted the [Reference 1](#) submittal and indicates that the asymmetric blowdown loads resulting from double-ended pipe breaks in primary loop piping need not be considered in the design basis at St. Lucie Unit 2.

The current structural design basis includes the application of LBB methodology to eliminate consideration of the dynamic effects resulting from pipe breaks in the RCS primary loop piping. The purpose of this LR section is to describe the evaluations performed to demonstrate that the elimination of these breaks from the structural design basis remains valid following implementation of the EPU, and that the primary loop piping, for which St. Lucie Unit 2 credits LBB, continues to comply with the requirements of GDC-4, SRP Section 3.6.3 and NUREG-1061, Volume 3.

To demonstrate the elimination of pipe breaks in primary loop piping from consideration of dynamic effects, the following objectives had to be achieved:

- Demonstrate that margin exists between the “critical” flaw size and a postulated flaw that yields a detectable leak rate,
- Demonstrate that there is sufficient margin between the leakage through a postulated flaw and the leak detection capability,
- Demonstrate margin on the applied load, and
- Demonstrate that fatigue crack growth is negligible.

These objectives were met in the current LBB evaluation by addressing the changes due to the EPU conditions that could potentially affect the [Reference 1](#) LBB evaluation of the primary coolant loop piping.

2.1.6.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The loadings, operating pressure, and temperature parameters for the EPU were used in the current LBB evaluation.

The parameters that are important in the evaluation are the piping forces, moments, the normal operating temperature (NOT) and the normal operating pressure (NOP). These parameters were used as input in the evaluation. The EPU NOT range and NOP conditions are provided in [LR Table 1.1-1](#).

The LBB acceptance criteria are based on the SRP Section 3.6.3 and NUREG-1061, Volume 3, which recommend the following LBB margins:

- Margin of 10.0 on detectable leak rate,
- Margin of 2.0 on leakage flow size, and
- Margin of $\sqrt{2}$ on loads for leakage flow size.

2.1.6.2.3 Description of Analyses and Evaluations

Primary Loop Piping

Westinghouse performed a plant-specific LBB evaluation for the primary loop piping. The evaluation compared the parameters previously documented in [Reference 1](#) and approved by the NRC in [Reference 3](#) to those parameters changed as a result of the EPU conditions. The EPU NOT range and NOP were reviewed in the evaluation. The results of the review determined the following:

- the NOP did not change due to the EPU,
- the postulated leakage crack length was calculated in [Reference 1](#) on the basis of “pressure only” loads and therefore also did not change, and
- the safe shutdown earthquake (SSE) loads on the primary loop piping do not change from those loads previously used in [Reference 1](#) to demonstrate acceptable margins for LBB.

It was determined that the only changes in the input parameters affecting LBB were the normal operating loads on the primary loop piping, which were different from those originally used in [Reference 1](#). The evaluation determined that the EPU piping loads are bounded by the piping loads previously evaluated in [Reference 1](#) to demonstrate acceptable margins for LBB.

The EPU LBB evaluation is based on the current evaluation ([Reference 1](#)) and includes the recommendations and criteria proposed in NUREG-1061, Volume 3, and the SRP Section 3.6.3. The primary loop piping normal operating, SSE and pressure loads due to the EPU conditions were used in the EPU LBB evaluation. The results of the evaluation demonstrated that all the

LBB recommended margins for the primary loop piping continue to be satisfied for the EPU conditions.

Limitations on the Application of LBB

The LBB approach is not considered applicable to high energy fluid system piping, or portions thereof, that operating experience has indicated particular susceptibility to failure from the effects of corrosion (e.g., intergranular stress corrosion cracking), water hammer or low and high cycle (i.e., thermal, mechanical) fatigue. For St. Lucie Unit 2 LBB applications, these limitations are addressed in [Reference 1](#) for primary loop piping and approved by the NRC in [Reference 3](#). The EPU conditions do not affect [Reference 1](#) conclusions with respect to these limitations.

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

As discussed above, LBB is within the scope of License Renewal as a TLAA. Operation of the reactor coolant pressure boundary under EPU conditions has been evaluated to determine if there any new aging effects requiring management or if any existing aging management programs are affected. 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, no changes are necessary to any existing aging management programs and the TLAA remains valid. Furthermore, 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.

2.1.6.2.5 Results

The evaluation results demonstrated the following:

- Leak Rate – A margin of 10.0 exists between the calculated leak rate from the leakage flow and the leakage detection capability as described in UFSAR Section 5.2.5;
- Flaw Size – A margin of 2.0 or more exists between the critical flaw size and the leakage flow size; and
- Loads – A margin of $\sqrt{2}$ exists for loads.

The results of the current LBB evaluation demonstrated that the original LBB conclusions documented in [Reference 1](#) for the St. Lucie Unit 2 primary loop piping do not change for the EPU conditions.

It is therefore concluded that the LBB acceptance criteria continue to be satisfied for the St. Lucie Unit 2 primary loop piping at the EPU conditions. The recommended margins continue to be satisfied and the conclusions shown in the [Reference 1](#) LBB analyses remain valid. It is therefore concluded that the dynamic effects of primary loop pipe breaks need not be considered in the structural design basis of at the EPU conditions.

2.1.6.3 Conclusion

FPL has reviewed the evaluation of the effects of the EPU on the LBB analyses for St. Lucie Unit 2 and determined that (1) there are no changes in primary system pressure due to the EPU, and (2) temperature range and the associated effects on the LBB analyses have been adequately addressed. FPL has further determined that the evaluations demonstrated that the LBB analyses will continue to remain valid following implementation of the EPU and that the primary loop piping, that credits LBB, will continue to meet its current licensing basis with respect to the requirements of GDC-4. Therefore, FPL finds the EPU acceptable with respect to all aspects of LBB for St. Lucie Unit 2.

2.1.6.4 References

1. 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.
2. Reactor Coolant System Asymmetric Loads Evaluation Program Final Report, Combustion Engineering, Inc., July 1, 1980.
3. SER-055 Revision 000, Acceptance for Referencing of Topical Report CEN-367, Leak-Before-Break Evaluation of Primary Coolant Loop Piping In Combustion Engineering Designed Nuclear Steam Supply Systems, October 30, 1990.

2.1.7 Protective Coating Systems (Paints) - Organic Materials

2.1.7.1 Regulatory Evaluation

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

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to Title 10 of the Code of Federal Regulations (10 CFR) Part 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

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.

Service Level I protective coatings are laboratory tested to withstand the worst case DBA conditions in order to demonstrate that coating failure and the associated potential consequences cannot occur.

A detailed engineering specification documents the protective coating systems used for Service Level I applications on steel and concrete surfaces inside the RCB.

UFSAR Section 6.3.2.2.2a provides a summary of the response to Generic Letter (GL) 98-04, issued to address concerns related to potential for degradation of the emergency core cooling system and the containment spray system after loss-of-coolant accidents because of construction and protective coating deficiencies and foreign material in containment. The FPL 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 Unit 2 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.

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 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. FPL does not use commercial grade dedication for Service Level I protective coatings in containment.

Additionally, the following inspections are discussed in FPL'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; and
3. Inspection of containment coatings at the end of each refueling outage to ensure that quantities of unqualified coatings are below acceptable limits.

Consistent with FPL's response to GL-98-04, visual inspection and condition assessment of coatings inside containment are performed every outage. Degradation of coated base material is identified through inspections performed by system monitoring, and, during routine maintenance. Where coatings are found degraded, they are repaired in accordance with the corrective action program.

In addition to the licensing basis described in the UFSAR, the protective coating system was evaluated for License Renewal. As documented in NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003, the protective coating system was determined to be outside the scope of License Renewal.

2.1.7.2 Technical Evaluation

2.1.7.2.1 Introduction

Protective coating systems (paints) provide a means for protecting the surfaces of facilities and equipment from corrosion and contamination from radionuclides and provide wear protection during plant operation and maintenance activities. Coatings typically do not perform a nuclear safety function. However, any detachment from protected surfaces is an especially important consideration inside the Containment. Qualified containment coatings are required to remain intact after a design basis LOCA to avoid compromising the ECCS or safety-related CS system by plugging containment sump screens with debris.

This section addresses the impact of the extended power uprate (EPU) on the Protective Coatings Program.

2.1.7.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The NRC's acceptance criteria for protective coating systems are based on 10 CFR 50, Appendix B, which states quality assurance requirements for the design, fabrication, and construction of safety-related structures, systems, and components. The criteria are also based on RG 1.54, Revision 1, for guidance on application and performance monitoring of coatings in nuclear power plants. Additional criteria for Service Level I protective coatings is contained in GL 98-04. Specific review criteria are contained in SRP, Section 6.1.2.

2.1.7.2.3 Description of Analyses and Evaluations

An evaluation was performed to address the impact of the EPU on the Protective Coatings Program. The evaluation considered the qualification criteria used for coatings applied to steel and concrete surfaces inside the reactor containment and their ability to withstand the effects of design basis accident conditions.

Service Level I coatings are specifically qualified for and tested to withstand the worst case accident conditions analyzed for the containment environment. These protective coatings are required to prevent corrosion and facilitate decontamination of structures and equipment. Additionally, the coatings are designed to remain intact under postulated accident conditions involving elevated levels of temperature, pressure, radiation, and chemical spray. The application of Service Level I protective coatings is considered a "Special Process" and is controlled in accordance with industry standards and regulatory guidelines. Service Level I coatings were qualified to design basis LOCA conditions. The results of pre-EPU qualification testing were compared to design basis LOCA conditions postulated to occur following implementation of EPU in order to determine whether the results of historical testing (pre-EPU) would be suitable to bound EPU conditions. Existing Service Level I protective coatings inside containment were qualified by laboratory testing and certified for use by the manufacturer.

It is noted that the effects of EPU on the Protective Coatings Program is limited to the qualification criteria of Service Level I coatings to withstand design basis LOCA conditions. The evaluation of other service level classifications for coatings is excluded since they are not qualified for a design basis LOCA environment and do not directly support reactor operation. Therefore, only Service Level I protective coatings are permitted inside containment and other coatings are prohibited for use inside containment.

The effects of containment spray and sump pH changes were reviewed to determine any impact to the qualification of coatings as a result of EPU. The EPU does not involve any direct modifications to the CS system or its associated iodine removal system (IRS) and the requirements for initial hydrazine (N_2H_4) injection into the CS will be unchanged by the EPU. The maximum boric acid concentration in the refueling water tank (RWT) and safety injection tanks (SITs) is not changing as a result of EPU; therefore, the minimum containment sump pH will remain at approximately 7. The minimum boric acid concentration of the RWT and the SITs is being increased 180 ppm as a result of the EPU; therefore, the maximum containment sump pH is slightly reduced. Thus, with respect to chemical effects, the EPU improves the worse-case environmental conditions. The other LOCA parameters of interest for Service Level I coatings: temperature, pressure and radiation, are more adverse as a result of the EPU.

Service Level I protective coatings are qualified to the following temperature, pressure and radiation criteria:

- Qualification Test Temperature
 - 0 to 2.8 Hrs 286°F
 - 2.8 – 23.9 Hrs 219°F
- Qualification Test Pressure 54 psig
- Qualification Integrated Radiation Dose 3×10^8 Rads

Table 2.1.7-1 compares the LOCA containment temperature, pressure and radiation levels for the EPU to those values used in the Service Level I coatings qualification program (DBA test conditions). The EPU conditions are bounded by the DBA test conditions.

2.1.7.2.4 Impact on Renewed Plant Operating License Evaluations and Licensing Renewal Programs

As discussed above, the protective coatings were determined to be outside the scope of License Renewal; therefore, with respect to the protective coating system, the EPU does not impact any License Renewal evaluations.

2.1.7.2.5 Results

The maximum LOCA containment sump pH under EPU conditions is reduced from that of the current analysis. Although the EPU results in increased LOCA containment temperature, pressure and radiation, the EPU conditions are bounded by the results of the DBA test conditions. Therefore, the effect of EPU on Service Level I coatings is considered acceptable and the coatings will perform satisfactorily under normal operating and accident conditions and the program will continue to comply with the requirements of GL 98-04. Inspection of Service Level I coatings will continue to be performed by qualified personnel in accordance with FPL specification C-034.

2.1.7.3 Conclusion

FPL has reviewed the assessment of the effects of the protective coating systems for their suitability for and stability under design basis LOCA conditions and concludes that it has adequately incorporated protective coatings in the analyses. FPL further concludes that the protective coating system inside containment will continue to meet its current licensing basis with respect to the requirements of 10 CFR 50 Appendix B. Therefore, FPL finds the proposed EPU acceptable with respect to the protective coating system inside containment.

Table 2.1.7-1
EPU Containment LOCA Parameters vs. Service Level I Coatings DBA Test Conditions

Condition	DBA Test Conditions	EPU-DBLOCA
Maximum Temperature at LOCA conditions		
0 to 2.8 Hrs	286°F	267°F
2.8 – 23.9 Hrs	219°F	209°F
Maximum Pressure at LOCA conditions		
Pressure	54 psig	43.48 psig
Integrated Radiation Dose at LOCA conditions		
Radiation Dose	3×10^8 Rads	1.42×10^8 Rads

2.1.8 Flow-Accelerated Corrosion

2.1.8.1 Regulatory Evaluation

Flow-accelerated corrosion (FAC) is a corrosion mechanism occurring in carbon steel components exposed to flowing single or two-phase water. Components made from stainless steel are immune to FAC, and FAC is significantly reduced in components containing small amounts of chromium or molybdenum. The rates of material loss due to FAC depend on velocity of flow, fluid temperature, steam quality, oxygen content, and pH. During plant operation, control of these parameters is limited and the optimum conditions for minimizing FAC effects, in most cases, cannot be achieved. Loss of material by FAC will, therefore, occur.

Florida Power and Light (FPL) has reviewed the effects of the proposed extended power uprate (EPU) on FAC and the adequacy of the FAC Program to predict the rate of loss so that repair or replacement of damaged components could be made before they reach critical thickness. The FAC Program is based on NUREG-1344, NRC Generic Letter (GL) 89-08, and the guidelines in Electric Power Research Institute (EPRI) Report NSAC-202L-R2 and 202L 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, and 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.

St. Lucie Unit 2 Current Licensing Basis

The FAC Program has been developed in response to NRC Bulletin 87-01, Thinning of Pipe Walls in Nuclear Power Plants, NRC GL 89-08, Erosion/Corrosion-Induced Pipe Wall Thinning, and the guidelines in EPRI Report NSAC-202L-R2 & 202L-R3. The CHECWORKS™ SFA computer code is utilized as recommended by NSAC-202L-R2 & 202L-R3 to support analysis relative to predicting the loss of material. The FAC Program is designed to ensure that flow accelerated corrosion does not result in unacceptable degradation of the structural integrity of carbon steel piping systems.

Criteria and review guidance needed to review EPU applications in the area of flow-accelerated corrosion are contained in the EPRI Report NSAC-202L-R2 & 202L-R3.

The FAC Program manages the aging effect of loss of material due to FAC. The program predicts, detects, monitors, and mitigates FAC in high energy carbon steel piping associated with the main steam, extraction steam, main feedwater, heater drains and blowdown systems, and is based on industry guidelines and experience.

The FAC Program addresses internal loss of material of drain lines and selected steam trap lines due to flow accelerated corrosion.

In addition to the licensing basis described in the UFSAR, the components susceptible to FAC were evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in

Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3 of the SER identifies that components susceptible to FAC are within the scope of License Renewal. The program used to manage the aging effects associated with FAC is discussed in SER Section 3.0.5.8 and Chapter 18 of the UFSAR.

2.1.8.2 Technical Evaluation

2.1.8.2.1 Introduction

The following elements of the current FAC Program are addressed in subsequent sections:

- Program scope and susceptibility screening,
- Analysis method determination,
- Criteria for selection of piping components (i.e., pressure rated pipe and fittings) for inspection,
- Component re-examination frequency,
- Inspection techniques,
- Scope of inspection of piping systems,
- Comparison of predicted and measured wall thickness,
- Criteria for repair/replacement of piping components, and
- Description of a recent piping component repair/replacement.

2.1.8.2.2 Program Scope and Susceptibility Screening

The FAC Program contains the requirements and methods employed to support the detection of pipe wall thinning due to FAC of safety-related and non-safety-related carbon and low alloy steel piping systems. Piping degradation caused by other wear mechanisms (i.e., cavitation, particle erosion, impingement, intergranular stress corrosion cracking, microbiologically-influenced corrosion (MIC), external corrosion, and general corrosion) is not included in the FAC Program.

NSAC-202L-R2 & 202L-R3 were utilized to determine the susceptible systems and exclusion criteria. All systems and lines in the plant which are susceptible to FAC are identified and evaluated. FAC susceptible piping is divided into two categories. The categories are those lines and systems that meet the criteria to be modeled, using EPRI CHECWORKS™ SFA, and those that do not, i.e. "Susceptible Non-Modeled". As discussed in NSAC-202L-R2 & -R3, all plant systems are considered susceptible to FAC unless excluded by the following criteria:

- Piping material – stainless steel or stainless clad materials (a low-alloy steel with normal chromium content $\geq 1\frac{1}{4}$ percent),
- Content – steam - Superheated, or dry saturated,
- Energy level – Operating below 200°F or does not have FAC concerns except for conditions of two phase flow,

- Piping which carries raw water – Oxygen levels > 1000 ppb, and
- System usage – When a system is in operation < 2 percent of the time or the operating temperature of a system is > 200°F for < 2 percent of the operating time except for conditions of two phase flow which does not have any temperature limitations

The following systems have been identified in the FAC Program as being susceptible to FAC through the screening process and are therefore included in the scope of the FAC Program:

- Main Steam,
- Extraction Steam,
- Feedwater,
- Condensate,
- Heater Drains,
- Heater Vents,
- Steam Generator Blowdown, and
- Turbine Crossunder Piping

The FAC Program uses the CHECWORKS™ SFA predictive model to evaluate the existing plant piping and components to establish and prioritize the methods and locations to perform inspections. The program evaluates piping and components with single and two phase flow.

2.1.8.2.3 Analysis Method Determination

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. Predicted wear rates of piping components are obtained using the Wear Calculation feature of CHECWORKS™ SFA.

The FAC computer program utilizes CHECWORKS™ SFA for prediction of minimum wall thickness. When the predicted wall thickness reaches the minimum wall thickness site engineering shall perform a piping / component structural calculations to satisfy the code and site procedural requirements.

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-Not-Modeled systems.

For determination of wear rates in Susceptible-Non-Modeled lines, ultrasonic testing (UT) or radiographic 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 in-service 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 in-service life between the dates of examination.

Radiography is used normally in the “Long-Term Flow Accelerated Corrosion Monitoring Program” for all 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-Not-Modeled piping and components in the FAC Program, ultrasonic testing measurements are taken at selected locations. The FPL FAC Coordinator then determines the wear rate and predicts the wall thickness at next outage, and the time to the next inspection.

The FAC Program and outage inspection plan includes drawings marked-up with identifying designations and locations for inspecting the following:

- Lines that are modeled in CHECWORKS™ SFA,
- Large bore lines (nominal outer diameter greater than 2 inches) that are included in the FAC Program, but not modeled in CHECWORKS™ SFA,
- Small bore lines (nominal outer diameter between $\frac{3}{4}$ inches up to and including 2 inches) that are included in the FAC Program, and
- Lines based on industry and plant specific operating experience.

The FAC outage inspection plan also shows the component nominal, maximum, and minimum thicknesses for specific piping segments/components included in the FAC Program.

2.1.8.2.3.1 Criteria for Selection of Piping Components for Inspection

The FAC coordinator is responsible for the collection of abnormal operating experiences, line-ups, etc. for both units and evaluating this information for preparation of the inspection plan. Selection of piping components for inspection for the following topics is addressed in the following sections:

- CHECWORKS™ SFA analysis of large bore systems
- Susceptible non-modeled large bore systems,
- Susceptible non-modeled small bore systems,
- Consideration of plant and industry experience,
- Component re-inspection, and
- Other reviews.

CHECWORKS™ SFA Analysis of Large Bore Systems

Once a system is adequately represented in CHECWORKS™ SFA an analysis is performed to predict FAC wear rates and remaining service life for un-inspected components (i.e., time until the minimum wall thickness required to satisfy code requirements occurs). Inspection locations are selected and prioritized based on the ranking of wear, wear rate, and time ranking. At St. Lucie Unit 2, the component remaining life is the time to achieve the minimum wall thickness required and is denoted by “ $t_{\min}$ ” or “ $t_{\text{crit.}}$ ”

Susceptible-Non-Modeled Large Bore Systems

Certain large bore systems have widely varying operating conditions that have prevented the development of reasonably accurate analytical models. The inspection of these lines is selected using a combination of existing plant conditions, engineering judgment, and industry experiences. The site FAC Coordinator provides feedback of plant specific operating experience that may affect the FAC Program. The FAC Coordinator prepares the FAC outage inspection plan. Locations that are considered include the following:

- Downstream of orifices,
- Downstream of flow control valves and level control valves,
- Nozzles,
- Tees and laterals,
- Complex geometric piping and component configurations,
- Component connections that include backing rings or counter bores, and
- Components that are adjacent to components that have been replaced in the past

Susceptible-Non-Modeled Small Bore Systems

A review of historical inspections and replacement data is performed to determine prior inspection coverage on each component. The FAC Coordinator ensures that the susceptible components within each system have been inspected, as well as locations downstream of components causing high flow velocities or turbulence.

Consideration of Plant and Industry Experience

Plant and industry experiences are taken into consideration for the process of identification of susceptible components for inspection. Industry experience, including FPL fleet experience, is reviewed and applicability to St. Lucie Unit 2 is determined. This information is used to support the preparation of FAC outage inspection plan.

Baseline Inspection

Baseline inspections are performed after component repair or replacement has been performed to establish the initial conditions or the “as-left” conditions following a repair.

Component Re-inspection

Components are scheduled for re-inspection based on the following:

- Suspect/questionable inspection results which require confirmation,
- Predicted life is less than the time to the next refueling outage (component is either repaired or replaced),
- Monitoring of component wear at a specified time interval, and
- Information provided by the FAC coordinator.

Re-inspection requirements based on initial inspections that were non-quantitative (i.e., visual) are determined based on the judgment of the FAC Coordinator.

Other Reviews

Review of condition reports initiated during the cycle that may require follow-up UT exams are performed to identify additional locations for inspection. Review of UT and RT examination coverage downstream of steam traps is performed to identify additional locations for inspection.

2.1.8.2.3.2 Component Re-examination Frequency

Components that have been inspected are re-examined at a frequency consistent with the calculated component life based on the inspection results. Re-examination is scheduled for a refueling outage proceeding the predicted time when t_{min} , the minimum wall thickness required to satisfy FPL program requirements, will be reached.

2.1.8.2.3.3 Inspection Techniques

The techniques used for the performance of inspections are UT, RT, and visual. UT is utilized to detect wall thinning and provide wall thickness data that is to be analyzed by CHECWORKS™ SFA to determine wear rates. Piping may be examined using RT to identify FAC degradation as specified by the FAC Coordinator. RT is an acceptable method to inspect small bore piping. It is used only as an investigative tool on large bore piping. Visual examination of large bore piping is performed when appropriate to detect FAC using established guidelines.

2.1.8.2.3.4 Scope of Inspection of Piping Systems

A FAC outage inspection plan is issued identifying inspections required for that outage, i.e., FAC inspection interval. This plan is derived from a review of the following.

- CHECWORKS™ SFA analysis wear trending,
- Large and small bore susceptible-non-modeled system component assessment,
- Component re-inspection trending, and
- Plant and industry operating experience.

The Inspection plan identifies the components to be inspected during the outage as follows:

- Large bore and small bore UT examinations,
- Large bore and small bore RT examinations, and
- Components that require visual inspections, such as, turbine crossunder piping.

2.1.8.2.3.5 Comparison of Predicted and Measured Wall Thickness

The FAC Program establishes the minimum requirements for planned inspection and evaluation based on comparisons between CHECWORKS™ SFA wall thickness predictions and reported wear rate at current plant conditions. [Tables 2.1.8-1](#) and [2.1.8-2](#) provide a comparison of the changes in wear rates and predicted and observed wall thicknesses for various components that were selected as a representative sample of current high risk lines monitored within the FAC Program.

2.1.8.2.3.6 Criteria for Repair/Replacement of Piping Components

Repair/Replacement Criteria for Large Bore Piping Components

For CHECWORKS™ SFA modeled and susceptible-non-modeled large bore piping, the predicted thickness at the next refueling outage and the predicted life beyond the next refueling outage are calculated using the inspection results, [Table 2.1.8-2](#), and the wear rate. The acceptance criteria for the continuing life of a component is established by determining that the measured wall thickness minus the projected wear allowance for the next cycle will exceed the acceptance criteria of [Table 2.1.8-3](#).

The evaluations performed in accordance with the FAC Program use the value of the calculated minimum allowable wall thickness as determined by the applicable piping codes. When the wall thickness is found below the larger of (1) of the code required minimum wall thickness for hoop stress, or (2) 0.150 inch the piping shall be evaluated for replacement. Based on the structural evaluation, if the component meets the stress requirements for the predicted wall thickness at the end of the operating cycle, the component is acceptable for continued operation. If the structural calculated stress level cannot be justified, the component would be either repaired or replaced.

The existing criteria for repair/replacement of large bore piping components are consistent with the guidelines in EPRI Report, NSAC-202L-R2 & 202L-R3.

Repair/Replacement Criteria for Small Bore Piping Components

Repair/replacement criteria for small-bore piping are based primarily on measured degradation data. As discussed in the FAC Program volumetric nondestructive examinations (RT) are used to determine small bore component degradation. Once wall thickness is found below (1) the thickness required for hoop stress due to pressure, (2) 30 percent of T_{nominal} , or (3) less than 0.100 inch, replacement needs are identified and plans put in place, even though the minimum required wall thickness is actually lower and the wear calculation may identify remaining life which will allow the component to be in service for several more operating cycles. The minimum thickness criteria in the [Table 2.1.8-3](#) will govern replacement even though the code minimum thickness may be less. The intent is to replace these components long before they reach their

code minimum thicknesses where these thicknesses are relatively thin. In addition, sections of adjacent piping and/or parallel lines may be replaced with FAC resistant material.

The existing criteria for repair/replacement of small bore piping components are consistent with the guidelines in EPRI Report, NSAC-202L-R2 & 202L-R3.

2.1.8.2.3.7 Description of a Recent Piping Component Repair/Replacement

FPL has developed a FAC long term plan for material condition improvements at St. Lucie Unit 2 which was issued as part of the FAC health report. This report has identified potential areas of degradation of piping components where material condition improvements can be made, i.e. replacement of carbon steel with chrome-moly materials.

Replacement piping components upgrades are identified prior to each outage and scheduled for replacement.

During the 2005 SL-2-16 outage, the 2A drain line from the reducer on HD-8 to heater 5B before LCV-11-30A was replaced with FAC-resistant material. Also during that outage drain line 2C from the tee on HD-130 to heater 5A before LCV-11-30C1 was replaced with FAC-resistant material. During the 2007 SL-2-17 outage the main steam piping required weld build up in five locations. This was completed and blended for future inspections.

2.1.8.2.3.8 Identified in Evaluation Criteria RS-001

FAC is a corrosion mechanism occurring in carbon steel components exposed to flowing single or two-phase water. Components made from stainless steel are immune to FAC, and FAC is significantly reduced in components containing small amounts of chromium or molybdenum. The rates of material loss due to FAC depend on velocity of flow, fluid temperature, steam quality, oxygen content, and pH. During plant operation, control of these parameters is limited and the optimum conditions for minimizing FAC effects, in most cases, cannot be achieved. Loss of material by FAC will, therefore, occur. A review has been performed on the effects of the proposed EPU on FAC and the adequacy of the FAC Program to predict the rate of loss so that repair or replacement of damaged components could be made before they reach critical thickness.

The FAC Program is based on EPRI NP-3944, NUREG-1344, GL 89-08, and the guidelines in EPRI Report NSAC-202L-R2 & 202L-R3. It consists of predicting loss of material using the CHECWORKS™ SFA computer code, and visual inspection and volumetric examination of the affected components.

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

Some components susceptible to FAC are within the scope of License Renewal. Operation of the components susceptible to FAC under EPU conditions has been evaluated to determine the impact on the FAC Program. Changes to the piping and equipment included in the FAC Program as a result of the EPU are within the scope of the existing program and in compliance with program criteria. Therefore, the EPU does not affect the conclusions in the License Renewal

Safety Evaluation Report regarding the FAC Program and no new aging effects requiring management are identified.

2.1.8.2.5 Results

The following topics are addressed in the evaluation of the EPU impact on the FAC Program:

1. Comparison of Calculated Fluid Velocities with Industry Guidelines at EPU Conditions,
2. Evaluation of Small Bore Piping at EPU Conditions,
3. Review of Heat Balance Temperature Data at Current and EPU Conditions,
4. Evaluation of the Moisture Separator Re-heaters (MSRs) and Feedwater Heaters, at EPU Conditions,
5. Update of the CHECWORKS™ SFA Model for EPU Conditions,
6. FAC Program Requirements, Methods, and Criteria, and
7. Modifications Required in Support of the EPU.

1. Comparison of Calculated Fluid Velocities with Industry Guidelines at EPU Conditions

Lines/components in the following systems, a comparison was made between the calculated fluid velocities at EPU conditions with industry guidelines as a measure of whether there is an increased potential for FAC.

- Main Steam (MS)

Flow velocities at EPU conditions for the MS piping are bounded by the industry guideline velocities with the following exceptions:

- Flow through MS piping from the main steam isolation valve (MSIV) to the MS common header exceeds the industry guideline by approximately 14 percent, and
- Flow through main steam piping from the steam generator (SG) outlet to the MSIV exceeds the industry guideline by approximately 7 percent.

The MS lines identified above are currently included in the FAC Program contain high quality steam and will continue to be monitored.

- Extraction Steam

Flow velocities at EPU conditions for the extraction steam piping are bounded by the industry guideline velocities with the following exceptions

- Flow velocity through the extraction steam piping for low pressure (LP) heater 4 A/B exceeds industry guideline by approximately 3 percent,
- Flow velocity through the cold reheat piping from the high pressure turbine exhaust to the extraction steam supply connection for LP heater 4 A/B currently exceeds industry

guidelines by approximately 33 percent; under EPU conditions the velocity exceed industry guidelines by approximately 40 percent, and

- Flow velocity through the cold reheat piping from the LP heater 4 A/B steam supply connection to the MSRs currently exceeds industry guidelines by approximately 8 percent; under EPU conditions the velocity exceeds industry guideline velocities by approximately 10 percent.

The CHECWORKS™ SFA wear rate changes, summarized in LR [Table 2.1.8-1](#), do not predict a significant increase in wear rate. The extraction steam lines identified above are currently included in the FAC Program and will continue to be monitored.

- Condensate and Feedwater

Flow velocities at EPU conditions for the feedwater heaters, condensate and feedwater piping are bounded by industry guideline velocities with two exceptions, as follows:

- The 8-inch main feedwater pump recirculation lines currently exceed industry guidelines; however wear of the line has been acceptable. The flow velocity at EPU conditions will not adversely change. FAC monitoring will continue in accordance with FAC Program, and
- Feedwater heaters 1A/B through 4A/B are predicted to experience nozzle flow velocities that exceed the industry guidelines at EPU conditions.

The CHECWORKS™ SFA wear rate changes, summarized in LR [Table 2.1.8-1](#) predict an increase in wear rate and this remains an area of higher FAC concern. The condensate and feedwater systems will continue to be monitored in accordance with FPL's FAC Program after EPU.

- Feedwater Heater Drains and Reheater Drains

The current feedwater normal drains flow velocity for feedwater heater 5 to feedwater heater 4 exceeds the industry guidelines by 7.5 percent and the EPU flow velocity increases that by an additional 2.5 percent. The flow velocity for feedwater heater 2 to feedwater heater 1 increases from below industry guidelines to approximately 380 percent above industry guidelines. A modification will be performed to lower the elevation of the level control valve (LCV) and/or increasing the line size due to high velocity caused by flashing of steam upstream of the LCV. This significantly lowers the velocity upstream of the valve and therefore will be in line with the other velocities in the EPU operating conditions.

The current feedwater heater alternate drains flow velocities in general exceed the industry guidelines and therefore the EPU flow velocities will also exceed the industry guidelines. The alternate drains are used infrequently for emergency level control of the feedwater heaters and are therefore considered acceptable under EPU operating conditions.

Analysis of the moisture separator drain lines to the No. 4 feedwater heaters indicates the potential for entrained steam. The review for EPU verified this flow regime to be acceptable and the conditions associated in the drain lines were evaluated with a specific FAC analysis. While the velocities exceed industry criteria at the pre- and post-EPU conditions, FAC analysis and UT inspections for wall thickness indicate the lines are not subject to adverse erosion/corrosion. The analysis results will be validated via the existing FAC Program.

The feedwater heater, moisture separator, and reheater drain lines will continue to be monitored in accordance with the FAC Program. The feedwater heaters, moisture separator drain lines, and reheater drain lines identified above are currently included in the FAC Program. The feedwater heater, moisture separator and reheater drain lines identified for which calculated velocity exceeds the industry guidelines, are currently part of the FAC Program. The CHECWORKS™ SFA wear rate changes, summarized in LR Table 2.1.8-1 predict an increase in wear rate and this remains an area of higher FAC concern. The feedwater heater, moisture separator and reheater drain lines will continue to be monitored in accordance with FPL's FAC Program after EPU.

- Steam Generator Blowdown

The normal blowdown flow rate for the replacement SG at EPU conditions will not be changing from the current conditions. The steam generator blowdown system fluid velocities at EPU conditions are bounded by the industry guidelines. Normal operation is continuous blowdown of both SGs. The steam generator blowdown system is currently included in the FAC Program. Examination/evaluation of the blowdown lines per the FAC Program will be continued after the EPU. Input parameters to CHECWORKS™ SFA do not specifically consider particles that will be carried into the SGs from higher secondary system flow rates. However, any changes that result in an increase in wear of the steam generator blowdown piping due to EPU conditions would be identified by the periodic inspections of the system per the FAC Program.

2. Evaluation of Small Bore Piping at EPU Conditions

The EPU may result in increased flow rates in some small bore piping, e.g. main steam drains. Monitoring and inspection of small bore lines is based on engineering experience and judgment. Monitoring/inspection of small bore lines in accordance with the FAC Program will continue after EPU.

3. Review of Heat Balance Temperature Data at Current and EPU Conditions

Based on the review of the temperature data documented in the heat balance for the current conditions and the EPU conditions, there are no lines where the temperature increases from below 200°F to above 200°F at EPU conditions. Therefore there are no additional lines to be added to the FAC Program based on an increase in energy level.

4. Evaluation of the MSRs and Feedwater Heaters at EPU Conditions

- The MSRs, which are being replaced during the EPU, are inspected each outage;
- Feedwater heater shells are inspected and will continue to be inspected in accordance with the FAC Program;
- Feedwater heaters 1A/B through 4A/B are expected to experience nozzle flow velocities that exceed the industry guidelines at EPU conditions. The feedwater heater manufacturer has determined that operation of these lines is considered acceptable for EPU conditions. These components will continue to be monitored by the FAC Program.

5. Update of the CHECWORKS™ SFA Model for EPU Conditions

- 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.
- An enhanced monitoring program will be implemented to develop baseline EPU erosion rates, define inspection periodicity, predict long-term degradation rates, and perform maintenance as required.

6. FAC Program Requirements, Methods, and Criteria

- The EPU has resulted in areas where the flow velocity has increased. Most of the EPU operating flow velocity increases over the current operating flow velocities have been small and do not require plant modifications. Therefore the criteria of the existing FAC Program are considered adequate at this time for the identification of potential pipe wall degradation under EPU uprate operating conditions. As a result of this analysis the existing FAC Program will continue to be implemented following the implementation of the EPU.

7. Modifications Required in Support of the EPU

- A modification will be required to reduce the flow velocities in the line from feedwater heaters 2A/B to feedwater Heaters 1A/B.

2.1.8.3 Conclusion

FPL has evaluated the effect of the proposed EPU on the FAC analysis for the plant and concludes that the impact of changes in the plant operating conditions on the FAC analysis has been adequately addressed. FPL further concludes that it has been demonstrated that 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 proposed EPU is acceptable with respect to FAC.

Table 2.1.8-1
Comparison of Current and EPU Analytical Wear Rates

System	Line Description	Component ID	Component Geometry	Pipe Specification	CHECWORKS Current Wear-Rate 100% Power (mils/year)	CHECWORKS Wear-Rate EPU Power (mils/year)
Condensate:	CD: DRCLRA-HTRDR TIE IN -2-30	24C37-E-1-6	Elbow	24" - 0.688" Sch. 40	4.995	6.310
Condensate:	CD: HD TIE IN-HTR 4A 2-30,31	24C37-E-3-10	Elbow	24" - 0.688" Sch. 40	6.266	6.939
Condensate:	CD: HTR 4B-BF PUMP B 2-32	24C50-E11-33	Elbow	24" - 0.688" Sch. 40	3.942	4.132
Condensate:	CD: HTR 2A-3A PSL-2-27,28	20C27-P-2-7	Pipe	20" - 0.594" Sch. 40	2.940	2.794
Condensate:	CD: HTR 3B-DRNCLRB PSL-2-29	20C40-P-5-11	Pipe	20" - 0.594" Sch. 40	3.922	4.056
Extraction Steam	ES: LPES TO FWH 3A,B -2-12,15,	24ES6-E-2-10	Elbow	24" - 0.375" Sch. 20	1.142	1.460
Extraction Steam	ES: XUES TO FWH 4A -2-14	20ES3-P6-12	Pipe	20" - 0.375" Sch. 20	0.037	0.039
Feedwater	BF: HTR 5A TO SEISMC -2-22,23	20BF8-T-1-13 (U/S)	Tee	20" - 1.500" Sch. 120	8.518	9.669
Feedwater	BF: SEISMC TO SG 2A PSL-2-25	I20BF14P34-79	Pipe	20" - 1.031" Sch. 80	6.635	7.500
Feedwater	BF: PUMPB TO HTR 5B -2-21,22	20BF2-P-5-10	Pipe	20" - 1.500" Sch. 120	6.425	6.751
Heater Drain	HD: DRNCLR B TO PUMP B -2-46	16HD38-E-6-23	Elbow	16" - 0.375" Sch. STD	3.834	3.927
Heater Drain	HD: HEADER 20HD44 -2-51	20HD44-T2-34 (D/S)	Tee	20" - 0.594" Sch. 40	4.775	4.888
Heater Drain	FWH 3B TO FWH 2B -2-55	6HD65-P-12-23	Pipe	6.625" - 0.280" Sch. 40	2.576	3.016
Heater Drain	HD: FWH 4B TO DRNCLR 2B -2-48	30HD27-E-2-4	Elbow	30" - 0.375" Sch. STD	2.058	2.243
Heater Drain	HD: FWH 5A TO FWH 4A -2-44	10HD22-E6-12	Elbow	10.75" - 0.365" Sch. 40	6.676	6.836

Table 2.1.8-1 (Continued)
Comparison of Current and EPU Analytical Wear Rates

System	Line Description	Component ID	Component Geometry	Pipe Specification	CHECWORKS Current Wear-Rate 100% Power (mils/year)	CHECWORKS Wear-Rate EPU Power (mils/year)
Extraction Steam	ES: HP B TO FWH 5B -2-13	12ES2-P-1-3	Pipe	12.75" - 0.375" Sch. STD	6.904	5.074
Main Steam	MS: CLBK A TO HDR -2-2	34MS32-E-7-38	Elbow	34" - 1.200" Sch. USR	0.380	0.762
Main Steam	MS: HDR TO MSR A,B -3,8,9,10	8MS19-P-7-14	Pipe	8.625" - 0.322" Sch. 40	1.194	0.414
Main Steam	MS: HDR to SV Inlet 2,4 -2-3	38MS14-E-14-56	Elbow	38" -.1.350" Sch. USR	2.091	2.471
Heater Drain	HR: MSR A RHTR TO FWH5B -36,37,	8HD128-E-2-5	Elbow	8.625" - 0.500" Sch. 80	2.210	2.515
Heater Drain	HR: MSRAB SHL TO FWH4B -33,34	10HD1-P-12-24	Pipe	10.75" - 0.365" Sch. 40	1.628	1.718

Table 2.1.8-2
Comparison of Predicted and Measured Wall Thickness

Line Description	Component ID	Pipe Specification	CHECWORKS Current Wear-Rate 100% Power (mils/year)	CHECWORKS Line Correction Factor	Predicted Remaining Service Life Following SL1-20 @ EPU Wear Rate (months)	Predicted Thickness at Current Wear Rate at the end of Cycle 19 (inches)	NDE (UT or RT) Measured Thickness (inches) ⁽²⁾
CD: DRCLRA-HTRDR TIE IN -2-30	24C37-E-1-6	24" - 0.688" Sch. 40	4.995	2.616	17.8	0.605	0.675 @ 74456
CD: HD TIE IN-HTR 4A 2-30,31	24C37-E-3-10	24" - 0.688" Sch. 40	6.266	2.616	144.6	0.680	0.750 @ 97286
CD: HTR 4B-BF PUMP B 2-32	24C50-E11-33	24" - 0.688" Sch. 40	3.942	2.616	707.6	0.837	0.900 @ 63854
CD: HTR 2A-3A PSL-2-27,28	20C27-P-2-7	20" - 0.594" Sch. 40	2.940	2.505	106.7	0.518	0.564 @ 63854
CD: HTR 3B-DRNCLRB PSL-2-29	20C40-P-5-11	20" - 0.594" Sch. 40	3.922	2.505	94.9	0.527	0.588 @ 63854
ES: LPES TO FWH 3A,B -2-12,15,	24ES6-E-2-10	24" - 0.375" Sch. 20	1.142	1.000 ⁽¹⁾	2213.9	0.331	No NDE
ES: XUES TO FWH 4A -2-14	20ES3-P6-12	20" - 0.375" Sch. 20	0.037	1.000 ⁽¹⁾	47634.4	0.354	0.355 @ 74456
BF: HTR 5A TO SEISMC -2-22,23	20BF8-T-1-13	20" - 1.500" Sch. 120	8.518	8.443	46.0	1.239	No NDE
BF: SEISMC TO SG 2A PSL-2-25	I20BF14P34-79	20" - 1.031" Sch. 80	6.635	8.443	322.7	0.923	0.998 @ 97286
BF: PUMPB TO HTR 5B -2-21,22	20BF2-P-5-10	20" - 1.500" Sch. 120	6.425	3.441	199.7	1.311	No NDE
HD: DRNCLR B TO PUMP B -2-46	16HD38-E-6-23	16" - 0.375" Sch. STD	3.834	1.787	286.7	0.257	No NDE
HD: HEADER 20HD44 -2-51	20HD44-T2-34 (DS)	20" - 0.594" Sch. 40	4.775	1.787	747.5	0.833	0.913 @ 63854
FWH 3B TO FWH 2B -2-55	6HD65-P-12-23	6.625" - 0.280" Sch. 40	2.576	2.690	742.2	0.207	No NDE
HD: FWH 4B TO DRNCLR 2B -2-48	30HD27-E-2-4	30" - 0.375" Sch. STD	2.058	3.611	309.9	0.358	0.386 @ 86560

Table 2.1.8-2 (Continued)
Comparison of Predicted and Measured Wall Thickness

Line Description	Component ID	Pipe Specification	CHECWORKS Current Wear-Rate 100% Power (mils/year)	CHECWORKS Line Correction Factor	Predicted Remaining Service Life Following SL1-20 @ EPU Wear Rate (months)	Predicted Thickness at Current Wear Rate at the end of Cycle 19 (inches)	NDE (UT or RT) Measured Thickness (inches) ⁽²⁾
HD: FWH 5A TO FWH 4A -2-44	10HD22-E6-12	10.75" - 0.365" Sch. 40	6.676	3.611	106.7	0.220	0.327 @ 63854
ES: HP B TO FWH5B -2-13	12ES2-P-1-3	12.75" - 0.375" Sch. STD	6.904	0.504	104.0	0.229	0.342 @ 74456
MS: CLBK A TO HDR -2-2	34MS32-E-7-38	34" - 1.200" Sch. USR	0.380	1.000 ⁽¹⁾	1579.6	1.189	No NDE
MS: HDR TO MSR A,B -3,8,9,10	8MS19-P-7-14	8.625" -.322" Sch. 40	1.194	4.105	319.3	0.287	No NDE
MS: HDR to SV Inlet 2,4 -2-3	38MS14-E-14-56	38" -.1.350" Sch. USR	2.091	4.105	343.6	1.290	No NDE
HR: MSR A RHTR TO FWH5B -36,37,	8HD128-E-2-5	8.625" - 0.500" Sch. 80	2.210	2.720	687.3	0.423	No NDE
HR: MSRAB SHL TO FWH4B -33,34	10HD1-P-12-24	10.75" -.365" Sch. 40	1.628	2.816	1293.7	0.282	No NDE
1. Inspection data was not used to calibrate these lines. Line Correction Factor is equal to 1.00.							
2. Latest component inspection data measured thickness is recorded along with operating hours at time on inspection.							

Table 2.1.8-3
Minimum Wall Thickness Acceptance Criteria

Type	Acceptance Criteria
Seismic/safety related (previously analyzed)	Previously determined minimum wall
Seismic/safety related (not previously analyzed)	87.5% T_{nominal}
Balance of Plant (Hoop stress min. wall > 0.5 T_{nominal})	Hoop stress min. wall due to pressure
Balance of Plant (Hoop stress min. wall < 0.5 T_{nominal})	Use the largest of: 1. Hoop stress due to pressure, 2. 30% T_{nominal}, 3. 0.150 inches (large bore) or 0.100 inches (small bore)

2.1.9 Steam Generator Tube Inservice Inspection

2.1.9.1 Regulatory Evaluation

Steam generator (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 Florida Power and Light (FPL) review in this area covered the effects of changes in differential pressure, temperature, and flow rates resulting from the proposed extended power uprate (EPU) on plugging limits and potential degradation mechanisms (e.g., flow-induced vibration).

The NRC 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 Standard Review Plan (SRP) Section 5.4.2.2 and other guidance provided in Matrix 1 of Review Standard (RS)-001.

Additional review guidance is contained in Technical Specification (TS) 3.4.5, Steam Generator Tube Integrity for SG surveillance requirements, NRC draft Regulatory Guide (RG) 1.121 for SG tube plugging limits, NRC Generic Letter (GL) 95-03, and NRC Bulletin 88-02 for degradation mechanisms, and Nuclear Energy Institute (NEI) 97-06 for structural and leakage performance criteria.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to Title 10 of the Code of Federal Regulations (10 CFR) Part 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

UFSAR Section 5.2.4, Inservice Inspection, states that provisions are made in the plant design for access to permit the conduct of preoperational and inservice inspections as specified in the ASME Boiler and Pressure Vessel Code, Section XI, Rules for Inservice Inspection of Nuclear Reactor Coolant Systems. The design and arrangement of the components are such that space is provided to conduct examinations either from the interior or the exterior or a combination of both. The ISI program is updated periodically to meet the 10 CFR 50.55a requirements.

The SGs are designed to minimize the time required for ISI. The SGs comply with the ISI requirements specified by the ASME Boiler and Pressure Code, Section XI, 1986 Edition, no addenda.

The minimum requirements for ISI of SGs are presented in TS 3.4.5. TS Surveillances 4.4.5.1 and 4.4.5.2 require implementation of the Steam Generator Program for the purpose of verifying SG tube integrity.

The steam generator program is identified in TS 3.4.5 and 6.8.4.I. Compliance with the TS ensures that the SGs remain capable of fulfilling their intended safety function through application of continued monitoring and structural assessment. The steam generator program has been developed based upon the processes and performance criteria defined in NEI 97-06.

In addition to the licensing basis described in the UFSAR, the SGs were evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.1.6 of the SER identifies that components of the SGs are within the scope of License Renewal. The program used to manage the aging effects associated with the SG tube integrity is discussed in SER Section 3.1.0.4 and Chapter 18 of the UFSAR.

2.1.9.2 Technical Evaluation

SG process parameters will change as a result of the EPU. For SG tube integrity, parameters that are expected to change include: temperatures, steam pressure, steam flow, and feedwater flow. LR [Section 2.2.2.5](#), Steam Generators and Supports, provides an analysis of the impact of the EPU on the SG, including thermal-hydraulic affects, tube integrity, flow-induced tube vibration, and tube wear.

The replacement SGs, installed in 2007, include design features and materials that minimize potential corrosion and cracking. For example, the tubes are fabricated with Alloy 690 thermally treated (TT) material, which has better corrosion resistance than the mill-annealed Alloy 600 material used in the original SGs. The replacement SGs incorporate many other design and material improvements, and the impacts of the EPU on the SGs have been assessed and found to be acceptable.

The tubes are supported by the stainless steel broached tube support plates which reduce corrosion at the tube support intersections within straight sections. Tube bends are supported by anti-vibration bars which are also fabricated from corrosion resistant stainless steel. The hydraulic expansion joints are installed full length in the tubesheet to minimize crevice corrosion and cracking of the tubes in the tubesheet. In addition, SG design addresses industry feedwater distribution system problems, such as, water hammer, thermal stratification, erosion, and internal feedwater header collapse. The SG distribution system satisfies all the current (at the time of design) NRC recommendations with respect to water hammer, provides flow stratification mitigation, and addresses industry concerns regarding corrosion, corrosion cracking, thermal fatigue, and material erosion. Furthermore, the SGs allow for inspection access to the feedwater header region through tunnels and ladders at each drum manway location.

The structural and leakage integrity of the SGs is maintained in accordance with TS 6.8.4.I, steam generator program and plant implementing procedures. The program ensures SG tube integrity through continued monitoring and maintenance of the SG tubes and testing of critical areas and features of the tubes via application of TS Surveillance 4.4.5.1 and plant implementing procedures. The Steam Generator Program will continue to be utilized to assess SG tubing structural and leakage integrity following the change in SG operating conditions (temperature, steam pressure, steam and feedwater flow) associated with the implementation of the EPU. This program will continue to be utilized to provide the basis for the maintenance and inspection of the SGs following implementation of the EPU.

2.1.9.2.1 Input Parameters, Assumptions, and Acceptance Criteria

The steam generator program procedures define the minimum requirements for an effective program. At full power, the reactor vessel outlet temperature T_{hot} was estimated to be 604.0 °F at EPU conditions. This value for T_{hot} represents the temperature at the inlet to the SG. In the event of a reduction in operating T_{hot} , there would be no exacerbation of tube corrosion degradation mechanisms potentially operative in the SGs, but an increase in pressure differential could have an impact on allowable degradation, i.e., condition monitoring and operational limits. The current differential pressure is 1365 psi, which will increase to an estimated maximum of 1400 psi with the EPU. The calorimetric measurement-based calculations used plant measured calorimetric data from cycle 17 to determine the change in T_{hot} . For an average T_{hot} of 596.3 °F for cycle 17, the expected best estimate difference is an increase of 7.7 °F (596.3 °F to 604.0 °F).

2.1.9.2.2 Description of Analyses and Evaluations

TS surveillance requirement 4.4.5.1 requires sg tube integrity to be verified in accordance with the steam generator program. TS Surveillance Requirement 4.4.5.2 requires verification that each inspected SG tube satisfies the tube repair criteria is plugged in accordance with the steam generator program. SG tube inspection is performed in accordance with the requirements TS 6.8.4.I, which establishes tube integrity performance criteria and defines provisions for condition monitoring assessments, tube repair criteria and inspection requirements (i.e., sample selection and inspection, frequency). Inspection reporting to the NRC is specified in TS 6.9.1.12. The steam generator program requires that an assessment of existing and potential degradation mechanisms be performed and that applicable non-destructive examination techniques be selected for use during the ISI.

Although process parameter changes due to the EPU may impact the initiation and growth rates of various degradation mechanisms, these changes are considered as part of the above program and will be considered in future degradation and condition monitoring assessments.

Tube inspections are planned and implemented in accordance with the steam generator program. After performing the SG tube inspections, a condition monitoring assessment is performed to determine if tube integrity performance criteria were maintained during the operating interval since the previous inspection. An operational assessment is performed to ensure that structural integrity and leakage performance criteria will be met during the operating interval until the next inspection. Tubes that are not projected to meet the structural integrity and/or leakage criteria are then removed from service by plugging, or repaired using an approved method. The existing and potential degradation mechanisms for steam generator tubes, based on inspections performed at the end-of-cycle 17, are limited to wear at tube supports.

SG tubing has not experienced any corrosion-related degradation. For the expected increase in T_{hot} (T_{hot} increasing from 596.3 °F to 604.0 °F), the impact on the initiation of corrosion degradation is expected to be negligible. This expectation is based on current operating experience at St. Lucie Unit 2 compared with other Alloy 690 TT plants operating at higher T_{hot} conditions and for longer operating periods in terms of effective full power hours. The inspection

scope for future tube examinations, and the continual monitoring of operating experience of other similar Alloy 690 TT plants, is sufficient to identify the onset of corrosion degradation.

The pressure differential across the tube wall used in the current operational assessment for cycle 18 is 1365 psi. Although this evaluated pressure differential is less than the projected EPU value of 1400 psi, the EPU is planned to start in cycle 19 or possibly later. Currently, St. Lucie Unit 2 is not skipping SG inspections and the next tube examination is planned for January 2011 at end-of-cycle 18. At that time, a new operational assessment and repair limits will be established for cycle 19 to Revision 3 of the tube integrity guidelines with EPU implemented. Therefore, there is no impact of EPU conditions on the current operational assessment.

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

As discussed above, the SGs are within the scope of License Renewal. Operation of the SGs under EPU conditions has been evaluated to determine if there any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.1.9.2.4 Results

An evaluation was conducted to assess the effects of the EPU on SG tube integrity due to potential changes in pressure, temperature, and flow rate. The SGs utilize Alloy 690 TT tubes and other design features that minimize the potential for tube degradation. Corrosion mechanisms such as primary water stress corrosion cracking (PWSCC), outer diameter stress corrosion cracking, pitting and denting, are influenced by increased operating temperatures. Mechanical processes, such as tube support wear; fatigue cracking and foreign objects wear would be more dependent on changes in the bundle flow rates.

Tube Support Wear – The SGs have experienced wear at tube supports; specifically at anti-vibration bars in the u-bend region and at tube support plates in straight sections. The cumulative plugging fraction for both SGs is very low for all causes: only 0.089 percent in SG 2A and 0.067 percent in SG 2B. Cumulatively, there are 2042 (11.3 percent) tubes with identified tube support wear, most of which are very shallow in nature. Inspection required by the existing steam generator program would detect large changes easily, and more subtle changes would be detected by the evaluation of wear rates of each inspection.

Foreign Objects – Wear may result from vibratory motion of the tubing or of a foreign object, depending on the specific design of the SG and the mass of the foreign object. Foreign object wear most frequently occurs in peripheral tubes where loose parts are too large to enter the tube

bundle or in cases where parts become lodged between tubes. The most common elevation at which foreign objects have been detected, sighted, and removed is the top of the tubesheet.

Secondary side visual inspections are routinely performed in both SGs during plant outages to evaluate the effectiveness of sludge lancing and to detect and investigate any potential foreign objects. At the end-of-cycle 17 inspections, two foreign objects were successfully removed from SG 2A top of tubesheet, and one foreign object was removed from the loose parts trapping system during steam drum inspections in SG 2B. All known foreign objects have been removed from both SGs, and there has been no tube damage observed, or tubes plugged, due to the presence of loose parts.

Based on the end of cycle 17 inspections, no actively tracked foreign objects remain in the SGs.

Corrosion Degradation –For the expected increase in T_{hot} (T_{hot} increasing from 596.3 °F to 604.0 °F), the impact on the initiation of corrosion degradation is expected to be negligible. The inspection scope for future tube examinations, and the continual monitoring of operating experience of other similar Alloy 690 TT plants, is sufficient to establish the onset of corrosion degradation.

2.1.9.3 Conclusion

FPL has evaluated the effects of the proposed EPU on SG tube integrity and concludes 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. FPL further concludes 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. Therefore, FPL finds the proposed EPU acceptable with respect to SG tube ISI.

2.1.10 Steam Generator Blowdown System

2.1.10.1 Regulatory Evaluation

Control of secondary-side water chemistry is important for preventing degradation of steam generator (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 Florida Power and Light Company (FPL) 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 inleakage and primary-to-secondary leakage).

The NRC's acceptance criteria for the SGBS are based on General Design Criteria (GDC)-14, insofar as it requires that the reactor coolant pressure boundary (RCPB) be designed so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture, and specific review criteria are contained in Standard Review Plan (SRP) Section 10.4.8.

St. Lucie Unit 2 Current Licensing Basis

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

- GDC-14 is described in UFSAR Section 3.1.14 Criterion 14 - Reactor Coolant Pressure Boundary.

The reactor coolant pressure boundary shall be designed, fabricated, created and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture.

The RCPB is defined in accordance with 10 CFR 50, Section 50.2(v) and ANSI N18.2, Section 5.4.3.2.

Accordingly, reactor coolant system (RCS) components are designed to meet the requirements of the ASME Code, Section III.

The RCPB is designed to accommodate the system pressures and temperatures attained under all expected modes of unit operation, including all anticipated transients, and to maintain the stresses within applicable limits.

UFSAR Section 10.4.8 describes the SGBS. The SGBS is utilized in conjunction with the chemical feed and secondary sampling systems (UFSAR Sections 10.3.5 and 9.3.2, respectively) to control the chemistry of the steam generator secondary side water.

The safety related portion of the SGBS, from the SG blowdown nozzle up to the outermost containment isolation valve, is designed to Quality Group B and seismic Category I requirements. The remainder of the system is designated non nuclear safety and non seismic.

The SGBS is designed to fulfill the following requirements:

- a. To control SG secondary side water chemistry as discussed in UFSAR Section 10.3.5,
- b. Monitor secondary side radioactivity for any primary to secondary leakage,
- c. Reduce the steam generator blowdown contaminants to an acceptable level prior to discharge to the environment,
- d. Provide a continuous blowdown rate of 0.2 percent of the total main steam flow during normal operating conditions,
- e. Permit a maximum blowdown rate of 1.0 percent of the total main steam flow during periods of abnormal condenser inleakage, and
- f. Provide blowdown system containment isolation capability.

SG secondary side water chemistry control is accomplished by:

- a. Control of feedwater purity to limit the amount of impurities introduced into the SG,
- b. Minimize feedwater oxygen content prior to entry into SG,
- c. Chemical addition to establish and maintain an environment which minimizes system corrosion,
- d. Continuous SG blowdown to reduce concentration effects within SG, and
- e. Condensate polisher filter demineralizer (CPFD) system use.

Secondary water chemistry is based on the zero solids treatment method. This method employs the use of volatile additives to maintain system pH and to scavenge dissolved oxygen present in the feedwater.

Zero solids treatment is a control technique whereby both soluble and insoluble solids are excluded from the steam generator. This is accomplished by maintaining strict surveillance over the possible sources of feed train contamination (e.g., main condenser seawater leakage, air inleakage and subsequent corrosion product generation).

The samples taken from the SGBS are used to continuously monitor the SG conductivity and pH, and are used as an indication of reactor coolant activity levels. SG blowdown sample lines are sized for 1.0 gpm flow.

In addition to the licensing basis described in the UFSAR, the SGBS was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.4.2 of the SER identifies that components of the SGBS system are within the scope of License Renewal. Programs used to manage the aging effects associated with the SGBS are discussed in SER Section 3.4.1 and Chapter 18 of the UFSAR.

2.1.10.2 Technical Evaluation

2.1.10.2.1 Introduction

The SGBS is discussed in UFSAR Section 10.4.8. Containment Isolation is discussed in UFSAR Section 6.2.4. The steam and power conversion system is discussed in UFSAR Sections 10.1-10.4. The secondary water chemistry is discussed in UFSAR Section 10.3.5. Condensate polishing is discussed in UFSAR Section 10.3.5.5.

The SGBS provides for continuous blowdown between 18,900 lb/hr and 94,500 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 (in conjunction with the chemical feed and secondary sampling systems), 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 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 120 °F which is cooled by the open cycle cooling system. The intake cooling water system provides the cooling for the open cycle heat exchangers.

Continuous blowdown from the SGs reduces accumulation of solids that result from the boiling process. The blowdown flow rates required during plant operation are based on chemistry control and tubesheet sweep requirements to control the buildup of solids.

The Secondary Sampling system, as discussed in UFSAR Section 9.3.2, provides verification of maintaining the total dissolved solids and pH within the required range for protecting the SG tubes and tube sheets.

2.1.10.2.2 Description of Analyses and Evaluations

The SGBS and components were evaluated to ensure they are capable of performing their intended functions.

The pressures and temperatures of SGBS piping was evaluated at EPU conditions and compared to current operating and design parameters. The valves, tanks, heat exchangers and process vessels were evaluated for the temperature and pressure conditions of EPU operation against their design temperatures and pressures.

The SG vendor confirmed the SGs have been designed considering a continuous blowdown flow rate equal to 1 percent of the steaming rate and this design remains valid for EPU. This maximum blowdown flow rate criterion is to maintain feedwater chemistry requirements should condenser in-leakage occur. Although the main steam flow rate increases, the allowable condenser in-leakage and the allowable primary to secondary leakage are not impacted at EPU and the maximum blowdown flow rate (94,500 lb/hr total from 2 SGs) remains unchanged at EPU. The normal blowdown flow rate remains bounded by the maximum flow rate. Since the maximum required flow rate is unchanged, supporting systems such as the radiation monitoring system, steam generator blowdown treatment facility, demineralization system, air blower

system, waste management system and spent resin system will continue to perform their intended function at EPU.

Monitoring of liquid effluents from the SGBS prior to release is addressed in LR [Section 2.10.1](#), Occupational and Public Radiation Doses.

The potential for increased erosion/corrosion is evaluated in LR [Section 2.1.8](#), Flow-Accelerated Corrosion.

Seismic qualification and dynamic qualification is addressed in LR [Section 2.2.5](#), Seismic and Dynamic Qualification of Mechanical and Electrical Equipment.

Safety related valve closure and testing requirements (containment isolation) are addressed in LR [Section 2.2.4](#), Safety-Related Valves and Pumps.

Piping and component supports are addressed in LR [Section 2.2.2.2](#), Balance of Plant Piping, Components, and Supports.

Protection against dynamic effects, including missiles, pipe whip and discharging fluids is addressed in LR [Section 2.2.1](#), Pipe Rupture Locations and Associated Dynamic Effects, and in LR [Section 2.5.1.3](#), Pipe Failures.

Environmental qualification of containment isolation valves is addressed in LR [Section 2.3.1](#), Environmental Qualification of Electrical Equipment.

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

As discussed above, the SGBS is within the scope of License Renewal. Operation of the SGBS under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.1.10.2.4 Results

The increased steam and feedwater flow rates at EPU conditions do not significantly affect the concentration of impurities throughout the turbine cycle nor increase the effect of the impurities on the SGs. The normal operating blowdown flow rate will remain within design limits and will continue to control chemistry as required. Therefore, no changes to the SGBS design flow rates or operating modes are needed as a result of the EPU.

The operation of the flow control valves and their control circuits is acceptable since the maximum blowdown flow rate does not change for EPU.

The maximum operating pressure in the secondary side of the SGs increases slightly (7.4 psi) and the maximum operating temperature is unchanged for EPU operation. However, the existing design pressure and temperature of the SG blowdown piping (985 psig and 550 °F) remain bounding and do not change at EPU. No modifications to the SGBS piping system, including the pumps, valves, tanks, vessels and heat exchangers are required as a result of implementation of the EPU.

The SGBS lines penetrating the containment are provided with air operated isolation valves which are designed to close for containment isolation in the event of CIAS or High Radiation signal. The maximum required blowdown flow rates experienced by these valves at EPU conditions are unchanged and remain within existing valve design capabilities and; therefore, these valves continue to meet their containment isolation design function.

The ability of the SGBS system to remove particulate and dissolved impurities from the SG secondary side during normal operation, including abnormal operational occurrences, will not be affected. Since the SGBS will continue to maintain SG secondary chemistry, EPU will not affect the plant's extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture of the reactor coolant pressure boundary.

UFSAR Section 6.2.4, Containment Isolation System, discusses the containment isolation function of the SGBS system isolation valves for lines penetrating the containment as necessary to assure at least two barriers for redundancy against leakage of radioactive fluids to the environment in the event of a loss-of-coolant accident. These barriers, in the form of isolation valves or closed systems are defined on an individual line basis. EPU does not change these provisions.

UFSAR Section 18.2.8, Flow-Accelerated Corrosion (FAC) Program predicts, detects, monitors, and mitigates flow accelerated corrosion in high energy carbon steel piping associated with the main steam, reactor coolant (SGs), main feedwater and SGBS, and is based on industry guidelines and experience. The SGBS system piping will continue to be monitored under the FAC Program. (LR Section 2.1.8, Flow-Accelerated Corrosion).

UFSAR Section 18.2.4, Chemistry Control Program, manages the aging effects of loss of material, cracking, and fouling for primary and secondary systems, closed cooling water, and fuel oil systems, structures, and components by controlling the chemical species that cause the underlying mechanism(s) that result in these aging effects. EPU does not affect the Chemistry Control Program.

2.1.10.3 Conclusion

FPL has reviewed the evaluation of the effects of the proposed EPU on the SGBS and concludes the evaluation has adequately addressed changes in system flow and impurity levels and their effects on the SGBS. FPL further concludes the evaluation has demonstrated the SGBS will continue to be acceptable and will continue to meet its current licensing basis with respect to the requirements of GDC-14 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to SGBS.

2.1.11 Chemical and Volume Control System

2.1.11.1 Regulatory Evaluation

The chemical and volume control system (CVCS) provides means for:

- Maintaining water inventory and quality in the reactor coolant system (RCS),
- Supplying pressurizer auxiliary spray,
- Controlling the boron neutron absorber concentration in the reactor coolant,
- Controlling the primary water chemistry and reducing coolant radioactivity level, and
- Supplying recycled coolant for demineralized water makeup for normal operation and high-pressure injection flow to the emergency core cooling system (ECCS) in the event of postulated accidents.

Florida Power and Light (FPL) reviewed the safety-related functional performance characteristics of CVCS components.

The NRC's acceptance criteria are based on:

- General Design Criterion (GDC)-14, insofar as it requires that the reactor coolant pressure boundary (RCPB) be designed so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture, and
- 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 event of anticipated operational occurrences.

Specific review criteria are contained in Standard Review Plan (SRP) Section 9.3.4.

The impact of the EPU on the boron recovery system (BRS) is provided in LR [Section 2.5.6.2](#), Liquid Waste Management Systems.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC GDC for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDC for the CVCS are as follows:

- GDC-14 is described in UFSAR Section 3.1.14 Criterion 14 – Reactor Coolant Pressure Boundary.

The RCPB shall be designed, fabricated, created and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture.

RCS components are designed to meet the requirements of the ASME Code, Section III. To establish operating pressure and temperature limitations during startup and shutdown of the

RCS, the fracture toughness rules defined in Appendix G of the ASME Code, Section III, are followed. Quality control, inspection, and testing as required by this standard, and allowable reactor pressure- temperature operations ensure the integrity of the RCS.

The RCPB is designed to accommodate the system pressures and temperatures attained under all expected modes of unit operation, including all anticipated transients, and to maintain the stresses within applicable limits.

Piping and equipment pressure parts of the RCPB are assembled and erected by welding unless applicable codes permit flanged, screwed, or compression joints. Welding procedures are employed which produce welds of complete fusion and free of unacceptable defects. All welding procedures, welders, and welding machine operators are qualified in accordance with the requirements of ASME Code, Section IX for the materials to be welded. Qualification records, including the results of procedure and performance qualification tests and identification symbols assigned to each welder are maintained.

The RCPB has provisions for inservice inspection in accordance with the requirements of ASME Code, Section XI, to ensure continuance of the structural and leaktight integrity of the boundary. For the reactor vessel, a material surveillance program conforming to the requirements of Appendix H of 10 CFR 50 is discussed in UFSAR Section 5.3.

- GDC-29 is described in UFSAR Section 3.1.29 Criterion 29 – Protection Against Anticipated Operational Occurrences.

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.

Plant conditions designated as Condition I and Condition II in ANSI N 18.2 are carefully considered in the design of the reactor protective system (RPS) and the reactivity control systems. Consideration of redundancy, independence and testability in the design, coupled with careful component selection, overall system testing, and adherence to detailed quality assurance, assure an extremely high probability that safety functions are accomplished in the event of anticipated operational occurrences.

UFSAR Section 9.3.4 states that the CVCS system is designed to perform the following functions:

- Maintain the chemistry, purity, and the activity level of the reactor coolant within prescribed limits during normal operation and during shutdown,
- Maintain the required volume of water in the RCS, compensating for reactor coolant contraction or expansion resulting from changes in reactor coolant temperature and for other reactor coolant losses or additions,
- Provide a controlled path for discharging reactor coolant to the waste management system,
- Control the boron concentration in the RCS to obtain optimum control element assembly positioning, to compensate for reactivity changes associated with major changes in reactor coolant temperature, core burnup, and xenon variations, and to provide shutdown margin for maintenance and refueling operations,

- Provide auxiliary pressurizer spray for operator control of pressure during the final stages of shutdown and to allow pressurizer cooling,
- Provide a means for functionally testing the check valves which isolate the safety injection system from the RCS,
- Collect the controlled bleedoff from the RCS pump seals,
- Leak test the RCS,
- Provide an alternate means for filling the RCS,
- Provide a means for hydrostatic testing of the RCS, and
- Provide a means for injecting concentrated boric acid into the RCS.

The CVCS supports containment isolation system functions as described in UFSAR Section 6.2.4. The CVCS system has piping sections that penetrate containment. The system isolation provides the means of isolating fluid that pass through containment penetrations such that any radioactivity that may be released into containment atmosphere following a postulated design basis accident is confined.

Technical Specification 3/4.1.2, Boration Systems, ensures that negative reactivity control is available during each mode of facility operation. The components required to perform this function include:

- Borated water sources,
- Charging pumps,
- Separate flow paths,
- Boric acid makeup pumps, and
- Emergency power supply from operable diesel generators.

In addition to the licensing basis described in the UFSAR, the CVCS was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.3.1 of the SER identifies that components of the CVCS are within the scope of License Renewal. Programs used to manage the aging effects associated with the CVCS are discussed in SER Section 3.3.1 and Chapter 18 of the UFSAR.

2.1.11.2 Technical Evaluation

2.1.11.2.1 Introduction

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

- To 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);
- To provide pressurizer auxiliary spray; and
- To 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 letdown flow is normally aligned to pass through the ion exchangers to 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 safety injection actuation signal (SIAS) during accident conditions or for safe shutdown of the plant. Excess coolant may be diverted into the waste management system.

2.1.11.2.2 Description of Analysis and Evaluations

The CVCS was evaluated to ensure the system is capable of performing its intended functions for the range of Nuclear Steam Supply System (NSSS) design parameters approved for the EPU (LR [Section 1.1](#), Nuclear Steam Supply System Parameters).

The changes in NSSS design parameters that could potentially affect the CVCS design bases functions 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, 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 system; and in the case of the regenerative HX, to the charging flow.

Regenerative Heat Exchanger

The regenerative HX cools the normal letdown flow from the RCS, which is at the RCS T_{cold} temperature. The design inlet (RCS T_{cold}) temperature of the regenerative HX is 550°F, which bounds the highest RCS T_{cold} temperature associated with the RCS no-load temperature of

532°F. The no-load RCS temperature, letdown flow, and charging flow do not change for the EPU. Although the full-load EPU T_{cold} temperature of 551°F (LR [Section 1.1](#), Nuclear Steam Supply System Parameters) will increase above the current design inlet value of 550°F, it is within 1°F of the design inlet T_{cold} value. The regenerative HX materials were evaluated and determined to be acceptable for a range of temperatures which bound the maximum EPU operating temperatures.

Letdown Heat Exchanger

The letdown HX cools the letdown flow from the regenerative HX. Since the 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 1°F difference in the letdown temperature can easily be accommodated within the capability of the letdown HX cooling water temperature control valve. Therefore, it is concluded that acceptable letdown HX performance is provided at the EPU conditions.

Charging, Letdown, and RCS Makeup (Boration, Dilution, and Purification)

As discussed in the previous sections for the CVCS HXs, there are no effects on their performance at the EPU conditions. Therefore, the charging and letdown flows at EPU conditions are unchanged 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 flow capacity performance of the RCS makeup system is not impacted by the change in RCS conditions resulting from the EPU conditions. However, the makeup system also 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 refueling water tank (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 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 will have an effect on the boration requirements that must be provided by the CVCS boration capabilities. The EPU analysis has determined that the increases in the BAM tank and RWT minimum concentration requirements are within the CVCS capability. The revised maximum concentration requirement for the RWT is conservative with the assumptions in the loss of coolant accident (LOCA) safety analysis for boron precipitation and within the solubility limit based on the RWT minimum temperature requirements. 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. Accordingly, the RSAC process will ensure the boration requirements are within the boration capability.

The 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 current programmed level will remain the same with the revised average temperature program endpoints. The current setpoints for charging and letdown control remain applicable 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 volume control tank and if necessary, from safety-related borated water sources. Safety-related makeup will always be available even when the VCT is drawn down below the low-low-level setpoint. The additional expansion/contraction at the EPU temperature conditions will result in acceptable system response.

Additionally, as noted in the above sections, there will be a slight increase in nominal letdown temperatures which 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. Normal purification flow is 40 gpm, as discussed in UFSAR Section 9.3.4.2.1.2. Since maximum purification flow is 128 gpm, adequate margin is available.

Refer to LR [Section 2.2.2](#), Pressure-Retaining Components and Component Supports, for an evaluation of the CVCS class 1 piping, including RCS nozzles and thermal sleeves.

The impact of the EPU on the Boron Recovery System is provided in LR [Section 2.5.6.2](#), Liquid Waste Management Systems.

2.1.11.2.3 Impact on Renewal Plant Operating License Evaluations and License Renewal Programs

As discussed above, the CVCS is within the scope of License Renewal. Operation of the CVCS under EPU conditions has been evaluated to determine if there any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.1.11.2.4 Results

The evaluations of the CVCS charging, letdown, and RCS makeup performance show the CVCS is acceptable at the EPU conditions. However, a change to Technical Specifications 3/4.1.2.7 and 3/4.1.2.8 will be required to increase boron concentrations in both the RWT and BAM tanks.

Additionally, the performance of the following CVCS functions (which are accomplished via charging, letdown, and makeup) are acceptable at EPU conditions:

- Control of the reactor coolant inventory, chemistry conditions, activity level, and boron concentration in accordance with the current licensing basis requirements with respect to GDC-29,
- Automatic diversion of letdown flow to the waste management system when the maximum permissible water level is reached in the VCT,
- Provision of pressurizer auxiliary spray, and
- Support of RCPB isolation in accordance with current licensing basis requirements with respect to GDC-14.

The CVCS boration requirements versus capability are addressed using the RSAC process for each core re-load cycle.

The performance of the CVCS components, including valves and piping, that support containment isolation are not affected by changes in the RCS design parameters resulting from the EPU.

2.1.11.3 Conclusion

FPL has reviewed the effects of the proposed EPU on the CVCS and concludes that it has adequately addressed changes in the temperature of the reactor coolant and their effects on the CVCS. FPL further concludes that the CVCS will continue to be acceptable and will also continue to meet its current licensing basis with respect to the requirements of GDC-14 and GDC-29 following implementation of the proposed EPU. Therefore, the proposed EPU is acceptable with respect to the CVCS.

2.2 Mechanical and Civil Engineering

2.2.1 Pipe Rupture Locations and Associated Dynamic Effects

2.2.1.1 Regulatory Evaluation

Structures, systems, and components (SSCs) important to safety could be impacted by the pipe-whip dynamic effects of a pipe rupture. Florida Power and Light (FPL) conducted a review of pipe rupture analyses to ensure that SSCs important to safety are adequately protected from the effects of pipe ruptures.

FPL's review covered:

- the implementation of criteria for defining pipe break and crack locations and configurations,
- the implementation of criteria dealing with special features, such as augmented in-service inspection (ISI) programs or the use of special protective devices such as pipe-whip restraints,
- pipe-whip dynamic analyses and results, including the jet thrust and impingement forcing functions and pipe-whip dynamic effects, and
- 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.

FPL's review focused on the effects that the proposed EPU may have on the above four items.

The NRC's acceptance criteria are based on General Design Criterion (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 Standard Review Plan (SRP) Section 3.6.2, and additional guidance is provided in Matrix of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC GDC for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDC for pipe rupture locations and associated dynamic effects is as follows:

- GDC-4 is described in the UFSAR Section 3.1.4, Criterion 4 – Environmental and Missile Design Bases.

Structures, systems and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging

fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and approved by the Commission demonstrates that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

SSCs are designed to accommodate the effects of and to be compatible with the pressure, temperature, humidity, and radiation conditions associated with normal operation, maintenance, testing, and postulated accidents including a LOCA, in the area in which they are located.

Non-Seismic Category I piping is arranged or restrained so that failure of any non-seismic Category I piping will neither cause a nuclear accident nor prevent essential seismic Category I structures or equipment from mitigating the consequences of such an accident.

Seismic Category I piping is arranged or restrained such that in the event of rupture of a seismic Category I pipe which causes LOCA, resulting pipe movement will not result in loss of containment integrity or adequate engineered safety features systems operation.

The following guidance documents are identified in UFSAR Section 3.6 for the original pipe break analysis:

1. Inside Containment:

Regulatory Guide (RG) 1.46, Protection Against Pipe Whip Inside Containment, May 1973 (R0).

2. Outside Containment:

The Giambusso Criteria; attachment to the December 1972 letter sent by A. Giambusso, Deputy Director for Reactor Projects, Directorate of Licensing to applicants and licensees, entitled "General Information Required for Consideration of the Effects of a Piping System Break Outside Containment" was used in addition to APCSB 3-1. The applicability of these criteria for St. Lucie Unit 2 was accepted during the NRC staff review as delineated in the Safety Evaluation Report (October 1981).

Subsequent to the requirements of a) and b) above, CEN-367-A, Leak-Before-Break Evaluation of Primary Coolant Loop Piping in Combustion Engineering Designed Nuclear Steam Supply Systems, provides the technical justification to eliminate reactor coolant system (RCS) hot and cold leg piping from the pipe rupture analysis. This evaluation demonstrates that the primary loop piping meets all of the criteria for application of leak before break presented in NUREG-1061, Volume 3. As a result, the mechanical/structural loads associated with dynamic effects of guillotine and slot breaks in RCS hot and cold leg piping are no longer considered a plant design basis.

RG 1.46 was superseded by SRP 3.6.2 in July 1981. NRC Generic Letter (GL) 87-11 revised NRC Branch Technical Position MEB 3-1, Postulated Rupture Locations in Fluid System Piping Inside and Outside Containment, as contained in the SRP, Section 3.6.2, Determination of Rupture Locations and Dynamic Effects Associated with the Postulated Rupture of Piping in June

1987. The revision eliminates all dynamic effects (missile generation, pipe whipping, pipe break reaction forces, jet impingement forces, compartment, subcompartment and cavity pressurizations and decompression waves within the ruptured pipe) and all environmental effects (pressure, temperature, humidity and flooding) resulting from arbitrary intermediate pipe ruptures. This action allows the elimination of pipe whip restraints and jet impingement shields installed to mitigate the effects of arbitrary intermediate pipe ruptures provided the requirements delineated in US NRC GL 87-11, [Relaxation in Arbitrary Intermediate Pipe Rupture Requirements, dated June 19, 1987] and NUREG-0800, USNRC Standard Review Plan, Section 3.6.2, Branch Technical Position (BTP) 3-1, [Postulated Rupture Locations in Fluid System Inside and Outside Containment] are met.

Postulated Piping Failures in Fluid Systems Inside Containment

UFSAR Section 3.6 describes the design bases criteria and protective design features that are used to demonstrate that the essential systems and components, and essential structures are adequately protected against the effects of postulated piping failures. High energy piping failure includes the effects of jet impingement, reactive forces and pipe whip, compartment pressure and environmental conditions. UFSAR Section 3.6.1.2.1 describes the systems, or portions of those systems, inside containment that are evaluated as high-energy pipelines for pipe rupture. UFSAR Section 3.6.2 describes the break locations and dynamic effects of pipe rupture. The high energy pipe rupture analysis inside containment is documented in UFSAR Appendix 3.6A.

Postulated Piping Failures in Fluid Systems Outside Containment

The systems outside containment that are evaluated as high energy pipelines for pipe rupture as well as the break locations and dynamic effects are described in UFSAR Sections 3.6.1 and 3.6.2. The high energy pipe rupture analysis outside containment is documented in UFSAR Appendix 3.6B.

Other UFSAR sections discussing the design of balance of plant and non-class 1 piping and supports that are potentially impacted by pipe rupture and their dynamic effects include:

- UFSAR Section 3.2, Classification of Structure, Systems, and Components, provides details with respect to the seismic and quality group classification of piping and piping components.
- UFSAR Section 3.7, Seismic Design, and specifically Section 3.7.3.1, Seismic Subsystem Analysis methods, provides details with respect to the seismic qualification of piping and piping components.
- UFSAR Section 3.9.2, Mechanical System and Components, specifically Section 3.9.2.1.1, Vibrational Testing.

In addition to the licensing basis described in the UFSAR, the pipe rupture locations and associated dynamic effects were evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems and structures to identify those systems or portions of systems that are in the scope of License Renewal. Those systems and structures determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Sections 2.4.1 and 2.4.2.11 of the SER identify that components of the

systems inside the containment and auxiliary building are within the scope of License Renewal. The programs used to manage the aging associated with the pipe rupture locations and associated dynamic effects are discussed in SER Section 3.5 and Chapter 18 of the UFSAR. Time limited aging analyses associated with pipe break locations are discussed in SER Section 4.1.

2.2.1.2 Technical Evaluation

2.2.1.2.1 Introduction

The impact of EPU on the determination of pipe break locations and the associated dynamic effects have been evaluated. Systems in which design basis pipe breaks are postulated to occur, the design basis pipe break criteria, analysis methodologies for the evaluation of pipe whip, jet impingement effects and description of protective measures for postulated pipe breaks are addressed in Section 3.6, Appendices 3A, 3B, 3C 3D and 3E of the UFSAR. The purpose of postulation of pipe breaks is to comply with the requirements of GDC-4, of Appendix A to 10 CFR Part 50 for the design of nuclear power plant structures and components. FPL conducted a review of pipe break postulation and associated pipe rupture analyses to ensure that SSCs are adequately protected from the dynamic effects of pipe ruptures such as pipe whip, jet impingement.

LR [Section 2.5.1.3](#) addresses the impact of the EPU on piping system failures outside of the containment.

LR [Section 2.2.2.2](#) addresses the impact of EPU on balance of plant piping, components and supports.

2.2.1.2.2 Description of Analyses and Evaluations

Postulated Piping Failures in Fluid Systems Inside Containment

UFSAR Section 3.6.1.2 provides a list of high and moderate energy piping systems or portions of systems located inside the primary containment for which pipe breaks are postulated to occur.

Design basis pipe break criteria are presented in UFSAR Section 3.6.1 and Appendices 3.6A and 3.6C.

The current structural design basis includes the application of leak before break (LBB) methodology per NUREG-1061, to eliminate consideration of the dynamic effects resulting from pipe breaks in the RCS primary loop piping. LBB is addressed in LR [Section 2.1.6](#), which describes the evaluations performed to demonstrate that the elimination of these breaks from the structural design basis. This LBB analysis continues to be valid following the implementation of EPU, and that primary loop piping for which the licensee credits LBB continue to comply with the requirements of GDC-4 and NUREG-1061 Volume 3. The evaluations performed in support of LR [Section 2.1.6](#) are credited in this LR with respect to excluding the dynamic effects of postulated ruptures in primary coolant loop piping hot and cold legs.

Although the requirement for designing for dynamic effects associated with a RCS hot or cold leg break have been eliminated from the plant design bases, the original design features installed to

mitigate the consequences of such a break remain in place and functional with the exception of the steam generator (SG) sliding base support. As a result of the installation of the replacement SGs the shim plate attached to the SG sliding base support has been permanently removed thereby deleting the north-south direction LOCA restraint for the SG sliding base support.

Postulated Piping Failures in Fluid Systems Outside Containment

UFSAR Section 3.6.1.2 also provides a list of high energy piping lines located outside the primary containment for which pipe breaks are postulated to occur.

The criteria for postulating pipe breaks for piping located outside containment are presented in UFSAR Section 3.6.2.2.2.

The AEC letter from A. Giambusso dated December 18, 1972, requested an analysis of the effects of postulated failures of high energy lines outside containment. Design basis break and crack locations, type and orientation are postulated in accordance with the information presented in UFSAR Appendix 3.6B

Affected piping systems as described in UFSAR Section 3.6.1 were evaluated to address revised EPU operating conditions. Applicable pipe rupture/environmental crack postulation criteria were reviewed as well as changes to piping operating temperatures and pressures. Piping system stress levels resulting from EPU were reviewed against pipe break evaluation requirements. Pipe stresses for break exclusion zones were demonstrated to be within acceptable limits.

The EPU evaluations performed for applicable piping systems did not result in any new or revised break / crack locations, and the design basis for pipe break, jet impingement, pipe whip and environmental considerations remain valid for EPU.

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

As discussed above, the pipe rupture locations and associated dynamic effects are within the scope of License Renewal. Operation of the affected systems under EPU conditions has been evaluated to determine if there any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.2.1.2.4 Results

For the balance of plant piping systems, the evaluation for EPU conditions did not result in any new or revised pipe break locations, and based on evaluations performed for EPU, the following were demonstrated:

- Existing criteria for defining pipe break and crack locations and configurations are unaffected by EPU,
- Criteria dealing with special features, such as augmented ISI programs or the use of special protective devices such as pipe whip restraints is unaffected by EPU,
- Existing pipe whip dynamic analyses and results, including the jet thrust and impingement forcing functions and pipe whip dynamic effects remain valid for EPU, and
- Existing design of SSC's remain acceptable to protect safety related SSC's from the effects of pipe whip and jet impingement loading for EPU.

2.2.1.3 Conclusion

FPL has reviewed the evaluations related to determinations of pipe rupture locations and associated dynamic effects and concludes that they have adequately addressed the effects of the proposed EPU on them. FPL further concludes that the evaluations have demonstrated that SSCs important to safety will continue to meet their current licensing basis with respect to the requirements of GDC-4 following implementation of the proposed EPU. Therefore, FPL 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

Introduction

In keeping with the format of Review Standard (RS)-001 Rev. 0, this LR section is arranged differently than other LR sections. The following regulatory evaluation subsection generally applies to all the specific components addressed individually in later technical evaluation subsections. In addition to the generic regulatory evaluation, any amplifications or qualifications necessary for individual component types are provided in the introduction section for each component.

This document contains a current licensing basis (CLB) subsection that addresses St. Lucie Unit 2 compliance with the generic regulatory evaluation criteria. In addition to the generic CLB subsection, when necessary, a component-specific CLB provides further details pertinent to that component, and explains any exception to the generic CLB.

Regulatory Evaluation

Florida Power and Light (FPL) has reviewed the structural integrity of pressure-retaining components (and their supports) designed in accordance with the ASME B&PV Code, Section III, Division 1 and General Design Criteria (GDC)-1, -2, -4, -14 and -15. The review focused on the effects of the proposed EPU on the design input parameters and the design-basis loads and load combinations for normal, upset, emergency and faulted conditions. The review covered the analyses of flow-induced vibration and the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. The review also included a comparison of the resulting stresses and cumulative fatigue usage factors (CUFs) against code-allowable limits.

The acceptance criteria are based on:

- 10 CFR 50 Part 55a and GDC-1, insofar as they require that structures, systems, and components (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;
- 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;
- 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;
- GDC-14, insofar as it requires that the reactor coolant pressure boundary (RCPB) be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture; and
- GDC-15, insofar as it requires that the reactor coolant system (RCS) be designed with sufficient margin to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation.

Specific review criteria are contained in Standard Review Plan (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.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1

UFSAR Sections 3.1, 3.2, 3.5, 3.6, 3.7, 3.8, 3.9, and Chapter 5 address the quality assurance, classification and design of safety-related pressure retaining components and component supports.

The specific GDCs for the pressure-retaining components and component supports' design as well as compliance with the requirements of 10CFR50.55a(a)(1) are as follows:

- 10CFR50.55a(a)(1) is described in UFSAR Section 5.2.1.1, Compliance with 10 CFR 50.55a.

RCS components are designed and fabricated in accordance with 10 CFR 50.55a. The actual addenda of the ASME B&PV Code applied to the original design of each component are listed in UFSAR Table 5.2-1.

- GDC-1 is described in UFSAR Section 3.1.1 Criterion 1 – Quality Standards and Records.

Structures, systems and components important to safety shall be designed, fabricated, erected and tested to quality standards commensurate with the importance of the safety functions to be performed. Where generally recognized codes and standards are used, they shall be identified and shall be supplemented or modified as necessary to assure a quality product in keeping with the required safety function. A quality assurance program shall be established and implemented in order to provide adequate assurance that these structures, systems, and components will satisfactorily perform their safety functions. Appropriate records of the design, fabrication, erection and testing of structures, systems and components important to safety shall be maintained by or under the control of the nuclear power unit licensee throughout the life of the unit.

Structures, systems and components (SSCs) of the facility are classified according to their relative importance to safety. Those items vital to safety such that their failure might cause or result in an uncontrolled release of an excessive amount of radioactive material are designated seismic Category I. They and items of lesser importance to safety are designed, fabricated, erected and tested according to the provisions of recognized codes and quality standards. Discussions of the applicable codes, standards, records and quality assurance program used to implement and audit the operation processes were originally presented in UFSAR Section 17.2; however, this information is now provided in FPL Quality Assurance Topical Report FPL-1. A complete set of facility structural, arrangement and system drawings is maintained under the control of FPL throughout the life of the plant. Quality assurance written data and comprehensive test and operating procedures are likewise assembled and maintained by FPL. The classification of seismic Category I structures and safety related systems and components is discussed in UFSAR Section 3.2.

- GDC-2 is described in UFSAR Section 3.1.2 Criterion 2 – Design Bases for Protection Against Natural Phenomena

Structures, systems and components important to safety shall be designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunamis and seiches without loss of capability to perform their safety functions. The design bases for these structures, systems and components shall reflect: (1) appropriate consideration of the most severe of natural phenomena that have been historically reported for the site and surrounding area, with sufficient margin for the limited accuracy, quantity, and period of time which the historical data have been accumulated, (2) appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena and (3) the importance of the safety functions to be performed.

SSCs important to safety are designed to withstand the effects of natural phenomena without loss of capability to perform their safety functions. Natural phenomena factored into the design of plant structures, systems and components important to safety are determined from recorded data for the site vicinity with appropriate margin to account for uncertainties in historical data.

The most severe natural phenomena postulated to occur at the site in terms of induced stresses is the safe shutdown earthquake (SSE). Those structures, systems, and components vital for the mitigation and control of accident conditions are designed to withstand the effects of a loss of coolant accident (LOCA) coincident with the effects of the SSE. SSCs vital to the safe shutdown of the plant are designed to withstand the effects of any one of the most severe natural phenomena, including flooding, hurricanes, tornadoes and the SSE.

Design criteria for wind and tornado, flood and earthquake are discussed in UFSAR Sections 3.3, 3.4 and 3.7, respectively.

- GDC-4 is described in UFSAR Section 3.1.4 Criterion 4 – Environmental and Missile Design Basis.

Structures, systems and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and approved by the Commission demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

SSCs important to safety are designed to accommodate the effects of and to be compatible with the pressure, temperature, humidity, and radiation conditions associated with normal operation, maintenance, testing, and postulated accidents including a LOCA, in the area in which they are located.

Due to the application of leak before break methodology to the RCS hot and cold leg piping, the dynamic effects of a loss of coolant accident do not have to be considered. A technical evaluation

was performed to demonstrate that the probability or likelihood of large pipe breaks occurring in the primary coolant loops is sufficiently low that they need not be a design basis.

Protective walls and slabs, local missile shielding, or restraining devices are provided to protect the containment and engineered safety features systems within the containment against damage from missiles generated by equipment failures. The concrete enclosing the RCS serves as radiation shielding and an effective barrier against internally generated missiles. A missile shield is provided for control element drive mechanisms. Penetrations and piping extending outward from the containment, up to and including isolation valves are protected from damage due to pipe whipping, and are protected from damage by external missiles, where such protection is necessary to meet the design bases.

Non-Seismic Category I Piping is arranged or restrained so that failure of any non-seismic Category I piping will neither cause a nuclear accident nor prevent essential seismic Category I structures or equipment from mitigating the consequences of such an accident.

Seismic Category I piping is arranged or restrained such that in the event of rupture of a seismic Category I pipe which causes LOCA, resulting pipe movement will not result in loss of containment integrity or adequate engineered safety features systems operation.

The structures inside the containment vessel are designed to sustain dynamic loads which could result from failure of major equipment and piping, such as jet thrust, jet impingement and local pressure transients, where containment integrity is needed to cope with the conditions.

Refer to UFSAR Sections 3.5, 3.6, 3.7, and 3.11 for details.

- GDC-14 is described in UFSAR Section 3.1.14 Criterion 14 – Reactor Coolant Pressure Boundary.

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.

The RCPB is defined in accordance with 10 CFR 50, Section 50.2(v) and ANSI N18.2, Section 5.4.3.2.

RCS components are designed to meet the requirements of the ASME Code, Section III. To establish operating pressure and temperature limitations during startup and shutdown of the RCS, the fracture toughness rules defined in Appendix G of the ASME Code, Section III, is followed. Quality control, inspection, and testing as required by this standard and allowable reactor pressure-temperature operations ensure the integrity of the RCS.

The RCPB is designed to accommodate the system pressures and temperatures attained under all expected modes of unit operation, including all anticipated transients, and to maintain the stresses within applicable limits.

Piping and equipment pressure parts of the RCPB are assembled and erected by welding unless applicable codes permit flanged, screwed, or compression joints. Welding procedures are employed which produce welds of complete fusion and free of unacceptable defects. All welding procedures, welders, and welding machine operators are qualified in accordance with the requirements of ASME Code, Section IX for the materials to be welded. Qualification records,

including the results of procedure and performance qualification tests and identification symbols assigned to each welder are maintained.

The pressure boundary has provisions for inservice inspection in accordance with the requirements of ASME Code, Section XI, to ensure continuance of the structural and leaktight integrity of the boundary. For the reactor vessel, a material surveillance program conforming with the requirements of Appendix H of 10 CFR 50 is given in UFSAR Section 5.3.

- GDC-15 is described in UFSAR Section 3.1.15 Criterion 15 – Reactor Coolant System Design Criterion.

The Reactor Coolant System and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.

The design criteria and bases for the RCPB are described in the response to GDC-14.

The operating conditions for normal steady state and transient plant operations are established conservatively (see UFSAR Section 4.4.3). Normal operating limits are selected so that an adequate margin exists between operating and design limits. The plant control systems are designed to ensure that plant variables are maintained well within the established operating limits. The plant transient response characteristics and pressure and temperature distributions during normal operations are considered in the design as well as the accuracy and response of the instruments and controls. These design techniques ensure that a satisfactory margin is maintained between the plant's normal operating conditions, including design transients, and the design limits for the reactor coolant pressure boundary.

The plant control systems function to minimize deviations from normal operating limits in the event of most anticipated operational occurrences (ANSI N18.2 Condition II Occurrences). Where control systems response would be inadequate or fail upon demand, the reactor protective system (RPS) and the engineered safety features system (ESFS) function to mitigate the consequences of such events.

The RPS and ESFS function to mitigate the consequences of accidents (ANSI N18.2 Condition III or IV occurrences). Analyses show that the design limits for the reactor coolant pressure boundary are not exceeded in the event of any ANSI N18.2 Condition II, III or IV occurrences See UFSAR Section 5.2 and UFSAR Chapter 7 for further information.

Compliance with the requirements of IN 95-016, IN 02-026, IN 96-049, GL 96-06, RG 1.84, RG 1.147, DG 1.1089, DG 1.090 and DG 1091 is addressed in the technical evaluation section associated with LR [Sections 2.2.2.1 through 2.2.2.7](#) as applicable.

In addition to the licensing basis described in the UFSAR, the pressure retaining components were evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. The individual NUREG-1779 sections which apply to both components and component supports are discussed in LR [Sections 2.2.2.1 through 2.2.2.7](#).

2.2.2.1 Nuclear Steam Supply System Piping, Components and Supports

2.2.2.1.1 Introduction

This License Report (LR) section addresses Nuclear Steam Supply System (NSSS) piping, components, and supports. Discussion regarding the balance of plant (BOP) piping and supports is presented in LR [Section 2.2.2.2](#), BOP Piping, Components and Supports. The NSSS piping, which is comprised of the reactor coolant system (RCS) piping, consists of two heat transfer piping loops (loops A and B) connected in parallel to the reactor vessel (RV). Each loop contains two reactor coolant pumps (RCP) and a steam generator (SG). Each RCS loop consists of: 1) a hot leg pipe from the RV to the SG, 2) a cross-over leg (i.e., RCP suction leg) pipe from the SG to each of the RCPs, and 3) a cold leg (i.e., RCP discharge leg) pipe from each RCP to the RV. The RCS also includes a pressurizer, quench tank, and connecting piping.

The pressurizer is connected to loop B. Branch piping connections into the RCS piping are provided as necessary. The RCS piping system is supported by the primary equipment supports of the RCS, namely the RV supports, the SG supports, the RCP supports, and the pressurizer supports. The RCPs and their supports are discussed in LR [Section 2.2.2.6](#), Reactor Coolant Pumps and Supports; the pressurizer and supports are discussed in LR [Section 2.2.2.7](#), Pressurizer and Supports.

St. Lucie Unit 2 Current Licensing Basis

The generic CLB in LR [Section 2.2.2](#) applies to this LR section relative to NSSS piping, components and supports.

The reactor coolant piping is designed and analyzed for normal operation and all transients discussed in UFSAR Section 3.9.1. In addition UFSAR Section 3.9.1 presents loading combinations and stress criteria associated with faulted conditions. The ASME Code and Addenda the piping is designed to is specified in UFSAR Section 5.2.1.

To minimize the possibility of stress corrosion cracking, the reactor coolant piping is fabricated from SA-516 GR 70 base material mill clad with SA-240, Type 304L stainless steel. The surge line, spray lines, and other small lines are totally made of stainless steel. Nozzles are shop fabricated with safe ends to preclude dissimilar field welds.

The design of NSSS components is described in UFSAR Chapter 5.

The criteria applied in the design of the RCS supports are that the specific function of the supported equipment be achieved during all normal, earthquake, and loss of coolant accident (LOCA) conditions. Specifically, the supports are designed to support and restrain the RCS components under the combined design basis earthquake and LOCA loadings in accordance with the stress and deflection limits listed in UFSAR 3.9.3.1.

The RCS support points are illustrated in UFSAR Figures 3.8-41, 3.8-42, 3.8-43, 3.8-44, and 3.8-52.

The RCS in-service inspection is discussed in UFSAR Section 5.2.4.

Refer to LR [Sections 2.2.2.2](#) through [Sections 2.2.2.7](#) for additional information pertaining to NSSS components and supports.

The licensing basis associated with the NSSS piping, components, and supports, including primary equipment supports for the SGs, RCPs, pressurizer, are identified in the following UFSAR sections:

- UFSAR Section 3.2, Classification of Structures, Systems, and Components (SSCs), provides details with respect to the seismic classification of piping and piping components;
- UFSAR Section 3.7, Seismic Design, provides details with respect to the seismic design of SSCs that comprise the NSSS Scope qualification of piping and piping components;
- UFSAR Section 3.9, Mechanical System and Components, provides details with respect to the design of RCS components;
- UFSAR Section 3.9.3.1 Loading Combinations, Design Transients and Stress Limits, provides details of fatigue analyses required by the applicable codes listed in UFSAR Table 5.2-1;
- UFSAR Section 5.4, Component and Subsystem Design, provides details with respect to the design of NSSS structures, systems, and components; and
- UFSAR Section 5.4.3, Reactor Coolant Piping, provides details with respect to the design bases, description, evaluation, and testing and inspection of the Reactor Coolant Piping.

In addition to the licensing basis described in the UFSAR, the NSSS piping, components, and supports were evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.1.1 of the SER identifies that components of the NSSS piping, components, and supports are within the scope of License Renewal. Programs used to manage the aging effects associated with the NSSS piping, components, and supports are discussed in SER Section 3.1.1.1 and Chapter 18 of the UFSAR.

2.2.2.1.2 Technical Evaluation

The approach taken in the evaluation for the extended power uprate (EPU) was to reconcile the existing design basis analysis results from a given structural analysis, relative to EPU-related effects. If the results did not confirm that the existing design basis remained bounding, an EPU-specific analysis was performed, and the results of that analysis were compared to the current results to resolve any discrepancies.

Note that the primary structural analyses for normal operating, seismic, and pipe break conditions are performed separately. Therefore, the input forcing functions, or applied loadings, for these conditions are not combined to produce a single set of inputs. Instead, the individual normal operating, seismic, and branch line pipe breaks (BLPB) analysis results are combined in accordance with the UFSAR 3.8.2 and the design specifications to produce the specified service level stress results, which are then compared to the Code allowables.

2.2.2.1.2.1 Input Parameters, Assumptions, and Acceptance Criteria

The following four basic sets of input parameters were used in the technical evaluation for the EPU:

- Design parameters for 3020 MWt identified in LR [Table 1.1-1](#) of LR [Section 1.1](#), Nuclear Steam Supply System Parameters,
- NSSS design transients identified in LR [Section 2.2.6](#), NSSS Design Transients,
- Loop LOCA hydraulic forcing functions forces identified in LR [Section 2.8.5.6.3](#), Emergency Core Cooling System (ECCS) & LOCA, and
- The associated Loop LOCA RV motions identified in LR [Section 2.2.3](#), Reactor Pressure Vessel Internals and Core Supports.

The acceptance criteria for the RCS main coolant piping are based on the ASME Code ([Reference 1](#)), as used in the current design basis.

The original acceptance criteria for the pressurizer surge line were also based on the ASME Code ([Reference 1](#)). The surge line was subsequently evaluated to the acceptance criteria of ASME Code, Section III, 1986 ([Reference 2](#)) in order to include the effects of thermal stratification on stress and fatigue. The surge line thermal stratification evaluation was performed to address in NRC Bulletin 88-11 ([Reference 7](#)). In part, [Reference 7](#) states:

...licensees of plants in operation over 10 years (i.e., low power license prior to January 1, 1979) are requested to demonstrate that the pressurizer surge line meets the applicable design codes* and other UFSAR and regulatory commitments for the licensed life of the plant, considering the phenomena of thermal stratification and thermal striping in the fatigue and stress evaluations, where Note * is: "Fatigue analysis should be performed in accordance with the latest ASME Section III requirements incorporating high cycle fatigue."

The results of the effort performed to address [Reference 7](#) are contained in [Reference 8](#), which reported that the structural integrity of the pressurizer surge line is maintained for the transients due to thermal stratification.

The acceptance criteria for the NSSS primary equipment supports are based on the ASME B&PV Code ([References 3, 4 and 5](#)) as used in the current design basis.

Florida Power & Light (FPL) has implemented an Alloy 600 Management Program that was developed utilizing the EPRI Material Reliability Program (MRP) guidance. This program is focused upon both pressure and non-pressure boundary RCS components constructed of Alloy 600 and welds constructed of the associated alloy 82/182 filler materials. This program includes the management of short and long term inspection, evaluation and mitigation. For additional information pertaining to primary water stress corrosion cracking (PWSCC) of Alloy 600 materials refer to LR [Section 2.1.5](#).

Design Parameters for EPU Operation

The design parameters for operation at the EPU, as identified in LR [Table 1.1-1](#) of LR [Section 1.1](#) were used in the normal operating loads analysis, the reconciliation of the RCS components and the re-evaluation of the pressurizer surge line.

NSSS Design Transients

The impact on the design transients due to the changes in full power operating temperatures for the EPU is addressed in LR [Section 2.2.6](#), NSSS Design Transients. It was concluded that a 1°F temperature increase in the plant loading and unloading transient will result from the EPU operation. This small change has a negligible effect on RCS stress and fatigue results for the piping and the primary components, because the design basis temperature and pressure curves defining the transients were determined in a conservative manner when the RCS was designed. Consequently, a 1°F change in the through-wall thermal gradients for a subset of the design basis transients (plant loading and unloading) has a negligible effect on stresses and fatigue usage, which are due to the effects of the full set of plant transients (e.g., plant heatup and cooldown, plant load change, reactor trip, hydrostatic and leak test, loss of flow, and abnormal loss of load).

For the pressurizer surge line, the impact of the design transients with respect to thermal stratification and fatigue analysis is impacted by the ΔT between the pressurizer and the hot leg temperature. The controlling ΔT 's for the pressurizer surge line are associated with plant heatup and cooldown events, which are not transients affected by the EPU. See LR [Section 2.2.6](#) for further discussion of the heatup and cooldown transients.

Loop LOCA Hydraulic Forcing Functions Forces and Associated Loop LOCA RV Motions

The impact of the EPU on the loop LOCA hydraulic forcing functions (HFFs) is addressed in LR [Section 2.8.5.6.3](#) and the associated loop LOCA RV motions are addressed in LR [Section 2.2.3](#). Leak-before-break (LBB) eliminates pipe breaks from the RCS main loop piping (see LR [Section 2.1.6](#)). As a result of LBB, the limiting pipe breaks considered in the EPU design basis with respect to RCS and RV dynamic/mechanical response are BLPBs.

The response of the RCS loop to BLPBs is bounded by the response of the RCS loop to the originally postulated LOCAs due to the fact that the larger original pipe break applied loads cause larger loads, displacements, and accelerations in the RCS. Therefore, the RCS piping LOCA analyses evaluation which was based on the larger original mechanistic pipe breaks, remains bounding for the EPU.

2.2.2.1.2.2 Description of Analyses and Evaluations

The design parameters that will change due to the EPU were reviewed for impact on the RCS piping and branch lines attached to the RCS at the RCS branch nozzle connections. Margins for primary and primary plus secondary stresses, and for cumulative fatigue usage were determined, where fatigue usage is measured by the cumulative usage factor (CUF), which has an ASME Code allowable limit of 1.0.

As discussed in the UFSAR, Section 3.7.3.1.2.2, the RCS loop seismic analysis was performed using the ICES STRUDL II and TMCALC programs. Since the EPU does not affect the seismic analysis parameters, a seismic re-analysis of the RCS loop is not necessary for the EPU.

The original RCS asymmetric loads LOCA analysis was performed using the ICES STRUDL II and DAGS computer programs. Since LBB eliminated main coolant loop piping LOCAs, BLPBs are the design basis RCS loop analysis pipe breaks considered for the EPU. Furthermore, since

main coolant loop piping LOCA effects bound the effects due to BLPBs, the LOCA analyses from the current (pre-EPU) design basis analysis remain applicable for the EPU, as discussed in LR [Section 2.2.2.1.2.1](#) under the heading “Loop LOCA Hydraulic Forcing Functions Forces and Associated Loop LOCA RV Motions.” In summary, large mechanistic breaks no longer have to be considered. Subsequently, the design basis results remain valid and applicable to the EPU.

For the EPU, the RCS loop was re-analyzed for normal loading effects (dead weight (DWt) and thermal expansion) using the ANSYS program. The ANSYS model of the RCS for these loading cases was developed to reflect the current as-built plant configuration and the EPU conditions. The DWt analysis that was performed in conjunction with the thermal expansion analysis reflected the weight of the RCS at the EPU steady state conditions. The thermal analysis evaluated the RCS loop for the T_{hot} and T_{cold} temperatures associated with the EPU.

The use of the ANSYS, STRUDL, DAGS, and TMCALC computer codes has been accepted by the NRC, and is discussed in the UFSAR, Section 3.9.1.2.2.

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

As discussed above, the NSSS piping, components, and supports are within the scope of License Renewal. Operation of the NSSS piping, components, and supports under EPU conditions has been evaluated to determine if there any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.2.2.1.2.4 Results

The maximum RCS piping stresses and CUFs for the EPU and the corresponding code allowables are presented in LR [Table 2.2.2.1-1](#) for all RCS piping except the surge line, whose stresses and maximum CUFs are summarized in LR [Table 2.2.2.1-2](#). The stresses are combined in accordance with the ASME code criteria as described in [Reference 1](#). From the results tabulated in LR [Tables 2.2.2.1-1](#) and [2.2.2.1-2](#), the RCS piping stresses and CUFs are within the allowable limits and acceptable for the EPU. Note that the surge line stresses and CUFs contained in LR [Table 2.2.2.1-2](#) are from the current analyses of record (AORs), because the change in operating conditions associated with the EPU doesn't change the resulting normal operation loads acting on the surge line.

The applicable RCS piping primary equipment support loads associated with the EPU parameters were evaluated and determined to be acceptable (see LR [Sections 2.2.2.3](#), [2.2.2.5](#), and [2.2.2.6](#)).

The RCP suction and discharge nozzle loads were compared to the allowables associated with the original equipment design. The forces and moments on the suction and discharge nozzles due to the EPU all decreased, with the exception of the forces on the discharge nozzle, where some components of force increased and others decreased. LR [Section 2.2.2.6](#) contains a more detailed discussion of the RCP nozzle load changes due to the EPU, and the reasons why they remain acceptable.

The applicable RCS piping loads resulting from the EPU operating temperatures, as defined by the EPU NSSS parameters identified in [Table 1.1-1](#) of LR [Section 1.1](#) were evaluated for impact on LBB ([Reference 6](#)) in LR [Section 2.1.6](#).

It was determined that operation at EPU conditions will result in some of the RCS piping displacements at the intersection of the centerline of the RCS piping and the branch piping system nozzle connections to increase. Subsequent analysis of the affected nozzles determined that the nozzle loads were acceptable. Furthermore, assessments of the affected branch piping systems attached to the RCS determined that the branch line piping and support loads were also acceptable.

For the pressurizer surge line, variations in the pressurizer and hot leg temperature difference due to the EPU, which affect the design transients with respect to thermal stratification and fatigue analysis, have been evaluated. The limiting ΔT s for the pressurizer surge line remain the ΔT s associated with the plant heatup and cooldown events which are not affected by the EPU.

As discussed in LR [Section 2.2.2.1.2.1](#) above, the current design basis pressurizer surge line analysis results, including the effects of thermal stratification, remain applicable for the EPU and meet the acceptance criteria

2.2.2.1.3 Conclusion

The parameters associated with the EPU have been evaluated for their effect on the following:

- 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, and
- Primary equipment support loads (RV, SGs, and RCPs).

The evaluation determined that the parameters associated with the EPU have no adverse effect on the analysis of the RCS piping system, including any impact on the primary equipment nozzles. The RCS piping stresses meet the required stress criteria as summarized in LR [Table 2.2.2.1-1](#). The primary equipment nozzle loads are acceptable. The RCS piping loads associated with the EPU are discussed in LR [Section 2.1.6](#). The RCS primary equipment support loads meet the required stress criteria as summarized in the LR [Section 2.2.2.3](#), Reactor Vessel

and Supports, LR [Section 2.2.2.5](#), Steam Generator and Supports, and LR [Section 2.2.2.6](#), Reactor Coolant Pumps and Supports.

Changes in the main loop piping branch nozzle displacements that are associated with this evaluation have no significant impact on the branch piping systems that are attached to the RCS. As such, the AORs for the attached piping systems, which have been analyzed in a conservative manner, are not impacted by the EPU.

The temperatures and the design transients impacted by the EPU have an insignificant effect on the pressurizer surge line design basis analysis, including the effects of thermal stratification. Therefore, the EPU has no adverse impact on either the thermal stratification or the fatigue analysis for the pressurizer surge line remain bounding.

The current fatigue analysis bounds the EPU conditions, and since the 40-year design transient set bounds 60 years of operation, the current fatigue analysis remains bounding for the EPU throughout 60 years of operation. Additional details are discussed in the LR [Section 2.14](#), Impact of EPU on the Renewed Plant Operating License.

For the impact on the environmentally assisted fatigue evaluations, see LR [Section 2.14.2](#).

FPL concludes that the evaluations have adequately accounted for the effects of the proposed EPU on NSSS piping, components and supports. Based on this, it is concluded that the pressure-retaining components and their supports will continue to meet their current licensing basis with respect to the requirements of 10 CFR 50.55a, GDC-1, GDC-2, GDC-4, GDC-14, and GDC-15. FPL finds the proposed EPU is acceptable with respect to the structural integrity of the pressure-retaining components and their supports.

2.2.2.1.4 References

1. ASME Boiler and Pressure Vessel Code, Section III, for Nuclear Vessels, 1971 Edition, Section III, up to and including the Winter 1972 Addenda.
2. ASME Boiler and Pressure Vessel Code, Section III, for Nuclear Vessels, 1986 Edition.
3. ASME Boiler and Pressure Vessel Code, Section III, for Nuclear Vessels, 1971 Edition, through Summer 1972 Addenda.
4. ASME Boiler and Pressure Vessel Code, Section III, 1977 Edition, thru the Summer 1977 Addenda, Including Subsection NF.
5. ASME Boiler and Pressure Vessel Code, Section III, 1977 Edition, up to and including the Winter 1978 Addenda
6. CEOG Report CEN-367-A, Revision. 000, "Leak-Before-Break Evaluation of Primary Coolant Loop Piping in Combustion Engineering Designed Nuclear Steam Supply Systems," February 1991.
7. NRC Bulletin 88-11, Pressurizer Surge Line Thermal Stratification, December 20, 1988.
8. CEOG Task 587, Report No. CEN-387-P, Rev. 1-P-A, "Pressurizer Surge Line Flow Stratification Evaluation," May 1994.

Table 2.2.2.1-1
Maximum RCS Piping Stress and Usage Factor Results

Table 2.2.2.1-1 (Continued)
Maximum RCS Piping Stress and Usage Factor Results

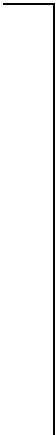
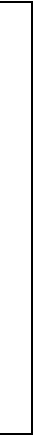
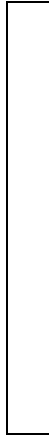


Table 2.2.2.1-1 (Continued)
Maximum RCS Piping Stress and Usage Factor Results



Table 2.2.2.1-2
Surge Line Stress and Usage Factor Results



2.2.2.2 Balance of Plant Piping, Components, and Supports

2.2.2.2.1 Regulatory Evaluation

Balance of plant (BOP) piping, components and supports are reviewed as part of the extended power uprate (EPU). This section covers portions of Class 1 piping, components and supports that are not included in LR [Section 2.2.2.1](#), Nuclear Steam Supply System (NSSS) Piping, Components and Supports, all Class 2 and 3, and non-nuclear piping that are part of the piping systems considered for evaluation for EPU. LR [Section 2.2.2.1](#) covers Class 1 reactor coolant_ (RC) loop piping and the pressurizer surge line.

St. Lucie Unit 2 Current Licensing Basis

The generic current licensing basis (CLB) in LR [Section 2.2.2](#) applies to the BOP piping, components and supports with the following amplifications.

UFSAR sections that discuss the design of BOP piping and supports include:

- UFSAR Section 3.2, Classification of Structures, Systems, and Components (SSCs), provides details with respect to the seismic and quality group classification of piping and piping components;
- UFSAR Section 3.7, Seismic Design, provides details with respect to the design and analysis of seismically qualified SSCs; and
- UFSAR Section 3.9.3, ASME Code Class 1, 2 and 3 Components, Component Supports and Core Support Structures, provides details with respect to design and analysis of BOP piping and supports.

In addition to the licensing basis described in the UFSAR, the BOP piping, components and supports were evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Sections 2.3.3, 2.3.4 and 2.3.5 of the SER identify that components of the BOP piping, components and supports are within the scope of License Renewal. Programs used to manage the aging effects associated with the BOP piping, components and supports are discussed in SER Section 3.3.17 and Chapter 18 of the UFSAR.

2.2.2.2.2 Technical Evaluation

2.2.2.2.2.1 Introduction

The impact of EPU on the BOP piping, pipe supports and associated equipment has been evaluated. This evaluation includes safety related piping specified as ASME Code Class 1 piping that is not addressed in LR [Section 2.2.2.1](#) NSSS Piping, Components and Supports as well as piping configured such that it can adversely interact with safety related (SSCs). The results of

this evaluation indicate that potential modification of pipe supports is required in order to ensure continued compliance with the CLB.

The BOP piping, pipe supports and associated equipment that were evaluated for EPU conditions included the following systems:

- Auxiliary feedwater,
- Auxiliary steam,
- Chemical and volume control,
- Circulating water,
- Component cooling water,
- Condensate,
- Containment spray,
- Extraction steam,
- Feedwater,
- Fuel pool cooling,
- Heater drains,
- Intake cooling water,
- Main steam,
- Pressurizer piping (spray, safety and relief),
- Safety injection, (beyond RC loop pressure boundary)
- Shutdown cooling, (beyond RC loop pressure boundary)
- Steam generator blowdown, and
- Turbine cooling water.

The codes of record for BOP piping and supports from UFSAR Section 3.0, are listed below.:

- ASME Boiler & Pressure Vessel (B&PV) Code, Section III, Nuclear Power Components, 1971 Edition through Summer 1973 Addenda,
- ANSI B31.1.0 Power Piping, 1967 Edition through Summer 1973 Addenda,
- American Institute of Steel Construction (AISC) Manual 7th Edition.

However, later editions of the above listed codes were used in some of the existing design basis calculations (as part of requalification efforts), such as the use of ASME B&PV Code, 1980 Edition in the case of the RC loop branch piping qualifications. Whenever a later edition of a code was used, the reconciliation with the code of record was included in the documentation to justify its use.

Refer to LR [Section 2.2.2.1](#) for discussion on the impact of EPU on RC piping, including the pressurizer surge line.

2.2.2.2.2 Description of Analyses and Evaluations

System operation at EPU conditions generally results in increased pipe stress levels and pipe support and equipment loads due to slightly higher operating temperatures, pressures and flow rates internal to the piping. The piping systems were evaluated as follows:

For RC loop branch piping that are located beyond the RC loop pressure boundary, the effect of increases in RC loop branch nozzle displacements for the EPU imposed on the respective branch piping was evaluated to ensure that the increases in imposed branch nozzle displacements do not result in unacceptable stress intensity values and cumulative usage factors (CUF).

Portions of the following piping systems experienced an increase in temperature, pressure, and/or flow rate resulting from EPU requiring detailed pipe stress and/or pipe support evaluations:

- Main steam,
- Condensate,
- Extraction steam,
- Feedwater,
- Heater drains, and
- Component cooling.

For a given piping system, the largest temperature increase obtained from the heat balance diagrams developed for EPU or other applicable references, such as vendor documents and engineering reports, was evaluated.

Thermal change factors are determined, as required, to compare and evaluate changes in thermal operating conditions.

- The thermal “change factor,” which is based on the ratio of EPU temperature to the actual analyzed temperature, is defined as $\frac{T_{EPU}}{T_{Pre-Uprate}}$, where T_{EPU} = Temperature at EPU conditions and $T_{Pre-Uprate}$ = Existing temperature of the piping being evaluated.

Based on the magnitude of the calculated thermal change factor, the following engineering activities were performed and/or conclusions reached:

- For thermal change factors less than or equal to 1.00 (that is, the pre-uprate condition envelopes or equals the EPU condition), the piping system was concluded to be acceptable for these EPU conditions; and
- For all thermal change factors greater than 1, an additional assessment / evaluation was performed to assess the specific increase in temperature, in order to determine piping system acceptability. These evaluations were performed in accordance with piping and support analysis requirements. In addition to these assessments and evaluations, piping thermal

expansion walkdowns of the affected piping systems will be performed, as described in **Section 2.2.2.2.4.**

Operating pressure increases due to EPU mostly affect systems related to the main power cycle (main steam, condensate, feedwater, extraction steam, and heater drains). Since the pipe stress evaluations for these piping systems have been determined in accordance with the B31.1 Code or ASME Code Section III, increases in operating pressures are acceptable, as long as the EPU operating pressure remains within the current design pressure of the system. If the EPU operating pressure exceeds the design pressure, the impact is evaluated relative to the applicable pipe stress analysis calculations.

Flow rate increases due to EPU occur mainly in those systems forming the main power cycle (i.e., main steam including the main bypass and dump valve lines, condensate, feedwater, extraction steam, and heater drains). The two piping systems of most concern with respect to flow rate increases are main steam, including the main bypass and dump valve lines, and feedwater, which contain fast closing valves. The increase in flow rates due to EPU conditions for main steam including the main bypass and dump valve lines and feedwater systems are evaluated relative to the applicable pipe stress analysis calculations. The remaining power cycle piping involves systems that do not contain any fast closing valves. Hence, flow rate increases due to EPU for these piping systems are concluded to be acceptable without further evaluation.

RC loop branch piping located beyond the RC loop pressure boundary, was evaluated to assess the effect of EPU increases in RC loop branch nozzle displacements to ensure that those increases did not result in unacceptable stress intensities and CUF values.

There were no changes to seismic inputs (amplified response spectra) or loads resulting from EPU. The existing seismic design basis for all piping and supports remains valid and is unaffected by EPU. Hence, BOP piping and support loadings will continue to meet the current licensing basis with respect to the requirements of General Design Criterion (GDC)-2.

Piping systems that experienced an increase in temperature, pressure, and/or flow rate were evaluated using a detailed computer piping analysis or manual calculations as appropriate.

Piping configured such that it can adversely interact with safety related SSCs was reviewed in order to ensure that interactions as a result of EPU would not impact the operability of piping and components.

In addition to the methodology described above, plant walkdowns were performed on portions of the BOP piping systems to review the piping layouts and support configurations to assess adequacy of the deadweight spans and to review the thermal flexibility of the installed piping systems.

The following computer programs were used to perform the EPU piping stress and piping welded attachment stress evaluations and the generation of fluid transient forcing functions. These computer programs were used to calculate stresses and loads using the appropriate equations from the ASME III and / or ANSI B31.1 Codes. Using an approved quality assurance program, these computer programs have been verified and validated and shown to be accurate.

PC-PREPS

PC-PREPS is a PC based QA Category I structural analysis computer code qualified in accordance with Shaw Stone & Webster Quality Standard QS-2.7. This computer code uses linear elastic theory to analyze and qualify structural members, welds, local tube steel stresses, anchor bolts and surface mounted base plates in accordance with AISC, AWS and/or ASME criteria. The program may also be used to compare vendor items with their allowable loads and movements. PC-PREPS has several code check options available to qualify structural members.

PIPESTRESS

PIPESTRESS program was used to perform detailed pipe stress analysis. This is a program for performing linear elastic analysis of three dimensional piping systems subject to a variety of loading conditions. Simple non-linearities in one-dimensional supports can be modeled. Piping systems may be investigated for compliance with piping codes and with other constraints on system response.

PIPESTRESS is part of the integrated package "PepS", which contains the piping analysis program "PIPESTRESS" and a pre and post processor "EDITPIPE". The PIPESTRESS Quality Assurance Program implements quality assurance requirements of a "safety-related" software program for use in the nuclear power industry. A previous version of this computer program was used in the design basis analysis of piping systems.

PITRUST-PC

PITRUST-PC is a computer program which calculates local stress intensity at the junction of two cylindrical vessels. The calculated stresses, including those due to pressure, are determined for the run cylinder. The program has application where a trunnion is welded to a run-pipe or where a branch pipe exits from a vessel or run-pipe.

The method and theory of calculating stresses follows that promulgated by the Welding Research Council Bulletin No. 107 (Wichman et al 1965). The program is capable of complying with requirements of ASME B&PV Code – Section III – Nuclear Power Plant Components and ANSI-B31.1 Power Piping.

PITRUST-PC input consists basically of program control options, run-pipe dimensions, internal operating pressure, trunnion outside diameter, and loading specification.

Program output tabulates the applied loadings and local stresses at the junction of the trunnion and run-pipe.

RELAP5

The RELAP5 computer code was used to determine forcing functions for the pressurizer power operated relief valve (PORV) opening event.

The RELAP5 computer code is a PC based QA Category 1 light water reactor (LWR) transient analysis code developed at the Idaho National Engineering Laboratory (INEL) for the NRC. The RELAP5 program is a highly generic code that, in addition to calculating the behavior of a reactor coolant system (RCS) during a transient, can be used for simulation of a wide variety of hydraulic

and thermal transients in both nuclear and non-nuclear systems involving mixtures of steam, water, non-condensable, and solute.

STEAM-PC

The STEAM-PC computer program was used to determine forcing functions for a main steam isolation valve closure event and a turbine stop valve closure fluid transient event.

The STEAM-PC computer program is a generalized fluid transient analysis code that is used to perform steady-state and transient analyses of a steam filled flow network. The program has the capability to model any compressible fluid flow network containing valves, safety/relief valves, reservoirs, branch piping, and steam chests. The steam is modeled as an ideal gas with homogenous and adiabatic fluid properties. This computer program is used in Ginna Station, Comanche Peak Steam Electric Station Units 1 and 2, and Point Beach Nuclear Plant power uprate projects.

WATHAM-PC

The WATHAM-PC computer program was used to determine forcing functions for the feedwater regulatory valve and isolation valve closure and feedwater pump trip events.

The WATHAM-PC computer program is a generalized fluid transient code that is used to perform transient analysis of a water filled flow network due to pump start-up, pump trip and valve opening and closing. The program has the capability to model any incompressible fluid flow network containing in-line and discharge pumps, reservoirs, branch piping, check valves, air inlet valves, in-line and discharge valves, trapped air pockets and voids. This computer program is used in Ginna Station, Comanche Peak Steam Electric Station Units 1 and 2, and Point Beach Nuclear Plant power uprate projects.

Other evaluations of issues that potentially impact BOP piping and supports are addressed in the following LR Sections:

- Protection against dynamic effects, including GDC-4 requirements, of pipe whip and discharging fluids, is discussed in LR [Section 2.2.1](#), Pipe Rupture Locations and Associated Dynamic Effects and LR [Section 2.5.1.3](#), Pipe Failures;
- Protection against internally generated missiles and turbine missiles, including GDC-4 requirements, is discussed in LR [Section 2.5.1.2](#), Missile Protection; and
- Design of RCS and related components, including GDC-14 and GDC-15 requirements, is discussed in LR [Section 2.2.2.1](#), NSSS Piping and Supports, Class 1.

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

As discussed above, the BOP piping, components and supports are within the scope of License Renewal. Operation of the BOP piping, components and supports under EPU conditions has been evaluated to determine if there any new aging effects requiring management or if any existing aging management programs are affected. 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.

The proposed pipe support additions and modifications for the condensate, component cooling water, feedwater and main steam piping will not impact the License Renewal system evaluation boundaries. The required pipe support additions and modifications, which will be implemented as part of the plant modification process will not add any new or previously unevaluated materials to the BOP piping and support systems. No new aging effects requiring management are identified. Piping system internal and external environments remain within the parameters previously evaluated. The time-limited aging analyses evaluations applicable to BOP piping remain bounding.

2.2.2.2.4 Results

Existing pipe stress analysis results remain acceptable for EPU conditions. The results of the pipe support evaluations for systems impacted by EPU concluded that in general supports remain acceptable, although certain BOP system pipe supports (such as main steam, feedwater, component cooling water and condensate) will require modification/addition to accommodate the revised loads due to EPU conditions. These pipe support modifications will be installed before the implementation of the EPU. The modifications will ensure continued compliance with CLB criteria.

The results of equipment nozzle evaluations and loads imposed on containment penetrations concluded that these components remain within acceptable limits for EPU conditions. LR [Tables 2.2.2.2-1](#) and [2.2.2.2-2](#) list loads imposed on main steam and feedwater nozzles associated with steam generators. LR [Tables 2.2.2.2-1](#) and [2.2.2.2-2](#) describe loads imposed on containment penetrations for main steam and feedwater piping and their acceptability. LR [Table 2.2.2.2-3](#) lists piping reinforcement requirements for component cooling water piping to satisfy operating temperatures due to EPU. LR [Table 2.2.2.2-4](#) lists loads imposed on feedwater pumps 2A and 2B discharge nozzles.

Fluid transient forcing functions acting on the pressurizer safety relief valve (SRV) and PORV piping due to the low temperature overpressure protection (LTOP) operating mode were evaluated for EPU. Based on the analysis, the maximum calculated stress due to LTOP event is 4,416 psi. This is less than the existing stress due to PORV steam discharge of 6,377 psi. Therefore, all PORV and SRV piping is acceptable for EPU LTOP loads.

Pipe stress analysis reevaluations as a result of EPU conditions did not result in any new pipe breaks or modifications to existing pipe break locations. Hence, existing conclusions reached with respect to pipe break evaluations continue to remain valid for EPU.

In summary, the BOP piping systems will continue to meet the current licensing basis with respect to the requirements of GDC-1, -2, -4, -14 and -15.

Additionally, the implementation of EPU will result in higher flow rates that will impact the levels of flow induced piping vibration in BOP piping systems that comprise the main power cycle. These piping systems include the following:

- Main steam,

- Feedwater,
- Condensate,
- Heater drain and vent,
- Extraction steam, and
- Turbine generator gland seal and exhaust.

A plan has been developed to address flow induced vibration in piping affected by EPU. The plan began with the development of a program to address scope, method, evaluation and acceptance criteria. The scope for all piping vibration evaluations will include the pipelines that are modified by EPU and the EPU-affected lines that were identified through the corrective action program. The methodology to be used for the monitoring and evaluation and the acceptance criteria for all piping vibration evaluations will be in accordance with ASME OM-S/G-2007, Part 3. With respect to piping vibration, the ability to analytically predict potential flow- induced piping vibration displacements and resulting stresses due to higher flow rates resulting from EPU is complex. It involves assessing many piping system attributes, such as plant piping configuration, valve alignment and support locations and functions which are being modified as part of EPU. The more effective method of precluding piping failure due to flow-induced vibration due to changes from EPU is the implementation of the plan developed to extensively monitor actual piping response to actual plant conditions. This method and plan, successfully implemented for EPUs, stretch power uprates and measurement uncertainty recapture for several PWR nuclear plants including Beaver Valley Units 1 and 2, Seabrook, Ginna, North Anna Units 1 and 2, Millstone Unit 3 and Comanche Peak Units 1 and 2, provides a more proactive and reliable means of addressing potential piping vibration issues.

The piping within the scope of the EPU vibration monitoring program will be observed by experienced test engineers at several different plant operating power levels to identify areas where piping vibration displacement is occurring. The initial sets of observations (pre-baseline as defined in the vibration monitoring plan) will be at the pre-EPU full power level and will establish the baseline pipe vibrations. Several pre-baseline piping vibration walkdowns have already been performed. Walkdowns performed in December 2008 and during 2009 and 2010 provided specific data on existing piping vibration levels at St. Lucie Unit 2. The piping vibration levels observed during the pre-baseline walkdowns were at levels that required further evaluation. Detailed analyses were performed to determine piping vibration stresses at locations of vibration concern. Based upon the results of the detailed analyses, nine plant modifications will be implemented to preclude vibration failures at these analyzed locations. A total of six piping modifications and three pipe support installations/modifications will be implemented prior to EPU implementation.

Walkdowns for EPU observations will take place at the post-EPU power level test plateaus (from 25 percent to 100 percent power) established for power ascension testing. By comparing the observed pipe vibrations/displacements at various power levels with those observed at the pre-baseline power level, increased pipe vibrations will be identified and the need for additional evaluations will be determined. As stated above, the criteria for all piping evaluations will be in accordance with ASME OM S/G 2007 Part 3.

During baseline walkdowns being performed for piping vibration, piping systems subjected to a temperature increase associated with EPU (i.e., main steam, condensate, feedwater, extraction steam, and heater drains) will be inspected to identify locations where there is a potential for unacceptable thermal expansion interaction. The increases in thermal expansion displacements associated with EPU are expected to be less than 1/16 inch and, therefore, these increased displacements should not be a significant concern. However, 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. Refer to LR Section 2.12 for discussion of the power ascension and testing plan.

2.2.2.2.3 Conclusion

The evaluations have addressed the structural integrity of pressure-retaining components and their supports. For the reasons set forth above, the BOP and non-class 1 piping evaluations have adequately addressed the effects of the proposed EPU on BOP and non-class 1 piping components and their supports. Based on the above, it is concluded that the evaluations have 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.

**Table 2.2.2.2-1
Steam Generator Nozzle Loads - Main Steam Nozzles**

Description	Forces (Kips)		Moments (in-Kips)	
	Axial (F _a)	Shear (F _v)	Bending (M _b)	Torsion (M _t)
Steam Generator 2A				
Total Loads =(DW + DBE + THIST(TSV) + THER) (Note 1)	10.3	20	2676	552
Total Loads =(DW + DBE + THIST(MSIV) + THER) (Note 1)	10.3	20	2670	550
Steam Generator 2B				
Total Loads =(DW + DBE + THIST(TSV) + THER) (Note 1)	8.1	20	2586	732
Total Loads =(DW + DBE + THIST(MSIV) + THER) (Note 1)	8.1	20	2581	731
Note 1: DW = Dead Weight, DBE = Design Basis Earthquake, THER = Thermal THIST(TSV) = Time History Loads due to Turbine Stop Valve Closure event THIST(MSIV) = Time History Loads due to Main Steam Isolation Valve Closure event				

Table 2.2.2.2-2
Steam Generator Nozzle Loads - Feedwater Nozzles

Description	Forces (Kips)		Moments (in-Kips)	
	Axial (F _a)	Shear (F _v)	Bending (M _b)	Torsion (M _t)
Steam Generator 2A				
Total Loads =(DW + DBE + THIST(FRV) + THER) (Note 1)	2	11	535	1,478
Total Loads =(DW + DBE + THIST(FIV) + THER) (Note 1)	2	11	536	1,493
Steam Generator 2B				
Total Loads =(DW + DBE + THIST(FRV) + THER) (Note 1)	7.4	14	1,410	485
Total Loads =(DW + DBE + THIST(FIV) + THER) (Note 1)	7.4	15	1,428	466
Note 1: DW = Dead Weight, DBE = Design Basis Earthquake, THER = Thermal THIST(FRV) = Time History Loads due to Feedwater Regulating Valve Closure event THIST(FIV) = Time History Loads due to Feedwater Isolation Valve Closure event				

Table 2.2.2.2-3
Containment Penetration Loads Summary - Main Steam Penetrations

Description	Forces (Kips)		Moments (in-Kips)	
	Axial (F _a)	Shear (F _v)	Bending (M _b)	Torsion (M _t)
Penetration P-1				
Total Loads (EPU)	93	35	2,921	3,389
Calculated Stress intensity (EPU)	24,160			
Allowable Stress Intensity	61,141			
Design Margin	0.395			
Penetration P-2				
Total Loads (EPU)	55	35	1,595	2,938
Calculated Stress Intensity (EPU)	16,959			
Allowable Stress Intensity	61,141			
Design Margin	0.277			

**Table 2.2.2.2-4
Containment Penetration Loads Summary -Feedwater Penetrations**

Description	Forces (Kips)		Moments (in-Kips)	
	Axial (F _a)	Shear (F _V)	Bending (M _b)	Torsion (M _t)
Penetration P-3				
Total Loads (EPU)	19	14	281	760
Current Design Load	19	98	2,640	2,520
Current Stress Intensity based on Current Design Load	31,944 psi			
Allowable Stress Intensity	60,520 psi			
Design Margin	0.53			
Penetration P-4				
Total Loads (EPU)	16	16	1,022	663
Current Design Load	19	98	2,640	2,520
Current Stress Intensity based on Current Design Load	31,944 psi			
Allowable Stress Intensity	60,520 psi			
Design Margin	0.53			
Note: Calculated loads for EPU are determined acceptable based on comparison against current design loads and the current stress intensity.				

Table 2.2.2.2-5
Piping Reinforcement Locations Component Cooling Water Piping

Pipe Stress Analysis Description	Number of Modifications	Piping Stress Isometric Node Number	Reinforcement Description
CCW: SDHX and CFC Cooler Return from CCW Bldg to CCW Pumps	4	7	0.562" pad on 24" x 20" Tee
		29	
		102	0.562" pad on 24" x 16" Tee
		104	
CCW: SDHX and CFC Cooler Return to CCW Bldg	2	7427	0.562" pad on 20" x 12" Tee
		8659	0.562" pad on 20" x 12" Tee
CCW: I-6-CC-153 From CCW Surge Tank to Return Header B (I-20-CC-26)	1	20	0.562" pad on 20" x 6" Tee
CCW: CCW Cooler Return from Control Room Air Conditioning	1	6421	0.562" pad on 20" x 4" Tee

**Table 2.2.2.2-6
Feedwater Pump Nozzle Load Summary**

Feedwater Pump 2A						
Case Number	Forces (Lbs)			Moments (Ft-Lbs)		
	Fx (Shear)	Fy (Shear)	Fz (Axial)	Mx (Bending)	My (Bending)	Mz (Torsion)
Deadweight (DW)	-63	-560	94	-163	-92	-1526
ABSMAX (TH-1, TH-2, TH-3,TH-4)	1,574	1,928	621	1,331	3,585	2,054
MAX (FRV, FIV)	130	233	608	434	338	586
Static Total	1,637	1,368	527	1,168	3,677	3,580
Dynamic Total	1,767	1,601	1,135	1,602	4,015	4,166
2 x API Allowable	3,200	2,600	4,000	9,400	7,000	4,600
Static Interaction Ratio	0.51	0.53	0.13	0.12	0.53	0.78
Dynamic Interaction Ratio	0.55	0.62	0.28	0.17	0.57	0.91
Feedwater Pump 2B						
Case Number	Forces (Lbs)			Moments (Ft-Lbs)		
	Fx (Shear)	Fy (Shear)	Fz (Axial)	Mx (Bending)	My (Bending)	Mz (Torsion)
Deadweight (DW)	-188	-1023	-19	515	59	-1001
ABSMAX (TH-1, TH-2, TH-3,TH-4)	1,629	957	1,184	4,013	1,133	683
MAX (FRV, FIV)	104	208	526	96	108	266
Static Total	1,817	1,980	1,203	4,528	1,192	1,684
Dynamic Total	1,921	2,188	1,729	4,624	1,300	1,950
2 x API Allowable	3,200	2,600	4,000	9,400	7,000	4,600
Static Interaction Ratio	0.57	0.76	0.3	0.48	0.17	0.37
Dynamic Interaction Ratio	0.6	0.84	0.43	0.49	0.19	0.42
Notes: ABSMAX = Absolute Maximum Value MAX = Maximum Value TH-1 = Thermal Mode 1 – Both Pumps On TH-2 = Thermal Mode 2 – Feed Pump 2B Off TH-3 = Thermal Mode 3 – Feed Pump 2A Off TH-4 = Thermal Mode 4 – Both Pumps Off, Lines @ 40°F Static Total = Max [DW, (DW + TH₁), (DW + TH₂), (DW + TH₃), (DW+ TH₄)] Dynamic Total = {MAX(FRV, FIV) + Max [DW, (DW + TH₁), (DW + TH₂), (DW + TH₃), (DW+ TH₄)]} Static Interaction Ratio = Static Total / 2xAPI Allowable Dynamic Interaction Ratio = Dynamic Total / 2xAPI Allowable						

2.2.2.3 Reactor Vessel and Supports

2.2.2.3.1 Introduction

The reactor vessel (RV) and its supports are reviewed as part of the EPU by Florida Power and Light (FPL). The RV is described in UFSAR Sections 3.9, 4.1 and 5.3. The RV supports are described in UFSAR Sections 3.8.3.1.5 and 5.4.14.2. The regulatory evaluation included in LR [Section 2.2.2](#) also applies to the reactor vessel and its supports.

The RV, as the principal component of the reactor coolant system (RCS), contains the heat-generating core and associated supports, controls, and instrumentation, and coolant circulating channels. Primary outlet and inlet nozzles provide for the exit of heated coolant and its return to the RV for recirculation through the core.

In 2007, a replacement reactor vessel closure head (RVCH) was installed.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to Title 10 of the Code of Federal Regulations (10 CFR) Part 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The generic current licensing basis in LR [Section 2.2.2](#) applies to the RV and supports, with the following amplifications.

The RV is a right circular cylinder with two hemispherical heads. The lower head is permanently welded to the lower end of the RV shell but the upper closure head can be removed to provide access to the RV internals. The RV flange is a forged ring with a machined edge on the inside surface to support the core support barrel, which in turn supports the reactor internals and the core.

The inlet and outlet nozzles on the RV are located on a common plane just below the RV flange. Ample thickness in the RV provides most of the reinforcement required for the nozzles. Additional reinforcement is provided by the individual nozzle attachments. A boss located around the outlet nozzles on the inside diameter of the RV wall provides a mating surface for the core support barrel and guides the outlet reactor coolant flow.

The RV is designed in accordance with the ASME Boiler and Pressure Vessel Code Section III for Class 1 components. The applicable design code for the RV is presented in UFSAR Table 5.2-1. UFSAR Table 5.3-10 provides the RV design parameters.

The principal ferritic materials used in the RV are listed in UFSAR Table 5.2-3. These materials are specified to be in accordance with ASME Code, Section III, 1971 Edition including Summer 1972 Addenda.

The RV construction is basically that of formed plates welded into cylinders and hemispherical heads. Flanges on the closure head, upper shell, and the nozzles are forgings. This typifies

construction of the RV in the preceding introductory material. No special fabrication methods were used in the fabrication of the RV.

The RV is inspected per the requirements of Section XI of the ASME Code, as governed by 10 CFR 50.55a(g), and described in UFSAR Section 5.2.4.

The RV and RV supports are designed to withstand stresses associated with various operating and design transients described in UFSAR Section 3.9.1.1. The RV is supported at three points on a steel girder column assembly within the RV cavity. The columns are bolted to the underside of the steel girders and to the RV cavity floor. The horizontal ends of the steel girders are embedded in the primary shield wall. Loads from the RV are transferred to the steel girder - column assemblies by means of the support shoes welded to the nozzle of the RV and the bearing plates on top of the steel girders. The support shoes are free to slide longitudinally along the axis of the nozzles and only a frictional load is transmitted to the support structures in this direction. Transverse and downward loads are transmitted into the girder in direct bearing. The horizontal and vertical loads are then transferred to the supporting concrete by means of the embedded ends of the steel girders and the anchor bolt/anchor plate anchorages.

In addition to the licensing bases described in the UFSAR, the RV and supports were evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.31.3 of the SER identifies that components of RV and supports are within the scope of License Renewal. Programs used to manage the aging effects associated with the RV and supports are discussed in SER Section 3.1.3 and Chapter 18 of the UFSAR.

2.2.2.3.2 Technical Evaluation

2.2.2.3.2.1 Introduction

The approach taken in the evaluation for the EPU was to initially attempt to reconcile the existing design basis analysis results from a given structural analysis, relative to EPU-related effects. If an argument confirming that the existing design basis results remained valid and acceptable was not possible, an EPU-specific analysis was performed, and the results of that analysis were compared to the existing pre-EPU results to resolve any discrepancies with a load and/or stress reconciliation.

Note that the primary structural analyses for normal operating, seismic, and pipe break conditions are performed separately. Therefore, the input forcing functions, or applied loadings, for these conditions are not combined to produce a single set of inputs. Instead, the individual normal operating, seismic, and branch line pipe breaks (BLPB) analysis results are combined in accordance with the UFSAR Section 5.4.14 and the design specifications to produce the specified service level stress results, which are then compared to the Code allowables.

2.2.2.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The major inputs used in the RV and supports evaluation are the EPU parameters provided in LR [Section 1.1](#), Nuclear Steam Supply System (NSSS) Parameters, and the EPU NSSS design transients provided in LR [Section 2.2.6](#), NSSS Design Transients. These LR sections provide the operating and transient conditions for the EPU conditions. Hot and cold leg temperatures and hot and cold leg transients are applicable to the RV.

The EPU NSSS system design transient parameters, which define each transient in terms of pressure and temperature changes over time, were considered in the EPU evaluations. There are no other changes to the pressure or thermal-hydraulic design parameters (e.g., mass flow rate) due to the EPU that would affect the RV or its supports. Finally, the EPU conditions did not change the number of occurrences of each transient.

The inputs for seismic analysis of the RV, including seismic accelerations and RV mass and stiffness, are not affected by the EPU conditions. Therefore, the seismic analyses are not impacted by the EPU.

The acceptance criteria for the RV and supports with the original RVCH are based on the ASME B&PV Code ([Reference 1](#)). Subsequent analyses performed for the replacement RVCH are based on a latter edition of the ASME B&PV Code ([Reference 2](#)). [Reference 1](#) continues to apply to the remainder of the RV and the supports.

Based on leak-before-break (LBB) evaluations, loss-of-coolant accidents (LOCAs) in the RCS main loop piping do not need to be included in the mechanical/dynamic design basis (see LR [Section 2.1.6](#), Leak-Before-Break). As a result, the limiting pipe breaks considered in the EPU design basis with respect to RCS mechanical/dynamic response are BLPBs. The response of the RCS loop to BLPBs is bounded by the response of the RCS loop to the originally postulated LOCAs.

2.2.2.3.2.3 Description of Analyses and Evaluations

Design Transients

The evaluation of the RV and its supports for the EPU compared the normal operating temperatures (NOT), normal operating pressures (NOP) and NSSS design transients defined in LR [Section 2.2.6](#), Design Transients, and LR [Section 1.1](#), NSSS Parameters, to those considered in the analyses of record (AORs) for the RV. The impact of changes to full power operating temperatures during design transients for the EPU operation is addressed in LR [Section 2.2.6](#). With one exception, the NSSS temperatures, pressures, and design transients defined for the EPU either did not change from or were bounded by those transients considered in the AORs. The one exception was a 1°F temperature increase in the plant loading and unloading transient results for the EPU, which is discussed below.

RCS Loop Analysis/Evaluation

Either new loads throughout the RCS were determined by analysis, or existing design basis RCS loads were determined to remain applicable for the EPU by evaluation. In either case, the load

analysis/evaluation results for the RCS loop model were then used to reconcile the individual subcomponents for the EPU conditions.

Updated dead weight (DWt) and thermal expansion analyses of the RCS loop, as described in LR [Section 2.2.2.1](#), NSSS Piping, Component, and Supports, were performed for the EPU conditions. The RCS loop model that was analyzed reflected the current configuration of the RCS, and the thermal expansion analysis was based on the NOT associated with the EPU.

EPU effects on the existing seismic and pipe break design basis results, and the resulting stresses due to normal operating, seismic, and pipe break load combinations, were assessed through the evaluation/reconciliation process. The load analysis/evaluation results were used to reconcile individual subcomponent designs for the EPU conditions.

Evaluation of RV Nozzles and RV Supports

Updated RV nozzle and support loads were calculated from the EPU RCS loop analyses described above and in LR [Section 2.2.2.1](#). The RV nozzles and their supports were evaluated by comparing the EPU normal operating loads (i.e., DWt plus thermal expansion) to the respective RV nozzle and support loads of the AOR.

The 1°F temperature increase in the plant loading and unloading transient due to the EPU has a negligible effect on the stresses and fatigue of the RV nozzles and their integral supports; because the design basis temperature and pressure curves defining the transients were determined in a conservative manner when the RCS was designed. These transient definitions enveloped the anticipated effects of the normal operating, upset, emergency, and faulted conditions. Consequently, a 1°F change in the through-wall thermal gradients for a subset of the design basis transients has at most a negligible effect on stresses and fatigue usage, which are due to the combined effects of the full set of transients. As a result, no additional transient analyses were required for evaluating these components for the EPU.

Evaluation of the Replacement RVCH, RV Core Ledge and Core Stabilizer Lugs

An evaluation was performed to reconcile the normal operating portion of the AOR regarding the replacement RVCH, RV core ledge region at the head/vessel interface, and the core stabilizer lugs (also called the core support barrel (CSB) snubber lugs) with EPU conditions. The core ledge region and the core stabilizer lugs provide bearing surfaces to limit the lateral CSB motion. The replacement RVCH studs were also considered in the evaluation.

Evaluation of Surveillance Holder

The surveillance holder hydraulic loads, and internal pressure and differential thermal expansion changes due to the operating transients were re-evaluated for the EPU. The EPU does not increase the hydraulic loads, which were conservatively determined for the AOR. The EPU pressure and temperature were compared to those in the AOR. It was determined that the only increase due to the EPU was the 1°F increase in the initial temperature for the plant unloading transient. This 0.2 percent temperature increase has a negligible effect on the stresses and the cumulative usage factor (CUF) of the surveillance holder.

Evaluation of Flow Skirt

The flow skirt (also referred to as the flow baffle) was re-evaluated based on the EPU parameters. The EPU pressure and temperature were compared to those in the AOR. It was determined that only the pressure on the flow skirt changed due to the EPU.

Since evaluation of the input parameters showed that pressure on the flow skirt changed, a stress re-analysis of the flow skirt due to normal flow was performed consistent with the AOR. The temperature change in the plant loading and unloading transient due to the EPU was considered negligibly small in this assessment. Due to the conservative nature of the pressure stress analysis, any combined stresses (e.g., due to temperature and pressure) will also be conservative.

The effects of vibration were also assessed for the EPU. It was concluded that the response frequency of the predominant mode (307.7 Hz) was quite separated from the driving frequencies of 14-15 Hz and 70-75 Hz. Thus the requirement for self-induced vibration in the AOR was satisfied.

Structural Steel Supports (Steel Beams and Columns)

The RV is supported at three points on a steel girder-column assembly within the reactor cavity. The horizontal ends of the girder are embedded in the 7 ft - 3 in thick concrete primary shield wall at elevation 23 ft. The column is bolted to the underside of the steel girders and to the reactor cavity floor at elevation -2.92 ft.

The support shoes welded to the RV nozzles are free to slide longitudinally along the axis of the nozzles transmitting a frictional load to the support structure in this direction. In the transverse direction, steel plates at the top of the girder transfer the load from the shoe in direct bearing. Downwardly acting loads are transmitted directly into the supporting girder.

The reactor support cooling system utilizes air from the containment atmosphere to cool the reactor support girders and remove heat which is transmitted from the reactor support shoe. The reactor cavity cooling system ventilates the annular space between the reactor vessel and primary shield wall in order to limit concrete temperature to 150°F during normal operation.

Maximum support loads from the DWt and normal NOT analysis of the RCS for EPU are compared to maximum pre-EPU loads in [Table 2.2.2.3-4](#). Support nomenclature is as shown on [Figure 2.2.2.3-1](#). Since EPU loads are lower than pre-EPU loads for both deadweight and normal operation cases, the original structural analysis of the supports is bounding.

A thermal analysis of the reactor cavity under EPU conditions was prepared to evaluate the effect of the increased EPU power on the temperatures in the reactor cavity. The analysis was based on the ANSYS model prepared for St. Lucie Unit 1 given that the RV supports for both unit 1 and unit 2 are geometrically identical and that the analyses contained in Appendix 3H of the Unit 1 UFSAR have already been used to perform analyses for Unit 2 ([Reference 3](#)). The only pertinent difference between the Unit 1 and Unit 2 supports is the slider plate material: Unit 1 slider plate is a bronze manganese alloy and Unit 2 is Meehanite GA 50.

Results of the ANSYS analysis using Meehanite concluded that the distribution of temperatures is very similar between EPU and pre-EPU normal operating conditions, the magnitude of the

temperatures from the ANSYS EPU calculations are generally lower than the pre-EPU conditions included in Appendix 3H of the Unit 1 UFSAR, and the net effect of the temperature changes is bounded by the original analysis. Therefore, the analysis for normal operation, loss of fans and LOCA cases in Appendix 3H of the Unit 1 UFSAR remain valid for EPU conditions for Unit 2.

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

As discussed above, the RV and supports are within the scope of License Renewal. Operation of the RV and supports under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Refer to LR [Section 2.14](#) for a discussion pertaining to the application of the Aging Management Program associated with the management of environmentally assisted fatigue. Furthermore, 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.

2.2.2.3.2.5 Results

Replacement RVCH, Core Ledge, and Closure Head Studs

The replacement RVCH, closure head studs, and core ledge interface between the closure head and the vessel were evaluated for the effects of the EPU. The core ledge normal operating loads, which are due to the RVI weights and the force exerted on the core ledge by the replacement RVCH, RV head area equipment, and the replacement RVCH holddown device, do not change due to the EPU. Therefore, it has been determined that the current design basis results for the core ledge remain valid for the EPU normal operating loads.

RV Nozzles and RV Supports

The evaluations of the RV inlet and outlet nozzles and the integral RV support feet determined that the normal operating loads on these nozzles and supports do not increase. Therefore, the RV nozzle and integral RV support stresses and CUFs from the AORs, as given in LR [Table 2.2.2.3-1](#), do not change due to the EPU.

Seismic and pipe break effects do not change due to the EPU, as discussed in LR [Section 2.2.2.3.2.2](#).

RV Core Stabilizer Lugs

The 1°F temperature increase in T_{cold} due to the EPU has a negligible effect on fluid density, and the EPU RCS flow rate is essentially the same as the current flow rates. Therefore, the current vibratory inputs remain valid for the EPU with respect to the core stabilizer lugs, and the effects of the EPU on primary stresses at the core stabilizer lugs are negligible.

LR [Table 2.2.2.3-1](#) includes a summary of the stresses on the core stabilizer lugs.

Surveillance Holder

The surveillance holder evaluation for the EPU determined that all stresses continue to meet the ASME Code Section III ([Reference 1](#)) allowables. A summary of stresses and CUFs of the surveillance holder components is given in LR [Table 2.2.2.3-2](#).

In addition, the natural and driving frequencies of the surveillance holder do not change due to the EPU, and the predominant natural frequency remains well above the driving frequency range, as shown in LR [Table 2.2.2.3-2](#).

Flow Skirt

An evaluation of flow skirt vibratory response was performed for the EPU. It was determined that frequency at the predominant natural mode of vibration was well removed from the driving frequency ranges, as shown in LR [Table 2.2.2.3-3](#). Therefore, the flow-induced requirement that is specified for the flow skirt continues to be met for the EPU.

The results of flow skirt evaluation for the EPU show that all stresses continue to meet the ASME Code Section III ([Reference 1](#)) allowables. A summary of stresses and CUFs of the flow skirt components is given in LR [Table 2.2.2.3-3](#).

Structural Steel Supports (Steel Beams and Columns)

EPU deadweight loads are lower than pre-EPU loads and EPU thermal loads are higher than pre-EPU loads. However, EPU thermal loads are lower than the original design deadweight loads (same stress allowable); therefore the EPU thermal loads are bounded by the original design. The DWt plus thermal load combination is also bounded by the original design.

Results of the thermal analysis of the reactor cavity under EPU conditions concluded that the Unit 1 Cavity heating analysis bounds the Unit 2 analysis. Since the Unit 1 cavity heating analysis is bounded by the existing pre-EPU analysis in Appendix 3H of the Unit 1 UFSAR, the Unit 2 cavity heating analysis is also bounded by Appendix 3H of the Unit 1 UFSAR for normal operation, LOCA and the loss of fans case.

2.2.2.3.3 Conclusion

FPL has reviewed the structural integrity of the RV and RV supports. For the reasons set forth above, FPL concludes that the review has adequately addressed the effects of the proposed EPU on the RV and RV supports. Based on the above, FPL further concludes that the review has demonstrated that the RV and RV supports will continue to meet its current licensing basis with respect to 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, FPL finds the proposed EPU acceptable with respect to the structural integrity of the RV and RV supports.

2.2.2.3.4 References

1. ASME Boiler and Pressure Vessel Code, Section III for Nuclear Vessels, 1971 Edition up to and including the Summer 1972 Addendum.

2. ASME Boiler and Pressure Vessel Code, Section III, 1989 Edition.
3. FPL Letter L-77-266, "St. Lucie Unit No. 2 Docket No. 50-389 Reactor Pressure Vessel Support System," dated August 30, 1977.

Table 2.2.2.3-1
Significant RV and RV Supports Results Summary

Table 2.2.2.3-1 (Continued)
Significant RV and RV Supports Results Summary

Table 2.2.2.3-2
Surveillance Holder Results Summary

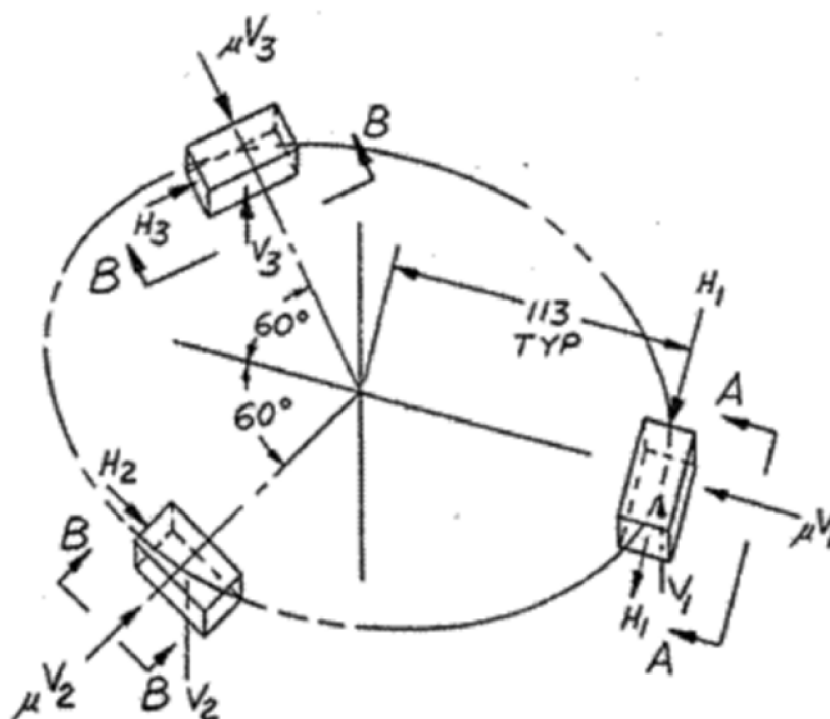
1.

Table 2.2.2.3-3
Flow Skirt (Flow Baffle) Results Summary

**Table 2.2.2.3-4
Vessel Support Load Comparison**

Point	Pre-Uprate (kips)			EPU (kips)		
	Thermal	Deadweight	NOT (DWt+Th)	Thermal	Deadweight	NOT (DWt+Th)
H1	36	0	36	0	0	0
V1	494	661	1155	542	505	1047
H2	36	0	36	0	0	0
V2	95	632	727	100	494	594
H3	36	0	36	0	0	0
V3	95	632	727	102	494	596
F	±396			±163		

Figure 2.2.2.3-1
Reactor Vessel Support Reactions



REACTOR VESSEL
SUPPORT REACTIONS

2.2.2.4 Control Rod Drive Mechanism

2.2.2.4.1 Introduction

St. Lucie Unit 2 refers to the control rod drive mechanisms (CRDM) as the control element drive mechanisms (CEDM). The Florida Power and Light (FPL) evaluation of the CEDM is an assessment of the impact on the structural integrity of the assemblies from the thermal transients and maximum operating temperatures and pressures that result from the EPU operating conditions. The CEDM pressure-retaining components were reviewed for the EPU.

FPL's review focused on the CEDM pressure vessel assembly. Other CEDM subassemblies are addressed by other licensing report sections and are evaluated under different criteria, as appropriate.

FPL's review covered the ability of the pressure retaining sections of the CEDM to meet the applicable General Design Criteria (GDC). This review addressed material compatibility with primary system fluids and design of the CEDM equipment, which is part of the reactor coolant pressure boundary (RCPB), to meet applicable design transients. The review addressed the structural integrity of pressure-retaining components designed in accordance with the ASME B&PV Code, Section III, Division 1, 1998 Edition through 2000 Addenda, for normal, upset, emergency and faulted conditions. FPL also reviewed the analyses of flow induced vibration and the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses.

Specific review criteria are contained in Standard Review Plan (SRP) Sections 3.9.1, 3.9.2, 3.9.3, and 5.2.1.1, as well as other guidance is provided in Matrix 2 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria for Nuclear Power Plants as specified in Appendix A to Title 10 of the Code of Federal Regulations (10 CFR) Part 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The generic current licensing basis (CLB) discussed in LR [Section 2.2.2](#) applies to this LR section. The CLB of LR [Section 2.2.2](#) describes the GDC and related guidance applicable to this review of reactor coolant system (RCS) pressure retaining components and component supports (CEDMs, pressurizer, reactor coolant pumps (RCPs), reactor vessel (RV) structure, steam generators (SGs)). Those are: 10 CFR 50.55a, GDC-1; GDC-2, -4, -14 and -15.

The CEDMs are designed to function during and after all normal plant transients. The CEDMs are designed to function normally during and after being subjected to the operating basis earthquake loads.

The design and construction of the CEDM pressure housings fulfil the requirements of the ASME Code, Section III, Class 1. The CEDM pressure housings are part of the RCPB, and they are designed to meet stress requirements consistent with those of the vessel. The pressure housings are capable of withstanding, throughout the design life, all normal operating loads, which include the steady-state and transient operating conditions specified for the vessel. Mechanical

excitations are also defined and included as a normal operating load. The CEDM pressure housings are service rated at 2500 psia and 650°F. The loading combinations and stress limit categories are presented in UFSAR Section 3.9.4.3 and are consistent with those defined in the ASME Code.

UFSAR Section 3.9.4.1.1 states that the CEDMs are mounted and seal welded on nozzles on top of the reactor vessel closure head. The CEDMs consist of the upper and lower CEDM pressure housings, motor assembly, coil stack assembly, reed switch assemblies, and extension shaft assembly. The drive power is supplied by the coil stack assembly, which is positioned around the CEDM housing. A position indicating reed switch assembly is supported by the upper pressure housing shroud, which encloses the upper pressure housing assembly.

The pressure boundary components consist of a lower and upper pressure housing and vent assembly at the top of the upper housing. The vent assembly is composed of a ball seal housing, vent stem, housing nut and steel ball. With the exception of the steel ball, all items are designed and fabricated in accordance with the requirements of the ASME B&PV Code, Section III, 1998 Edition through 2000 Addenda. One Code Case is also used in the design and fabrication of the pressure boundary components. Specifically, the section of the motor housing surrounding the motor electromagnets employs material in conformance with Code Case N-2 (1334-3). The RCPB material selection complies with the requirements of the ASME B&PV Code, Section II, 1998 Edition through 2000 Addenda and ASME B&PV Code, Section XI, 1998 Edition through 2000 Addenda.

In addition to the licensing basis described in the UFSAR, CEDMs were evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.1.3 of the SER identifies that components of the CEDMs are within the scope of License renewal. Programs used to manage the aging effects associated with the CEDMs are discussed in SER Section 3.1.3 and Chapter 18 of the UFSAR.

It is noted that the CEDMs were replaced as part of the reactor vessel closure head (RVCH) replacement effort. The CEDMs are evaluated for License Renewal relative to EPU implementation in Section 2.2.2.4.2.4 below.

2.2.2.4.2 Technical Evaluation

2.2.2.4.2.1 Introduction

2.2.2.4.2.2 The CEDMs are designed and analyzed to meet the ASME Code. The current CEDM analysis was the basis for the EPU evaluation of the CEDMs. The CEDM structural integrity depends on the characteristics of the CEDM, the reactor coolant pressure, the vessel outlet temperature, the nuclear steam supply system (NSSS) design transients, motor impulse loads, and reactor vessel head excitation due to seismic loads, loss of coolant accident (LOCA) loads, pump pulsation loads, and random turbulence loads due to flow. Since

the CEDM pressure boundary is located on the reactor vessel head, it experiences no additional flow induced vibration other than the reactor vessel head excitation due to random turbulence flow. The reactor coolant pressure, the vessel outlet temperature, and the NSSS design transients associated with the EPU were used as new inputs for this evaluation. The reactor vessel head excitation due to seismic, LOCA, pump pulsation and random turbulence is not impacted by the EPU. Input Parameters, Assumptions, and Acceptance Criteria

The analytical methodologies, assumptions, ASME Code editions, and computer programs used to evaluate the CEDMs for EPU conditions remain the same as those used to perform the current analysis of record.

The acceptance criteria for the ASME Code structural analysis of the CEDM RCPB are that the analyzed stresses do not exceed the stress allowables in the ASME Code, and that the cumulative fatigue usage factors from the ASME Code fatigue analysis remain less than 1.0. LR [Table 2.2.2.4-1](#) provides the criteria and cross-references to the applicable sections of the ASME Code. The CEDM pressure boundary includes the motor housing, upper pressure housing, and vent stem and housing nut. The CEDM nozzle is not within the scope of LR [Section 2.2.2.4](#); the CEDM nozzle and the head penetration are evaluated in LR [Section 2.2.2.3](#), Reactor Vessel and Supports.

2.2.2.4.2.3 Description of Analyses and Evaluations

Operating Pressure and Temperature

The NSSS temperatures and pressures associated with the EPU as given in LR [Section 1.1](#), Nuclear Steam Supply System Parameters, [Table 1.1-1](#) were compared to those used for the current CEDM design and analysis. There is no change in the reactor coolant pressure of 2250 psia for any of the six cases of Performance Capability Working Group (PCWG) parameters developed for the EPU. The hot leg temperature (T_{hot}) of 604°F defined by the vessel outlet temperature at best estimate flow at full power is the same T_{hot} used in the current analysis of record. Since T_{hot} and reactor coolant pressure do not change, the NSSS parameters developed for the CEDM analysis of record bound the NSSS parameters used in the CEDM evaluation for EPU conditions. Therefore, there is no impact on the stress intensities.

Transient Discussion

The NSSS design pressure and thermal transients, discussed in LR [Section 2.2.6](#), NSSS Design Transients, were compared to those used in the CEDM analysis of record. There are no changes to the pressure transients or the controlling thermal transients as a result of EPU. The EPU program NSSS design transient values are bounded by the NSSS design transients values associated with the CEDM analysis of record. Therefore, there is no impact on stress intensities. The EPU evaluation increased the number of leak test cycles from 200 to 320. Using 320 leak cycles, new usage factors were evaluated as part of the EPU.

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

As discussed above, the CEDMs are within the scope of License Renewal. Operation of the CEDMs under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.2.2.4.2.5 Results

The PCWG parameters (LR [Section 1.1](#), Nuclear Steam Supply System Parameters) and NSSS design transients (LR [Section 2.2.6](#), NSSS Design Transients), other than leak test cycles, are bounded by the parameters and transients used for the current analysis of record. The seismic, LOCA, pump pulsation and random turbulence loads are not impacted by the EPU. Therefore, the stress and stress intensity results of the current analysis of record remain bounding and applicable to the EPU. Revised cumulative usage factors using the increased leak test cycles were evaluated as part of the EPU. The EPU analysis and analysis of record used the ASME Code 1998 Edition with Addenda through 2000. A summary of the maximum stresses and updated fatigue usage factors for each of the CEDM pressure boundary components for EPU conditions is presented in LR [Tables 2.2.2.4-2 through 2.2.2.4-6](#). These tables compare maximum stresses to allowable limits for all the service conditions specified in ASME Code Section NB-3220: Design, Level A, Level B, Level C, Level D, and test service conditions. Since all stress and fatigue limits are satisfied, the CEDMs are structurally qualified for EPU conditions.

2.2.2.4.3 Conclusion

FPL has reviewed the evaluation related to the structural integrity of pressure-retaining components of the CEDM. For the previously presented reasons, FPL concluded that the effects of the proposed EPU on these components have been adequately addressed. FPL further concluded that, following implementation of the proposed EPU, these pressure retaining components will continue to meet their current licensing basis with respect to the requirements of 10 CFR 50.55a, GDC-1, GDC-2, GDC-4, GDC-14, and GDC-15. Therefore, FPL found the proposed EPU, with respect to the structural integrity of the pressure-retaining components, acceptable.

Table 2.2.2.4-1
ASME Code Criteria and Nomenclature Used in LR Tables 2.2.2.4-2 through 2.2.2.4-6

Design Conditions [NB-3221]
$P_m < S_m$
$PL < 1.5S_m$
$PL + Pb < \alpha S_m$
Level B [NB-3223]
$P_m < 1.1S_m$
$PL < (1.1)(1.5)S_m$
$PL + Pb < 1.1\alpha S_m$
Level B primary stresses are acceptable since design pressure bounds Level B pressures, and the Level B limits are greater than the design limits.
Level C [NB-3224]
$P_m < 1.2S_m$
$PL < (1.2)(1.5)S_m$
$PL + Pb < 1.2\alpha S_m$
Level C primary stresses are acceptable since design pressure bounds Level C pressures, and the Level C limits are greater than the design limits.
Level A and Level B Conditions [NB-3222 and NB-3223]
Range of $PL + Pb + Q < 3S_m$
$U < 1$
Level D Conditions [Appendix F]
$P_m < \text{Lesser of } 2.4S_m \text{ or } 0.7S_u$
$PL + Pb < \text{Lesser of } 3.6S_m \text{ or } 1.05S_u$
Test Conditions [NB-3226]
$P_m < 0.9S_y$
$P_m + Pb < 1.35S_y$ when $P_m < 0.67S_y$, or
$P_m + Pb < (2.15S_y - 1.2P_m)$ when $0.67S_y < P_m < 0.9S_y$
Shear Stress [NB-3227.2]
$\tau < 0.6S_m$

Table 2.2.2.4-1 (Continued)
ASME Code Criteria and Nomenclature Used in LR Tables 2.2.2.4-2 through 2.2.2.4-6

Progressive Distortion at Non-Integral Connection [NB-3227.3]	
$PL + Pb + Q < Sy$	
Triaxial Stress [NB-3227.4]	
$\sigma_1 + \sigma_2 + \sigma_3 < 4Sm$ (all service conditions except Level D)	
Where:	
Pm	= general primary membrane stress intensity
PL	= primary local membrane stress intensity
PL + Pb	= primary membrane plus bending stress intensity
PL + Pb + Q	= primary plus secondary stress intensity
Sm	= design stress intensity
τ	= shear stress
$\sigma_1, \sigma_2, \sigma_3$	= Three primary principle stresses
Sy	= yield stress
Su	= ultimate strength
U	= cumulative fatigue usage factor
α	= shape factor: the ratio of the load set producing a fully plastic section to the load set producing initial yielding in the extreme fibers of the section

Table 2.2.2.4-2
Primary and Secondary Stresses
EPU Design Conditions @ 650°F
(Margin = [(Allowable – Stress) / Allowable] x 100)

Table 2.2.2.4-3
Primary and Secondary Stresses
EPU Level A and Level B Conditions
(Margin = [(Allowable – Stress)/Allowable] x 100)

Table 2.2.2.4-4
Primary Stresses
EPU Level D Conditions
(Margin = [(Allowable – Stress) / Allowable] x 100)

Table 2.2.2.4-5
EPU Test Conditions
(Margin = [(Allowable – Stress) / Allowable] x 100)

Table 2.2.2.4-6
EPU Special Stress Limits
(Margin = [(Allowable – Stress) / Allowable] x 100)

2.2.2.5 Steam Generators and Supports

2.2.2.5.1 Introduction

The steam generators (SGs) and associated supports are reviewed as part of the extended power uprate (EPU). The SGs are described in Updated Final Safety Analysis Report (UFSAR) Sections 3.9, 5.1, and 5.4.2. The SG supports are described in UFSAR Section 5.4.14. St. Lucie Unit 2 uses two AREVA replacement SGs of type 89/19TI. The regulatory evaluation included in LR [Section 2.2.2](#) also applies to the SGs and supports.

The SG and supports evaluation was performed as ten separate, but coordinated, evaluations:

1. Thermal-hydraulic,
2. Structural integrity,
3. Design pressure differential,
4. Tube integrity,
5. Tube vibration and wear evaluation,
6. Foreign objects,
7. Tube repair hardware,
8. Steam drum,
9. Chemistry, and
10. Supports.

The technical evaluation included as part of this LR describes the input parameters, assumptions and acceptance criteria used to evaluate SG performance relative to the EPU. AREVA supplied, replacement SGs of type 89/19TI were installed in the fall of 2007.

A summary regarding the adequacy of the SGs and their supports under EPU conditions concludes this LR subsection.

St. Lucie Unit 2 Current Licensing Basis

The generic current licensing basis (CLB) provided in LR [Section 2.2.2](#) applies to the SG and its supports, with the following amplifications.

The SGs are vertical shell and U-tube heat exchanger with integral moisture separating equipment. The reactor coolant flows through the inverted U-tubes, entering and leaving through the nozzles located in the lower head of the SG. Steam is generated on the shell side and flows upward through the moisture separators to the outlet nozzle at the top of the vessel. Steam is then passed through the moisture separator reheaters, turbine, and the condenser. Condensate is returned to the SGs via the feed pumps and the feedwater heaters. There are two SGs.

UFSAR Section 5.4.2.1.1 states that all pressure boundary materials used in the SGs are selected and fabricated in accordance with the requirements of Section III of the ASME Code. A

general discussion of materials specifications is given in UFSAR section 5.2.3, with types of materials listed in UFSAR Tables 5.2-3.

The Code Class 1 components of the SG meet the fracture toughness requirements of the ASME Code and 10 CFR 50 Appendix G as discussed in UFSAR Subsection 5.2.3.3.1. Fracture toughness data for the SG materials is presented in UFSAR Tables 5.2-8, 5.2-10, and 5.2-11.

The SG contains 8999 U-tubes for heat transfer for primary to secondary water. Each tube is expanded into the tube sheet so that there are no voids or crevices occurring along the entire length of the tube sheet interface. The tubes are also welded to the Ni-Cr-Fe alloy clad on the reactor coolant surface of the tubesheet. The tube to tubesheet welding conforms with the requirements of the ASME Code, Sections III and IX. Support for the tube bundles are by stainless steel broached tube support plates. Additional support is provided by stainless steel anti-vibration bars to prevent excessive flow-induced vibration.

UFSAR Section 5.4.2.1.3 states that the SG tubes are fabricated from Inconel 690 to insure compatibility with both primary and secondary waters. This section also addresses localized corrosion which has led to SG tube leakage in some operating plants. Alloy 690 tubes are less susceptible to various forms of degradation. This section also addresses a corrosion phenomenon known as "denting". The potential for tube denting has been reduced in the SGs by the installation of tube support plates and anti-vibration bars system that are stainless steel with a high chromium content that forms a tight adherent oxide layer. This combination eliminates the potential for denting.

UFSAR Section 5.4.2.2 states that the SGs are inspected per the requirements of Section XI of the ASME Code. The reactor coolant pressure boundary (RCPB) Inservice Inspection and Testing is described in UFSAR Section 5.2.4.

UFSAR Section 5.4.14.2 states that the SG is supported at the bottom of a sliding base bolted to an integrally attached conical skirt. The sliding base rests on low friction bearings which allow unrestrained thermal expansion of the reactor coolant system (RCS). Two keyways within the sliding base guide the movement of the SG during the expansion and contraction of the RCS and, together with a stop and anchor bolts, prevent excessive movement of the bottom of the SG during seismic events and following a loss of coolant accident (LOCA).

A system of keys and snubbers located on the upper end guide the top of the SG during expansion and contraction of the RCS and provide restraint during seismic events and following a LOCA or a steam line break.

The RCS supports are designed to the criteria for load combinations and stresses which are presented in UFSAR Subsection 3.9.3.1. The criteria are used to determine the loads the supports must consider as a result of the effects of pipe rupture and seismic conditions.

UFSAR Table 3.9-2 summarizes design and fatigue analysis transients for Class 1 piping and components, which apply to the SG, for normal, upset, emergency, faulted and test conditions. UFSAR Chapter 15 addresses component responses to various limiting design transients in more detail.

All accident analyses presented in Chapter 15 of the UFSAR were evaluated to determine the effects of replacing the original SGs with AREVA replacement SGs.

In addition to the licensing basis described in the UFSAR, the SGs and supports were evaluated for St. Lucie Unit 2 License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.1.6 of the SER identifies that components of the SGs and supports are within the scope of License Renewal. Programs used to manage the aging effects associated with the SGs and supports are discussed in SER Section 3.1.6 and Chapter 18 of the UFSAR.

2.2.2.5.2 Technical Evaluation

The technical evaluations of the areas identified in LR [Section 2.2.2.5.1](#) are discussed in LR [Sections 2.2.2.5.2.1 through 2.2.2.5.2.9](#).

2.2.2.5.2.1 Supports

2.2.2.5.2.1.1 Introduction

Thermal-hydraulic (T-H) analyses were performed to ensure that the SGs continue to operate within their design bases following implementation of the EPU. The SGs were evaluated for EPU conditions that include a nuclear steam supply system (NSSS) power level of 3034 MWt (3020 MWt core power + 14 MWt RCS heat input) or 1517 MWt/SG. Prior to the EPU, the plant has operated at the nominal NSSS power level of 2710 MWt which includes 10 MWt RCS heat input. Moreover, prior to EPU, the design conditions for the SGs have allowed for a 10 percent uprate which equates to a NSSS power level of 2981 MWt (1.10×2710 MWt NSSS power level) or 1490.5 MWt/SG. The evaluation performed herein is based on an increase in core power level of approximately 11.85 percent over the originally licensed core power level of 2700 MWt and provides a comparison of the T-H parameters associated with 1490.5 MWt/SG and those associated with 1517 MWt/SG.

SG conditions were calculated to consider the effects of an increase in core thermal power on:

- steam pressure,
- steam flow,
- circulation ratio,
- moisture carryover,
- dry-out,
- heat transfer coefficient,
- pressure drop (primary and secondary), and
- water level stability.

The calculations confirm that these parameters remain within their acceptance criteria.

Results of this T-H evaluation have concluded that the SGs will continue to provide satisfactory thermal-hydraulic performance for the 1517 MWt/SG operating conditions. Detailed discussions regarding the analyses and evaluations and the conclusions reached are provided below.

2.2.2.5.2.1.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters and Assumptions

To illustrate the differences due to the increase in power level to 1517 MWt/SG, values have been presented for the 1490.5 MWt/SG conditions, where available, and the 1517 MWt/SG conditions.

The 1490.5 MWt/SG and 1517 MWt/SG conditions were evaluated for each of the four cases presented below, using the design fouling factor of $50 \times 10^{-6} \text{ }^{\circ}\text{F ft}^2 \text{ hr/btu}$ where applicable. The beginning of life (BOL) and end of life (EOL) conditions serve as bounding endpoints for the four cases.

- Clean tubes, all tubes in service, (BOL),
- Fouled tubes, all tubes in service,
- Clean tubes, 20 percent plugged @ 1490.5, 10 percent plugged @ 1517, and
- Fouled tubes, 20 percent @1490.5, 10 percent @1517, (EOL).

The values illustrated in the LR [Table 2.2.2.5-1](#) identify the SG operating parameters at BOL and EOL conditions for 1490.5 MWt/SG and 1517 MWt/SG operating conditions.

SG water level at 100 percent load is set at $\frac{1}{2}$ above the top of the tubesheet (TTS) and is conservatively assumed to remain at this level from 0 percent load to 100 percent load for all conditions and cases. At this water level, the moisture separators perform optimally.

SG primary coolant outlet temperature (T_{cold}) at 0 percent load is taken to be $\frac{1}{2}$. T_{cold} represents a linear ramping from 0 percent load $\frac{1}{2}$ to the corresponding 100 percent load temperature.

The 100 percent load SG outlet temperature at the 1517 MWt/SG conditions was increased by calorimetric analysis to $\frac{1}{2}$.

Blow-down flow-rate is taken to equal 1 percent of the steam flow-rate.

Acceptance Criteria

Thermal-hydraulic acceptance criteria for the 1517 MWt/SG operating conditions are as follows:

- Steam pressure: > 885 psia at BOL and > 815 psia at EOL,
- Steam flow rate: > 5.90×10^6 lbm/hr,
- Bundle flow and circulation ratio: minimal change,
- Moisture carry-over (MCO) < 0.1 percent of steam flow,
- Average heat flux: < dry-out conditions,
- Global heat transfer coefficient and heat transfer area: minimal change,
- Primary side pressure drop: $\frac{1}{2}$ and minimal ΔP change,

- Secondary side pressure drop: minimal change, and
- Water level stability: damping coefficient [].

2.2.2.5.2.1.3 Description of Analyses and Evaluations

T-H studies and evaluations were performed using the PERFGV computer code, the ANETH computer code, and various mockups for performance testing and benchmarking. The PERFGV code provides performance and T-H parameters of U-tube type SGs for BOL and EOL conditions at various power levels. Performance characteristics were analyzed to identify any operating parameter changes associated with the increase in power between the replacement SG design power level of 1490.5 MWt/SG and the EPU power level of 1517 MWt/SG. The ANETH computer code is a one-dimensional code used for water level instability analysis. Mockup testing was used to analyze environmental conditions (corrosion, dry-out, and hide-out) and to verify and benchmark computer code analyses, water level stability, and moisture carryover. The results of these analyses and testing efforts demonstrate that the SGs are acceptable for continued operation at EPU operating conditions. Detailed discussions for each acceptance criterion are provided below.

Method Discussion

SG characteristics such as steam pressure, steam flow rate, bundle flow rate, circulation ratio, moisture carryover, heat flux, heat transfer coefficient, heat transfer area, primary and secondary side pressure drops, and water level stability were calculated and evaluated for acceptability at 1517 MWt/SG conditions. These characteristics were compared to 1490.5 MWt/SG conditions where applicable. BOL conditions assume zero percent tube plugging and clean (not-fouled) conditions. EOL assumes fouled conditions and 20 percent tube plugging for 1490.5 MWt/SG conditions and 10 percent plugging for 1517 MWt/SG conditions.

- **Steam pressure:** The SG outlet (static) steam pressure was evaluated to ensure that minimal BOL (885 psia) and EOL (815 psia) pressure requirements will be maintained at the 1517 MWt/SG operating conditions. Steam pressure is influenced by temperature (T_{hot} , T_{cold} , FW), FW pressure, downcomer water level, bundle losses, heat transfer rates, separator losses, fouling, etc. Typically an increase in steam pressure results in improved plant performance. Steam pressure was evaluated at BOL and EOL for the 1490.5 MWt/SG and 1517 MWt/SG operating conditions.
- **Steam flow rate:** The steam flow rate was evaluated to ensure that minimal BOL and EOL steam flow requirements of 5.90×10^6 lbm/hr at 99.9 percent quality are satisfied at the 1517 MWt/SG operating conditions. Steam flow rates were also compared to 1490.5 MWt/SG conditions to quantify any differences between 1490.5 MWt/SG and 1517 MWt/SG conditions.
- **SG Bundle flow rate and Circulation Ratio:** SG bundle flow and circulation ratio (CR) were evaluated to determine the resulting change in bundle flow rate at the 1517 MWt/SG operating conditions. As the re-circulated water from the moisture separation equipment re-enters the downcomer, it is joined by the incoming feedwater. Collectively, this flow enters the tube bundle at the bottom of the downcomer to form the bundle flow. The ratio of the bundle flow to the incoming feedwater flow determines the circulation ratio. The SG bundle

flow rate is equal to the product of the circulation ratio and the feedwater flow rate. Both the bundle flow rate and circulation ratio are sensitive to downcomer water level height. As discussed in LR [Section 2.2.2.5.2.1.2](#), the water level is assumed to remain constant at 411.3 inches above the top of tubesheet from 0 percent load to 100 percent load.

- **Moisture Carryover:** Moisture carryover (MCO) was evaluated to ensure it remains below the 0.1 percent design value at the 1517 MWt/SG conditions. During the steam flow process, the primary separators serve as the first stage of moisture removal. Moisture is removed by gravity during the transit from the primary to secondary separators. The secondary separators (dryers) account for the final stage of moisture removal prior to the steam exiting the SG. Any remaining moisture in the steam flow, upon exiting the SG, is referred to as MCO. From an operational perspective, MCO results in reduced thermal power of the unit. Significant MCO can result in turbine blade damage due to water droplet impingement. MCO may also result in flow assisted corrosion (FAC) of the steam piping (See LR [Section 2.1.8](#)). The MCO shall not exceed one-tenth of one percent (0.10 percent) of the steam flow at the SG outlet steam nozzle under any operating condition. During initial evaluation of the replacement SGs for MCO, inputs of 6.62×10^6 lbm/hr steam flow, 820 psia saturation pressure, and an upstream MCO value of 15 percent were used. These values equal or bound the 1517 MWt/SG operating conditions.
- **Heat Flux:** Heat flux was evaluated to assess its impact, notable on dry-out, at the 1517 MWt/SG conditions. The heat flux across the SG tube wall is directly proportional to the heat load, or power level, and inversely proportional to the in-service heat transfer area. Heat flux is measured in units of energy per unit time per unit area (BTU/hr-ft² or W/m²). One manifestation of an exceedingly large heat flux is “Dry-Out”. Dry-out occurs when steam pockets form locally on the outer tube wall, which degrades nucleate boiling heat transfer. The most susceptible regions are regions with low flow velocity and close contacts. Dry-out may accelerate hide-out (deposition of harmful species dissolved in the secondary water concentrating in confined areas of the SG). Dry-out can also lead to a local superheat at the tube wall and ultimately result in tube fatigue due to the alternate drying and wetting action. During initial testing of the replacement SGs for dry-out, the test conditions bounded the worst case EPU conditions (fouled tubes and maximum plugging limits) and also targeted problem areas of the SG (tube/ supports). Testing was performed at secondary pressures ranging from 650 to 1100 psi, qualities ranging from 0 and primary temperatures ranging from 0. Various tube/ contact configurations were studied (flat and circular contacts).
- **Global Heat Transfer Coefficient and Heat Transfer Area:** The global heat transfer coefficient (GHTC) and heat transfer area were evaluated for changes due to the increase to 1517 MWt/SG power. The GHTC is proportional to the heat transferred across the tube wall (BTU/ hr or MWt) and inversely proportional to the bundle heat transfer area (ft²) and the log-mean temperature difference (°F). The log-mean temperature difference is based on the differences between (T_{hot} and T_{sat}) and (T_{cold} and T_{sat}), where T_{sat} corresponds to the saturation temperature of the U-bend pressure. The GHTC is expressed in units of (BTU/ °F-ft²-hr) and was calculated using the PERFEG code 0. The GHTC and heat transfer area were evaluated at BOL and EOL for 1490.5 MWt/SG and 1517 MWt/SG conditions.

- **Primary side pressure drop:** Primary side pressure drop was evaluated to ensure that the original SG pressure drop of [] is not exceeded at the 1517 MWt/SG operating conditions and to identify any ΔP changes associated with the EPU power increase. Primary side pressure drop results from pressure losses at the channel head inlet, at the tube inlet, along the tubes, at the tube outlet, and at the channel head outlet. Pressure losses result from form (geometry) and frictional losses. Pressure losses typically increase with increased fluid flow-rate. Since EPU flow-rates exceed the [] benchmark, EPU pressure losses are conservative. Pressure losses were evaluated at BOL and EOL for the 1490.5 MWt/SG and 1517 MWt/SG operating conditions.
- **Secondary side pressure drop:** Secondary side pressure drop was evaluated to assess any changes between 1490.5 MWt/SG and the 1517 MWt/SG conditions. Secondary side pressure drop is a result of single phase and two phase frictional losses, cross flow losses, expansion losses, contraction losses, separator losses, and momentum losses. Secondary side pressure losses were evaluated at BOL and EOL for the 1490.5 MWt/SG and 1517 MWt/SG operating conditions.
- **Water level stability:** Water level stability was analyzed using the ANETH one-dimensional code [].

2.2.2.5.2.1.4 Results

The above mentioned T-H parameters have been evaluated and determined to be within the design limits for operation at the 1517 MWt/SG conditions with tube plugging levels of up to ten percent (10 percent). The following results summarize the SG T-H analysis at the EPU NSSS power level of 3034 MWt. Results at the current NSSS power level of 2981 MWt are also included for comparison.

- **Steam pressure:** The outlet steam static pressures at BOL and EOL conditions are illustrated in LR [Table 2.2.2.5-2](#). At 1517 MWt/SG, a slight increase in steam pressure is expected at BOL conditions and a 26 psi increase at EOL conditions. Both the BOL and EOL EPU steam pressures exceed the 885 and 815 psia design minimums, respectively. These results demonstrate acceptable steam pressures at EPU operating conditions.
- **Steam flow:** Steam flows at BOL and EOL conditions are illustrated in LR [Table 2.2.2.5-3](#). At 1517 MWt/SG, steam flow rates are expected to increase slightly. The minimum steam flow requirement of 5.90×10^6 lbm/hr at 99.9 percent quality has been satisfied in all cases. Since MCO over remains less than 0.1 percent, the steam flow rates at EPU operating conditions are considered acceptable.
- **SG Bundle flow rate and Circulation Ratio:** Comparison of 1490.5 MWt/SG and 1517 MWt/SG bundle flow and circulation ratio at BOL and EOL are illustrated in LR [Table 2.2.2.5-4](#). The results show only a small change in flow rates at EPU conditions. These small changes are not expected to result in additional accumulation of sludge or contaminants at EPU operating conditions.
- **Moisture Carry-Over:** Initial evaluation of the replacement SGs for MCO was performed at bounding EPU conditions and resulted in a MCO value of 0.072 percent. Since the conditions

of the initial evaluation bound the 1517 MWt/SG operating conditions, it is expected that MCO will continue to remain <0.1 percent of the steam flow at EPU operating conditions.

- **Heat Flux:** The 1490.5 MWt/SG and 1517 MWt/SG heat flux EOL test results are presented in LR [Table 2.2.2.5-5](#). The results show that for linear contact points (flat lands and AVBs) dry-out was not experienced at 1490.5 MWt/SG conditions. Since the 1490.5 MWt/SG conditions are bounding, dry-out is not expected to occur at the 1517 MWt/SG operating conditions. The 1490.5 MWt/SG conditions are bounding due to less available heat transfer area (tube surface area) associated with the larger (20 percent) 1490.5 MWt/SG plugging limit, compared to the smaller (10 percent) 1517 MWt/SG plugging limit. See LR [Table 2.2.2.5-6](#) for heat transfer areas.
- **Global Heat Transfer Coefficient and Heat Transfer Area:** Results of the global heat transfer coefficient and heat transfer area evaluations are illustrated in LR [Table 2.2.2.5-6](#) at BOL and EOL. At BOL, an approximate 4 percent decrease in the GHTC is noted at the 1517 MWt/SG conditions. Tube plugging differs between 1490.5 MWt/SG and 1517 MWt/SG conditions at EOL and precludes making a direct comparison of the GHTC. These small differences in the GHTC are judged to have only minor affects on SG operation at EPU operating conditions.
- **Primary side pressure drop:** SG primary side pressure drops at BOL and EOL are illustrated in LR [Table 2.2.2.5-7](#). When comparing the 1490.5 MWt/SG and the 1517 MWt/SG conditions, the results show nearly equal pressure drops at BOL and nearly a 5 psi decrease at EOL (due to differing levels of SG tube plugging). Both BOL and EOL pressure drops at 1517 MWt/SG conditions remain below the 45.89 psi requirement [1]. Based on these results, together with the bounding [1] primary side 1517 MWt/SG flow-rates, acceptable primary side pressure drops are expected for EPU operating conditions.
- **Secondary side pressure drop:** Comparison of the secondary side pressure drops at BOL and EOL are illustrated in LR [Table 2.2.2.5-8](#). Only slight increases in pressure drop are noted at BOL and EOL for the 1517 MWt/SG conditions. These results demonstrate acceptable secondary side pressure drops at EPU operating conditions.
- **Water level stability:** The water level stability analysis shows that instability will not be reached for damping coefficients of [1]. The lowest damping coefficient associated with the SGs at the 1517 MWt/SG conditions is [1]. Since the damping coefficient exceeds the minimum [1] times, water level stability should remain acceptable at EPU operating conditions.

2.2.2.5.2.2 Steam Generator Structural Integrity

2.2.2.5.2.2.1 Introduction

The structural integrity evaluation of the SG was performed using an EPU core power level of 3020 MWt (NSSS power level of 3034 MWt or 1517 MWt/SG), steam generator tube plugging (SGTP) over the range from 0 to 10 percent, with a primary cold leg temperature (T_{cold}) of 551°F, a full load SG outlet pressure ranging from [1]psia, and a feedwater temperature of 436°F. The stresses, stress intensity ranges, and fatigue usage factors in the SG for the EPU range of

conditions were determined by reconciling the original design basis analyses against the EPU conditions (1517 MWt/SG).

The scope of the stress reconciliation reanalysis was the entire SG pressure boundary and all internal and external pressure boundary attachments. Formal analyses were performed for the tubesheet, tube bundle, primary divider plate, primary head and internal attachments, secondary shell and internal/external attachments, primary and secondary nozzles, primary and secondary manways, handholes, inspection ports, and studs and covers on all bolted openings.

2.2.2.5.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The structural evaluation was performed for the EPU core power level and SG conditions specified in LR [Section 2.2.2.5.2.2.1](#) above.

Loads on the internal attachments remain unchanged for 1517 MWt/SG conditions. Changes to nozzle and support loads applicable to the 1517 MWt/SG conditions have been included in the revised certified design specification and were used in the updated structural analyses. No changes were identified for design, faulted and test conditions for operation at the 1517 MWt/SG conditions. Furthermore the original structural analyses remain applicable relative to plant operation at 1517 MWt/SG conditions. The bolt preloads for bolted pressure boundary openings were established on the basis of “leak proofing” the joints. The original design basis preloads were used in the updated structural analyses.

The design basis analysis demonstrating protection against non-ductile fracture has been reconciled with the 1517 MWt/SG conditions. Based on temperature comparisons and updated fatigue calculations, the 1517 MWt/SG conditions have been shown to have limited impact on areas concerned with non-ductile fracture and remain bounded by original design basis analysis of the plant cool down transient which was unchanged for 1517 MWt/SG conditions.

The 1517 MWt/SG conditions resulted in modification to several transients corresponding to normal, upset, and emergency conditions used to develop the original design of the SGs. To quantify the range of stress intensities associated with the modified transients, structural analyses of the SGs were performed in order to calculate new stress intensity ranges and fatigue usage factors for normal and upset conditions. For the changes in 1517 MWt/SG emergency conditions, there was no effect on the primary stress analyses performed since the maximum pressures used are still bounding; however, these conditions were reconciled with the original analyses with regard to evaluation of potential for non-ductile fracture. Acceptance of the results for 1517 MWt/SG conditions was based on demonstrating continued compliance with the structural criteria in the American Society of Mechanical Engineers Boiler & Pressure Vessel (ASME B&PV) Code Section III, Subsection NB ([Reference 1](#)). These acceptance criteria are the same as those used for the original design basis analyses of the SGs.

Continued compliance with the SG design basis analysis is the acceptance criteria for the structural analysis for 1517 MWt/SG conditions. For the structural evaluation of the pressure boundary components, the acceptance criteria from ASME B&PV Code Section III, Subsection NB for Class 1 components are used. Excessive plastic deformation is prevented by limits on the acceptable primary stresses. Plastic instability and incremental collapse are prevented by limits on the acceptable primary-plus-secondary stresses. High-strain, low-cycle

fatigue is prevented by limits on the total stresses and their cycles. Satisfaction of these limits demonstrates continued compliance with the current design acceptance criteria and, therefore, the adequacy of the SG design for operation at the 1517 MWt/SG conditions for the remainder of the 40-year design life of the SG.

The SG internal components, other than the tube bundle, are not part of the pressure boundary and, therefore, are not governed by the ASME Code. However, the general philosophy of ASME B&PV Code Section III was used for performing the structural and fatigue analysis of these components. These components were reviewed and it was determined that they satisfy the applicable ASME B&PV Code stress and fatigue criteria.

FAC is affected by metallurgical factors, hydrodynamic factors (flow velocity, surface roughness, flow path geometry and steam quality), and environmental factors (temperature and chemistry). The SG design was developed to avoid corrosion problems that have been observed in operating SGs. These features include the selection of corrosion-resistant materials for construction, improved tube support design, improvement in fluid dynamics for introduction of the feedwater, high circulation ratio and high blowdown rate capability. The only factors affecting the FAC rates that change due to 1517 MWt/SG operating conditions are water film velocities and operating temperatures. Since primary side surfaces are fully clad with high chromium material which is less susceptible to FAC, the assessment is only relevant for the SG secondary side.

The highest flow regions are the feedwater nozzle / header, blowdown, and the primary separators. The materials selected for these parts are specifically chosen with regard to their ability to resist FAC associated with the high flow rates by using either stainless steels (feedwater header and primary separators) or carbon / low alloy steels with a minimum specified chromium (Cr) content of 0.15 percent (feedwater and blowdown nozzles). The most critical components are those made from carbon or low alloy steel without requirements for increased Cr content which are located in the downcomer and also experiences high velocities. The velocity in the downcomer increases for the 1517 MWt/SG condition from [] to []

2.2.2.5.2.2.3 Description of Analyses and Evaluations

From a structural standpoint, the increased pressure and temperature variations during 1517 MWt/SG normal- and upset-operating conditions impact the SG. Both the primary and secondary side SG components are affected to differing degrees by these increased pressure and temperature variations, resulting in increased stress intensity ranges and fatigue usage factors. The SG ASME code design conditions are unaffected by the EPU conditions.

The SG EPU structural evaluation was performed by rerunning the existing SG design basis analyses relative to the 1517 MWt/SG conditions specified. The scope of the reanalysis included the entire SG pressure boundary and all internal and external pressure boundary attachments. Formal analyses were performed for the tubesheet, tube bundle, primary divider plate, primary head and internal attachments, secondary shell and internal/external attachments, primary and secondary nozzles, primary and secondary manways, handholes, inspection ports, and studs and covers on all bolted openings.

For SG features provided with possible multiple configurations such as secondary manways, handholes, and inspection ports with either welded inserts or gaskets, recirculation nozzle with or

without a cap, and instrument taps with a plug or stabilizer, only the configuration which resulted in the highest stress intensity range and/or fatigue usage for 1490.5 MWt/SG conditions was reevaluated for the 1517 MWt/SG conditions.

The re-analyses performed for 1517 MWt/SG conditions generally used the same finite element methods performed for the initial SG design to determine the temperature fields associated with thermal calculations and stress and displacement fields associated with mechanical or thermo-mechanical calculations. Using the AREVA finite element program SYSNUKE, the stress field including temperature variation and stress distribution through the wall thickness is determined.

The results obtained from the finite element methods were then input to an AREVA post-processing program (RCCM-ASME), to calculate the linearized stress intensity range and fatigue usage factor at each selected location for stress analysis in accordance with ASME B&PV Code Section III, Subsection NB. For the special case of the tubesheet, the AREVA program PLAQUE TUBULAIRE is utilized to determine stresses taking into account the stress concentration factors associated with the tubesheet hole pattern.

All components were considered to operate at the 1517 MWt/SG conditions for the full 40-year design life of the SG.

2.2.2.5.2.4 Results

It was determined that the SG pressure boundary and internal/external attachments continue to remain in compliance with the structural criteria of the ASME B&PV Code Section III, Subsection NB and, therefore, are adequate for operation at the 1517 MWt/SG conditions.

The most critical results from the structural evaluation are presented in LR [Table 2.2.2.5-9](#). All applicable ASME B&PV Code stress and fatigue criteria have been satisfied for the SG for the 1517 MWt/SG conditions.

An assessment of the FAC rates at 1517 MWt/SG conditions was performed and concluded that the current design corrosion allowances remain applicable for 1517 MWt/SG conditions. The increased velocity in the downcomer results in an increased wall thinning rate of approximately 2.4 percent for low alloy steel. Other secondary side internal components made from carbon steel are not subject to severe conditions regarding FAC as proven over 25 years of operation in operating plants with the same design. The design of the SG provides sufficient margin between the maximum velocity and the velocity threshold that could lead to FAC in the secondary environment for the materials considered. Periodic inspection of the SGs is addressed in the Steam Generator Integrity Program.

An evaluation of the divider plate concluded that divider plate cracking should not occur at either 1490.5 MWt/SG or 1517 MWt/SG conditions since the divider plate and weld metal are composed of Inconel 690 material which has been shown to be resistant to PWSCC at the process conditions associated with either of these NSSS thermal power levels. Also, because the divider plates used in the SGs are welded directly to the tubesheet butting (Type 152 material), stub runners are not required and, therefore, misalignment cannot occur to cause the high residual stress condition that results in the cracking. Problems with the design of the divider plate have not been observed in over fifteen years of plant operation. It should be noted that cracking

has been observed previously in divider plates composed of Inconel 600 material where stub runner misalignment has occurred to cause a high residual stress condition. Also, the Inconel 600 material is less resistant to PWSCC than the Inconel 690 material.

2.2.2.5.2.3 Design Pressure Differential

2.2.2.5.2.3.1 Introduction

An analysis was performed to determine if the [Reference 1](#) limits on design primary-to-secondary pressure differential drop (ΔP) remain satisfied considering EPU SG design transients and EPU (1517 MWt/SG) loading conditions.

2.2.2.5.2.3.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters and Assumptions

At both 1490.5 MWt/SG and 1517 MWt/SG, the design pressure limit for primary-to-secondary pressure differential is 2250 psi.

At both 1490.5 MWt/SG and 1517 MWt/SG, the maximum design pressure is 2485 psig on the primary side and 985 psig on the secondary side.

Acceptance Criteria

In accordance with [Reference 1](#), the primary-to-secondary differential pressure for the normal/upset transient conditions is subject to the following requirements which are applicable for both 1490.5 MWt/SG and 1517 MWt/SG conditions:

- Normal condition transients: Maximum primary-to-secondary pressure is equal to 2250 psig; and
- Upset condition transients: If the pressure during an upset transient exceeds the design pressure limit, the stress limits corresponding to design conditions apply using an allowable stress intensity value of 110 percent of those defined for design conditions. For the SGs, 110 percent of the design pressure differential limit corresponds to 2475 psi.

2.2.2.5.2.3.3 Description of Analyses and Methodology

The primary-to-secondary design pressure differential evaluation was performed taking into account the information presented in LR [Sections 1.1](#) and [2.2.6](#). Open Item A.1. The pressure differentials across the primary-to-secondary-side pressure boundary under the 1517 MWt/SG conditions were calculated and compared with the ASME B&PV Code limits. Only the pressure differentials for the EPU affected transients were calculated since the goal was to determine if the specified 1517 MWt/SG conditions cause an increase in the design primary-to-secondary pressure differential drop. The pressure differentials were conservatively calculated by subtracting the minimum secondary side pressure occurring during a transient from the maximum primary side pressure occurring during a transient, even if they don't occur at the same time.

2.2.2.5.2.3.4 Results

The maximum primary-to-secondary pressure differentials for normal and upset conditions are provided in LR [Table 2.2.2.5-10](#). The results of the analyses performed for the primary-to-secondary-side pressure differential are all below the applicable design pressure limits of 2250 psi and 2475 psi for normal and upset conditions respectively.

2.2.2.5.2.4 Tube Integrity

2.2.2.5.2.4.1 Introduction

Technical Specification Task Force (TSTF) Standard Technical Specification Change Traveler TSTF-449, Steam Generator Tube Integrity, represents the culmination of NRC and industry efforts to develop a programmatic, largely performance-based regulatory framework for ensuring SG tube integrity. The availability of this Technical Specification (TS) improvement was announced in the Federal Register on May 6, 2005 (70 FR 24126), as part of the consolidated line item improvement process (CLIIP) (Reference 2). In order for St. Lucie Unit 2 to adopt the provisions of the TSTF, FPL submitted a license amendment request to the NRC on May 25, 2006 ([Reference 3](#)), for approval of changes to TS. Consistent with TSTF-449, the proposed TS changes included the following:

- Revise the TS definitions of identified leakage (1.15c) and pressure boundary leakage (1.22);
- Replace the existing TS 3/4.4.5, Steam Generators, requirements with the new Steam Generator Tube Integrity requirements;
- Revise TS 3/4.4.6, Reactor Coolant System Leakage;
- Add new TS 6.8.4.I, Steam Generator Program; and
- Add new TS 6.9.1.12, Steam Generator Tube Inspection Report.

On May 29, 2007, the NRC approved the requested changes to the St. Lucie Unit 2 TS ([Reference 4](#)).

2.2.2.5.2.4.2 Description of Analyses and Evaluations

In support of the EPU, a reconciliation analysis of the accident loads affecting the tubing was completed for EPU full power conditions (1517 MWt/SG). Loads in the U-bend region were calculated for safe shutdown earthquake (SSE), LOCA, and steam line break postulated events consistent with structural integrity performance criteria industry requirements.

The structural limits define the allowable tube degradation levels in terms of wall loss for a given degradation length, and are based on satisfying the structural integrity performance criteria (SIPC) contained in Nuclear Energy Institute (NEI) 97-06, Steam Generator Program Guidelines (May 2005).

2.2.2.5.2.4.3 Input Parameters, Assumptions and Acceptance Criteria

Input Parameters and Assumptions

Important considerations in determining structural limits for tube burst are tube pressure differential loads for normal operation and accident conditions, as well as any non-pressure loads created during design basis accident conditions that may reduce the burst strength. Structural limits currently determined for St. Lucie Unit 2 have considered both pressure and non-pressure loads for the original design. A normal operating pressure differential (NOPD) of 1365 psi has been assumed in the current operational assessment for cycle 18. This NOPD is a conservative estimate for the 1517 MWt/SG tube differential pressure. It should be noted that the limiting condition for meeting structural integrity performance criteria is three times NOPD.

Acceptance Criteria

SG tube integrity shall remain compliant with TS requirements.

2.2.2.5.2.4.4 Results

Based on the reevaluation at the 1517 MWt/SG conditions, FPL has concluded that the replacement SG tube accident loads are bounding and are conservative for the 1517 MWt/SG conditions. In addition, the NOPD for steady state operation will be less than 1400 psi. This is based on a conservative in-service pressure and saturation pressure in the U-bend region for 100 percent power, fouled, and with 10 percent tube plugging.

Given the above review, there is no impact to the current structural limits for the following reasons:

1. The NOPD across the tube wall used in the current operational assessment for Cycle 18 is 1365 psi, and falls within the industry accepted tolerance limit of 50 psi ([Reference 5](#)) when compared with the estimated value of less than 1400 psi at 1517 MWt/SG; and
2. The original design basis analysis for non-pressure accident loads bounds the 1517 MWt/SG conditions.

In consideration of the above it is noted that the SG tube inspection was conducted in January 2011 at the end of cycle 18. The January 2011 inspection includes a condition monitoring assessment and operational assessment with repair limits that are compliant with Revision 3 of the Tube Integrity Guidelines ([Reference 6](#)). The operational assessment for Cycle 19 will be the first to address the change in conditions for implementation of EPU. Therefore, there is no impact upon the Cycle 18 operational assessment and repair limits as a result of EPU.

Refer to LR [Section 2.1.9](#) for discussion pertaining to SG tube inservice inspection.

2.2.2.5.2.5 Tube Vibration and Wear Evaluation

2.2.2.5.2.5.1 Introduction

Flow-induced vibration (FIV) analysis and tube wear calculations were performed to demonstrate that the SG tubes are adequately supported to prevent detrimental FIV and fretting wear at the

EPU conditions. It was demonstrated that the tubes are not susceptible to fluid-elastic instability at the EPU conditions and that the accumulated tube wear over the life of the SGs remains below the established allowable limit of 40 percent.

2.2.2.5.2.5.2 Input Parameters, Assumptions, and Acceptance Criteria

FIV performance of the tube bundle and tube wear for the 1517 MWt/SG EPU power level for steady state operating conditions under EPU was obtained by scaling the values for 1490.5 MWt/SG for the replacement SGs by a factor representative of the dynamic pressure term ($\frac{1}{2} \rho V^2 = 1.02$) between power levels. In general, the fluid-elastic stability margin of the tube bundle is inversely proportional to the square root of the dynamic pressure term and the response of the tube bundle to random turbulent excitation or vortex shedding excitation is proportional to the dynamic pressure term.

The most limiting scaling factor for the EPU operating condition was determined for the EOL operating condition []

The acceptance criteria for the EPU conditions for each of the FIV mechanisms evaluated, including tube wear, are as follows:

Fluid-elastic Instability

- Critical velocity ratio < 0.75 precluding fluid-elastic instability. This stability criterion represents a 33 percent margin of safety.

Random Turbulence Excitation

- The acceptance criterion for the displacements is based on one-half the gap clearance between adjacent tubes. Since the computed displacement response (inch, RMS) to turbulence is based on a probability of excursions, $\frac{1}{2}$ of the gap clearance is divided by a factor of 5 or 5 sigma (i.e., 0.025 inch, root mean square, (RMS)), which is representative of approximately a 100 percent probability that this allowable displacement will not be exceeded during 40 EFY of operation. This acceptance criterion is conservative and is in accordance with [Reference 7](#).
- Allowable high cycle fatigue stress of 2800 psi, rms at 10^{13} cycles.

The responses of the structures are computed in statistical units of measurement (e.g., the stress in units of psi, RMS). A statistical analysis technique is used to develop an RMS fatigue curve from the ASME fatigue curve for austenitic steel, which was based on tests performed with sinusoidal loads. The full details of this technique are described in [Reference 7](#), Chapter 11. These curves were derived from the corresponding fatigue curves based on long-duration tests with deterministic loads, as published in the ASME Section III Boiler & Pressure Vessel Code. The RMS fatigue curves were derived using the fatigue curves "A, B, & C" for the fatigue life calculations for the FIV analysis of high cycle fatigue loadings.

Tube Wear

The accumulated tube wear over 40 year life < 40 percent nominal tube wall thickness in accordance with TS 6.8.4.l.c.

The aforementioned acceptance criteria for tube vibration and wear provides reasonable assurance that SG tube integrity will remain consistent with the Steam Generator Program performance criteria contained in Plant TS (Section 6.8.4.I.1.b). Wear growth rates are evaluated at each inspection as part of the Steam Generator Program (Refer to LR [Section 2.2.2.5.2.4](#)).

Indications of tube wear were detected in the SGs during in-service inspection (ISI) of the tubing during refueling outage 18 (SL2-18) (May 2009, 16 months after SGs installation). Wear was the only degradation mechanism identified during the 2009 tube inspection. The majority of the wear indications were located at the AVBs that support the U-bends to preclude excessive vibrations. A higher than expected total of 5857 indications on 2046 tubes in the two SGs have been reported. None of the tubes exceeded the TS plugging limit of 40 percent through-wall depth. A total of 14 tubes were preventatively plugged to provide added margin for Cycle 18 operation.

A comprehensive investigation is currently underway with the SG vendor to determine the reason(s) for the wear rates being experienced. Additional ISI data will be gathered during the SL2-19 Refueling Outage to ascertain the required inspection frequency and ensure that tube integrity performance criteria are maintained. The Steam Generator Program requires that the inspection frequency be determined based on actual and projected wear rates.

2.2.2.5.2.5.3 Description of Analyses and Evaluation

FIV analyses of the SG tubes for fluid-elastic instability (FEI) and random turbulence excitation (RTE) considered the steady state operating conditions for the 1490.5 MWt/SG power level. Critical regions in the tube bundle were analyzed, taking into account crud or locked tube support conditions. A 1 percent viscous damping value was applied to the most limiting locked tube support plate conditions. The FIV analyses modeled the AVB tube supports, the largest u-bend spans for each AVB pair, and the maximum gap velocities from the T-H analysis. Homogenous flow was assumed to predict conservative mixture velocities.

An explicit analysis for vortex-shedding excitation (VSE) was not performed for the tube bundle since the secondary side flow turbulence, the non-uniform flow in the entrance of the first span and u-bend regions of the tube bundle, and the tightly packed tube bundle disrupt the wake shedding vortices from forming downstream of the tubes. Further, wake shedding is an organized phenomenon which has not been observed in tube bundles subjected to two-phase flow condition.

In the tube wear analysis, an instantaneous work rate was determined for each interval of time. [] The analysis conservatively assumed that all of the wear occurs on the tube and none on the contacting support and that the tube-to-support gap sizes remain consistent over the 40 year life of the plant. The analysis included an evaluation of the effects of manufacturing non-conformances of the broached holes of the tubes support plates.

The assessment of the FIV performance of the tube bundle and the tube wear for the 1490.5 MWt/SG steady state operating condition was provided in the Steam Generator Certified Design Report for the SGs. The bounding case scenario corresponded [].

These operating conditions provided a bounding FIV assessment of the tube bundle and effectively bounded the start-up conditions for FIV responses. These operating conditions are bounding as they produced the highest secondary side velocities across the tube, thus producing

conservative FIV analysis results. The thermal-hydraulic analysis methodology for FIV input conditions is similar to the analysis in LR [Section 2.2.2.5.2.1](#), Steam Generator Thermal-Hydraulic Evaluation.

2.2.2.5.2.5.4 Results

A summary of the FIV results for 1490.5 MWt/SG conditions and 1517 MWt/SG conditions are provided in the LR [Table 2.2.2.5-11](#). The FIV results for the EPU operating conditions are obtained from the product of the FIV results for the 1490.5 MWt/SG power level and the 1.02 scaling factor identified above. These FIV results are based on homogenous flow models which results in higher flow velocities across the tubes. Additionally, the results were determined assuming fully “crudged” supports, which conservatively results in less damping since the stainless steel broached tube support plate design utilized by the replacement SGs are not expected to develop fully crudged, locked supports. The combination of a conservative full power SG pressure, homogenous flow, and locked crudged supports ensures that the FIV results are bounding for the 1517 MWt/SG conditions.

At the most limiting location in the u-bend, the maximum expected tube wear for the 1490.5 MWt/SG operating condition resulting from 40 years of operation with gaps plugged at the upper support plate and a constant nominal gap during 40 years was estimated to be $\square$. An evaluation of the 1517 MWt/SG conditions shows that the kinetic energy in the critical region of the u-bend decreases by approximately 1 percent $\square$. Therefore, it was concluded that the wear analysis at 1490.5 MWt/SG is also applicable to the 1517 MWt/SG conditions. A study was also performed that showed a significant decrease in predicted wear is obtained by including the change in gap size, particularly after the first two years of operation (i.e. the wear is greatest during the first years of operation and then decreases).

Inspections performed per the TS-required SG Program have identified wear indications resulting in the need for plugging a small number of tubes. SG tube inspections and condition monitoring and operational assessments will continue in accordance with the program and the recent tube wear indications are being assessed as required by the program.

The results provided above demonstrate that the SG tube bundles are adequately designed and supported for the FIV and fretting wear that might occur over the 40-year design life with operation at the 1517 MWt/SG conditions. The SG Program will continue to monitor SG tube performance and ensure that SG tube integrity is maintained.

2.2.2.5.2.6 Foreign Objects

2.2.2.5.2.6.1 Introduction

The SG are monitored for foreign objects via examinations required by TS and NEI 97-06, Steam Generator Program Guidelines ([Reference 8](#)), including eddy-current inspection and secondary side visual inspection. A foreign object may be a loose part in the tube bundle or it may be fixed, i.e. a part lodged between tubes. Efforts are made during secondary side inspections to remove all identified foreign objects upon discovery. Any foreign object remaining in the SGs, whether fixed or loose, is documented, analyzed for future impact on SG tube integrity, and is added to a

list of foreign objects that are monitored during subsequent examinations. If inspections at two consecutive refueling outages indicate an object is no longer present, continued monitoring for that object is not required and the object is listed in a table for objects no longer being actively tracked. A separate table lists objects removed from the SGs.

Two foreign objects have been detected in the tube bundle of SG 2A, one on the tubesheet on the hot leg side and one in the no-tube lane on the cold leg. No loose parts or foreign objects have been detected in SG 2B. Both foreign objects that were detected in SG 2A were removed and no signs of wear associated with the objects were detected on eddy-current inspection or secondary side visual inspection. Currently, there are no foreign objects in SG 2A or 2B that require monitoring.

For 1517 MWt/SG conditions, an evaluation was performed to determine if the modified operating conditions would adversely affect the tube wear caused by possible future foreign objects.

2.2.2.5.2.6.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters and Assumptions

The current analysis considers:

- Previous foreign object wear experience at St. Lucie and other AREVA replacement SGs; and
- Secondary side thermal-hydraulic conditions for 1517 MWt/SG conditions (LR [Section 2.2.2.5.2.1](#)).

Major assumptions in the current analysis include:

- The SG tubes have been structurally qualified for a maximum allowable wear scar using the performance criteria defined in NEI 97-06 ([Reference 8](#));
- All tubes with wear scars exceeding the repair criterion of 40 percent through-wall penetration or the Electric Power Research Institute (EPRI) uniform wall thinning structural limit for a given axial fret length will be plugged in accordance with TS 6.8.4.l.c;
- Normal eddy-current inspections of the tube verify that the conservative repair criteria are not exceeded; and
- The SGs are operating at 1517 MWt/SG conditions (LR [Section 2.2.2.5.2.1](#))

Acceptance Criteria

SG tube integrity shall remain consistent with the performance criteria of NEI 97-06 ([Reference 8](#)) at 1517 MWt/SG conditions.

2.2.2.5.2.6.3 Description of Analyses and Evaluation

Secondary Side Foreign Object Analysis

With certain changes in SG operating conditions, such as power level, feedwater temperature, steam pressure, or plugging level, there could be a corresponding change in the T-H characteristics relevant to foreign object induced tube wear. Foreign object wear is a function of the drag force, object vibration, and tube displacement. The drag force and displacements of the foreign object are a function of fluid density and velocity (dynamic pressure). Higher fluid densities and velocities will result in an increased wear rate due to the loose part. The saturated water density for the 1517 MWt/SG condition (LR [Section 2.2.2.5.2.1](#)) is slightly lower compared to the 1490.5 MWt/SG condition analyzed to benchmark the current operation of the plant. The feedwater mass flow is slightly increased for the 1517 MWt/SG conditions and the recirculation ratio is slightly less, resulting in a total secondary side mass flow entering the tube bundle that is slightly higher for the 1517 MWt/SG conditions compared to the 1490.5 MWt/SG conditions. As described in LR [Section 2.2.2.5.2.5.2](#), the worst case increase in the dynamic pressure for the 1517 MWt/SG condition, including the affects of fouling and tube plugging, is 2 percent for an approximate 4 percent increase in the tube wear rate for the 1517 MWt/SG conditions.

FIV and wear analyses show that the critical FIV responses and calculated wear rates for bundle entrance tubes remain acceptable for the 1517 MWt/SG conditions. There is sufficient margin in the wear rates calculated for the benchmark conditions (LR [Section 2.2.2.5.2.5.4](#)) that the repair criteria will not be exceeded for the 1517 MWt/SG conditions.

There is no history of a foreign object in the U-bend region of the SG and it is unlikely that any object will be transported up to the u-bend region in the future. Based on the assessment for FIV and wear rates for the 1517 MWt/SG conditions (LR [Section 2.2.2.5.2.5.4](#)), which conservatively used the scaling factor for the tube bundle entrance to evaluate the u-bend region, the critical FIV responses and calculated wear rates for the u-bend region remain acceptable for the 1517 MWt/SG conditions. There is sufficient margin in the wear rates calculated for the benchmark conditions (LR [Section 2.2.2.5.2.5.4](#)) that the repair criteria will not be exceeded for the 1517 MWt/SG conditions.

In conclusion, the potential for tube wear due to a foreign object in the first span or at a higher elevation is increased by a maximum factor of 4 percent, which includes the affects of fouling and tube plugging. Sufficient margin in the wear rates remain to ensure that the repair criteria will not be exceeded for the 1517 MWt/SG conditions.

Primary Side Foreign Object Analysis

The Best-Estimate RCS mass flow rate is calculated for the 1517 MWt/SG conditions at BOL and EOL. The mass flow rate, and hence, the primary side velocity is essentially unchanged for the BOL, 0 percent tube plugging condition. The mass flow rate, at EOL, corresponding to the maximum plugging limit (20 percent at 1355 MWt/SG versus 10 percent at 1517 MWt/SG) is increased by 3 percent for the EPU conditions. This increase does not significantly affect the potential for foreign object damage on the primary side.

2.2.2.5.2.6.4 Results

Condition monitoring and operational assessments are reported at each inspection outage for the SGs and include any damage or potential for damage due to foreign objects. As noted in the evaluation provided above, the secondary side 1517 MWt/SG conditions will not result in an unacceptable wear rate due to a foreign object and the potential for foreign object damage on the primary side does not increase due to operation at 1517 MWt/SG conditions. All foreign material will be evaluated on a cycle-to-cycle basis to determine the acceptability of future operation.

2.2.2.5.2.7 Tube Repair Hardware

2.2.2.5.2.7.1 Introduction

Tube repair hardware refers to components that are installed in SGs to address tube degradation, such as plugs and stabilizers. Tube repair hardware has been limited exclusively to mechanical rolled plugs.

Cable stabilizers may be installed with a plug and serve to maintain the structural integrity of the plugged tube in the event that a tube severance occurs. The installation of a cable stabilizer provides additional damping to the tube, which limits the motion of the tube and increases its fatigue margin and also limits the motion of a cantilevered tube section if the tube should sever. A stabilizer also provides additional wear volume. There are currently no stabilizers installed in the SGs. Stabilization criteria developed specifically for the Unit 2 SGs are reviewed as part of each pre-outage degradation assessment.

2.2.2.5.2.7.2 Input Parameters, Assumptions and Acceptance Criteria

Input Parameters and Assumptions

The plant operating and transient parameters at the EPU power level of 3034 MWt (core thermal power + RCS heat input) or 1517 MWt/SG were evaluated.

The critical parameter affecting the qualification of the mechanical rolled plugs is the differential pressure between the primary and secondary sides of the SG. The maximum pressure differentials were evaluated for design, normal, upset, and faulted conditions as well as hydrostatic test conditions. Both the 1517 MWt/SG NSSS parameters defined in LR [Section 1.1](#) and the NSSS design transients defined in LR [Section 2.2.6](#) were evaluated.

The critical parameters affecting the qualification of a stabilizer are the secondary side fluid densities and cross-flow velocities. The qualification of the cable stabilizers for the 1517 MWt/SG conditions was performed using a bounding scaling factor described in LR [Section 2.2.2.5.2.5](#) and the results of a previous analysis for 1490.5 MWt/SG power level for full power, steady-state normal operating conditions considering the secondary-side flow conditions resulting from fouled tubes (design fouling of $50 \times 10^{-6} \text{ }^{\circ}\text{F}\cdot\text{ft}^2\cdot\text{hr}/\text{Btu}$) and 20 percent of the tubes plugged.

Assumptions

No assumptions that require justification were made in the analyses of the plugs or stabilizers.

Acceptance Criteria

Mechanical Rolled Plugs

The stresses on the mechanical rolled plug due to design, normal, upset, emergency, faulted and test conditions must remain within the allowable values of [Reference 9](#). The plug must be shown to be exempt from a detailed fatigue analysis/testing based on the criteria of [Reference 9](#) or a fatigue analysis and/or testing must be performed and the total usage factor must be less than 1.0. The total leakage from all plugs during normal operation and accident conditions must remain within the allowable leakage limit set for the repair hardware, which is a small percentage of the leakage allowed per TS 3.4.6.2.c. The plug must not eject from the tube under normal operating or accident conditions at 1517 MWt/SG.

Cable Stabilizers

Stabilized tubes must not result in any deleterious contact with adjacent tubes. The same acceptance criteria provided in LR [Section 2.2.2.5.2.5.2](#) were applied to the FIV analysis of the cable stabilizers.

2.2.2.5.2.7.3 Description of Analyses and Evaluations

Mechanical Rolled Plugs

The largest pressure differential between the primary and secondary sides of the SG results in the bounding condition for the mechanical rolled plugs. The stress analysis conservatively evaluated the maximum pressure differentials on the primary side with the secondary side depressurized, which maximizes the stresses in the plug. The plug was evaluated for exemption from a detailed analysis for cyclic service as defined by NB-32224.d of [Reference 9](#). The stress analysis and qualification testing of the plug evaluated loadings from all operating and accident transient conditions, including pressure, thermal expansion, tubesheet hole dilation, deadweight, FIV, and seismic accelerations. The qualification testing was conservatively performed [].

Cable Stabilizers

Currently, there are no cable stabilizers installed in the SGs. However, both a short tubesheet stabilizer and a U-bend stabilizer have been qualified for installation in the SGs. The FIV analysis of the cable stabilizers was performed for the 1490.5 MWt/SG power level for the bounding full power, steady-state normal operating conditions considering the secondary-side flow conditions resulting from fouled tubes (design fouling of 50×10^{-6} °F-ft²-hr/Btu) and 20 percent of the tubes plugged. To qualify the cable stabilizers for the 1517 MWt/SG conditions defined in LR [Section 2.2.2.5.2.1](#), []

2.2.2.5.2.7.4 Results

Mechanical Rolled Plugs

The mechanical rolled plugs have been qualified for a 40-year operating life at the 1517 MWt/SG conditions defined in LR [Section 2.2.2.5.2.1](#). The plug design meets the stress/fatigue analysis requirements of the 1989 Edition of the ASME B&PV Code, Section III ([Reference 9](#)). The total plug leakage for the 20 percent plugging limit is acceptable and the plug will not eject from the

tube under normal operating or accident conditions. The plug design and material have been reconciled to the code of construction for the SGs, 1998 Edition of the ASME B&PV Code, (Reference 1).

Cable Stabilizers

Tubesheet and U-bend cable stabilizers have been qualified for installation in the SGs for the 40-year operating life at the 1517 MWt/SG conditions defined in LR Section 2.2.2.5.2.1. A stabilized tube will not result in deleterious contact with adjacent tubes.

2.2.2.5.2.8 Steam Drum

2.2.2.5.2.8.1 Introduction

An evaluation was performed to assess potential degradation of steam drum components due to operation at 1517 MWt/SG.

2.2.2.5.2.8.2 Input Parameters, Assumptions and Acceptance Criteria

Input Parameters

The assessment of the performance of the steam drum components considers the T-H conditions for 1517 MWt/SG identified in LR Section 2.2.2.5.2.1, along with previous SG operating experience and materials used for the SG design.

Assumptions

None

Acceptance Criteria

The relevant acceptance criteria used as the basis for the evaluation performed are as follows:

- Increased steam flow will not result in detrimental acoustic loading or FIV of the steam separators, dryers or their support system;
- Degradation will not adversely impact or compromise the thermal performance or moisture separation function of the affected component;
- Degradation will not adversely impact or compromise the structural integrity of the component; and
- Degradation will not create a loose part that will adversely impact or compromise the safe operation of the plant.

2.2.2.5.2.8.3 Description of Analyses and Evaluations

The evaluation of the impact of increased steam and feedwater flow at 1517 MWt/SG conditions is based upon examining past inspection results of the steam drum components of SGs and reviewing erosion/corrosion evaluations and corrosion allowances considered in the structural qualification of the replacement SG components.

2.2.2.5.2.8.4 Results

Results of the evaluation performed to assess the potential for acoustic loading, FIV and FAC related degradation of the steam drum components, including detection capability and removal of loose parts within the SGs following implementation of EPU to 1517 MWt/SG are discussed below.

Acoustic or Flow-Induced Vibration due to Increased Steam Flow

Steam flows in the SGs are increased at the 1517 MWt/SG conditions. However, the magnitude of the flow increases, going from a NSSS thermal power level of 1490.5 MWt/SG, for which the SGs were originally designed, to the 1517 MWt/SG NSSS thermal power level is considered minimal. The full power steam flowrate increases $\square$ per SG which constitutes less than a 1 percent increase in steam flowrate.

FIV Loadings due to Increased Steam Flow

For the SGs, FIV analysis of the steam separation equipment for acoustic loading or vortex shedding has not been performed. This is because industry operating experience has shown essentially no issue with respect to FIV with this equipment in domestic or comparable French designed pressurized water reactors (PWRs) (Doel, Tihange, and Civaux Units 1 and 2), and steam flows for 1517 MWt/SG conditions increase by less than 1 percent above the level for which the SGs were originally designed.

As part of the SG design process, screening criteria are utilized to determine those structures potentially at risk for FIV. Steam separation equipment is selectively designed to be less prone to FIV; component design incorporates features which optimize both slenderness ratio as well as flexibility. SG secondary system fluid properties as well as the amount of surface area located within flow regions are predicated in part upon the design of these components. Another key design consideration is the minimization of pressure drops through the SG.

The SGs employ a commonly used design for the steam separation equipment which provides for steam separation in two main stages. The first stage employs cyclones which strip out large quantities of water, and the second stage employs “dryer vanes” which extract the last 10-15 percent of moisture, leaving only dry steam to exit the SG through venturis located in the steam outlet nozzle. Within each region of the SG the flow velocities and moisture content will vary significantly.

Cyclones and steam dryer banks are, therefore, sized to allow adequate steam separation with very little pressure drop, which results in lower velocities. These lower steam velocities provide a significant reduction in the potential for FIV. The fluid velocities internal to the cyclones are $\square$ and the Froude number $\square$ which is clearly below the turbulent flow regime and sufficiently low such that performing FIV analysis of the steam separation equipment is not required.

The dryer banks are of a proven double-pocket chevron-type design. The vane banks are inclined to create a larger surface area which results in minimizing flow resistance. The average flow velocity through the dryers is only $\square$ with peak velocities less than $\square$ for 1517 MWt/SG conditions. This design has been extensively used in France since 1996 with no reported issues. At the exit of the dryer banks, the steam enters the large space above the dryer assembly and exits the SG through the steam outlet nozzle venturis.

The dryer frame support system is welded to the inside diameter (ID) of the secondary side shell and is composed of various sections of flat plate and other structural shapes welded into a rigid assembly. The support system incorporates a series of drains that return water removed from the dryers to a lower portion of the SGs. Due to the length of the drains from the dryers to the operating water level, the drains are analyzed for flow-induced vibrations, along with the feedwater ring and J-tubes, and the recirculation pipe. Conservative drain flows were modeled for the 1517 MWt/SG conditions and it was concluded that there is no risk of vortex shedding lock-in. The velocities of the steam and/or saturated water in the regions of the J-tubes, feedwater ring, recirculation pipe and drains are unchanged by EPU conditions.

Acoustic Resonance due to Increased Steam Flow

With regard to acoustic resonance, the SG steam outlet nozzle is equipped with a 7-nozzle flow limiter (venturis) that provides choked-flow in the event of a main steam line break (MSLB).

Although the PWR industry has experienced few vibration issues related to flow instability at flow limiters, pressure pulses and main steam line vibrations were experienced after installation of the AREVA replacement SGs at Ringhals-3 in 1995. The original design of the Ringhals-3 replacement SG steam flow restrictor incorporated a single-hole venturi. It was replaced in 1998 with the 7-nozzle design, which has performed subsequently without issue. The root cause of the excessive vibrations in the steam line was found to be attributed to the single-hole venturi.

No associated evaluations for acoustic-type pressure pulsation effects have been performed for the SGs because the design of the 7-nozzle steam flow restrictor does not deviate from the long-standing AREVA design, and the operating experience of AREVA designed SGs equipped with the same steam flow restrictor have shown no unusual vibrations or pulsations in the steam line. Furthermore, significant vibration increases in the main steam line have not been observed in PWRs, except for the case of Ringhals-3 during the time period when the single-port venturi was installed, prior to its replacement with the 7-hole venturi.

The SGs have the angled face of the dryer vane cells in direct alignment with the exit port. This design provides for a rigid corrugated structure that is expected to have significant damping capability such that any pressure pulse entering the face would be significantly diminished before it impacts the perforated flat plate on the upstream side (underside) of dryer cells. The net damping effect has not been quantified, but it is considered to be adequate since no operational problems have been observed.

Detection of pressure pulsations and/or significant vibrations in the main steam system, as found at Ringhals-3, would give advance warning of any instability should it develop. The SGs are equipped with a steam pressure tap in the steam dome above the dryers. The tap provides for direct measurement of any pulses reflecting back into the steam space.

From an operating perspective, there have been no FIV related issues with steam drum internals on any AREVA designed SG, except for a single-hole venturi steam flow restrictor design that was subsequently corrected, as previously mentioned.

In summary, the low steam flow velocities combined with considerable dryer clearances reduce the potential for FIV and acoustic-type pressure loadings acting across the dryers. Therefore, it is concluded that the steam drum internals of the SGs should not incur damaging affects attributed

to FIV or acoustic type loading due to the slightly increased steam and feedwater flow rates (of less than 1 percent) at 1517 MWt/SG conditions.

From a structural integrity perspective, as stated in the second paragraph of LR **Section 2.2.2.5.2.2.2**, loads on the internal attachments remain unchanged for 1517 MWt/SG conditions. This statement is intended to reflect that the loads (forces and accelerations) on the internal components themselves are also not affected by the 1517 MWt/SG conditions and is supported by the fact that the forces and accelerations originally determined for the 1490.5 MWt/SG conditions remain valid for the 1517 MWt/SG conditions. This was validated by comparing the recalculated values based on the 1517 MWt/SG conditions to the original values based on the 1490.5 MWt/SG conditions. Regarding the steam dryer equipment, the mechanical loading conditions provided to the dryer manufacturer taken from the AREVA Loading Specification bound the 1517 MWt/SG conditions. In addition, the steam design conditions specified to originally size and design the dryer equipment were intentionally overly conservative and bound the 1517 MWt/SG conditions. As neither the mechanical loading nor the hydraulic loading have changed, the dryer equipment continues to meet the design criteria of ASME Section III for the 1517 MWt/SG conditions.

FAC Related Degradation

As discussed in the Acoustic Resonance due to Increased Steam Flow subsection above, full power steam flowrates increase by less than 1 percent with an increase in NSSS thermal power level from 1490.5 MWt/SG to 1517 MWt/SG. Feedwater flows increase by a similar amount or less than 1 percent for 1517 MWt/SG conditions. The slightly higher feedwater flowrate, coupled with a comparable reduction in feedwater temperature, will have a negligible impact on FAC rates for the feedwater system and will continue to provide for conditions that sufficiently minimize accumulation of contaminants on the secondary side of the tubesheet.

With regard to corrosion, the design specification for the SGs at 1490.5 MWt/SG conditions required that unclad carbon steel wetted surfaces within the ASME Section III jurisdictional boundaries (i.e., pressure boundary) shall include a corrosion allowance of 1/16 (0.0625) inch. The corresponding equipment specification for the replacement SGs increased the required corrosion allowance to 0.079 inch to accommodate allowances for both general corrosion and chemical cleanings. The components within the steam drum which constitute the secondary side pressure boundary, including the shells, elliptical head with steam outlet nozzle, feedwater nozzle, recirculation nozzle and secondary manway are all constructed of SA-508 Grade 3 Class 2 material. Also, instrument taps are constructed of SA-105 material. The SG secondary side sizing calculations report considers the designated corrosion allowance for determination of the required wall thickness and opening reinforcement calculations. Therefore, the pressure boundary portions of the steam drum provide for adequate margin against corrosion for the 1490.5 MWt/SG conditions, which also remains valid for the 1517 MWt/SG conditions.

The feedwater distribution system of the SGs (including feed ring and J-tubes), primary moisture separators (including riser, helix and cyclone outlet), and dryer vanes are all constructed from austenitic stainless steel materials, which do not require consideration of a corrosion allowance. All other secondary side internals are composed of carbon steel material but are not subjected to severe operating conditions that would contribute to excessive erosion/corrosion.

An environmental qualification report for the SGs documents a FAC analysis performed in accordance with **Reference 10** for both 1490.5 MWt/SG and 1517 MWt/SG conditions. Analysis guidelines presented in **Reference 10** categorize the parameters affecting FAC into three sets: hydrodynamic factors, environmental factors and metallurgical factors.

Hydrodynamic factors which influence FAC include: flow velocity, surface roughness, flow path geometry, and steam quality (void fraction) for two-phase flows. Environmental factors which influence FAC include: temperature, chemistry and pH. The primary metallurgical factor which influences the thinning rate of a given material is its chromium content.

Flows in the moisture separators are, by design, highest at the exit of the hub/helix location such that the liquid is separated from the steam. The internal components and shell of the separators are, therefore, designed for these flow rates. The FAC analysis demonstrates that the exit velocities at the 1517 MWt/SG conditions are within appropriate limits to ensure that the thermal performance or moisture separation function of the separators is not compromised. The analysis has concluded that there is a sufficient margin between the maximum flow velocity and the velocity threshold at which FAC may occur such that the occurrence of FAC in the secondary side environment for the material grades considered is unlikely for the 1517 MWt/SG conditions. This conclusion is supported by more than 25 years of favorable operation experience (OE) associated with the first 20 French 1300 MWe units (80 SGs).

Loose Parts or Foreign Material Exclusion (FME)

Industry wide OE confirms that loose parts or foreign objects may be transported from the feedwater system to the secondary side of the SG, potentially causing damage to tubes or other internal hardware. The SGs are provided with mounting pads to interface with existing plant loose parts monitoring system devices. Acoustic monitors are positioned on the primary head and the secondary shell in order to detect impacts on either side of the tubesheet.

The SGs are also equipped with a loose parts trapping system (LPTS) installed near the top of the downcomer, located between the bundle wrapper and the pressure shell. The LPTS is composed of fine-grid, stainless steel grating and is designed to capture foreign objects introduced through incoming feedwater flow and prevent them from entering the tube bundle region. The LPTS provides FME control for tools or parts dropped from above during outage maintenance activities. In addition, the feedwater ring is equipped with two inspection ports that can be opened to allow inspection and retrieval of loose parts that may become trapped in the feedwater header and are too large to exit through the feedwater ring J-tubes. Items trapped inside the feedwater ring would be detected during scheduled inspections and removed through the inspection port in accordance with plant procedures.

Steam dryer components are typically not subjected to extensive visual examination, as those inspections are targeted for components which are deemed potentially at risk. Such items would include the manway access opening to the space above the dryers. As previously noted, steam flow velocities above the dryers are very low, and in the event that a foreign object is generated within the steam dryer system, buoying of the foreign object is prevented in the very low steam flow (5 ft/s max) such that wear due to a foreign object is not allowed to occur at the elevation of the dryer support plate.

Further discussion regarding detection and removal of foreign objects is presented in LR [Section 2.2.2.5.2.6](#).

In conclusion, the potential degradation of steam drum internal components attributed to higher flow rates at the 1517 MWt conditions will be negligible, since the increases in steam and feedwater flow rates are less than 1 percent.

Inspections Following the First Cycle of Operation with SGs:

Secondary side inspections (SSI) were performed on the two AREVA 86/19TI SGs during RFO 18 (May 2009) following their first fuel cycle of operation. They included the inspection of steam drum internal components in each SG and specifically involved searching for the presence of foreign material in the LPTS.

Visual inspection of the two steam drum areas was performed by entering the SGs through the secondary manways. Inspections were performed from the top of each of the primary separators utilizing a Pan, Tilt, Zoom (PTZ) camera. A listing of the component inspection locations is maintained in the AREVA document Secondary Side Visual Inspection Plan for FP&L St. Lucie Unit 2 RFO 18.

The only abnormal conditions observed in the steam drum during the secondary side visual inspection and foreign object search and retrieval (FOSAR) activities were loose bolts discovered on the feedwater ring inspection port covers in both SGs and a foreign object discovered on the LPTS of SG-B. The LPTS was determined to be structurally sound and the steam drum region showed no abnormalities in the structure or the hardware. Continued monitoring of steam separators, dryers and other steam drum internal components by visual examination will be performed on a regular basis as part of the SG secondary side inspection program.

Summary

Evaluations were performed to assess potential degradation mechanisms of steam drum components due to plant operation at 1517 MWt/SG. Conclusions of the evaluations are that there is little potential for degradation attributed to acoustic loading, FIV, or FAC of the steam drum components at the higher power level.

2.2.2.5.2.9 Chemistry Evaluation

2.2.2.5.2.9.1 Introduction

Water chemistry of both the primary and secondary sides in nuclear power plants is controlled to maximize the long-term availability of PWR plants. In addition, primary water chemistry control can, and has been, effectively used to control radiation field buildup on ex-core surfaces. Guidelines have been provided to utilities by EPRI for primary and secondary chemistry ([References 11 and 12](#)). In addition, other organizations, such as NEI, have provided guidelines with respect to specific equipment (e.g., SGs) which are incorporated into the EPRI guidelines. These documents form an industry consensus approach for chemistry programs which are embodied in the plant Steam Generator Integrity Program ([Reference 13](#)).

Upgrades in power potentially affect water chemistry of the nuclear power plant because of changes in temperature and/or flow rates.

Additional information pertaining to RCS water chemistry can be found in LR [Section 2.1.11](#) and UFSAR Section 9.3.4.2.1. Refer to LR [Section 2.8.5.6.3.5.1](#) for a discussion pertaining to post – LOCA boron precipitation.

2.2.2.5.2.9.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters and Assumptions

The following represents the input parameters and assumptions used in support of the evaluation of SG chemistry.

- The input parameters derived from LR Section 1.1, EPRI primary and secondary chemistry guidelines, and strategic water chemistry plans for the primary and secondary sides as embodied in the Steam Generator Integrity Program; and
- It is assumed that St. Lucie Unit 2 continues to operate with primary and secondary chemistry maintained in accordance with the Steam Generator Integrity Program.

Acceptance Criteria

No specific changes in chemistry of either the primary or the secondary side are expected due to the EPU because the chemistry will continue to be controlled after the EPU by plant procedures and specifications conforming to industry accepted guidelines as embodied in the Steam Generator Integrity Program.

2.2.2.5.2.9.3 Description of Analyses and Evaluations

EPRI guidelines recognize the difference in design and operating characteristics of nuclear plants and prescribe that each plant generate strategic water chemistry plans for the primary and secondary water chemistries. This allows chemistry programs specifically tailored for each plant. The Steam Generator Integrity Program provides those strategic plans for St. Lucie Unit 2.

2.2.2.5.2.9.4 Results

SG water chemistry is based on the Steam Generator Integrity Program. The program defines the mission and objectives of the primary and secondary elements of the chemistry program, along with associated mechanisms. The chemistry program is based on the latest industry guidance published by the Institute of Nuclear Power Operations (INPO) and EPRI. No significant changes to the primary or secondary chemistry programs are expected as a result of the EPU. The SG water chemistry is controlled based upon strategies contained in their primary and secondary strategic chemistry programs. Chemistry continues to be controlled following implementation of the EPU by plant procedures and specifications conforming to industry accepted guidelines as embodied in the strategic water chemistry documents. In addition, the temperatures stated in the design parameters in LR [Section 1.1](#) are in the range where other plants control chemistry based on the same industry guidelines.

2.2.2.5.2.10 Supports

2.2.2.5.2.10.1 Introduction

The lower SG sliding base (SGSB) supports described in UFSAR Section 5.4.14.2b have been evaluated for EPU. The reactor coolant loop (RCL) piping loads on the SGSB supports due to the parameters associated with the EPU were reviewed relative to their impact on the existing SGSB supports design basis. The RCL piping loads on the SGSB supports due to deadweight (DWt), thermal expansion, operating basis earthquake (OBE), SSE, LOCA, and pipe break loads per the current design basis were evaluated for the EPU program. The upper guide support structure was not evaluated since this structure is subjected only to SSE loads and pipe rupture loads and these loads are not affected by EPU.

The support skirt is not a pressure retaining component. However, it is analyzed in accordance with the requirements of paragraph NB-3200 of the ASME B&PV Code Section III, 1971 Edition ([Reference 14](#)) which are the same requirements as those used to analyze the base metal (lower shell, tubesheet and channel head). Only primary stresses were evaluated and compared with appropriate limits to validate the SG supports at the 1517 MWt/SG conditions.

2.2.2.5.2.10.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters and Assumptions

The RCL piping loads on the SGSB supports due to deadweight, thermal expansion, OBE, SSE, LOCA, and pipe break loading cases are obtained from the piping system analyses for the EPU program as described in LR [Section 2.2.2.1](#), Nuclear Steam Supply System Piping, Components and Supports.

The loads analyzed on the support skirt vary with conditions. For each operating condition, the design loads seen in LR [Tables 2.2.2.5-12](#) and [2.2.2.5-13](#) are the result of the combination of several effects:

- Design conditions: Dead weight (DWt) and thermal expansion and OBE;
- Normal and upset conditions: DWt and thermal expansion and OBE;
- Faulted conditions: DWt and thermal expansion and SSE and pipe rupture; and
- Test conditions: DWt and thermal expansion.

Acceptance Criteria

The sliding base plate (SBP) was designed in accordance with the ASME B&PV Code, ([Reference 14](#)).

Acceptance criteria for the concrete foundation are ACI 318-63 ([Reference 15](#)).

The acceptance criteria for the support skirt are based upon the requirements contained in paragraph NB-3200 of [Reference 1](#).

2.2.2.5.2.10.3 Description of Analyses and Evaluations

The SGs are supported by a SBP bolted to the integral conical support skirt, mounted on low friction bearing plates anchored to a concrete foundation. Keyways within the SGSB prevent excessive movement during a seismic event and following a LOCA. Keys and snubbers at the upper end restrain the SGs during seismic events and following a LOCA or steam line break.

Analysis of DWt as well as NOP analyses of the RCS were performed to assess the effects of the EPU on the RCS components. In addition, a DWt only analysis for ambient temperature conditions with flooded SGs was performed to maximize the loads on the SG supports. This analysis was performed to ensure that the maximum loads on the SG sliding base and building supports are considered. A comparison between maximum pre-EPU and maximum EPU loads is presented in [Table 2.2.2.5-14](#). The original analyses of the SG SBP and SBP bolts were evaluated for EPU conditions and it was concluded that both the SBP and SBP bolts are qualified for EPU conditions.

Any transient loads that were altered due to the 1517 MWt/SG conditions that affected the SG conical support skirt were rerun. The changes to the transient loads for the EPU conditions are shown in LR [Table 2.2.2.5-13](#). Only the thermal expansion and deadweight loads were changed from the 1490.5 MWt conditions. The thermal expansion loads used in the analyses are associated with the four sets of conditions listed in LR [Section 2.2.2.5.2.10.2](#) and only apply to the conical support skirt, channel head/skirt weld and the foot of the conical support skirt as noted in LR [Tables 2.2.2.5-12](#) and [2.2.2.5-13](#). Progressive deformation analysis (3Sm analysis), fatigue analysis (usage factor computation), thermal ratchet analysis and level B service limits analysis were rerun using the 1517 MWt/SG EPU conditions. The new parameters were evaluated against the revised design conditions and found to be acceptable.

2.2.2.5.2.10.4 Results

As stated above, the evaluation of the original analysis of the SG SBP and SBP bolts for EPU conditions concluded that both the SBP and SBP bolts are qualified for EPU conditions.

DWt load to the foundation under EPU conditions is [] which exceeds the pre-EPU DWt load of [] However, it is lower than the pre-EPU NOP load of [] and therefore bounded by that loading condition. In addition, the original calculation of the SG foundations considers a downward load of [] in one of the analyzed cases, which far exceeds the EPU load. Comparison results indicate that EPU loads are bounded by the original analysis as shown on [Table 2.2.2.5-14](#). Load nomenclature is as shown on [Figure 2.2.2.5-2](#).

GSGB supports were not evaluated for lateral forces since SSE and rupture loads remain unchanged for EPU. In all cases, the stresses for all SG support components satisfy applicable acceptance criteria.

The SG support loads from the RCL piping system EPU analyses as described in LR [Section 2.2.2.1](#), NSSS Piping, Components and Supports remain bounded by the current design basis SG support loads.

The SG support skirt analyses show that the ASME code criteria of [Reference 14](#) are still met for the 1517 MWt/SGEPU conditions. Furthermore, for the support skirt and channel head/skirt weld,

the usage factor remains below 1.0 for the 1517 MWt conditions and is determined to be [] It was previously determined to be [] for the 1490.5 MWt conditions.

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

As discussed above, the SGs and supports are within the scope of License Renewal. Operation of the SGs and supports under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.2.2.5.4 Conclusion

FPL has reviewed the structural integrity of pressure-retaining components and their supports. For the reasons set forth above, FPL concludes that the review has adequately addressed the effects of the proposed EPU on these components and their supports. Based on the above, FPL further concludes that the review has demonstrated that pressure-retaining components and their supports will continue to meet their current licensing basis with respect to 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, FPL finds the proposed EPU acceptable with respect to the structural integrity of the pressure-retaining components and their supports.

2.2.2.5.5 References

1. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB, 1998 Edition through 2000 Addenda.
2. Federal Register, 70 FR 24126, May 6, 2005.
3. Letter from Gordon L. Johnston (FPL), Proposed License Amendment Steam Generator Tube Integrity, to US Nuclear Regulatory Commission, dated May 25, 2006.
4. Letter from Brenda L. Mozafari (Nuclear Regulatory Commission), St. Lucie Plant, 2 – Issuance of Amendment Regarding Steam Generator Tube Integrity (TAC No. MD2322) to J.A. Stall (FPL), dated May 29, 2007.
5. Steam Generator Integrity Assessment Guidelines, Revision 2, Electric Power Research Institute, EPRI TR 1012987, (July 2006).
6. Steam Generator Integrity Assessment Guidelines, Revision 3, Electric Power Research Institute, EPRI TR 1019038, (November 2009).

7. M.K. Au-Yang, Flow-Induced Vibration of Power and Process Plant Components. New York: ASME Press, 2001.
8. Nuclear Energy Institute (NEI) 97-06, Revision 2, Steam Generator Program Guidelines, May 2005.
9. ASME Boiler and Pressure Vessel Code, Section III, Division 1, Subsection NB and Code Case N-474, Rules for Construction of Nuclear Vessels, 1989 Edition with No Addenda, American Society of Mechanical Engineers, New York, New York.
10. TR-106611-R1, Flow Accelerated Corrosion in Power Plants, by EPRI, EDF and Seimens.
11. EPRI PWR, Primary Water Chemistry Guidelines 1014986 Vol. 1 and 2, Rev. 6.
12. EPRI PWR, Secondary Water Chemistry Guidelines 1008224, Rev. 7.
13. ADM-02.02 Steam Generator Integrity Program Administration Rev. 008, April 24, 2009.
14. EPRI PWR, Primary to Secondary Leak Guidelines 1008219, Rev. 3.
15. ASME Boiler and Pressure Vessel Code Section III, 1971 Edition.
16. ACI 318-63 Building Code Requirements for Reinforced Concrete.

**Table 2.2.2.5-1
SG Operating Parameters at BOL and EOL
for 1490.5 MWt/SG and 1517 MWt/SG Operating Conditions**

Power Level (MWt)		1490.5 BOL	1490.5 EOL	1517 BOL	1517 EOL
Tube plugging (% tubes)		0	20	0	10
SG Primary Parameters	Pressure (psia)	□	□	□	□
	Flow rate (10 ⁶ lbm/hr)	□	□	□	□
	Inlet temperature (°F)	□	□	□	□
	Outlet temperature (°F)	□	□	□	□
	Pressure drop (psi)	□	□	□	□
SG Secondary Parameters	FW flow rate (10 ⁶ lbm/hr)	□	□	□	□
	FW inlet temperature (°F)	□	□	□	□
	FW static pressure (psi)	□	□	□	□
	Steam static pressure (psi)	□	□	□	□
	Steam flow (10 ⁶ lbm/ hr)	□	□	□	□
	Circulation ratio	□	□	□	□
	Water level above TTS (in)	□	□	□	□
	Water+steam mass (10 ³ lb)	□	□	□	□
	Pressure drop (psi)	□	□	□	□

Table 2.2.2.5-2
Outlet Steam Static Pressure

	1490.5 MWt/SG Outlet Steam Static Pressure (psia)	1517 MWt/SG Outlet Steam Static Pressure (psia)
BOL	□	□
EOL	□	□

Table 2.2.2.5-3
Steam Flow-rate

	1490.5 MWt/SG Steam Flowrate (10 ⁶ lbm/hr)	1517 MWt/SG Steam Flowrate (10 ⁶ lbm/hr)
BOL	□	□
EOL	□	□

Table 2.2.2.5-4
Bundle Flow and Circulation Ratio

	1490.5 MWt/SG FW flow (10 ⁶ lbm/hr)	1490.5 MWt/SG CR	1490.5 MWt/SG Bundle flow (10 ⁶ lbm/hr)	1517 MWt/SG FW flow (10 ⁶ lbm/hr)	1517 MWt/SG CR	1517 MWt/SG Bundle flow (10 ⁶ lbm/hr)
BOL	□	□	□	□	□	□
EOL	□	□	□	□	□	□

**Table 2.2.2.5-5
Heat Flux**

Parameter	1490.5 MWt/SG @ EOL	1517 MWt/SG @ EOL
Maximum SG heat flux (BTU/hr-ft ²)	□	□
Maximum U-Bend heat flux (BTU/hr-ft ²)	□	□
Maximum steam quality (%)	□	□

Table 2.2.2.5-6
Global Heat Transfer Coefficient

	1490.5 MWt/SG Heat Transfer Area (ft ²)	1490.5 MWt/SG GHTC $\left(\frac{\text{BTU}}{\text{F}\cdot\text{ft}^2\cdot\text{hr}}\right)$	1517 MWt/SG Heat Transfer Area (ft ²)	$\left(\frac{\text{BTU}}{\text{F}\cdot\text{ft}^2\cdot\text{hr}}\right)$
BOL	□	□	□	□
EOL	□	□	□	□

Table 2.2.2.5-7
Primary Side Pressure Drop

	1490.5 MWt/SG Primary Side Pressure Loss (psi @ gpm)	1517 MWt/SG Primary Side Pressure Loss (psi @ gpm)
BOL	□	□
EOL	□	□

Table 2.2.2.5-8
Secondary Side Pressure Drop

	1490.5 MWt/SG Secondary Side Pressure Loss (psi)	1517 MWt/SG Secondary Side Pressure Loss (psi)
BOL	□	□
EOL	□	□

**Table 2.2.2.5-9
EPU Evaluation Summary
Critical Locations of SG Pressure Boundary Components**

Component	Load Condition	Stress Category	1490.5 MWt/SG Stress (ksi)	1517 MWt/SG Stress (ksi)	Allow. Stress
			Fatigue	Fatigue	Allow. Fatigue
Primary head at juncture between bowl / flat bottom	Normal/Upset	Pm + Pb + Q Fatigue	□	□	90 1.0
Tubesheet – perforated region	Normal/Upset	Pm + Pb + Q Fatigue	□	□	90 1.0
Tubesheet – non perforated region	Normal/Upset	Pm + Pb + Q Fatigue	□	□	90 1.0
Primary inlet nozzle-to-shell juncture	Normal/Upset	Pm + Pb + Q Fatigue	□	□	90 1.0
Primary inlet nozzle safe end	Normal/Upset	Pm + Pb + Q Fatigue	□	□	53.4 / 53.1 (Note 1) 1.0
Primary head / inlet nozzle dam ring juncture	Normal/Upset	Fatigue	□	□	1.0
Primary outlet nozzle-to-shell juncture	Normal/Upset	Pm + Pb + Q Fatigue	□	□	90 1.0
Primary outlet nozzle safe end	Normal/Upset	Pm + Pb + Q Fatigue	□	□	53.4 / 53.1 (Note 1) 1.0
Primary head / outlet nozzle dam ring juncture	Normal/Upset	Fatigue	□	□	1.0

Table 2.2.2.5-9 (Continued)
EPU Evaluation Summary
Critical Locations of SG Pressure Boundary Components

Component	Load Condition	Stress Category	1490.5 MWt/SG Stress (ksi)	1517 MWt/SG Stress (ksi)	Allow. Stress
			Fatigue	Fatigue	Allow. Fatigue
Lower secondary shell / tubesheet juncture	Normal/Upset	Pm + Pb + Q Fatigue	□	□	90 1.0
Partition plate	Normal/Upset	Fatigue	□	□	1.0
Blowdown holes in tubesheet	Normal/Upset	Fatigue	□	□	1.0
Primary manway drain tube	Normal/Upset	Fatigue	□	□	1.0
Primary inlet nozzle drain tube	Normal/Upset	Fatigue	□	□	1.0
Primary head near support skirt weld	Normal/Upset	Pm + Pb + Q Fatigue	□	□	90 1.0
Support skirt	Normal/Upset	Pm + Pb + Q Fatigue	□	□	90 1.0
Primary manway cover	Normal/Upset	Pm + Pb + Q Fatigue	□	□	90 1.0
Primary manway flange	Normal/Upset	Pm + Pb + Q Fatigue	□	□	90 1.0
Primary manway studs	Normal/Upset	Pm + Pb + Q Fatigue	□	□	60.6 avg 90.9 max 1.0

Table 2.2.2.5-9 (Continued)
EPU Evaluation Summary
Critical Locations of SG Pressure Boundary Components

Component	Load Condition	Stress Category	1490.5 MWt/SG Stress (ksi)	1517 MWt/SG Stress (ksi)	Allow. Stress
			Fatigue	Fatigue	Allow. Fatigue
Tubes	Normal/Upset	Pm + Pb + Q	□	□	80.1
		Fatigue			1.0
Tube to tubesheet connection	Normal/Upset	Pm + Pb + Q	□	□	80.1
		Fatigue			1.0
Tube to tubesheet weld	Normal/Upset	Fatigue	□	□	1.0
Main steam nozzle (outside limit of reinforcement)	Normal/Upset	Pm + Pb + Q	□	□	90
		Fatigue			1.0
Main steam nozzle (within limit of reinforcement)	Normal/Upset	Pm + Pb + Q	□	□	90
		Fatigue			1.0
Elliptical head	Normal/Upset	Pm + Pb + Q	□	□	90
		Fatigue			1.0
Upper/ conical shell	Normal/Upset	Pm + Pb + Q	□	□	90
		Fatigue			1.0
Upper internals supporting shell	Normal/Upset	Pm + Pb + Q	□	□	49.65
		Fatigue			1.0
Feedwater nozzle	Normal/Upset	Pm + Pb + Q	□	□	90
		Fatigue			1.0
Secondary manway cover	Normal/Upset	Pm + Pb + Q	□	□	90
		Fatigue			1.0

Table 2.2.2.5-9 (Continued)
EPU Evaluation Summary
Critical Locations of SG Pressure Boundary Components

Component	Load Condition	Stress Category	1490.5 MWt/SG Stress (ksi)	1517 MWt/SG Stress (ksi)	Allow. Stress
			Fatigue	Fatigue	Allow. Fatigue
Secondary manway flange	Normal/Upset	Pm + Pb + Q Fatigue	□	□	90 1.0
Secondary manway studs	Normal/Upset	Pm + Pb + Q Fatigue	□	□	61.5 avg. 92.25 max 1.0
Handhole cover	Normal/Upset	Pm + Pb + Q Fatigue	□	□	90 1.0
Handhole flange	Normal/Upset	Pm + Pb + Q Fatigue	□	□	90 1.0
Handhole studs	Normal/Upset	Pm + Pb + Q Fatigue	□	□	61.5 avg. 92.25 max 1.0
Recirculation nozzle	Normal/Upset	Pm + Pb + Q Fatigue	□	□	90 1.0
Instrument taps	Normal/Upset	Pm + Pb + Q Fatigue	□	□	55.8 (w/ plug & noz) 90 (shl) 1.0

Table 2.2.2.5-9 (Continued)
EPU Evaluation Summary
Critical Locations of SG Pressure Boundary Components

Component	Load Condition	Stress Category	1490.5 MWt/SG Stress (ksi)	1517 MWt/SG Stress (ksi)	Allow. Stress
			Fatigue	Fatigue	Allow. Fatigue
Inspection port cover	Normal/Upset	Pm + Pb + Q Fatigue	□	□	90 1.0
Inspection port flange	Normal/Upset	Pm + Pb + Q Fatigue	□	□	90 1.0
Inspection port studs	Normal/Upset	Pm + Pb + Q Fatigue	□	□	61.5 avg. 92.25 max 1.0
Bundle wrapper support	Normal/Upset	Pm + Pb + Q Fatigue	□	□	90 1.0
Bundle wrapper anti-rotation key	Normal/Upset	Pm + Pb + Q Fatigue	□	□	90 1.0
Feedwater ring supports	Normal/Upset	Pm + Pb + Q Fatigue	□	□	90 1.0
Notes: 1. Allowable Stress Intensities are for 1490.5 MWt/SG and 1517 MWt/SG conditions, respectively. 1517 MWt/SG value is taken at 610F due to the increase in peak temperature during upset conditions for loss of reactor coolant flow (1490.5 MWt/SG value taken at 600F). 2. This value is the maximum range of stress intensity excluding thermal bending stress (with $K_e = 1.746$ in accordance with NB-3228.5) for areas exceeding the $3S_m$ limit on the range of primary plus secondary stress intensity.					

Table 2.2.2.5-10
Summary of Design Pressure Differential (ΔP) for EPU

Load Condition	Limiting Transient	ΔP (psi)	Allowable (psi)
Normal	Step load increase	1510	2250
Upset	Loss of Turbine Generator Load	1630	2475

Table 2.2.2.5-11
FIV Results for 1490.5 MWt/SG and 1517 MWt/SG Conditions

FIV Mechanism	1490.5 MWt/SG/SG	1517 MWt/SG/SG	Acceptance Criteria
FEI	□	□	< 0.75
RTE	Max Amplitude =□ Max Stress = □	Max Amplitude = □ Max Stress = □	< 2.5E-2 inch, RMS < 2800 psi, RMS at 10¹³ cycles

Table 2.2.2.5-12
Loading on SGs 2A and 2B Lower Assembly Support Skirts
for 1490.5 MWt/SG

		Forces (Kips) (Note 1)			Moments (In-Kips) (Note 1)		
		Fx	Fy	Fz	Mx	My	Mz
Normal and Upset Conditions	Weight	□	□	□	□	□	□
	Thermal		□	□	□	□	□
	OBE	□	□	□	□	□	□
	SSE	□	□	□	□	□	□
Accident (Note 3)							
I		□	□	□	□	□	□
II		□	□	□	□	□	□
III		□	□	□	□	□	□
IV		□	□	□	□	□	□
V		□	□	□	□	□	□
VI		□	□	□	□	□	□
VII		□	□	□	□	□	□
VIII		□	□	□	□	□	□
IX		□	□	□	□	□	□
Notes: 1. Positive loads act on the vessel in the direction indicated on LR Figure 2.2.2.5-1 . As depicted on LR Figure 2.2.2.5-1 , Point “P” is located at the intersection of the SG centerline and the horizontal plane containing the lower face of the support skirt bolting ring. 2. The friction force Fx varies as follows for both SG 2A and 2B: a. from □ during plant heat-up, b. from □ during normal operation, c. from □ during plant cooldown. 3. The above design loads include the combined effects of the normal operation, SSE seismic and pipe rupture conditions.							

Table 2.2.2.5-13
Loading on SGs 2A and 2B Lower Assembly Support Skirts
for 1517 MWt/SG

		Forces (Kips) (Note 1)			Moments (In-Kips) (Note 1)		
		Fx	Fy	Fz	Mx	My	Mz
Normal and Upset Conditions	Weight (Note 2)						
	Thermal (100% Power)						
	OBE						
	SSE						
Accident (Note 4)							
I							
II							
III							
IV							
V							
VI							
VII							
VI							
IX							
Notes: - As depicted on LR Figure 2.2.2.5-1, Point “P” is located at the intersection of the SG centerline and the horizontal plane containing the lower face of the support skirt bolting ring. - The deadweight loads are the envelope of the Cold Flooded and 100% Power conditions. - The friction force Fx varies as follows for SG 2A: - from [] kips during plant heat-up - from [] kips during normal operation - from [] kips during plant cooldown d. The friction force Fx varies as follows for SG 2B: - from [] kips during plant heat-up - from [] kips during normal operation - from [] kips during cooldown - The above design loads include the combined effects of the normal operation, SSE seismic and pipe rupture conditions.							

Table 2.2.2.5-14
Comparison of Pre-Uprate and EPU Loads

Load	Pre-Uprate Load (kips)		EPU Load (kips)	
	Deadweight	Thermal + Deadweight	Deadweight	Thermal + Deadweight
Y1	106	0	□	□
Y2	677	382	□	□
Y3	143	951	□	□
Y4	677	380	□	□
μY	483	515	□	□

Figure 2.2.2.5-1
Steam Generator Support Skirt Reactions

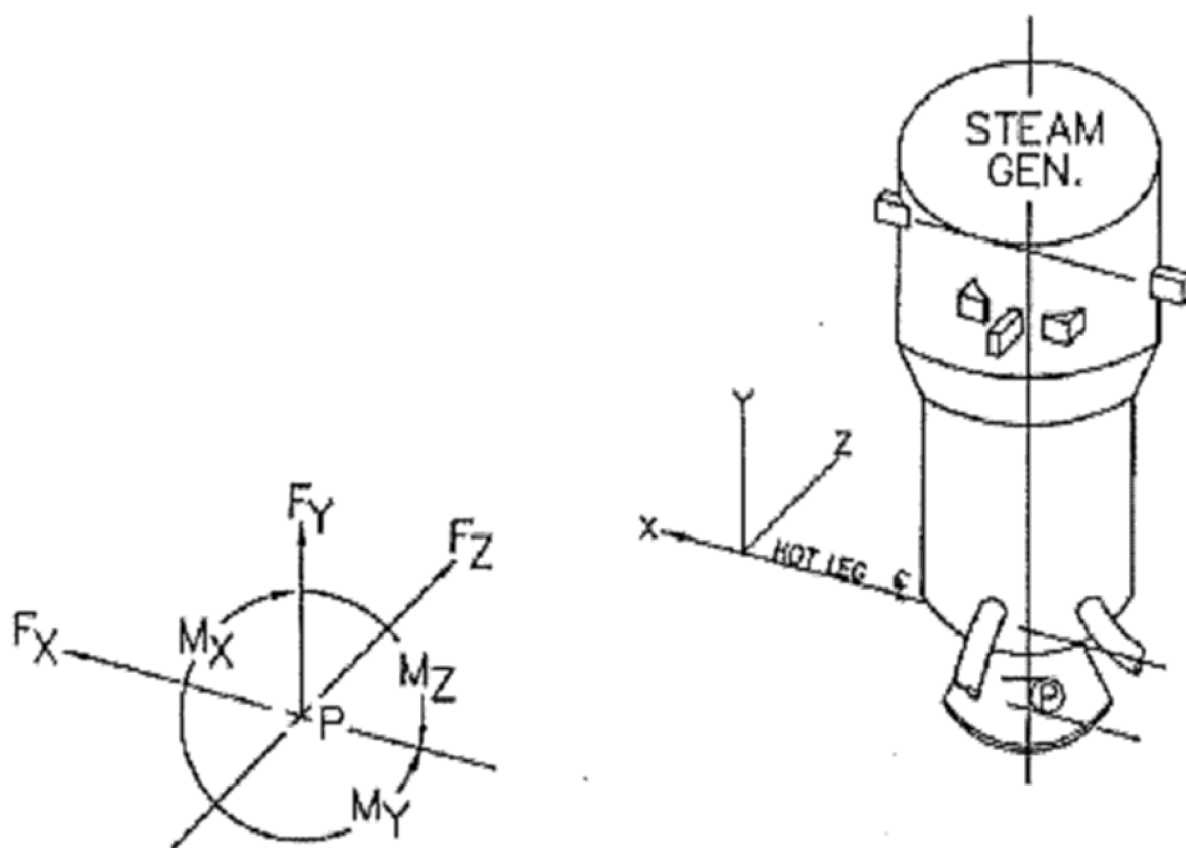
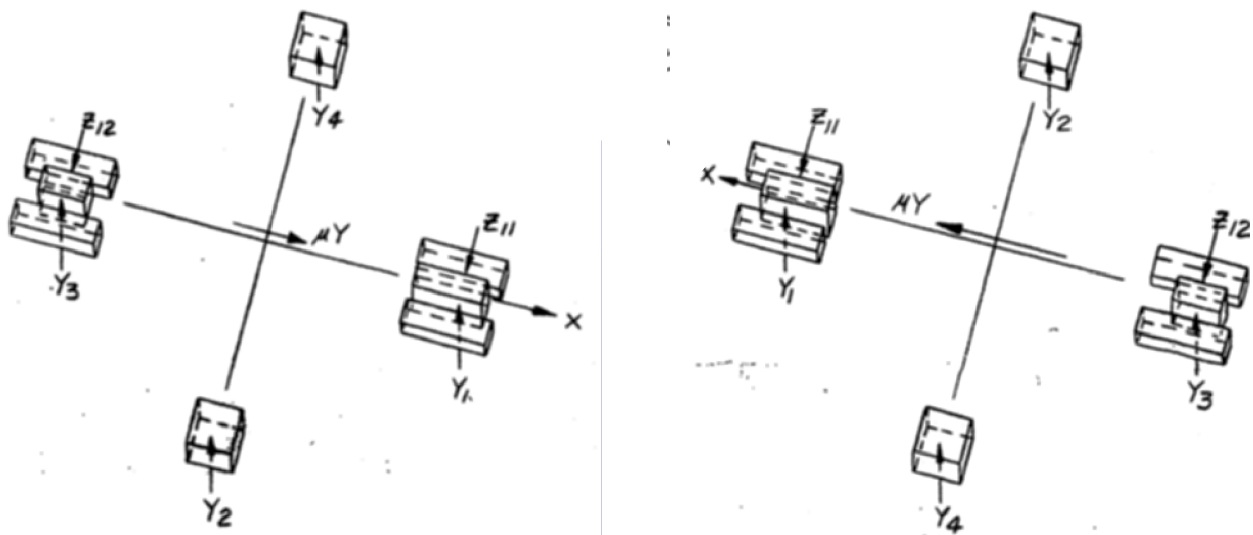


Figure 2.2.2.5-2
Steam Generator Lower Support Reactions



2.2.2.6 Reactor Coolant Pumps and Supports

2.2.2.6.1 Introduction

The reactor coolant pumps (RCPs) and their supports are reviewed as part of the extended power uprate (EPU). The RCPs are described in Updated Final Safety Analysis Report (UFSAR) Sections 3.9 and 5.4.1. The RCP supports are described in UFSAR Section 5.4.14. Each reactor coolant loop contains two vertically mounted, single bottom suction, horizontal discharge, centrifugal, motor-driven pumps. The regulatory evaluation included in LR [Section 2.2.2](#) also applies to the RCP and associated supports.

The functions of the RCP are:

- To maintain an adequate core cooling flow rate by circulating a large volume of primary coolant water at high temperature and pressure through the reactor coolant system (RCS),
- To provide adequate flow coastdown to prevent core damage in the event of a simultaneous loss of power to all RCPs, and
- To provide a portion of the reactor coolant pressure boundary (RCPB).

The technical evaluation included as part of this License Report (LR) describes the input parameters, assumptions and acceptance criteria used to evaluate RCP performance relative to the EPU.

St. Lucie Unit 2 Current Licensing Basis

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to Title 10 of the Code of Federal Regulations (10 CFR) Part 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The generic current licensing basis in LR [Section 2.2.2](#) applies to the RCPs and their supports, with the following amplifications.

The reactor coolant is circulated by four vertical, single bottom suction, horizontal discharge, centrifugal, motor driven pumps as shown in UFSAR Figure 5.4-1. The design parameters for the pumps are given in UFSAR Table 5.4-1. The piping and instrumentation diagram for the RCP is shown in UFSAR Figure 5.1-6. The pump performance curve is shown in UFSAR Figure 5.4-2.

The RCPs provide sufficient forced circulation flow through the RCS to assure adequate heat removal from the reactor core during power operation. A low limit on the RCP flowrate is established to assure that specified fuel design limits are not exceeded. Design flow is derived on the basis of the thermal-hydraulic considerations presented in UFSAR Section 5.1.

UFSAR Section 3.2 and Table 3.2-1 provide seismic classification, quality group, tornado wind/missile criterion, and flood criterion for structures, systems, and components (SSCs) such as the RCS piping integral to the RCPs. The reactor coolant pump pressure boundary is designed for the transients given in UFSAR Section 3.9.1.1 so that the ASME Code, Section III allowable stress limits are not exceeded for the specified number of cycles.

Each RCP is provided with four vertical spring-type hangers which provide support for normal operation and seismic conditions. In addition each pump has a horizontal hydraulic snubber to dampen torsional oscillation of the pump on the main coolant piping under seismic conditions. The support system is designed to accept the piping and pump movements resulting from the normal and abnormal transient operating conditions described in UFSAR Section 3.9.3.1.

The RCPB is nondestructively inspected as required by ASME Code, Section III for Code Class 1 components. The RCP casing inspections include complete radiography and liquid penetrant or ultrasonic testing. The RCP receives a hydrostatic pressure test in the vendor's shop and with the RCS. In-service inspection of the RCP pressure boundary is performed during plant life in accordance with ASME Code, Section XI.

In addition to the licensing basis described in the UFSAR, the RCPs and supports were evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.1.5 of the SER identifies that components of the RCPs and supports are within the scope of License Renewal. Programs used to manage the aging effects associated with the RCPs and supports are discussed in SER Section 3.1.5 and Chapter 18 of the UFSAR.

2.2.2.6.2 Technical Evaluation

2.2.2.6.2.1 Introduction

The approach taken in the evaluation for the EPU was to initially attempt to reconcile the existing design basis analysis results from a given structural analysis, relative to EPU-related effects. If an argument confirming that the existing design basis results remained valid and acceptable was not possible, an EPU-specific analysis was performed, and the results of the analysis were compared to the existing pre-EPU results to resolve any discrepancies with a load and/or stress reconciliation.

Note that the primary structural analyses for normal operating, seismic, and pipe break conditions are performed separately. Therefore, the input forcing functions, or applied loadings, for these conditions are not combined to produce a single set of inputs. Instead, the individual normal operating, seismic, and branch line pipe break (BLPB) analysis results are combined in accordance with UFSAR Section 3.9.3.1 and the design specifications to produce the specified service level stress results, which are then compared to the Code allowables.

2.2.2.6.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The inputs used in the RCP evaluation are the EPU parameters provided in LR [Section 1.1](#), Nuclear Steam Supply System (NSSS) Parameters, and the EPU NSSS design transients provided in LR [Section 2.2.6](#), NSSS Design Transients. These LR sections provide the operating and transient conditions for the EPU conditions. The RCPs are installed in the RCS cold legs

between the steam generator outlet and the reactor vessel inlet. Therefore, the cold leg temperatures and the cold leg transients are applicable to the RCPs.

The EPU NSSS system design transient parameters were considered in the EPU evaluations. There are no other changes to the pressure or thermal-hydraulic design parameters due to the EPU that would affect the RCPs or their supports. Under the EPU conditions, there were no changes to the design loads, load application points, or number of occurrences.

The inputs for seismic analysis of the RCP, including seismic accelerations and pump component mass and stiffness, are not affected by the EPU conditions. Therefore, seismic analyses and non-pressure boundary component evaluations are unaffected by the EPU.

The RCS structural analyses for normal operating, seismic, and pipe break conditions are performed separately. The input forcing functions, or applied loadings, are not combined to produce a set of inputs to an analysis for a specified loading condition. Instead, the results from individual normal operating, seismic, and BLPB analysis results are combined in accordance with the UFSAR and the design specifications to produce inputs to analyses that determine the stresses for the specified loading conditions. These stress analysis results are then compared to the ASME Code allowable stresses. For example, the loads considered in the determination of stresses for the Upset condition (i.e., the loads associated with dead weight (DWt) and the operating basis earthquake) would be obtained from two separate RCS loop analyses.

Based on leak-before-break (LBB) evaluations, loss-of-coolant accidents (LOCAs) in the RCS main loop piping do not need to be included in the mechanical/dynamic design basis (see LR [Section 2.1.6](#), Leak-Before-Break). As a result, the limiting pipe breaks considered in the EPU design basis with respect to RCS mechanical/dynamic response are BLPBs. The response of the RCS loop to BLPBs is bounded by the response of the RCS loop to the originally postulated LOCAs.

The acceptance criteria for the RCP and supports are based on the ASME B&PV Code ([Reference 1](#)).

2.2.2.6.2.3 Description of Analyses and Evaluations

The design parameters that will change due to the EPU were reviewed for impact on the existing RCP analyses. Margins for primary and primary plus secondary stresses, and for cumulative fatigue usage were determined for the RCP inlet and outlet nozzles. Fatigue usage is measured by the cumulative usage factor (CUF), which has an ASME Code allowable limit of 1.0. Effects of any change in RCP nozzle loads and stresses on the remainder of the RCP were then considered to complete the assessment of the RCPs.

Operating Temperatures and Pressures

Changes in operating temperatures and pressures affect the design transients. The following section discusses the effects of the EPU on design transients. Changes in temperatures also affect the thermal expansion that occurs in the RCS, which in turn affects the total mechanical loads applied to the RCP inlet and outlet nozzles. The effects of EPU-driven temperature changes were considered in the RCP evaluation.

Design Transients

The evaluation of the RCPs and RCP supports for EPU compared the operating temperatures, operating pressures and NSSS design transients defined in LR [Section 1.1](#), Nuclear Steam Supply System Parameters, to those inputs defined in the analyses of record (AOR) for the RCPs and RCP supports. The impact of changes due to full power operating temperatures on design transients for the EPU operation is addressed in LR [Section 2.2.6](#), NSSS Design Transients. With one exception, the NSSS temperatures, pressures, and NSSS transients defined for the EPU either did not change from or were bounded by those transients considered in the AORs. The one exception was a 1°F temperature increase in the plant loading and unloading transient results for the EPU operation. This change has a negligible effect on RCS primary component stresses and fatigue, which includes RCP and RCP support stresses and fatigue. Therefore, no additional transient analyses were required to evaluate the RCPs and RCP supports for the EPU.

RCS Loop Analysis

Updated DWt and thermal expansion analyses of the RCS loop, as described in LR [Section 2.2.2.1](#), NSSS Piping, Component, and Supports, were performed for the EPU conditions. The RCS loop model analyzed reflected the up-to-date configuration of the RCS, and the thermal expansion analysis was based on the normal operating temperatures (NOT) associated with the EPU.

RCP Evaluation

Updated RCP nozzle loads were calculated from the EPU RCS loop analyses discussed above. The RCP nozzles were evaluated by comparing the updated normal operating (DWt plus thermal expansion) loads to the current RCP nozzle loads.

The effects on stresses due to DWt, thermal expansion, through-wall thermal transient, seismic, and pipe break loads were considered for the EPU. The EPU affects the DWt and thermal expansion loads most directly, because of operating point temperature changes. However, temperature changes of this magnitude, a maximum of 1°F, have little effect on the material properties (e.g., Young's modulus) controlling the stiffness, and therefore, the vibratory response of the structure. Consequently, DWt and thermal expansion (primarily thermal expansion) were the only conditions requiring a loads reanalysis. Seismic and pipe break load changes for a 1°F increase in temperature are negligible.

The best estimate (BE) performance parameter analysis for the EPU determined a maximum required flow rate of 200,378 gpm per loop. The design flow rate is equal to the largest BE EPU flow rate, demonstrating that the original designs of the main closure components, casing, motors (including horsepower requirements), and pump internal sub-components (e.g., driveshaft, thrust bearings, impeller) are adequate for EPU conditions related to the flow rate, such as flow induced vibration.

RCP Vertical Supports Evaluation

The RCP vertical support structure consists of vertical compression spring hangers and the attached structural steel supports. Each RCP is supported by four spring hangers either attached to structural steel or directly anchored to concrete. Updated spring hanger support loads were calculated from the EPU RCS loop analyses discussed above. The RCP hanger loads were

evaluated by comparing the updated normal operating loads to the allowable hanger loads for the normal operating condition, as shown on LR [Table 2.2.2.6-1](#). Numbering of the supports is shown on LR [Figure 2.2.2.6-1](#).

The RCP support loads were evaluated by comparing the updated normal operating loads to either pre-EPU loads at another location with the same configuration or to an equivalent design support load for normal operation conditions based on the design load for faulted conditions. The RCP normal operating support loads are provided in LR [Table 2.2.2.6-2](#). Structural steel supports were originally designed for an 80.2 kip vertical load concurrent with an 11 kip horizontal load (DBE) under faulted condition. The equivalent design load for normal operating condition would be the faulted design load times the ratio of stress allowables or $80.2 \text{ kips} \times 0.66 = 55.14 \text{ kips}$.

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

As discussed above, the RCPs and supports are within the scope of License Renewal. Operation of the RCPs and supports under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.2.2.6.2.5 Results

The results of the evaluations of the RCP discharge and suction nozzles are that the normal operation design basis loads for these nozzles do not increase. Flow rate impact does not have to be considered, since, as stated above, the EPU flow rate is bounded by flow rates previously demonstrated to be acceptable for the pumps.

A comparison of current design loads to EPU results showed that the existing design basis loads for the pump suction and discharge nozzles have considerable margin. As-calculated EPU moments on both nozzles, and the forces on the suction nozzles are lower than the existing design basis loads. Although some components of the EPU discharge nozzle forces exceeded the existing analysis values, the EPU axial force dropped significantly and the bending moment remained approximately the same, thus guaranteeing that stress reanalysis results based on EPU loads would be bounded by the current stress results. Based on these comparisons, it was concluded that no increases in the existing set of design basis loads were required, and that the RCP nozzle stresses and CUFs from the analyses of record, as given in LR [Table 2.2.2.2-1](#), remain valid for the EPU.

The RCPs were designed to function as described in LR [Section 2.2.2.6.1](#) under the specified design conditions, while providing a maximum required flow rate. The analyses, which determined BE performance parameters under EPU conditions, have concluded that the flow

rate to which the pumps were designed (200,378 gpm per loop) is equal to the largest BE flow rate for the EPU. Since the RCPs can maintain the largest estimated flow rate under EPU conditions, they will continue to operate in a manner that satisfies the functional requirements listed in LR [Section 2.2.2.6.1](#).

Since the hydraulic snubber located at the top of the each RCP motor is inactive (i.e., offers no resistance) under normal operation conditions, there is no load path above the RCP nozzles. Since the seismic and pipe break effects are also not changed by the EPU (as discussed in LR [Section 2.2.2.6.2.2](#)), the stress AOR for the RCP casing, motor, motor mount flange and flange studs is not changed by the EPU.

The RCP spring hanger support loads for normal operation are given in LR [Table 2.2.2.6-1](#). EPU loads on the spring hangers are below the maximum working load of the spring and in all cases, the RCP support loads for EPU are either bounded by the original design or are less than the equivalent design load for normal operating conditions.

2.2.2.6.3 Conclusion

Florida Power and Light (FPL) has reviewed the structural integrity of the RCPs and their supports. For the reasons set forth above, FPL concludes that the review has adequately addressed the effects of the proposed EPU on these components and their supports. Based on the above, FPL further concludes that the review has demonstrated that the RCPs and their supports will continue to meet its current licensing basis with respect to 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, FPL finds the proposed EPU acceptable with respect to the structural integrity of the RCPs and their supports.

2.2.2.6.4 References

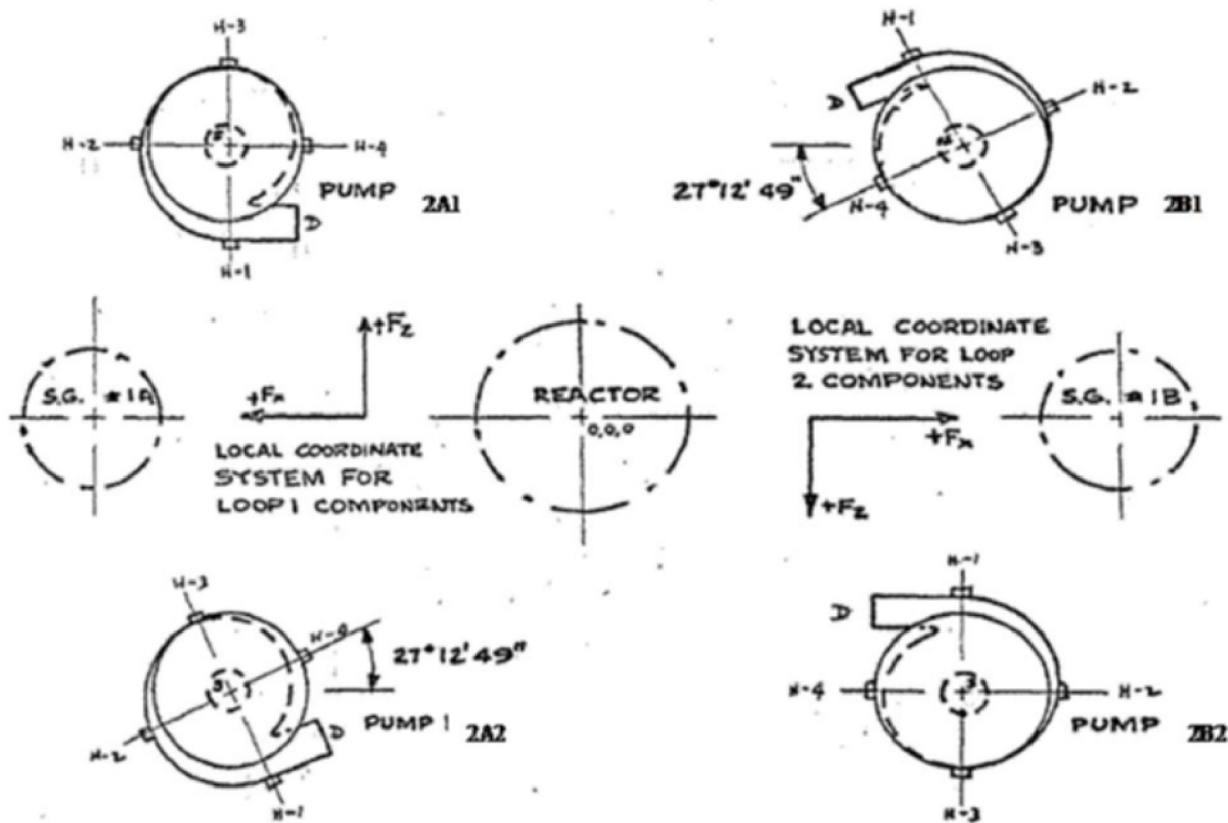
1. ASME Boiler and Pressure Vessel Code, Section III, 1971 Edition, up to and including the Summer 1973 Addenda.

Table 2.2.2.6-1
RCP Normal Operating Spring Hanger Loads

Table 2.2.2.6-2
RCP Normal Operating Support Loads

RCP	Support No.	Axial Loads on RCP Supports			Note
		Pre-EPU kips	EPU kips	Change kips	
2A1	H-1	25.6	47.0	21.4	(3)
	H-2	58.2	61.0	2.8	(1)
	H-3	69.7	59.0	-10.7	
	H-4	42.6	52.0	9.4	(2)
2A2	H-1	63.2	54.0	-9.2	
	H-2	63.8	59.0	-4.8	
	H-3	34.6	64.0	29.4	(1)
	H-4	35.0	39.0	4.0	(1)
2B1	H-1	63.2	54.0	-9.2	
	H-2	63.8	59.0	-4.8	
	H-3	34.6	64.0	29.4	(1)
	H-4	35.0	39.0	4.0	(1)
2B2	H-1	25.6	47.0	21.4	(1)
	H-2	58.2	61.0	2.8	(1)
	H-3	69.7	59.0	-10.7	
	H-4	42.6	52.0	9.4	(3)
1. EPU load is less than the maximum pre-EPU pipe column support load of 69.7 kips. 2. EPU load is less than the maximum pre-EPU load at a bearing plate support of 63.2 kips. 3. EPU load is less than the Equivalent NOP Design load = Faulted design load times the ratio of allowables ($80.2 \times 0.66 \text{ fy}/0.9 \text{ fy} = 55.14 \text{ kips}$)					

Figure 2.2.2.6-1
RCP Support Coordinate System



2.2.2.7 Pressurizer and Supports

2.2.2.7.1 Introduction

The pressurizer and supports are reviewed as part of the EPU. UFSAR Section 5.4.10 describes the pressurizer. UFSAR Section 5.4.14.2 describes the pressurizer support system. The regulatory evaluation included in LR [Section 2.2.2](#) is applicable to this LR section as well.

The technical evaluation included as part of this LR describes the input parameters, assumptions and acceptance criteria used to evaluate pressurizer performance relative to the EPU.

A summary regarding the adequacy of the pressurizer and its supports under EPU conditions concludes this LR subsection.

St. Lucie Unit 2 Current Licensing Basis

The generic current licensing basis (CLB) in LR [Section 2.2.2](#) applies to the pressurizer and its supports, with the following amplifications.

UFSAR Section 3.2 and Table 3.2-1 provide seismic classification, quality group, tornado wind criterion, flood criterion, missile criterion, and applicable ASME Code category for structures, systems and components such as the pressurizer. UFSAR Section 5.4.10.2 states that the pressurizer is designed and fabricated in accordance with ASME Code Section III, 1971 Edition through Summer 1972 as listed in UFSAR Table 5.2-1. UFSAR Table 5.4-6 provides pressurizer principal design parameters.

UFSAR Section 5.4.10.2 states in part that the pressurizer, as shown on UFSAR Figure 5.4-10 is a vertically mounted, bottom supported, seismic Category I, cylindrical pressure vessel. Replaceable direct immersion electric heaters are vertically mounted in the bottom head. The pressurizer is furnished with nozzles for spray, surge, safety valves, relief valve and pressure, temperature and water level instrumentation. A manway is provided in the top head. The interior surface is clad with weld deposited stainless steel.

It is shown by analysis, made in accordance with the requirements for ASME Code, Section III, Code Class 1, that the pressurizer is adequate for all normal operating and transient conditions expected during the life of the plant.

Overpressure protection of the reactor coolant system (RCS) is provided by three ASME Code spring-loaded pressurizer safety valves (PSVs). Refer to UFSAR Section 5.4.13 for more information on safety valves.

A discussion of the radiological considerations for the pressurizer is provided in UFSAR Section 12.3.

The pressurizer is a Quality Group A components as listed in UFSAR Table 3.9-1. These components are analyzed with the appropriate loading combinations of pressure, temperature and flow transients for the normal, upset, emergency, faulted and test conditions. Design load combinations and stress limits for the pressurizer are given in UFSAR Section 3.9.3.

The pressurizer is tested in accordance with requirements of Section III of the ASME Code and inspected in accordance with the requirements of Section XI of the ASME Code as required by Technical Specification 4.0.5.

UFSAR Section 5.4.14.2 states that the pressurizer is supported by a cylindrical skirt welded to the pressurizer and bolted to the support structure. The skirt is designed to withstand dead weight and normal operating loads as well as the loads due to earthquakes and LOCA.

UFSAR Section 5.4.10.5 states that design basis cyclic transients were revisited for the pressurizer surge line and nozzles to address thermal stratification and thermal stripping concerns raised by NRC Bulletin 88-11. The analysis developed a new set of design basis transients based on the collected data.

In addition to the licensing basis described in the UFSAR, the pressurizer and supports were evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.1.2 of the SER identifies that components of the pressurizer and supports are within the scope of License Renewal. Programs used to manage the aging effects associated with the pressurizer and supports are discussed in SER Section 3.1.2 and Chapter 18 of the UFSAR.

2.2.2.7.2 Technical Evaluation

2.2.2.7.2.1 Introduction

The pressurizer evaluation was comprised of a review of current component and NSSS system parameters analyzed in the original design analysis for the pressurizer, subsequent design report addenda, and various calculations done for EPU conditions. Parameters reviewed included temperature, design transients, and pressure. The impact of EPU on design transients was determined and reconciled. The NSSS uprate parameters are provided in LR [Section 1.1](#), Nuclear Steam Supply System Parameters, and the NSSS uprate design transients are found in LR [Section 2.2.6](#), NSSS Design Transients. Acceptance criteria for the pressurizer are based on the ASME Code, Section III, 1971 Edition through Summer 1972 Addenda.

Any impact of EPU on the pressurizer would result from the temperature effects associated with increasing the NSSS core thermal power level to 3034 MWt with an associated increase in RCS average design transient temperature from 577.0°F to 577.5°F, as described in LR [Section 2.2.2.7.2.3](#). The increase in RCS average temperature will not change the temperature or pressure of the pressurizer. Therefore, as a result of EPU, there are no physical changes required to the pressurizer or pressurizer supports.

2.2.2.7.2.2 Input Parameters, Assumptions and Acceptance Criteria

St. Lucie Unit 2 pressurizer analysis of record (AOR) was compared with the design inputs in LR [Section 1.1](#) and LR [Section 2.2.6](#). If differences were found in T_{hot} and T_{cold} , design transients, or

design loads, then pressurizer structural analyses and evaluations were performed as necessary to incorporate the revised design inputs. The acceptance criterion was that the pressurizer components meet the stress/fatigue analysis requirements of the ASME Code, Section III for the plant operation in accordance with EPU.

2.2.2.7.2.3 Description of Analyses and Evaluations

A review of the temperature and design transient parameters in LR Sections 1.1 and 2.2.6 showed that there was no change in the reactor coolant system (RCS) hot leg temperature (T_{hot}), and that the change in cold leg temperature (T_{cold}) was an increase of 1°F. The changes made to the design transients did not impact the pressurizer, since the primary side transients were either unaffected or not significantly affected. For this reason, it was concluded that the revised parameters would not impact the existing pressurizer stress and fatigue analyses. There is no change to fatigue usages due to EPU.

Due to slight temperature changes in the RCS, no physical changes are needed to the pressurizer. All horizontal reactions (i.e. forces and moments) caused by horizontal key loads are taken by the concrete shield walls. Since the support reactions are not changing under EPU conditions, any concrete shield wall loading associated with the EPU are bounded by the AOR.

The foundation is analyzed for vertical loads only. The design vertical load is 1.5×305.3 , or 458 kips. Proper anchorage and reinforcement are provided to transfer loads into base concrete. Information regarding the use of an equivalent static load to account for dynamic (e.g., seismic) effects is found in UFSAR Section 3.7.3.5. Due to the rigidity of the foundation structure, the equivalent static load method of analysis, with the associated 1.5 factor, is applicable. As EPU will not change vertical load, current evaluations bound all vertical loading on the pressurizer foundation associated with the EPU.

Seismic analyses and non-pressure boundary component evaluations were considered to be unaffected by EPU as the conditions in the original design specification remain bounding. The stress criteria include the maximum loads associated with the most severe transients during emergency conditions at operating temperature. The load combinations considered in the original design do not change under EPU conditions.

The thermal-hydraulic parameters were reviewed and do not change under EPU conditions. The parameters given in the pressurizer equipment specification and EPU condition parameters listed for the pressurizer were analyzed and no impact was found.

The pressurizer assembly was designed to satisfy the ASME Code Criteria for a design pressure of 2485 psig at a design temperature of 700°F. EPU conditions do not affect these parameters. Pressurizer transients are listed in the engineering specification for the pressurizer assembly, and were evaluated for EPU conditions. Based on these transient evaluations, the current pressurizer assembly evaluations are still applicable for EPU conditions, including normal, upset, emergency, and faulted conditions. Pressurizer heat up and cool down conditions are included under normal conditions and are bounded by existing evaluations.

The pressurizer surge line was evaluated for EPU normal operating conditions and transients. Normal operating pressure does not change for the EPU and the changes in the design transients and thermal anchor movements were deemed insignificant. Accordingly, the

pressurizer surge line nozzle loads, including thermal stratification loads, remain applicable after EPU implementation.

The PSV and power operated relief valve (PORV) piping was evaluated for EPU conditions; see LR [Section 2.2.2.2](#). Based on the analysis, it was determined that the maximum loads in the piping segments connected to the PORV and PSV nozzles are bounded by the current design, thus the nozzle loads are also bounded by the current design.

Current pressurizer instrument nozzle loads will continue to be bounding after EPU implementation since the operating and design pressure and temperature conditions for the pressurizer are not affected by the EPU.

The spray nozzle operating thermal loads are defined by the thermal transient conditions as contained in LR [Section 2.2.6](#). The spray control system and spray flow rates are not affected by the power uprate. Consequently, the conditions considered in the existing analyses of the spray nozzle bound the EPU conditions.

10 CFR 50, Appendix G, "Fracture Toughness Requirements" AOR analysis was evaluated for EPU conditions and it was determined that mechanical seal assemblies (MNSAs) and the half nozzle repair techniques for the small-bore nozzles on the pressurizer are acceptable. The repairs relocate the pressure boundary, such that it is convenient to leave the original crack in place. Consequently, the crack and any potential future growth of the crack does not impact the structural integrity of the vessel. The evaluation concluded that the 10 CFR 50, Appendix G fracture toughness requirements will be met under EPU conditions as there are no transients involved.

One primary side plant transient (plant loading and unloading) is affected to a small degree by EPU. The change in the transient is related to a 1°F change in the cold leg temperature, which has no measurable effect on the pressurizer. Therefore, it can be concluded that Appendix G fracture toughness requirements for the pressurizer instrument nozzles will also be met under EPU conditions.

The effects of flow induced vibration were also considered. This degradation mechanism is not a concern for the pressurizer because the components are subject to relatively low fluid flow velocities. However, vibratory excitation is discussed in the design specification for the pressurizer where the frequency range is 14-15 cps and 70-75 cps. The lower frequency range is defined as a mechanical vibration which will not change due to EPU weight conditions and loads remaining bounded. The upper frequency range is defined as a sinusoidal pressure variation of ± 5.0 psi in the primary pipe which contains the reactor coolant pump. The current vibration excitation analysis is included in the transient conditions evaluation and is not considered to be affected.

Current design stress and heat transfer data and calculations for pressurizer insulation do not change with EPU. EPU conditions are either bounded by the current insulation design specification or are not affected.

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

As discussed above, the pressurizer and supports are within the scope of License Renewal. Operation of the pressurizer and supports under EPU conditions has been evaluated to determine if there any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.2.2.7.2.5 Results

FPL has reviewed the functional design of the pressurizer and pressurizer supports for the effects of EPU. Current analyses bound EPU conditions and are not affected.

The impact of EPU on the pressurizer structural integrity and pressure boundaries has been evaluated and determined to be unaffected by EPU.

The impact of EPU on the structural and thermal loads has been evaluated as part of the reactor coolant system and calculations have been updated, if required. The new loads are still bounded by the pressurizer design basis and no modifications are needed.

The impact of EPU NSSS transients is discussed in LR [Section 2.2.6](#). No modifications have been made to the pressurizer or supports which will continue to satisfy the design basis in all transient conditions.

2.2.2.7.3 Conclusion

FPL has reviewed the structural integrity of pressure-retaining components and their supports. For the reasons set forth above, FPL concludes that the review has adequately addressed the effects of the proposed EPU on these components and their supports. Based on the above, FPL further concludes that the review has demonstrated that pressure-retaining components and their supports will continue to meet its current licensing basis with respect to 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, FPL finds the proposed EPU acceptable with respect to the structural integrity of the pressure-retaining components and their supports.

2.2.2.8 Conclusions for Pressure-Retaining Components and Component Supports

Florida Power and Light (FPL) has reviewed the evaluations related to the structural integrity of pressure-retaining components and their supports and concludes that the effects of the proposed EPU on these components and their supports have been adequately addressed. FPL further concludes that the pressure-retaining components and component supports will continue to meet the requirements of the current licensing basis with respect to 10 CFR 50.55a, General Design Criteria (GDC)-1, GDC-2, GDC-4, GDC-14, and GDC-15 following implementation of the proposed EPU. Therefore, FPL 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

2.2.3.1 Regulatory Evaluation

Reactor pressure vessel (RPV) internals consist of all the structural and mechanical elements inside the reactor vessel, including core support structures. Florida Power and Light (FPL) reviewed the effects of the proposed extended power uprate (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 loss-of-coolant accidents (LOCAs), and the identification of design transient occurrences.

FPL's review covered:

- The analyses of flow-induced vibration for safety-related and non-safety-related reactor internal components, and
- The analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. FPL's review also included a comparison of the resulting stresses and cumulative usage factor (CUFs) against the corresponding Code-allowable limits.

The NRC's acceptance criteria are based on:

- 10 CFR 50.55a and General Design Criterion (GDC)-1, insofar as they require that structures, systems, and components (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,
- 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,
- 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
- 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 Standard Review Plan (SRP) Sections 3.9.1, 3.9.2, 3.9.3, and 3.9.5; and other guidance is provided in Matrix 2 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Section 3.1 of the Updated Final Safety Analysis Report (UFSAR), the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDC for the RPV internals and core supports are as follows:

- GDC-1 is described in UFSAR Section 3.1.1, Criterion 1 – Quality Standards and Records.

Structures, systems and components important to safety shall be designed, fabricated, erected and tested to quality standards commensurate with the importance of the safety functions to be performed. Where generally recognized codes and standards are used, they shall be identified and evaluated to determine their applicability, adequacy and sufficiency and shall be supplemented or modified as necessary to assure a quality product in keeping with the required safety function. A quality assurance program shall be established and implemented in order to provide adequate assurance that these structures, systems, and components will satisfactorily perform their safety functions. Appropriate records of the design, fabrication, erection and testing of structures, systems and components important to safety shall be maintained by or under the control of the nuclear power unit licensee throughout the life of the unit.

SSCs of the facility are classified according to their relative importance to safety. Those items vital to safety such that their failure might cause or result in an uncontrolled release of an excessive amount of radioactive material are designated seismic Category I. They and items of lesser importance to safety are designed, fabricated, erected and tested according to the provisions of recognized codes and quality standards. Discussions of the applicable codes, standards, records and quality assurance program used to implement and audit the operation processes were originally presented in UFSAR Sections 17.1 and 17.2; however, this information is now provided in FPL Quality Assurance Topical Report FPL-1. A complete set of facility structural, arrangement and system drawings is maintained under the control of FPL throughout the life of the plant. Quality assurance written data and comprehensive test and operating procedures are likewise assembled and maintained by FPL. The classification of seismic Category I structures and safety related systems and components is discussed in UFSAR Section 3.2.

- GDC-2 is described in UFSAR Section 3.1.2, Criterion 2 – Design Bases for Protection Against Natural Phenomena.

SSCs important to safety shall be designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunamis and seiches without loss of capability to perform their safety functions. The design bases for these structures, systems and components shall reflect: (1) appropriate consideration of the most severe of natural phenomena that have been historically reported for the site and surrounding area, with sufficient margin for the limited accuracy, quantity, and period of time which the historical data have been accumulated, (2) appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena and (3) the importance of the safety functions to be performed.

The SSCs important to safety are designed to withstand the effects of natural phenomena without loss of capability to perform their safety functions. Natural phenomena factored into the design of plant SSCs important to safety are determined from recorded data for the site vicinity with appropriate margin to account for uncertainties in historical data.

The most severe natural phenomena postulated to occur at the site in terms of induced stresses is the safe shutdown earthquake (SSE). Those SSCs vital for the mitigation and control of accident conditions are designed to withstand the effects of a loss-of-coolant accident (LOCA) coincident with the effects of the SSE. SSCs vital to the safe shutdown of the plant are designed to withstand the effects of any one of the most severe natural phenomena, including flooding, hurricanes, tornadoes and the SSE (refer to UFSAR Chapter 2).

Design criteria for wind and tornado, flood and earthquake are discussed in UFSAR Sections 3.3, 3.4 and 3.7, respectively.

- GDC-4 is described in UFSAR Section 3.1.4, Criterion 4 – Environmental and Missile Design Bases.

SSCs important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and approved by the Commission demonstrates that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

SSCs important to safety are designed to accommodate the effects of and to be compatible with the pressure, temperature, humidity, and radiation conditions associated with normal operation, maintenance, testing, and postulated accidents including a LOCA, in the area in which they are located.

The structures inside the containment vessel are designed to sustain dynamic loads which could result from failure of major equipment and piping, such as jet thrust, jet impingement and local pressure transients, where containment integrity is needed to cope with the conditions.

For those components which are required to operate under extreme conditions such as design seismic loads or containment post-LOCA environmental conditions, the manufacturers submit type test, operational or calculational data which substantiate this capability of the equipment.

Refer to UFSAR Sections 3.5, 3.6, 3.7, and 3.11 for details on missile protection, pipe rupture and jet impingement protection, seismic design criteria and environmental qualification, respectively.

- GDC-10 is described in UFSAR Section 3.1.10, Criterion 10 – Reactor Design.

The reactor core and associated coolant, control and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

In ANSI N18.2, plant conditions have been categorized in accordance with their anticipated frequency of occurrence and risk to the public, and design requirements are given for each of the

four categories. The categories covered by this criterion are Condition I - Normal Operation and Condition II - Faults of Moderate Frequency.

The design requirement for Condition I is that margin shall be provided between any plant parameter and the value of that parameter which would require either automatic or manual protective action; it is met by providing an adequate control system (refer to UFSAR Section 7.7). The design requirement for Condition II is that such faults shall be accommodated with, at most, a shutdown of the reactor, with the plant capable of returning to operation after corrective action; it is met by providing a reactor protective system (refer to UFSAR Section 7.2).

SAFDLs are stated in UFSAR Section 4.4. Minimum margins to SAFDLs are prescribed in the technical specifications (TS) (limiting conditions for operations (LCO)), which support UFSAR Chapters 4 and 15. The plant is designed such that operation within LCO, with safety system settings not less conservative than limiting safety system settings prescribed in the TS, assures that SAFDLs will not be violated as a result of anticipated operational occurrences. During normal operation, operation of the plant within LCO ensures that SAFDLs are not approached within the minimum margins. Operator action, aided by the control systems and monitored by plant instrumentation, maintains the plant within LCO during normal operation.

The reactor internals support and orient the fuel assemblies, control element assemblies (CEA), incore instrumentation, and guide the reactor coolant through the reactor vessel. The reactor internals also absorb static and dynamic loads and transmit the loads to the reactor vessel flange. They will safely perform their functions during normal operating, upset, emergency, and faulted conditions. The internals are designed to safely withstand forces due to dead weight, handling, temperature and pressure differentials, flow impingement, vibration, and seismic acceleration. Reactor components are considered seismic Category I for seismic design. The design of the reactor internals limits deflection where required by function. The stress values of structural members under normal operating and expected transient conditions are not greater than those established by Section III, Subsection NG, of the ASME Code. The effect of neutron irradiation on the materials concerned is included in the design evaluation. The effect of accident loadings on the internals is included in the design analysis.

The reactor internal design bases are identified in UFSAR Section 3.9.5.4.1.

The materials used in fabrication of the reactor internal structures are primarily Type 304 stainless steel. The flow skirt is fabricated from Inconel. Welded connections are used where feasible; however, in locations where mechanical connections are required, structural fasteners are used which are designed to remain captured in the event of a single failure. Structural fastener material is typically a high strength austenitic stainless steel; however, in the less critical applications, Type 316 stainless steel is employed. Hardfacing of Stellite material is used at wear points. The effect of irradiation on the properties of the materials is considered in the design of the reactor internal structures. Work hardening properties of austenitic stainless steels are not used.

The components of the reactor internals are divided into two major parts consisting of the core support structure and the upper guide structure assembly.

The major structural member of the reactor internals is the core support structure. The core support structure is supported at its upper end by the upper flange of the core support barrel

(CSB), which rests on a ledge in the reactor vessel. Alignment is accomplished by means of four equally spaced keys in the flange, which fit into the keyways in the vessel ledge and closure head. The lower flange of the CSB supports, secures, and positions the lower support structure (LSS) and is attached to the LSS by means of a welded flexural connection. The LSS provides support for the core by means of a core support plate (CSP) supported by columns mounted on support beams that transmit the load to the CSB lower flange. The CSP provides support and orientation for the lower ends of the fuel assemblies. The core shroud, which provides a flow path for the coolant and lateral support for the fuel assemblies, is also supported and positioned by the CSP. The lower end of the CSB is restricted from excessive radial and torsional movement by six snubbers that interface with the reactor vessel wall. Refer to UFSAR Sections 3.9.5.1.1.1, 3.9.5.1.1.2, and 3.9.5.1.1.3 for additional information pertaining to the CSB, CSP and LSS, and core shroud, respectively.

The upper guide structure assembly consists of the upper guide structure support plate assembly, control element assembly shrouds, and a fuel assembly alignment plate (UFSAR Figure 3.9-14). The upper guide structure assembly aligns and laterally supports the upper end of the fuel assemblies, maintains the CEA spacing, holds down the fuel assemblies during operation, prevents fuel assemblies from being lifted out of position during a severe accident condition, protects the CEAs from the effect of coolant cross flow in the upper plenum, and supports the incore instrumentation plate assembly. The upper guide structure assembly is handled as one unit during installation and refueling. Refer to UFSAR Section 3.9.5.1.2, for additional information pertaining to the upper guide structure assembly.

The review requirements associated with Note 1 of Matrix 2, Section 2.1 of RS-001 relates to IN 2002-26 and the failure of the steam dryers and other plant components at Quad Cities Units 1 and 2 during operation under extended power uprate (EPU) conditions. IN 2002-26 is BWR specific and therefore not applicable to St. Lucie Unit 2.

IN 95-016 is also BWR specific and therefore not applicable to St. Lucie Unit 2.

In addition to the licensing basis described in the UFSAR, the RPV internals and core supports were evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.1.4 of the SER identifies that components of the Reactor Pressure Vessel Internals and Core Supports are within the scope of License renewal. Programs used to manage the aging effects associated with the RPV internals and core supports are discussed in SER Section 3.1.4 and Chapter 18 of the UFSAR.

2.2.3.2 Technical Evaluation

2.2.3.2.1 Introduction

The RPV internal system consists of the reactor internals, fuel, and control element drive mechanisms. The reactor internals functional description is provided below. The reactor internals

are designed to withstand forces due to normal, upset, and faulted conditions. No emergency condition has been identified for the applicable components.

Changes in the primary coolant system operating conditions (e.g., increase in power) also produce changes in the boundary conditions; this includes loads and temperatures experienced by reactor internal components. Ultimately, this results in changes in the stress levels in these components and changes in the relative displacement between the reactor vessel and the reactor internals. To ensure that the reactor internal components maintain their design functions, a systematic evaluation of the reactor components has been performed to assess the impact of the increased core power on the reactor internal components.

Reactor Internals Functional Description

The RPV internals addressed in this section are comprised of both the core support and internal structures. Core support structures, which provide direct support/restraint of the reactor core, include the LSS, CSB and upper guide structure (UGS) components. Internal structures, which do not provide direct support/restraint of the reactor core, include the core shroud, holddown ring, and incore instrumentation support system. The RPV internals support and orient the reactor core within the reactor vessel, provide a uniform distribution of coolant among the fuel assemblies, maintain the reactor core in a coolable geometry, provide and maintain a free path for the insertion of CEAs into the reactor core, and protect the CEAs and in-core instrument hardware from coolant crossflow. The RPV internals are designed to safely withstand loads due to deadweight, handling, flow impingement, vibration, pressure differentials, temperature differentials, seismic excitation and LOCAs; under normal operating, upset and faulted design loading conditions.

Reactor Internals Components and Function

Core Support Barrel

The CSB is a right circular cylinder including a heavy ring flange at the upper end and an internal ring flange at the lower end. The CSB is supported at its upper flange, which rests on a ledge in the reactor vessel. The lower flange of the CSB, in turn, supports the LSS, to which it is attached by means of a welded flexural connection. Press-fitted into the upper flange of the CSB are four alignment keys located 90 degrees apart. The reactor vessel, closure head and UGS flange are slotted in locations corresponding to the alignment key locations to provide proper alignment between these components. The upper cylindrical section of the CSB contains two outlet nozzles that interface with internal projections on the vessel nozzles to minimize leakage of coolant from inlet to outlet.

Amplitude limiting devices, or snubbers, are installed on the outside of the CSB near the bottom end. The snubbers consist of six equally spaced lugs around the circumference of the barrel and act as a tongue and groove assembly with the mating lugs on the pressure vessel. Minimizing the clearance between the two mating pieces limits the amplitude of vibration. During assembly, as the internals are lowered into the reactor vessel, the reactor vessel lugs engage the CSB lugs in an axial direction. Radial and axial expansion of the CSB is accommodated, and lateral movement of the CSB is restricted.

Core Support Plate and Lower Support Structure

The CSP is a stainless steel plate into which the necessary flow distributor holes for the fuel assemblies have been machined. Fuel assembly locating pins (four for each assembly) are shrunk-fit into this plate.

The fuel assemblies and core shroud are supported and positioned on the CSP which forms the top support member of a welded assembly consisting of a cylinder, a bottom plate, support columns and support beams. The complete welded assembly is comprised of the LSS. The CSP is supported by the columns, which are welded at their bases to the beams. The bottoms of the beams are welded to the bottom plate, which contains flow holes to provide proper flow distribution. The ends of the beams and the top periphery of the bottom plate are welded to the cylinder, which supports the outer edge of the CSP. The cylinder guides the main coolant flow and limits the core shroud bypass flow by means of holes located near the base of the cylinder.

Upper Guide Structure (UGS) Assembly

The UGS assembly consists of the UGS support plate assembly, the CEA shrouds, and the fuel alignment plate (FAP). The UGS assembly aligns and laterally supports the upper end of the fuel assemblies, maintains the CEA spacing, holds down the fuel assemblies during operation, prevents fuel assemblies from being lifted out of position during a severe accident condition, protects the CEAs from the effects of coolant crossflow in the upper plenum, and supports the in-core instrumentation (ICI) plate assembly.

The upper end of the assembly is a structure consisting of a support flange welded to the top of a cylinder. The support flange contains four alignment keyways, equally spaced at 90 degree intervals, which engage the alignment keys mounted in the CSB upper flange. A support plate is welded to the inside of the cylinder approximately in the middle. The support plate is welded to a grid array of deep beams, the ends of which are welded to the cylinder. The support plate aligns and supports the upper end of the CEA shrouds. The CEA shrouds extend from the FAP to an elevation above the UGS support plate. Each CEA shroud consists of a cylindrical upper section welded to a base, and a flow channel structure shaped to provide flow passage for the coolant through the FAP, while shrouding the CEAs from cross flow. The FAP is designed to support and align the upper ends of the fuel assemblies, and to support and align the lower ends of the CEA shrouds. The FAP also has four equally spaced slots which engage with pins protruding from the core shroud to limit lateral motion of the UGS assembly during operation. The FAP bears the upward force of the fuel assembly holddown devices. This force is transmitted from the alignment plate through the CEA shrouds to the UGS support plate, and thence to the holddown ring.

Holddown Ring

The holddown ring is positioned on top of the UGS flange and acts against a recess in the RV head flange. The holddown ring exerts a downward force on the UGS and CSB upper flanges, maintaining them in a clamped configuration to prevent rocking and sliding of the UGS and CSB assemblies relative to one another and to the reactor vessel. The holddown ring also

accommodates axial differential thermal expansion of the CSB flange and UGS flange relative to the RV flange support ledge and the RV head flange recess.

Core Shroud

The core shroud consists of two stainless steel ring sections welded to each other and to the CSP. Each welded assembly consists of vertical panels, vertical ribs and horizontal plates, or girth rings. The core shroud surrounds the reactor core and is supported on the LSS. The core shroud directs the flow of coolant upward around the fuel assemblies, but does not provide structural support for the fuel assemblies. A small gap is provided between the core shroud outer perimeter and the core support barrel. Holes are provided in the girth rings to provide upward coolant flow between the core shroud and the CSB, thereby minimizing thermal stresses in the core shroud and eliminating stagnant pockets.

Incore Instrumentation Support System

The incore instrumentation system begins outside of the reactor vessel, penetrates the vessel boundary through the reactor vessel closure head, and terminates near the bottom of the fuel assembly. The mechanical components which support the incore instrumentation inside the reactor vessel are considered reactor internals components.

The incore instrumentation support system consists of the instrument support plate, the instrument guide tubes and supporting hardware, and the instrument thimbles that extend downward into selected fuel bundles. The guide tubes route the instruments so that they are located and spaced throughout the core. The guide tubes and thimbles are attached to and supported by the instrument support plate assembly.

The instrument support plate assembly fits within the confines of the reactor vessel head and rests in the recessed section of the UGS assembly. Its weight is supported by four bearing pins, which are attached to the instrument support plate and act against the UGS support plate. Two of these pins also provide lateral support and location. The CEA shrouds extend through clearance holes in the instrument support plate. Above the instrument support plate, the guide tubes bend and are gathered to form stalks that extend into the reactor vessel head instrumentation nozzles.

2.2.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The principal input parameters used in the analysis of the reactor internal components and core supports are the reactor coolant system design parameters provided in LR [Section 1.1](#), Nuclear Steam Supply System Parameters, LR [Table 1.1-1](#). For the structural analysis/evaluations, the nuclear steam supply system design transients discussed in LR [Section 2.2.6](#), "NSSS Design Transients", were considered in the thermal analyses of the RPV internals.

FPL has performed evaluations/analyses to assess the effect of operating at EPU conditions on the reactor internals system. The analyses and evaluations were developed using the information presented in LR [Sections 1.1](#) and [2.2.6](#), and are discussed below.

Reactor Internals Heat Generation

The presence of radiation-induced heat generation rates in the reactor internals components, in conjunction with the reactor coolant fluid temperatures, results in thermal gradients within and

between the components. The resultant material temperature gradients cause thermal stresses and thermal growth that must be considered in the design and analysis of the various components. The primary design considerations are to ensure that thermal growth does not impede the functional requirements of the components and that the applicable ASME Code requirements are satisfied as part of the component evaluations.

The reactor internals components subjected to the highest radiation-induced heat generation rates are the core shroud, CSB, CSP, and FAP.

Three-dimensional discrete ordinates transport calculations were used to analyze the reactor internals gamma heating rates based on the EPU conditions. The EPU analyses for the gamma heating rates for the core shroud, CSB, FAP and CSP were based on x-y-z models. Short and long-term cases were analyzed for the reactor internals components to obtain conservative gamma heating rates suitable for subsequent structural evaluation.

The results of the gamma heating rate calculation were incorporated into the thermal analysis of the RPV internals, as well as the structural analysis of the components.

Acceptance Criteria

Reactor internal components are designed to ensure that the stress levels and deflections are within an acceptable range. The allowable stress values for core support structures are less than those given in Section III, Subsection NG of the ASME Boiler and Pressure Vessel Code, 1971 Edition with Addenda through Winter 1973. In the design of reactor vessel internal components which are subject to fatigue, the stress analysis is performed using the design fatigue curve of Figure I-9.2 in Section III of the ASME Boiler and Pressure Vessel Code and a CUF of less than 1.0 is the limiting criteria.

Acceptance criteria for internal structures are defined in Paragraph NG-1122 in Section III of the ASME Boiler and Pressure Vessel Code, Subsection NG. That paragraph stipulates that the construction of all internal structures shall not adversely affect the integrity of the core support structures.

Under design loadings plus operating basis earthquake forces, deflection is limited so that the CEAs can insert and adequate core cooling is maintained.

Under normal operating loadings plus SSE plus pipe rupture loadings resulting from a break equivalent in size to the largest line connected to the reactor coolant system piping, deflections are limited so that the core is held in place, adequate core cooling is maintained, and all CEAs can be inserted. Those deflections which would influence CEA movement are limited to less than 80 percent of the deflections required to prevent CEA insertion.

Under normal operating loadings plus SSE forces plus the maximum pipe break loadings resulting from the full spectrum of pipe breaks, deflections are limited so that the core is held in place and adequate core cooling is maintained. Although CEA insertion is not required for a safe and orderly shutdown for break sizes greater than the largest line connected to the reactor coolant system piping, calculations show that the CEAs are insertable for larger breaks, except for a few CEAs located near the vessel outlet nozzle which is feeding the postulated break.

Rocking and Sliding Analysis

As discussed in LR [Section 2.2.3.2.1](#), the holddown ring exerts a downward force on the UGS and CSB upper flanges; maintaining them in a clamped configuration to prevent rocking and sliding of the UGS and UGS assemblies relative to one another and to the reactor vessel. Sliding margin is defined as the ratio of the lateral (frictional) component of the net holddown load over the applied lateral hydraulic load. The net holddown load is calculated using the holddown ring, dead weight, fuel spring and the vertical hydraulic loads. Rocking margin is defined as the ratio of the moment generated by the net holddown load over the applied hydraulic moment. The derivation of allowable rocking and sliding margins is not based on any regulatory or design basis document. The allowable margin values used in the rocking and sliding analysis are based on good engineering practice and operating experience with numerous plants. As defined above, rocking or sliding margin is defined as the ratio of holddown load or moment to the applied load or moment. Any margin greater than 1.0 will prevent rocking or sliding and is therefore adequate. To provide conservatism, the rocking and sliding analysis uses allowable margins of 2.0 for 4 pump operation at 500°F, and 1.5 for other operating conditions.

2.2.3.2.3 Description of Analyses and Evaluations

The RPV internals have been analyzed for the EPU revised design parameters and the design basis load combinations. The analysis of the components was performed for the normal, upset, and faulted conditions. In general, design loads were combined by direct summation. For the faulted conditions, SSE and LOCA loads were combined using the square root of the sum of the squares (SRSS), as permitted by NUREG-0484 Rev. 01. The results of these analyses confirm that there is no adverse impact on the structural adequacy of the reactor internals components for the EPU conditions.

Thermal-Hydraulic System Evaluations

The design hydraulic loads were assessed for EPU conditions. The result of the assessment showed that the hydraulic loads on the RPV internals do not change based on EPU conditions. The bounding loads were incorporated into the stress analyses and evaluations for EPU conditions.

Flow-Induced Vibrations

This evaluation was performed in accordance with Section III of the ASME Code, 1971 edition with addenda through the Winter of 1973, which is the ASME Code edition-of-record for the RPV internals. Fatigue curves in this edition of the Code were limited to 10^6 cycles. The calculation of high-cycle ($> 10^6$ cycles) fatigue usage, normally associated with flow-induced vibration, was therefore not required for this evaluation. However, the dynamic hydraulic loads that cause flow-induced vibration are included in the revised hydraulic loads described above, and are accounted for in the stress evaluations.

Design Transients

Only the plant loading/unloading transient has changed. The cold leg full load temperature increases by 1°F. This change was incorporated in the analysis for the EPU.

Mechanical System Evaluations

LOCA Loads

The blowdown loads on the RPV internals that were calculated for the Cycle 1 analysis bound the loads for the EPU conditions. These are the loads that were previously analyzed for St. Lucie Unit 2. Therefore, the EPU does not impact the LOCA loads applied to reactor internal components discussed in this section.

Seismic Analyses

The EPU does not impact the seismic response of the reactor internals. The changes to the fuel for the EPU (described in LR Section 2.8.1) do not affect the seismic response of the reactor internals. Therefore, the seismic loads on reactor internals components are not affected by the EPU.

Evaluation of Reactor Internal and Core Support Structure Components

In addition to supporting the core, a secondary function of the RPV internals assembly is to direct coolant flows within the vessel. While directing primary flow through the core, the internals assembly also establishes secondary flow paths for cooling the upper regions of the reactor vessel and the internals structure components. Some of the parameters influencing the mechanical design of the assembly are the pressure and temperature differentials across its component parts and the flow rate required to remove heat generated within the structural components due to radiation (for example, gamma heating).

Component Analyses/Evaluations

A series of evaluations and analysis were performed on the reactor internal components for the EPU conditions. The most critical components that were analyzed/evaluated are:

- CSB,
- CSP,
- LSS beams and columns,
- Core shroud,
- UGS,
- FAP,
- CEA shrouds,
- Instrument tube supports,
- Reactor vessel level monitoring system support tubes, and
- Thimble support plate (TSP).

The results of these evaluations/analyses demonstrate that the above listed components are structurally adequate for the EPU conditions and the fatigue usage factors were less than 1.0. A summary of the stresses versus allowables and the corresponding fatigue usage factors is given in LR [Table 2.2.3-1](#).

A rocking and sliding analysis, as described in LR [Section 2.2.3.2.2](#), was performed using revised input loads associated with the EPU.

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

As discussed above, the RPV internals and core supports are within the scope of License Renewal. Operation of the RPV internals and core supports under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.2.3.2.5 Results

Analyses and evaluations have been performed to assess the effect of changes due to the EPU. The results of the stress evaluation are presented in LR [Table 2.2.3-1](#). Stress intensities in the RPV internals resulting from the incorporation of the revised input loads associated with the EPU satisfy the design criteria for both normal operating-plus-upset and faulted design conditions. Cumulative fatigue usage is < 1.0 for all of the components. The deflection of the CEA shrouds are shown to have 96 percent margin to the allowable deflection limits. In addition, the deflection of the extension shaft guide assemblies (ESGAs) have 90 percent margin to the allowable deflection limits. The reactor internals, therefore, maintain a free path for CEA insertion.

Rocking and sliding margins resulting from the incorporation of revised input loads associated with the EPU are acceptable for both the normal operating configuration and for plant design transients.

LR [Table 2.2.3-1](#) indicates that the core shroud primary plus secondary stress intensity exceeded the $3S_m$ limit imposed by the ASME Code. Per the Code, the $3S_m$ limit on the range of primary plus secondary stress intensity may be exceeded, provided the requirements of the simplified elastic-plastic analysis of Paragraph NG-3228.3 are met. In NG-3228.3 there are six requirements, (a) through (f), which are satisfied for the core shroud. Each of the criteria is listed here followed by a brief discussion as to how the criterion was met for the core shroud.

NG-3228.3(a) requires that the range of primary plus secondary membrane plus bending stress intensity, excluding thermal bending stresses, be less than or equal to $3S_m$. This is met for the core shroud.

NG-3228.3(b) requires that the value of S_a used for entering the design fatigue curve be multiplied by the K_e factor. This was done for the core shroud.

NG-3228.3(c) requires that the rest of the fatigue evaluation stay the same as required in NG-3222.4, except that the procedure of NG-3227.6 does not have to be used. This was done for the core shroud.

NG-3228.3(d) requires the structure to meet the thermal ratcheting requirement of NG-3222.5. This was met for the core shroud.

NG-3228.3(e) requires that the temperatures not exceed those listed for the various classes of Code materials. This was met for the core shroud.

NG-3228.3(f) requires that the material has minimum specified yield strength to minimum specified ultimate strength ratio of less than 0.80. This was met for the core shroud in the areas where the primary plus secondary stress intensity exceeds $3S_m$.

2.2.3.3 Conclusion

FPL has reviewed the evaluations related to the structural integrity of reactor internals and core supports and concludes that it has adequately addressed the effects of the proposed EPU on the reactor internals and core supports. FPL further concludes that it 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, FPL finds the proposed EPU acceptable with respect to the design of the reactor internal and core supports.

Table 2.2.3-1
Stress Evaluation Results for RVP Components

Table 2.2.3-1 (Continued)
Stress Evaluation Results for RVP Components

2.2.4 Safety-Related Valves and Pumps

2.2.4.1 Regulatory Evaluation

The Florida Power and Light (FPL) review included certain safety-related pumps and valves typically designated as Class 1, 2, or 3 under Section III of the American Society of Mechanical Engineer (ASME) Boiler and Pressure Vessel (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.

FPL's review focused on the effects of the proposed extended power uprate (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 NRC Generic Letter (GL) 89-10, GL 96-05, and GL 95-07.

FPL also evaluated 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:

- General Design Criterion (GDC)-1, insofar as it requires that structures, systems, and components (SSCs) important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed;
- GDC-37, GDC-40, GDC-43, and GDC-46, insofar as they require that the emergency core cooling system (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;
- 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
- 10 CFR 50.55a(f), insofar as it requires that pumps and valves subject to that section must meet the in-service testing (IST) program requirements identified in that section.

Specific review criteria are contained in Standard Review Plan (SRP) Sections 3.9.3 and 3.9.6; and other guidance is provided in Matrix 2 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conform with the NRC General Design Criteria for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

- GDC-1 is described in UFSAR Section 3.1.1 Criterion 1 – Quality Standards and Records.

Structures, systems and components important to safety shall be designed, fabricated, erected and tested to quality standards commensurate with the importance of the safety functions to be performed. Where generally recognized codes and standards are used, they

shall be identified and evaluated to determine their applicability, adequacy and sufficiency and shall be supplemented or modified as necessary to assure a quality product in keeping with the required safety function. A quality assurance program shall be established and implemented in order to provide adequate assurance that these structures, systems, and components will satisfactorily perform their safety functions. Appropriate records of the design, fabrication, erection and testing of structures, systems and components important to safety shall be maintained by or under the control of the nuclear power unit licensee throughout the life of the unit.

SSCs of the facility are classified according to their relative importance to safety. Those items vital to safety such that their failure might cause or result in an uncontrolled release of an excessive amount of radioactive material are designated seismic Category I. They and items of lesser importance to safety are designed, fabricated, erected and tested according to the provisions of recognized codes and quality standards. Discussions of the applicable codes, standards, records and quality assurance program used to implement and audit the operation processes were originally presented in UFSAR Section 17.2; however, this information is now provided in FPL Quality Assurance Topical Report, FPL-1. A complete set of facility structural, arrangement and system drawings is maintained under the control of FPL throughout the life of the plant. Quality assurance written data and comprehensive test and operating procedures are likewise assembled and maintained by FPL. The classification of safety-related SSCs is discussed in UFSAR Section 3.2.

- GDC-37 is described in UFSAR Section 3.1.37 Criterion 37 – Testing of Emergency Core Cooling System.

The emergency core cooling system shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leaktight integrity of its components, (2) the operability and performance of the active components of the system, and (3) the operability of the system as a whole and, under conditions as close to design as practical, the performance on the full operational sequence that brings the system into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of the associated cooling water system.

The safety injection system (SIS) is designed to permit appropriate periodic pressure and functional testing. The structural and leaktight integrity, operability, and performance of the SIS components and system are assured through testing conducted during normal plant operation under conditions as close to design as practicable. The operational sequence that bring the SIS into action, including transfer to alternate power sources, is designed to be tested in parts in such a manner as to verify the operability of the actuation system as a whole.

- GDC-40 is described in UFSAR Section 3.1.40 Criterion 40 – Testing of Containment Heat Removal System.

The containment heat removal system shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leaktight integrity of its components, (2) the operability and performance of the active components of the system, and (3) the operability of the system as a whole and under conditions as close to design as

practical the performance of the full operational sequence that brings the system into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of the associated cooling water system.

System piping, valves, pumps, fans, heat exchangers, and other components of the containment heat removal system are designed to permit appropriate periodic testing to assure their structural and leaktight integrity. The components are arranged so that each component can be tested periodically for operability and required functional performance.

- GDC-43 is described in UFSAR Section 3.1.43 Criterion 43 – Testing of Containment Atmosphere Cleanup Systems.

The containment atmosphere cleanup systems shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leaktight integrity of its components, (2) the operability and performance of the active components of the systems such as fans, filters, dampers, pumps, and valves and (3) the operability of the systems as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the systems into operation, including operation of applicable portions of the protection system, the transfer between normal and emergency power sources, and the operation of associated systems.

The shield building ventilation system and hydrogen control and sampling systems are designed and constructed to permit periodic pressure and functional testing.

- GDC-46 is described in UFSAR Section 3.1.46 Criterion 46 – Testing of Cooling Water System.

The cooling water system shall be designed to permit appropriate periodic pressure and functional testing to assure (1) the structural and leaktight integrity of its components (2) the operability and the performance of the active components of the system, and (3) the operability of the system as a whole and, under conditions as close to design as practical, the performance of the full operational sequence that brings the system into operation for reactor shutdown and for loss of coolant accidents, including operation of applicable portions of the protection system and the transfer between normal and emergency power sources.

Both the component cooling water (CCW) and intake cooling water (ICW) systems are in operation during normal plant operation or shutdown. The structural and leaktight integrity of the CCW and ICW systems components and the operability and performance of their active components are demonstrated in this way. The operation of pumps and heat exchangers are rotated on a scheduled basis to monitor operational capability of redundant components. Data can be taken periodically during normal plant operation to confirm heat transfer capabilities (refer to UFSAR Sections 9.2.1.4 and 9.2.2.4).

The systems are designed to permit testing of system operability encompassing simulation of emergency reactor shutdown or LOCA conditions, including the transfer between normal and emergency power sources.

- GDC-54 is described in UFSAR Section 3.1.54 Criterion 54 – Piping Systems Penetrating Containment.

Piping systems penetrating primary reactor containment shall be provided with leak detection, isolation, and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating these piping systems. Such piping systems shall be designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits.

Piping penetrating the containment vessel shell is designed to withstand at least a pressure equal to the containment vessel maximum internal pressure. The isolation system design requires a double barrier on all of the above systems not serving accident consequence limiting systems so that no single active failure can result in loss of isolation or intolerable leakage. These lines are provided with isolation valves as indicated in UFSAR Section 6.2.4.

Valves isolating penetrations serving engineered safety features systems will not automatically close with a containment isolation actuation signal (CIAS), but may be closed by remote manual operation from the control room to isolate any engineered safety feature when required.

Proper valve closing time is achieved by appropriate selection of valve, operator type and operator size. Refer to UFSAR Section 6.2.4 for additional isolation valve information.

To ensure continued integrity of the containment isolation system, periodic closure and leakage tests are performed as stated in UFSAR Section 6.2.4.4.

As addressed in UFSAR Section 3.9.6, the preservice and IST programs for code Class 1, 2 and 3 safety-related pumps and valves are developed employing Regulatory Guide 1.26, Revision 3, criteria for quality group classifications and standards (Quality Group A is the same as ASME Class 1, etc.). The programs are provided under separate cover and are implemented to assess operational readiness. The IST program is based on the requirements of the ASME Boiler and Pressure Vessel Code, Section XI, and the ASME/ANSI OM Code. The program is updated periodically to meet 10 CFR 50.55a(f) requirements. Specific code commitments are documented in the plant's IST program procedure.

Technical Specification (TS) 6.8.4.i, IST Program, addresses the test frequency requirements to be included in the IST Program.

Active pumps are defined as those pumps required to undergo a mechanical motion to either mitigate the effects of an accident or safely shutdown the plant. (UFSAR Table 3.9-1 provides a tabulation of Code Class 1 components). Code Class 2 and 3 active pumps are identified in UFSAR Table 3.9-8.

Active valves are those valves in which mechanical movement is required in order to perform its intended safety function. Active valves are identified in UFSAR Tables 3.9-9 and 10.

The operability of active pumps and valves must be assured under the loading conditions they will be subjected to during a postulated accident including the design basis earthquake. The IST program for pumps and valves provides requirements for the performance and administration of assessing the operational readiness of those pumps and valves with specific functions that are required to:

- Shutdown the reactor to the safe shutdown condition,
- Maintaining the safe shutdown condition, and/or
- To mitigate the consequences of an accident.

NRC GL 89-10 requires that operating nuclear plants develop and implement a program to ensure that switch settings on all safety-related MOVs are correctly selected, set and maintained to accommodate the maximum differential pressures expected on these valves during all postulated events within the design basis. As stated in UFSAR Section 3.9.3.2.2, the requirements of NRC GL 89-10 have been completed for the applicable valves.

As a result of GL 96-05, Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves, FPL committed to maintaining a periodic verification program to ensure safety related MOVs remain capable of performing their safety functions within the current licensing basis. The St. Lucie Unit 2 program addresses all the elements of GL 96-05, including all valves within the GL 89-10 program. The NRC states in part in their safety evaluation report (SER) pertaining to compliance with GL 96-05 that FPL has established an acceptable program to verify periodically the design-basis capability of the safety-related MOVs through the MOV program including its commitment to the Joint Owners Group Program on MOV Periodic Verification and the additional actions described in its submittals.

In a letter dated July 16, 1999, the NRC documented their acceptance of the actions related to pressure locking and thermal binding of safety-related power-operated gate valves (GL 95-07). The NRC states in part in their SER that FPL has performed appropriate evaluations of the operational configurations of safety-related power operated gate valves to identify valves that are susceptible to pressure locking or thermal binding and that FPL has taken appropriate corrective action to ensure that these valves are capable of performing their intended safety functions.

The Air Operated Valve (AOV) Program is a voluntary effort in concert with a joint owners group of nuclear steam supply system (NSSS) vendors to improve the reliability and operation of AOVs in the nuclear industry. While the program is not governed by any regulatory requirements or operating license conditions, it follows the requirements of the Maintenance Rule Program objectives supporting component performance under 10 CFR 50.65. Program organization and administration is solely determined by FPL to ensure that safety related AOVs will be capable of performing their intended design basis functions under normal plant operation and safe shutdown conditions.

In addition to the licensing basis described in the UFSAR, the safety related valves and pumps were evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in

Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. The evaluation of the safety related valves and pumps is addressed in the system-specific sections of this licensing report.

2.2.4.2 Technical Evaluation

2.2.4.2.1 Introduction

In-service Testing Program

As described in the plant administrative procedure, In-service Testing (IST) Program for Pumps and Valves, the program establishes testing requirements for the performance and administration of assessing the operational readiness of those pumps and valves with specific functions that are required to:

- Shutdown the reactor to the safe shutdown condition,
- Maintain the safe shutdown condition, and/or
- Mitigate the consequences of an accident.

As stated in UFSAR Section 7.4, St. Lucie Unit 2 was designed and licensed to operate with “safe shutdown.” Safe shutdown is defined depending on plant operating conditions as hot standby, hot shutdown, or cold shutdown conditions. “Capability for safe shutdown,” in all cases, is defined as maintaining the capability to reach cold shutdown conditions even though cold shutdown may not be required for maintaining the plant in a safe condition.

The IST Program was developed using the following documents:

- Title 10, Code of Federal Regulations, Part 50, Paragraph 50.55a,
- Standard Review Plan 3.9.6, In-service Testing of Pumps and Valves,
- St. Lucie Plant Safety Analysis Report,
- St. Lucie Unit 2 Technical Specifications, and
- NUREG-1482, Rev. 1, Guidelines for In-service Testing at Nuclear Power Plants.

The IST Program Plan has been prepared to meet the requirements of the ASME OM Code 2001 Edition through 2003 Addenda. Mandatory Appendix II of the ASME OM Code 2001 through 2002 Addenda (as modified by 10 CFR 50.22a(b)(3)(iv)(A), (B) and (D)) is used for check valve condition monitoring activities.

The fourth inspection interval at St. Lucie Unit 2 is based on the rules set forth in the 2003 Edition of ASME Boiler and Pressure Vessel Code, Section XI. The fourth interval is applicable from February 11, 2009 to February 10, 2018. The IST Program Plan includes a list of valves and pumps, which effectively defines the scope of the program.

The testing program for pumps meets the requirements of the ASME OM Code 2001 edition through 2003 addenda, Section ISTB “Inservice Testing Pumps in Light-Water Reactor Nuclear Power Plant.” Where these requirements have been determined to be impractical, specific

requests for relief were written. GL 89-04, Guidance on Developing Acceptable Inservice Testing Programs, has been used as guidance in developing the program.

The testing program for valves meets the requirements of the ASME OM Code 2001 edition through 2003 Addenda, Section ISTC, Inservice Testing of Valves in Light-Water Reactor Nuclear Power Plants; Mandatory Appendix I, Inservice Testing of Pressure Relief Devices in Light-Water Reactor Nuclear Power Plants, Mandatory Appendix II Check Valve Condition Monitoring Program, with the limitations imposed by 10 CFR 50.55a(b)(3)(iv)(A), (B) and (D). Where these requirements are determined impractical, specific requests have been written.

As discussed in the IST Program, the following categories of valves are subject to IST:

- Category A: Valves for which seat leakage is limited to a specific maximum amount in the closed position for fulfillment of their function,
- Category B: Valves for which seat leakage in the closed position is inconsequential for fulfillment of their function,
- Category C: Valves which are self-actuating in response to some system characteristic, such as pressure (relief valves) or flow direction (check valves),
- Category D: Valves which are actuated by an energy source capable of only one operation, such as rupture disks or explosive-actuated valves, and
- N/A: Valves which have been included into the IST Program as the result of either a regulatory or utility commitment.

Plant procedures provide the administrative requirements and responsibilities for implementing the IST Program for pumps and valves. An "IST Valve Reference Value Evaluation Sheet," providing stroke time information and test acceptance criteria, is prepared for each IST power-operated valve requiring a stroke time test. An "IST Pump Reference Value Evaluation Sheet," providing pump test information and test acceptance criteria, is prepared for each pump tested in the IST Program. Full stroke exercising of check valves to the open position is verified by passing the maximum required accident condition flow rate (i.e., the minimum required accident condition flow rate, for the accident scenario requiring the highest flow rate) through the valve. Valves which are containment isolation valves are tested in accordance with the Containment Leakage Rate Testing Program.

Information Notice (IN) 96-03, Main Steam Safety Valve (MSSV) Setpoint Variation as a Result of Thermal Effects, addresses the effects of the thermal environmental conditions on main steam safety valve setpoints. MSSVs are tested per the IST program under hot conditions prior to plant shutdown. Some of the valves are sent off-site during each outage for inspection and testing; the environmental conditions required for off-site valve testing are specified.

Motor Operated Valve Program

The effect of the EPU on MOVs was evaluated to determine any impact on the design basis criteria for each program component. MOV operators are required to withstand specific system conditions in order to ensure that their ability to perform a designated safety function is not degraded.

The purpose, scope, and technical requirements for compliance with the GL 89-10 MOV program are contained in the program description document. Also included are the requirements of associated program issues contained in GL 96-05 and GL 95-07. These documents recommend that licensees:

- Develop a comprehensive program to ensure safety-related MOVs will operate under design basis conditions (GL 89-10),
- Implement procedures for periodic verification of design basis capability of safety-related MOVs (GL 96-05), and
- Require that licensees take actions to ensure that safety-related power-operated gate valves that are susceptible to pressure locking or thermal binding are capable of performing their design basis functions (GL 95-07).

The MOV program valves have been screened for nuclear safety and risk significance and categorized by system criteria, safety and seismic classes, safeguards actuation source, and off-normal procedure requirements. Component specific calculations define the controlling parameters used in the system and functional design basis reviews under the scope of GL 89-10. The analyses include the following design attributes for both open and close power operated valve strokes as applicable:

- Maximum upstream and downstream line pressures,
- Maximum differential pressure,
- Fluid flow rate, and
- Fluid temperature.

For each program valve, a worst case scenario is determined from these factors and used as the basis for defining design basis conditions considered bounding. The resulting maximum expected differential pressure establishes the controlling input to determine valve thrust and torque criteria to be delivered by the operator. Feedback from operating experiences and laboratory testing provide input to refine estimated loads and adjust methodology for operator performance requirements. Institute of Nuclear Power Operations (INPO) and Electric Power Research Institute (EPRI) recommendations provide guidance for special cases where dynamic testing is not practical. FPL applies industry accepted methodology to determine suitable thrust loads based on applicable test data and adjusted valve factors. Design standards are developed to incorporate manufacturer information regarding limitations on application criteria for motor operators. Input from degraded voltage calculations, and structural weak link analyses are integrated in the operator design to provide additional enhancement to enable the valve to perform as required.

The MOV Program includes requirements to ensure the design basis capability of the safety-related MOVs is periodically verified by component testing and inspections performed on a regular basis. Trending analysis and monitoring are conducted when indications reveal declining performance. In unique cases involving industry wide problems with motor operated gate valves, modifications were performed to relieve internal restrictions impeding disc travel.

FPL has modified valves deemed susceptible to the effects of pressure locking or thermal binding based on NRC recommendations.

Air Operated Valve Program

The effect of the EPU on AOVs was evaluated to determine any impact on the design basis criteria for each program component. AOV operators are required to withstand specific system conditions in order to ensure that their ability to perform a designated safety function is not degraded.

The valves selected for the AOV Program were drawn from plant systems within the scope of the St. Lucie Maintenance Rule Program. This group represented AOVs which were safety related or risk significant, required to mitigate accidents or transients, included in emergency operating procedures, and needed to enable SSCs to perform their safety related function. The program is considered dynamic in nature to allow for enhancements and modifications based on experience gained from station testing, plant operating and industry experience, and current industry information.

FPL has established the following categories for categorizing AOVs based on a blended approach considering safety classification, safety significance, and requirement to change position in performance of a safety related function:

- Category 1: AOVs required to actively support a high safety significant function which are targeted as the highest priority for receiving design basis reviews, set point control, performance testing, and preventative maintenance.
- Category 2: AOVs required to actively support either a safety related or quality related function but are not deemed high safety significant. Maintaining controlled set points and preventative maintenance is still a priority while design basis reviews and performance testing is deemed discretionary.
- Category 3: AOVs having special considerations as determined by FPL to enable classification of valves that are not Category 1 or 2, but may have significance to the facility in terms of operation/generation impact, plant performance, unit efficiency, etc. AOV Program requirements are assigned at the discretion of a group consisting of the AOV component specialist, expert panel, and engineering manager to determine the support required to maintain their required level of performance.

System level design basis review calculations are used to determine the required operating load, actuator capability and allowable setpoints. The system level design basis review consists of both a system level review and a component level review to establish the worst case operating condition under which an AOV must operate and maintain position within the licensing basis of the plant. System conditions identified and documented in the system level review include the following:

- Maximum upstream and downstream line pressures,
- Maximum differential pressure,
- Fluid flow rate, and

- Fluid temperature.

2.2.4.2.2 Description of Analyses and Evaluations

The following topics related to safety-related valves and pumps are addressed:

1. Valve maximum stroke times,
2. Valve performance,
3. Accident condition flow rates for check valves,
4. Relief/safety valve set pressures,
5. Containment isolation valve leakage rate testing,
6. Pump performance,
7. Generic Letter 89-10,
8. Generic Letter 96-05,
9. Generic Letter 95-07,
10. AOV Program,
11. Lessons learned,
12. Impact of emergency diesel generator (EDG) frequency tolerance on MOV stroke times and IST Program test acceptance criteria, and
13. Impact of EDG voltage tolerance on MOV stroke times and the MOV Program.

The impact of the EPU on Topics 1 through 10 is evaluated. Topic 11 addresses lessons learned associated with the MOV and AOV Programs. Although not required for the EPU, Topics 12 and 13 address the impact of the TS change, submitted with this license amendment request, which requires that the EDGs operate at a steady state frequency of 60 ± 0.6 Hz ($\pm 1\%$) and a steady state voltage of 4160 ± 210 V ($\pm 5\%$).

Since the description and results of the analyses and evaluations are interrelated, these elements of the Technical Evaluation are addressed in Section 2.2.4.3, Results.

2.2.4.2.3 Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

As discussed above, the safety related valves and pumps are within the scope of License Renewal. Operation of the safety related valves and pumps under EPU conditions has been

evaluated in the system specific sections of this licensing report to determine if there any new aging effects requiring management or if any existing aging management programs are affected.

2.2.4.2.4 Results

1. Valve Maximum Stroke Times

- Per TS 3/4.7.1.5 Bases and UFSAR Table 6.2-53, the main steam line isolation valves (MSIVs) have a maximum closed stroke time of 5.6 seconds. This maximum closure time remains unchanged for the EPU.
- Per TS 3/4.7.1.6 Bases and UFSAR Table 6.2-53, the main feedwater isolation valves (MFIVs) have a maximum closed stroke time of 4.0 seconds. This maximum closure time remains unchanged for the EPU.
- Per TS 3/4.6.3, the isolation time of each power-operated or automatic containment isolation valve is required to be determined to be within its limit when tested pursuant to the IST Program. UFSAR Table 6.2-53 identifies the maximum closure times of valves required for containment isolation. The main function of containment isolation is to minimize the radiological offsite doses. The offsite dose analysis at EPU conditions does not require any changes in the current maximum closure times of valves required for containment isolation.
- On receipt of a containment isolation actuation signal or a high radiation signal, the following MOVs in the control room air conditioning system have a maximum closed stroke time of 11 seconds: two isolation valves in each outside air intake duct, two isolation valves in the toilet area air exhaust duct, and two isolation valves in the kitchen area exhaust duct. This maximum closure time remains unchanged for the EPU.

2. Valve Performance

a. Nuclear Steam Supply System Scope Systems

Valves in the following NSSS scope systems are evaluated:

- Reactor coolant system (RCS).
- Chemical and volume control system (CVCS), and
- Emergency core cooling system (ECCS) related systems:
 - Low pressure safety injection system (SIS)
 - High pressure SIS, and
 - Shutdown cooling system (SDCS).

No new valves are being added to the NSSS scope systems for the EPU. Current valve functions will remain.

Reactor Coolant System

The reactor vessel inlet temperature (T_{cold}) and outlet temperature (T_{hot}) will increase at EPU conditions, but will remain within the original valve and system design limits.

Since the pressurizer operating pressure will remain unchanged at EPU conditions, the power operated relief valve (PORV) block valves will not be affected. The main spray control valves will pass RCS coolant at the new T_{cold} , but within design temperature limits.

The RCS loop check valves that isolate the SIS lines from RCS pressures will be at the new T_{cold} , but within design conditions.

At EPU conditions the RCS valves will operate within their design temperature and pressure limits.

At EPU conditions, the RCS is predicted to have the same operating pressures and nominally the same reactor coolant pump (RCP) flows. Therefore, the EPU will not affect the current stroke time performance of IST Program valves in the RCS.

Chemical and Volume Control System

The CVCS is directly connected to the RCS at power with both the charging and letdown subsystems in operation. The control valves in the letdown subsystem will be exposed to the reactor coolant at the increased T_{cold} temperature, but are still within the original system design parameters. The volume control tank (VCT) operating conditions are expected to be unchanged. The subsystems provided for boron makeup and purification will remain at present operating conditions; these systems are unaffected by the core power change.

At EPU conditions the CVCS valves will operate within their design temperature and pressure limits.

No change in pump head performance for pumps in the CVCS is required due to the EPU (refer to Topic 6 below), and therefore the EPU will not affect the current stroke time performance of IST Program valves in this system.

ECCS Related Systems

The safety injection actuation signal (SIAS) will remain unchanged at EPU conditions so that the fluid conditions in the ECCS related systems at system start will not change and the water source from the refueling water tank (RWT) will be at current conditions.

The SDCS is isolated from the reactor during power operation. The SDCS initiation temperature will not be changed so the operation of the system will remain within the present operating envelope. The RCS hot leg suction isolation valves will be exposed to higher nominal temperatures, but within their original design temperatures. The valves isolating the SDCS from the low pressure SIS will not be exposed to any flow conditions outside their original design.

At EPU conditions, the valves in the ECCS related systems will operate within their design temperature and pressure limits.

No change in pump head performance for pumps in the low pressure SIS is required due to the EPU (refer to Topic 6 below). There are no significant changes to the minimum required accident condition flow rates for the low pressure SIS at EPU conditions. Therefore the EPU does not affect the current stroke time performance of IST program valves in this system.

No change in pump head performance for pumps in the high pressure SIS is required due to the EPU (refer to Topic 6 below). There are no significant changes to the minimum required accident

condition flow rates for the high pressure SIS at EPU conditions. Therefore the EPU does not affect the current stroke time performance of IST program valves in this system.

b. Balance of Plant (BOP) Scope Systems

Main Steam System

As addressed in LR [Section 2.5.5.1](#), the design conditions of all main steam system components have been determined to be greater than the EPU operating conditions.

As addressed in LR [Section 2.5.5.1](#), evaluations of loss of condenser vacuum and feedline break show that the MSSVs remain adequate for over-pressure protection.

The MSIVs are air-operated globe valves. As addressed under Topic 10 below, for the MSIV safety-related close stroke, the maximum expected differential pressure is increasing for EPU beyond the value used in the current valve/actuator capability analysis. However, the closing margin (percentage of actuator output greater than that required to stroke the valve) for the MSIVs remains adequate for the safety-related close stroke at EPU conditions. The impact of higher main steam flow rates through the MSIVs at EPU conditions was evaluated. The valve vendor confirmed that the valves are acceptable for the increased steam flow rates at EPU conditions, and that the valve closing time will not be affected by the EPU. Therefore, the EPU does not affect the stroke time performance of the MSIVs, and the valves will continue to close within the maximum closure time of 5.6 seconds.

As addressed in LR [Section 2.5.5.1](#), the performance of the atmospheric dump valves (ADV) is acceptable at EPU conditions with no plant changes.

As addressed under Topic 7 below, for main steam system MOVs in the IST Program (e.g., ADVs), the EPU does not affect the maximum differential pressures used for determining the MOV thrust and torque values at current conditions. The parameters affecting MOV stroke time (e.g., motor RPM, stroke length of valve and overall gear ratios of the actuators) are not affected by the EPU; therefore, the EPU does not affect the stroke time performance of MOVs in the main steam system.

The auxiliary feedwater (AFW) pump turbine/piping warm-up valves are solenoid-operated valves in the small diameter line which provides a small amount of warm-up steam to the AFW pump turbine and associated steam supply piping. The main steam system operating pressure at EPU conditions is less than one percent higher than the operating pressure at current conditions. Accordingly, the EPU will not affect the stroke time performance of these valves.

Main Feedwater System

As addressed in LR [Section 2.5.5.4](#), the design pressures and temperatures of feedwater components were evaluated at the EPU operating conditions; all components were found to be acceptable for EPU operation.

The MFIVs are hydraulically-operated gate valves. As addressed in LR [Section 2.5.5.4](#), the MFIVs have been evaluated for the increased flow rates, differential pressures, and temperatures at EPU conditions. These valves will continue to meet the existing required closure time (4.0 seconds) at the EPU conditions.

Containment isolation is accomplished by the provision of redundant safety-related MFIVs on the feedwater headers outside containment. The containment isolation requirements are unaffected by EPU and the current plant design features remain acceptable.

Auxiliary Feedwater (AFW) System

As addressed in LR [Section 2.5.4.5](#), the design temperatures of the suction, discharge, and recirculation piping in the AFW system remain adequate for EPU because the operating temperatures are bounded by the analyzed design temperatures.

As addressed under Topic 7 below, for the GL 89-10 MOVs in the AFW system, the EPU does not affect the maximum differential pressure used for determining the MOV stem thrust and actuator torque values at current conditions. The parameters affecting MOV stroke time (e.g. motor rpm, stroke length of the valve, overall gear ratio of the actuator) are not affected by the EPU. Therefore, the EPU does not affect the current stroke time performance of the GL 89-10 MOVs in this system.

The AFW pump discharge valves are solenoid-operated valves. The AFW system flow rates required for the limiting design basis events at EPU conditions remain unchanged from the flow rates required for these events at current conditions. The AFW pump head performance remains unchanged at EPU conditions (refer to Topic 6 below). Therefore the AFW system operating pressures at EPU conditions are bounded by current system operating pressures. Accordingly, the EPU does not affect the current stroke time performance of the AFW pump discharge valves.

Component Cooling Water (CCW) System

As addressed in LR [Section 2.5.4.3](#), the design temperatures of the CCW system valves bound the maximum CCW system normal operating temperatures at EPU operation. The maximum normal operating temperatures observed in the system occur during normal cooldown when the SCDS is placed into service. After implementation of EPU, the maximum CCW system temperatures will increase, but will continue to remain within allowable limits.

As addressed in LR [Section 2.5.4.3](#), the components cooled by the CCW system are capable of removing the required EPU heat loads with the existing CCW supply flow rates, with the exception of the control room air conditioning (CRAC) units. The CRAC units will be modified through the plant design change process prior to implementation of EPU to ensure they can operate with increased CCW supply temperatures. Since none of the cooled components require more cooling flow, the existing CCW and ICW flow rates through the CCW heat exchangers are not changed by the EPU. Any changes to the cooling water requirements to the CRAC units, if required, will be addressed as part of the plant design change process.

There is no change in the CCW pump head performance, and therefore is no change in CCW system operating pressures at EPU conditions. Accordingly, the EPU does not affect the current stroke time performance of IST Program valves in this system.

Evaluation of the stroke time performance of the reactor coolant pump cooling water supply and return valves is addressed under Containment Isolation Valves Communicating with the Containment Atmosphere, below.

Intake Cooling Water (ICW) System

As addressed in LR [Section 2.5.4.2](#), the ICW system design pressure and temperature do not change and the components within the system are acceptable for EPU operation.

Temperature control valves regulate the ICW flow through the CCW heat exchangers to maintain the CCW outlet temperature at its setpoint. The design flow rate for these valves bounds the flow rate at EPU conditions. The minimum required accident condition flow rates for the CCW system and the ICW system are not changing. Therefore, the temperature control valves that maintain the CCW temperature at its setpoint will continue to function properly at EPU conditions.

As addressed in LR [Section 2.5.4.3](#), the EPU does not affect the ICW system flow rates through the CCW heat exchangers, which are the safety-related components supplied by the system. The EPU does not affect the ICW pump head performance, and therefore does not affect the operating pressures in the safety-related portion of the system. Accordingly, the EPU does not affect the current stroke time performance of IST Program valves in the ICW system.

Containment Spray System

The containment spray system maximum operating temperature is based on the pump water temperature during the recirculation phase. At EPU conditions, the maximum containment sump water temperature remains less than the system piping / component design temperature.

The minimum required accident condition flow rates for the containment spray system are not affected by the EPU. The EPU does not affect pump head performance of the containment spray pumps. The EPU does not affect the containment spray system operating pressures during the post-LOCA injection mode. As discussed under Topic 10 below, for the containment sump outlet isolation valve safety-related open and close strokes, the maximum expected differential pressures are increasing for EPU beyond the values used in the current analysis. However, due to margin in the valve required torque (open/close), the EPU does not affect the minimum torque required to operate these valves.

Based on the above evaluation, the EPU does not affect the current stroke time performance of IST Program valves in this system.

Evaluation of the stroke time performance of the reactor cavity sump pump discharge valve is addressed under Containment Isolation Valves Communicating with the Containment Atmosphere, below.

Steam Generator Blowdown System (SGBS)

As addressed in LR [Section 2.1.10](#), the maximum operating temperature in the secondary side of the steam generators is unchanged for EPU operation and the maximum operating pressure increases slightly (7.4 psi). The maximum blowdown flow rate does not change for EPU.

As discussed under Topic 10 below, for the SGBS containment isolation valve safety-related close stroke, the maximum expected differential pressure is increasing for EPU beyond the value used in the current valve/actuator capability analysis. However, the closing margin for the SGBS containment isolation valves remains adequate for the safety-related close stroke at EPU conditions.

Based on the above evaluation, the EPU does not affect the current stroke time performance of IST Program valves in this system.

Control Room Ventilation System

There are no changes to the control room ventilation system design air distribution, airflow, or positive space pressurization resulting from the EPU. Therefore, the EPU does not affect the current stroke time performance of IST program valves to close within the required closure time of 11 seconds: four outside air intake isolation valves, two control room toilet area exhaust isolation valves, and two control room kitchen exhaust isolation valves.

Shield Building Ventilation System

As addressed under Topic 7 below, the EPU does not affect the maximum differential pressures determined in the system and functional design basis review calculation for the shield building ventilation system motor-operated isolation valves. The parameters affecting MOV stroke time (e.g. motor rpm, stroke length of the valve, overall gear ratio of the actuator) are not affected by the EPU. Therefore, the EPU does not affect the current stroke time performance of these MOVs.

There are no changes in the air flow rates or operating pressures in the outside air makeup lines to the shield building ventilation system filter subsystems, and therefore the EPU does not affect the current stroke time performance of the MOVs in these lines. The MOV in the cross-connect line downstream of the filter subsystems will be exposed to the increased EPU pressure from the shield building; however, the valve is normally open to allow cooling air to be drawn through an inoperative filter train.

Continuous Containment Purge/Hydrogen Purge System

As addressed in LR **Section 2.7.7**, there are no EPU changes or planned modifications to the continuous containment purge/hydrogen purge system, components, air flow rates, isolation signals or associated controls that would impact the system's ability to reduce the concentration of airborne radionuclides in the containment during normal operation. As addressed under Topic 10 below, the EPU does not affect the differential pressure used to determine the required torque values for closing the air-operated containment isolation valves in this system. Therefore, the EPU will not affect the current stroke time performance of the continuous containment purge/hydrogen purge system containment isolation valves.

Fuel Handling Building Ventilation System

There are no changes to the fuel handling building ventilation system design air distribution, air flow rates, or controls as a result of the EPU. Therefore, the EPU does not affect the current stroke time performance of the MOVs in the fuel pool exhaust line to the shield building ventilation system.

c. Containment Isolation Valves Communicating with the Containment Atmosphere

UFSAR Tables 6.2-52 and 6.2-53 identify lines which are open directly to containment atmosphere and connect to non-seismic Class I piping outside containment, or are connected to non-seismic Class 1 piping on both sides of the containment (Penetration Isolation Classes A1/A2). The following air operated/solenoid operated valves provide containment isolation for these lines. For certain scenarios (e.g., pipe break) these valves

can be exposed to containment pressure, resulting in the potential for increased flow through the valves and consequent impact on valve stroke time. As addressed in Topic 5 below, the peak calculated containment internal pressure for the design basis loss-of-coolant accident (LOCA), P_a , increases from 41.8 psig at current conditions to 43.48 psig at EPU conditions. Impact of the increase in peak containment pressure on the current stroke time performance of these valves is addressed below.

- Containment purge supply and exhaust valves (containment purge system)

Currently, during Operational Modes 1 through 4, the 48 inch containment purge supply and exhaust valves are sealed closed. For the scenario in which the valves are required to remain closed to provide containment isolation, the evaluation of maximum expected differential pressure (MEDP) in the valve/actuator capability analysis uses the containment design pressure, 44 psig. The valve/actuator capability analysis states that, although the valves are subject to an unseating scenario of 44 psid once the valves are closed, this scenario is not evaluated because, due to the valve design, no imbalance torque is generated causing an unseating concern. The EPU does not affect containment design pressure and does not affect the valve actuator/capability analysis. Therefore, the increase in peak containment pressure due to the EPU does not affect the capability of these valves to remain closed to provide containment isolation.

- Primary makeup water containment isolation valve (primary makeup water system)

The required thrust calculations for this valve use an upstream pressure of 125 psig and a differential pressure of 125 psid. Therefore, the increase in peak containment pressure due to the EPU does not affect the current stroke time performance of this valve.

- Service air containment isolation valve (service air system)

The operator for this valve is sized to operate against a differential pressure of 150 psid. Therefore, the increase in peak containment pressure due to the EPU does not affect the current stroke time performance of this valve.

- Instrument air containment isolation valve (instrument air system)

The required thrust calculations for this valve use an upstream pressure of 100 psig and a differential pressure of 100 psid. Therefore, the increase in peak containment pressure due to the EPU does not affect the current stroke time performance of this valve.

- Nitrogen supply to containment valve (waste management system)

The required thrust calculations for this valve use an upstream pressure of 700 psig and a differential pressure of 700 psid. Therefore, the increase in peak containment pressure due to the EPU does not affect the current stroke time performance of this valve.

- RCP cooling water supply and return valves (CCW system)

For the scenario consisting of a postulated LOCA with a subsequent CCW system pipe break inside containment, these valves are required to close to provide containment isolation. The MEDP for this scenario, 44 psi, is based on the containment design pressure, 44 psig. However, the MEDP used in the actuator capability calculation,

131.9 psi, is based on a scenario in which the CCW pumps are operating at shutoff head and an event occurs requiring containment isolation. Since the EPU does not affect the shutoff head of the CCW pumps and the current MEDP associated with this scenario remains bounding at EPU conditions, the EPU does not affect the current stroke time performance of these valves.

- Containment vent header valves (waste management system)

The required thrust calculations for these valves use an upstream pressure of 80 psig and a differential pressure of 80 psid. Therefore, the increase in peak containment pressure due to the EPU does not affect the current stroke time performance of these valves.

- Reactor cavity sump pump discharge valves (containment spray system)

For the scenario in which the valves are required to close to provide containment isolation, the evaluation of MEDP uses the containment design pressure, 44 psig. The valve/actuator capability analysis for these valves states that flow rate is not required for evaluation of the valve actuator. The EPU does not affect containment design pressure and does not affect the valve actuator capability analysis. Therefore, the increase in peak containment pressure due to the EPU does not affect the current stroke time performance of these valves.

- Reactor drain tank pump suction valves (waste management system)

For the scenario in which the valves are required to close to provide containment isolation, the evaluation of differential pressure in the valve/actuator capability analysis uses the containment design pressure, 44 psig, for both the upstream and downstream pressures. The valve/actuator capability analysis for these valves states that the worst case differential pressure for these valves is 0 psi with a line pressure of 44 psi, and that flow rate is not required for evaluation of the valve actuator. The EPU does not affect containment design pressure and does not affect the valve/actuator capability analysis. Therefore, the increase in peak containment pressure due to the EPU does not affect the current stroke time performance of these valves.

- Hydrogen sampling sample inlet and outlet valves (containment hydrogen sampling system)

These valves are specified to operate within the containment, with a pressure range of 0 to 44 psig, and a maximum unbalanced pressure across the valve seat of 44 psi. Accordingly, the EPU does not affect the current stroke time performance of these solenoid valves.

- Containment atmosphere radiation monitoring valves (radiation monitoring system)

The required thrust calculations for these valves use an upstream pressure of 44/210 psig and a differential pressure of 44/210 psid. Therefore, the increase in peak containment pressure due to the EPU does not affect the current stroke time performance of these valves.

- Containment vacuum valves (containment vacuum relief system)

For the scenario in which these valves are required to remain closed to provide containment isolation, the evaluation of MEDP uses the containment design pressure, 44 psig. The valve/actuator capability analysis for these valves states that a check valve in the line would limit reverse flow (i.e., flow from the containment) to approximately zero. The valve/actuator capability analysis states that, although the valves are subject to an unseating scenario of 44 psid once the valves are closed, this scenario is not evaluated because, due to the valve design, no imbalance torque is generated causing an unseating concern. Therefore, the increase in peak containment pressure due to the EPU does not affect the capability of these valves to remain closed to provide containment isolation.

- Continuous containment purge/hydrogen purge inlet and exhaust valves (continuous containment purge/hydrogen purge system)

As addressed under Topic 2.b above, the EPU does not affect the stroke time performance of the continuous containment purge/hydrogen purge system containment isolation valves.

3. Accident Condition Flow Rates for Check Valves

As indicated in LR [Section 2.2.4.2.1](#) above, full stroke time exercising of check valves to the open position is verified by passing the maximum required accident condition flow rate (i.e., the minimum required accident condition flow rate, for the accident scenario requiring the highest flow rate) through the valve.

Check valves tested at the minimum required accident condition flow rates include check valves in the following systems:

- Chemical and volume control system,
- High pressure safety injection system,
- Low pressure safety injection system,
- Containment spray system,
- Auxiliary feedwater system,
- Component cooling water system, and
- Intake cooling water system.

For the high pressure SIS and the low pressure SIS, there are no significant changes in the minimum required accident condition flow rates due to the EPU. For the other systems/portions of systems identified above, the EPU does not affect the minimum required accident condition flow rates.

4. Relief/Safety Valve Set Pressures

There are no changes in the setpoints of relief valves in the following systems due to EPU:

- Reactor coolant system,
- Chemical and volume control system,

- High pressure safety injection system,
- Low Pressure Safety Injection System, and
- Shutdown cooling system.

The current MSSV nominal setpoints, 1000 psia and 1040 psia, remain unchanged for the EPU. However, the current MSSV as found setpoint tolerances, "+1/- 3%", are being changed for EPU as follows:

- For MSSVs with a nominal setpoint of 1000 psia, the as-found setpoint tolerance is being changed to $\pm 3\%$,
- For MSSVs with a nominal setpoint of 1040 psia, the as-found setpoint tolerance is being changed to $+2/-3\%$.

The EPU does not affect the setpoints of the relief valves in the CCW system.

The EPU does not affect the setpoints of the relief valves in the EDG starting air system.

5. Containment Isolation Valve Leakage Rate Testing

As indicated in LR [Section 2.2.4.1](#) above, valves which are containment isolation valves are tested in accordance with the Containment Leakage Rate Testing Program (Appendix J Program). The minimum test pressure used in the tests which measure containment isolation valve leakage rates (Type C tests) is the peak calculated containment internal pressure for the design basis LOCA, P_a . Per TS 6.8.4.h, the value of P_a at current conditions is 41.8 psig. As addressed in LR [Section 2.6.1](#), the value of P_a at EPU conditions is 43.48 psig. Since the value of P_a at EPU conditions exceeds the value at current conditions, TS 6.8.4.h and the applicable Appendix J Program documents are required to be revised to incorporate the value of P_a at EPU conditions.

6. Pump Performance

There is no change in pump head performance for the following pumps at EPU conditions, and therefore, the flow rates used for testing these IST Program pumps are not affected by the EPU:

- Boric acid makeup pumps,
- Charging pumps,
- High pressure safety injection pumps,
- Low pressure safety injection pumps,
- Auxiliary feedwater pumps,
- Component cooling water pumps,
- Intake cooling water pumps, and
- Containment spray pumps.

The EDGs continue to operate within their design ratings at EPU conditions. Therefore, there is no impact on the performance of the following pumps, and the flow rates used for testing these IST Program pumps are not affected by the EPU:

- Diesel fuel oil transfer pumps,
- Diesel fuel electric priming pumps,
- Diesel soak back lube oil AC pumps,
- Diesel soak back lube oil DC pumps,
- Diesel turbo charger lube oil AC pumps, and
- Diesel turbo charger lube oil DC pumps.

There is no change in the pump head performance of the hydrazine pumps in the containment spray system at EPU conditions, and therefore the flow rates used for testing these pumps are not affected by the EPU.

The impact of EDG frequency tolerance on IST Program pump test acceptance criteria is addressed under Topic 12.

7. Generic Letter 89-10

a. Balance of Plant (BOP) Scope MOVs

The system and functional design basis review calculations for the GL 89-10 MOV Program valves in the following balance-of-plant systems were reviewed:

- Main Steam System

LR **Table 2.2.4-1** summarizes the existing MEDP data for the main steam system valves potentially affected by the EPU. Main steam system parameters used for evaluating operator capability are not affected by EPU. As discussed in the table, the current MEDPs for the main steam system MOVs are not exceeded by EPU because EPU source pressures are bounded by current conditions and EPU differential pressures are therefore also bounded.

- Auxiliary Feedwater System

LR **Table 2.2.4-1** summarizes the existing MEDP data for the AFW system valves potentially affected by the EPU. AFW system parameters used for evaluating operator capability are not affected by EPU. As discussed in the table, the current MEDPs for the AFW system MOVs are not exceeded by EPU because EPU source pressures are bounded by current conditions and EPU differential pressures are therefore also bounded.

- Containment Spray System

LR **Table 2.2.4-1** summarizes the existing MEDP data for the containment sump outlet isolation valves in the containment spray system. Containment parameters used for evaluating operator capability are affected by the EPU. As discussed in the table, for the isolation valve safety-related open and close strokes, the MEDPs are increasing for EPU

beyond the values used in the current analysis. However, due to margin in the valve required torque (open/close), the EPU does not affect the minimum torque required to operate these valves.

Existing parameters used in determining the MEDP values for the refueling water storage tank outlet isolation valves in the containment spray system are not affected by the EPU.

- Component Cooling Water System

LR Table 2.2.4-1 summarizes the existing MEDP data for the CCW system valves potentially affected by the EPU. CCW system parameters used for evaluating operator capability are not affected by the EPU. As discussed in the table, the current MEDPs for the CCW system MOVs are not exceeded by EPU because EPU source pressures are bounded by current conditions and EPU differential pressures are therefore also bounded.

- Intake Cooling Water System

LR Table 2.2.4-1 summarizes the existing MEDP data for the ICW to non safety-related piping isolation valves in the ICW system.

Existing parameters used in determining the MEDP values for the GL 89-10 MOVs in the ICW system are not affected by the EPU.

- Shield Building Ventilation System

LR Table 2.2.4-1 summarizes the existing MEDP data for the shield building ventilation system GL 89-10 MOVs potentially affected by the EPU. As discussed in the table, although the bounding upstream pressure for the open stroke increases for EPU, due to margin in the current open stroke MEDP, the current open stroke MEDP remains bounding at EPU conditions.

The results of the evaluations show that the EPU does not affect the maximum differential pressures/line pressures determined in the system and functional design basis review calculations for the GL 89-10 MOVs in the BOP scope systems, or that the values for these parameters at current conditions bound the values at EPU conditions. Therefore, these parameters do not affect the calculations which determine MOV thrust and torque values for these MOVs.

b. Nuclear Steam Supply System Scope MOVs

The impact of the EPU on the following systems was evaluated to determine if any of the MOVs in these systems were affected:

- Reactor coolant system,
- Chemical and volume control system, and
- Emergency core cooling system (ECCS)-related systems:
 - Low pressure safety injection system,
 - High pressure safety injection system, and
 - Shutdown cooling system.

The results of the evaluation determined that, for those few valves directly attached to the RCS which will see changes to their nominal operating conditions, the valves will not be exposed to temperature, pressure or flow conditions outside their original design specifications. Other than those valves directly attached to the RCS, the remaining MOVs are sufficiently isolated from RCS conditions to preclude any necessity for consideration of any additional MOV program evaluations.

c. Impact of EPU on MOV Motor Capability Torque Values

Design basis performance criteria require that the MOV operator be capable of delivering the required torque under the combined effects of high ambient temperature and degraded voltage conditions. Degraded voltages are used to determine the terminal voltage available to AC and DC powered MOVs. In addition to system line and differential pressures, the minimum available bus voltage inputs were verified by performing electrical load flow/short circuit analysis for the AC distribution system under EPU conditions. The results were determined to not impact the minimum voltage inputs used for the existing GL 89-10 MOV electrical and mechanical calculations to establish operator requirements. As indicated in LR [Section 2.3.3](#), evaluation demonstrates that there are no adverse voltage effects on the safety-related 480V load center buses protected by degraded voltage relays. As addressed in LR [Section 2.3.4](#), the 125V 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 FPL licensing basis with respect to GDC-17. Therefore, the EPU will not impact the motor terminal voltages used for the GL 89-10 Program valves.

Similarly, the effects of any changes to ambient temperatures due to EPU on degraded voltage or operator capability were reviewed; it was concluded that existing limits remain bounding and no impact to MOV performance will occur.

The impact of EDG voltage tolerance on minimum motor terminal voltage values used in determining MOV motor torque values under degraded voltage conditions is addressed under Topic 13.

8. Generic Letter 96-05

No MOVs are required to be added to the MOV Program as a result of the EPU.

As discussed under Topic 7 above, the EPU does not affect the bounding differential pressures determined in the system and functional design basis review calculations.

The results of an updated probabilistic risk assessment (PRA) will be used in the determination of any changes to the risk category of MOVs in the program. As addressed in LR [Section 2.13](#), the PRA model has been evaluated for the EPU by FPL to maintain consistency with plant configuration, latest performance history, and advances in programmatic technology. The risk rankings of the MOVs in the GL 96-05 Program will be updated as required based on the results of the updated PRA model, and any changes in the periodic verification requirements will be made.

9. Generic Letter 95-07

FPL has performed modifications on SDCS gate valves to address concerns expressed in GL 95-07. The SDCS hot leg suction valves have a 3/16 inch hole drilled on the RCS side of the disc to eliminate the potential for pressure locking. In the Safety Evaluation pertaining to St. Lucie Unit 2 compliance with GL 95-07 dated July 16, 1991, the NRC found this modification to be acceptable. Similarly, as identified by GL 95-07, the possibility of thermal binding was investigated and no instances were identified where thermal expansion of a valve body or associated piping resulted in forces being exerted on the valve disc which would restrict movement. Initiating factors contributing to these events have been attributed to gate valve design (dual or flexible discs) or piping configurations and not any system process condition.

Based on the above discussion, the EPU does not introduce any increased challenge for pressure locking or thermal binding and does not impact any previous responses or conclusions relative to GL 95-07 or the MOV Program.

10. AOV Program

a. BOP Scope AOVs

The system level design basis review calculations for the AOVs in the following BOP systems were reviewed:

- Main Steam System

LR Table 2.2.4-2 summarizes the existing MEDP data for the main steam system valves potentially affected by the EPU (MSIVs). Main steam system parameters used for evaluating operator capability are affected by the EPU. As discussed in the table, for the MSIV safety-related close stroke, the MEDP is increasing for EPU beyond the value used in the current analysis. However, the closing margin (percentage of actuator output greater than that required to stroke the valve) remains adequate for the safety-related close stroke at EPU conditions.

- Steam Generator Blowdown System

LR Table 2.2.4-2 summarizes the existing MEDP data for the SGBS valves potentially affected by the EPU (containment isolation valves). The parameters used for evaluating operator capability are affected by the EPU. As discussed in the table, for the SGBS containment isolation valve safety-related close stroke, the MEDP is increasing for EPU beyond the value used in the current analysis. However, the closing margin remains adequate for the safety-related close stroke at EPU conditions.

- Containment Purge System

LR Table 2.2.4-2 summarizes the existing MEDP data for the containment purge system valves potentially affected by the EPU. The parameters used for evaluating operator capability are not affected by the EPU. As discussed in the table, the current MEDP values for the containment purge system AOVs are not exceeded by EPU.

- Continuous Containment Purge/Hydrogen Purge System

LR Table 2.2.4-2 summarizes the existing MEDP data for the continuous containment purge/hydrogen purge system valves potentially affected by the EPU. The parameters used for evaluating operator capability are not affected by the EPU. As discussed in the table, the current MEDP values for the continuous containment purge/hydrogen purge system AOVs are not exceeded by EPU.

- Containment Spray System

LR Table 2.2.4-2 summarizes the existing MEDP data for the containment spray system valves potentially affected by the EPU. The parameters used for evaluating operator capability are not affected by the EPU. As discussed in the table, the current MEDP values for the containment spray system AOVs are not exceeded by EPU.

The system level design basis review calculations for AOVs in the following BOP systems were also reviewed.

- Component Cooling Water System

Parameters used for evaluating operator capability of CCW system AOVs are not affected by the EPU.

- Intake Cooling Water System

Parameters used for evaluating operator capability of ICW system AOVs are not affected by the EPU.

- Waste Management System

As addressed in Topic 2.c, the EPU does not affect the valve/actuator capability analysis of the reactor drain tank pump suction valves in the radioactive liquid waste system.

- Containment Vacuum Relief System

As addressed in Topic 2.c, the EPU does not affect the valve/actuator capability analysis of the containment vacuum valves in the containment vacuum relief system.

With the exception of the MSIVs and the SGBS containment isolation valves, the results of the BOP system evaluations show that the EPU does not affect the maximum differential pressures/line pressures determined in the system and functional design basis review calculations for the Category 1 AOVs discussed above. The values for these parameters at current conditions bound the values at EPU conditions. Therefore, these parameters do not affect the current calculations which determine AOV thrust and torque values.

For the MSIVs and the SGBS containment isolation valves, although the current maximum differential pressure is exceeded for the safety-related close stroke at EPU conditions, the closing margin is acceptable for the safety-related close stroke of these valves.

b. Nuclear Steam Supply System Scope AOVs

The impact of the EPU on the following systems was evaluated to determine if any of the AOVs in these systems were affected:

- Reactor coolant system,
- Chemical and volume control system, and
- ECCS-related systems:
 - Low pressure safety injection system,
 - High pressure safety injection system, and
 - Shutdown cooling system.

The results of the evaluation determined that, for those few valves directly attached to the RCS which will see changes to their nominal operating conditions, the valves will not be exposed to temperature, pressure, or flow conditions outside their original design specifications. Other than those valves directly attached to the RCS, the remaining AOVs are sufficiently isolated from RCS conditions to preclude any necessity for consideration of any additional AOV Program evaluations.

c. Risk Category of AOVs

The results of an updated probabilistic risk assessment (PRA) will be used in the determination of any changes to the risk category of AOVs in the program. As addressed in LR Section 2.13, the PRA model has been evaluated for the EPU by FPL to maintain consistency with plant configuration, latest performance history, and advances in programmatic technology. The results of the updated PRA model will indicate if any changes in the periodic verification requirements are needed as a result of the EPU.

11. Lessons Learned

a. MOV Program

The MOV Program is based on industry initiatives and vendor participation dedicated to maintaining performance standards and reliability of power operated valves. User feedback and active participation in technical forums enable proper surveillance to determine the monitoring and trending of valve performance. Condition reports are utilized to prioritize repairs based on safety classification significance and impact to valve/system operability. INPO OE/OPEX Forum is monitored to enable early detection of industry experiences.

b. AOV Program

FPL relies on industry feedback and operating experiences to monitor AOV performance and reliability issues to enhance the AOV program. Personnel responsible for AOV program implementation participate and interact with industry groups dedicated to AOV performance, including EPRI, INPO, the joint owners group, and NSSS vendors.

12. Impact of Emergency Diesel Generator Frequency Tolerance on MOV Stroke Times and IST Program Pump Test Acceptance Criteria

Although not required for the EPU, a TS change has been submitted with this license amendment request to require that the EDGs operate at a steady state frequency of 60 ± 0.6 Hz ($\pm 1\%$).

For MOVs with AC motors powered by the EDGs, the frequency tolerance will have a minor affect on MOV stroke times (i.e., maximum change in stroke time of $\pm 1\%$). For MOVs having a specified maximum stroke time identified under Topic 1 and for motor-operated containment isolation valves having a specified maximum stroke time, it has been determined that the current/reference stroke times, when increased by one percent, will not exceed the specified maximum stroke times of the valves. For MOVs that have a specified maximum stroke time, IST Program MOV stroke time test acceptance criteria values will be updated during the EPU Implementation Phase.

The change in frequency tolerance potentially impacts the IST program pump test acceptance criteria (i.e., minimum acceptable pump head at the flow rate used for testing). IST Program pump test acceptance criteria values will be updated during the EPU implementation phase. No modifications to IST program pumps due to EDG over/under frequency conditions are required.

13. Impact of Emergency Diesel Generator Voltage Tolerance on MOV Stroke Times and the MOV Program

Although not required for the EPU, a TS change has been submitted with this license amendment request to require that the EDGs operate at a steady state voltage of 4160 ± 210 V ($\pm 5\%$).

For MOVs with AC motors powered by the EDGs, the voltage tolerance of $\pm 5\%$ 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 $\pm 5\%$ will not affect the minimum motor terminal voltage values used in determining MOV motor torque values under degraded voltage conditions.

2.2.4.3 Conclusion

FPL has reviewed the assessment of the functional performance of safety-related valves and pumps and concludes that the review has adequately addressed the effects of the proposed EPU on safety-related pumps and valves. FPL further concludes that the review 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, FPL concludes that the review has demonstrated that safety-related valves and pumps will continue to meet their current licensing basis with respect to 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, FPL finds the proposed EPU acceptable with respect to safety-related valves and pumps.

**Table 2.2.4-1
BOP MOV GL 89-10 Program Impact To Actuators at EPU Conditions**

System	GL 89-10 Program Valves	Description	Maximum Expected Differential Pressure (MEDP)- Opening (O) - Closing (C)		EPU Impact
			Current Conditions	EPU Conditions	
Main Steam	2-MV-08-1A/1B	MSIV equalizer	985 psid (O), 1015 psid (C) <u>Note:</u> Bounding upstream pressure (O) is based on lowest MSSV nominal setpoint (985 psig). Bounding upstream pressure (C) is based on lowest MSSV nominal setpoint plus MSSV accumulation.	Current MEDPs for Main Steam System MOVs not exceeded by EPU because EPU source pressures are bounded by current conditions and EPU differential pressures are therefore also bounded. Notes: 1. EPU does not affect lowest MSSV nominal setpoint or MSSV accumulation.	None
	2-MV-08-3	AFW pump steam throttle / trip	1015 psid (O), 0 psid (C) <u>Note:</u> Valve opening MEDP is conservatively estimated to be the same as the opening MEDP of valves 2-MV-08-12, 13.		
Main Steam (continued)	2-MV-08-12/13	AFW pump turbine steam supply	1015 psid (O), 1015 psid (C) <u>Note:</u> Bounding upstream pressure (O/C) is based on lowest MSSV nominal setpoint (985 psig) plus maximum MSSV accumulation.	EPU does not affect plant procedural requirement to control RCS temperature between 525°F and 535°F, following a plant trip, using the ADVs for applicable events.	None
	2-MV-08-14, 15, 16, 17	ADV block valves	832 psid (O), 832 psid (C) <u>Note:</u> Bounding upstream pressure is SG pressure at RCS temperature of 525°F (lower end of RCS temperature control band of 535°F to 525°F when controlling RCS temperature using ADVs following a plant trip).		
	2-MV-08-18A/B, 19A/B	ADVs	1015 psid (O), 1015 psid (C) <u>Note:</u> Bounding upstream pressure (O/C) is based on lowest MSSV nominal setpoint (985 psig) plus maximum MSSV accumulation.		

Table 2.2.4-1 (Continued)
BOP MOV GL 89-10 Program Impact To Actuators at EPU Conditions

System	GL 89-10 Program Valves	Description	Maximum Expected Differential Pressure (MEDP)- Opening (O) - Closing (C)		EPU Impact
			Current Conditions	EPU Conditions	
Auxiliary Feedwater (AFW)	2-MV-09- 9/10	AFW pump discharge isolation valves to SGs 2A/2B	1374 psid (O), 1374 psid (C) <u>Note:</u> Bounding upstream pressure (O/C) is based on motor-driven AFW pump maximum discharge pressure.	Current MEDP for AFW System MOVs not exceeded by EPU because EPU source pressures are bounded by current conditions and EPU differential pressures are therefore also bounded. <u>Notes:</u> 1. Motor-driven AFW pump maximum discharge pressure not affected by the EPU. 2. Steam-driven AFW pump maximum discharge pressure not affected by the EPU.	None
	2-MV-09-11/12		1367 psid(O), 1367 psid (C) <u>Note:</u> Bounding upstream pressure (O/C) is based on steam-driven AFW pump maximum discharge pressure.		
Containment Spray (CS)	2-MV-07-2A/2B	Containment sump outlet isolation	27.0 psid (O), 21.8 psid (C) <u>Note:</u> Bounding upstream pressure (O/C) is based on maximum containment pressure at Recirculation Actuation Signal (RAS) for the LOCA double ended discharge leg slot (DEDLS) break case.	For safety-related open and close strokes, current MEDPs are exceeded by EPU MEDPs. <u>Note:</u> Containment pressure at RAS increases from 19.7 psig (current conditions) to 23.8 psig (EPU conditions).	Due to margin in the valve required torque (open/close), the EPU does not affect the minimum torque required to operate these valves.

Table 2.2.4-1 (Continued)
BOP MOV GL 89-10 Program Impact To Actuators at EPU Conditions

System	GL 89-10 Program Valves	Description	Maximum Expected Differential Pressure (MEDP)- Opening (O) - Closing (C)		EPU Impact
			Current Conditions	EPU Conditions	
Component Cooling Water (CCW)	2-MV-14-17/18/19/20	CCW to fuel pool heat exchangers	82.25 psid (O) (C) <u>Note:</u> Bounding upstream pressure (O) is based on CCW pump head at fuel pool heat exchanger service actuation during normal operation. Bounding upstream pressure (C) is based on CCW pump head when removing the fuel pool heat exchangers from service during normal operation or isolating a moderate energy line break in the CCW system.	Current MEDP for CCW System MOVs not exceeded by EPU. <u>Notes:</u> 1. The EPU does not affect the CCW pump head performance or CCW system flow rates during normal operation, including plant cooldown. 2. As addressed in LR Section 2.5.1.3, the EPU does not affect the current analysis of flooding due to a CCW pipe crack in the fuel pool heat exchanger room.	None
Intake Cooling Water (ICW)	2-MV-21-2/3	ICW to non-safety related piping isolation valves	88.04 psid (O), 62.5 psid (C) <u>Note:</u> Bounding upstream pressure (O) is based on ICW pump shutoff head. Bounding upstream pressure (C) is based on ICW pump discharge pressure under minimum ICW flow conditions (CCW heat exchanger temperature control valves in the throttled closed position).	Current MEDP for ICW System MOVs not exceeded by EPU. <u>Notes:</u> 1. The EPU does not affect ICW pump head performance, including shutoff head. 2. The EPU does not affect the throttled close position of the CCW heat exchanger temperature control valves.	None

Table 2.2.4-1 (Continued)
BOP MOV GL 89-10 Program Impact To Actuators at EPU Conditions

System	GL 89-10 Program Valves	Description	Maximum Expected Differential Pressure (MEDP)- Opening (O) - Closing (C)		EPU Impact
			Current Conditions	EPU Conditions	
Shield Building Ventilation	2-FCV-25-32/33	Isolation valves	1.0 psid (O), 0.8 psid (C) <u>Note:</u> Bounding upstream pressure (O) is maximum shield building annulus pressure following a LOCA at current conditions (3.6 inches wg). Bounding downstream pressure (O/C) is shield building ventilation fan suction pressure with the fan inlet valves closed.	<u>Notes:</u> 1. Bounding upstream pressure (O) is maximum shield building annulus pressure following a LOCA at EPU conditions (4.9 inches wg). 2. EPU does not affect the shield building ventilation system fans.	<u>Opening</u> Although the bounding upstream pressure (O) increases for EPU, due to margin in the current MEDP (O), the current MEDP (O) remains bounding at EPU conditions. <u>Closing</u> None

Table 2.2.4-2
BOP AOV Program Impact To Actuators at EPU Conditions

System	AOV Program Valves (Cat. 1)	Description	Maximum Expected Differential Pressure (MEDP)- Opening (O) - Closing (C)		EPU Impact
			Current Conditions	EPU Conditions	
Main Steam	2-HCV-08-1A/B	Main steam isolation	0 psid (O), 995.3 psid (C) (reverse flow) <u>Note:</u> Bounding upstream pressure for the safety-related close stroke (reverse flow) is based on lowest MSSV nominal setpoint plus 1% tolerance.	For safety-related close stroke, current MEDP is exceeded by EPU MEDP. <u>Note:</u> Bounding upstream pressure for the safety-related close stroke (reverse flow) is based on lowest MSSV nominal setpoint plus 3% tolerance.	Closing margin (percentage of actuator output greater than that required to stroke the valve) remains adequate for the safety-related close stroke at EPU conditions.
SG Blowdown	2-FCV-23-3/5	Containment isolation	1061.3 psid (O) (C) <u>Note:</u> Bounding upstream pressure for the safety-related close stroke is based on highest MSSV nominal setpoint plus 1% tolerance.	For safety-related close stroke, current MEDP is exceeded by EPU MEDP. <u>Note:</u> Bounding upstream pressure for the safety-related close stroke is based on highest MSSV nominal setpoint plus 2% tolerance.	Closing margin remains adequate for the safety-related close stroke at EPU conditions.

Table 2.2.4-2 (Continued)
BOP AOV Program Impact To Actuators at EPU Conditions

System	AOV Program Valves (Cat. 1)	Description	Maximum Expected Differential Pressure (MEDP)- Opening (O) - Closing (C)		EPU Impact
			Current Conditions	EPU Conditions	
HVAC	2-FCV-25-1 thru 6	Containment purge supply / exhaust	0.4 psid (O), 0.8 psid (C) <u>Note:</u> Bounding upstream pressure (O/C) is based on the maximum normal operating containment pressure allowed by the Technical Specifications for normal operation. Bounding downstream pressure (C) is based on the maximum vacuum the containment purge fans can achieve.	Current MEDP not exceeded by EPU. <u>Notes:</u> 3. EPU does not affect the maximum normal operating containment pressure allowed by the Technical Specifications for normal operation. 4. The EPU does not affect the containment purge fans.	None
	2-FCV-25-20/21/26/36	Continuous containment purge / hydrogen purge	45.6 psid (C) <u>Note:</u> Bounding upstream pressure (C) is containment design pressure. Bounding downstream pressure (C) is maximum vacuum the continuous containment purge /hydrogen purge fan can achieve.	Current MEDP not exceeded by EPU. <u>Notes:</u> 1. EPU does not affect containment design pressure. 2. The EPU does not affect the continuous containment purge / hydrogen purge fan.	None

Table 2.2.4-2 (Continued)
BOP AOV Program Impact To Actuators at EPU Conditions

System	AOV Program Valves (Cat. 1)	Description	Maximum Expected Differential Pressure (MEDP)- Opening (O) - Closing (C)		EPU Impact
			Current Conditions	EPU Conditions	
Containment Spray (CS)	2-LCV-07-11A/B	Reactor cavity sump pump discharge	1 psid (O), 41 psid (C) <u>Note:</u> Bounding upstream pressure for the safety-related close stroke is based on containment design pressure, reactor cavity sump pump shutoff head, and elevation static head (difference between elevation of the valves and elevation of containment sump when filled to floor elevation).	Current MEDP not exceeded by EPU. <u>Note:</u> EPU does not affect containment design pressure, the reactor cavity sump pump shutoff head, or the elevations of the valves and containment sump when filled to the floor level.	None
	2-FCV-07-1A/1B	Containment spray flow control	243.7 psid (O), 15 psid (C) <u>Note:</u> Bounding upstream pressure for the safety-related open stroke is based on containment spray pump shutoff head and St. Lucie Unit 1/2 refueling water tank (RWT) high level alarm setpoint. Bounding downstream pressure for the safety-related open stroke is based on containment spray actuation signal (CSAS) setpoint.	Current MEDP not exceeded by EPU. <u>Note:</u> EPU does not affect containment spray pump shutoff head, St. Lucie Unit 1/2 RWT high level alarm setpoint, or CSAS setpoint.	None

2.2.5 Seismic and Dynamic Qualification of Mechanical and Electrical Equipment

2.2.5.1 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 Florida Power and Light (FPL) review focused on the effects of the proposed extended power uprate (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. Acceptance criteria are based on:

- General Design Criterion (GDC)-1, insofar as it requires that structures, systems, and components (SSCs) important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed,
- 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,
- 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,
- GDC-14, insofar as it 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 fracture;
- 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,
- 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, and
- 10 CFR Part 50, Appendix B, which sets quality assurance requirements for safety-related equipment.

Specific review criteria are contained in Standard Review Plan (SRP) Section 3.10.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

- GDC-1 is described in UFSAR Section 3.1.1, Criterion 1 – Quality Standards and Records.

SSCs important to safety shall be designed, fabricated, erected and tested to quality standards commensurate with the importance of the safety functions to be performed. Where generally recognized codes and standards are used, they shall be identified and evaluated to determine their applicability, adequacy and sufficiency and shall be supplemented or modified as necessary to assure a quality product in keeping with the required safety function. A quality assurance program shall be established and implemented in order to provide adequate assurance that these structures, systems, and components will satisfactorily perform their safety functions. Appropriate records of the design, fabrication, erection, and testing of structures, systems and components important to safety shall be maintained by or under the control of the nuclear power unit licensee throughout the life of the unit.

Structures, systems and components (SSCs) of the facility are classified according to their relative importance to safety. Those items vital to safety such that their failure might cause or result in an uncontrolled release of an excessive amount of radioactive material are designated seismic Category I. They and items of lesser importance to safety are designed, fabricated, erected and tested according to the provisions of recognized codes and quality standards. Discussions of the applicable codes, standards, records and quality assurance program used to implement and audit the operation processes were originally presented in UFSAR Section 17.2; however, this information is now provided in FPL Quality Assurance Topical Report, FPL-1. A complete set of facility structural, arrangement and system drawings is maintained under the control of FPL throughout the life of the plant. Quality assurance written data and comprehensive test and operating procedures are likewise assembled and maintained by FPL. The classification of seismic Category I structures and safety related systems and components is discussed in UFSAR Section 3.2.

- GDC-2 is described in UFSAR Section 3.1.2, Criterion 2 – Design Bases for Protection Against Natural Phenomena.

Structures, systems and components important to safety shall be designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunamis and seiches without loss of capability to perform their safety functions. The design bases for these structures, systems and components shall reflect: (1) appropriate consideration of the most severe of natural phenomena that have been historically reported for the site and surrounding area, with sufficient margin for the limited accuracy, quantity, and period of time which the historical data have been accumulated, (2) appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena and (3) the importance of the safety functions to be performed.

The SSCs important to safety are designed to withstand the effects of natural phenomena without loss of capability to perform their safety functions. Natural phenomena factored into the design of plant SSCs important to safety are determined from recorded data for the site vicinity with appropriate margin to account for uncertainties in historical data.

The most severe natural phenomena postulated to occur at the site in terms of induced stresses is the safe shutdown earthquake (SSE). Those SSCs vital for the mitigation and control of accident conditions are designed to withstand the effects of a loss of coolant accident (LOCA) coincident with the effects of the SSE. SSCs vital to the safe shutdown of the plant are designed

to withstand the effects of any one of the most severe natural phenomena, including flooding, hurricanes, tornadoes and the SSE.

Design criteria for wind and tornado, flood and earthquake are discussed in UFSAR Sections 3.3, 3.4 and 3.7, respectively.

- GDC-4 is described in UFSAR Section 3.1.4, Criterion 4 – Environmental and Missile Design Bases.

Structures, systems and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and approved by the Commission demonstrates that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

SSCs important to safety are designed to accommodate the effects of and to be compatible with the pressure, temperature, humidity, and radiation conditions associated with normal operation, maintenance, testing, and postulated accidents including a LOCA, in the area in which they are located.

For those components which are required to operate under extreme conditions such as design seismic loads or containment post-LOCA environmental conditions, the manufacturers submit type test, operational or calculation data which substantiate this capability of the equipment.

Refer to UFSAR Sections 3.5, 3.6, 3.7, and 3.11 for details on missile protection, pipe rupture and jet impingement protection, seismic design criteria and environmental qualification, respectively.

- GDC-14 is described in UFSAR Section 3.1.14, Criterion 14 – Reactor Coolant Pressure Boundary.

The reactor coolant pressure boundary shall be designed, fabricated, created and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture.

Reactor coolant system (RCS) components are designed to meet the requirements of the ASME Code, Section III. To establish operating pressure and temperature limitations during startup and shutdown of the RCS, the fracture toughness rules defined in Appendix G of the ASME Code, Section III, are followed. Quality control, inspection, and testing as required by this standard and operation within allowable reactor pressure-temperature limits ensure the integrity of the RCS.

- GDC-30 is described in UFSAR Section 3.1.30, Criterion 30 – Quality of Reactor Coolant Pressure Boundary.

Components which are part of the reactor coolant pressure boundary shall be designed, fabricated, erected, and tested to the highest quality standards practical. Means shall be

provided for detecting and, to the extent practical, identifying the location of the source of reactor coolant leakage.

The RCPB components are designed, fabricated, erected, and tested in accordance with ASME Code, Section III.

Plant SSCs, including their foundations and supports, that are designed to remain functional in the event of a SSE are designated as seismic Category I, as indicated in UFSAR Table 3.2-1.

In compliance with GDC-2, plant SSCs which are important to safety are designed to remain functional in the event of a SSE if they are necessary to assure:

- the integrity of the reactor coolant pressure boundary,
- the capability to shut down the reactor and maintain it in a safe shutdown condition, or
- the capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to the guideline exposure of 10 CFR 100.

Seismic design criteria, including input criteria and system analysis methodologies, are developed and described in UFSAR Section 3.7.

Class 1E instrumentation and electrical equipment associated with the reactor protective system, engineered safety features equipment, emergency power system and auxiliary safety related systems are designed as seismic Category I to ensure their ability to perform their required function during, and/or following a postulated SSE and to supply standby electrical power following a SSE to safety related components.

As required by the Safety Evaluation Report commitment, seismic qualification of seismic Category I instrumentation and electrical equipment is in accordance with IEEE 344-1971 and multi-axis and multi-frequency testing unless specific requirements are met that demonstrate single-frequency or single-axis testing is sufficient. However, as indicated in UFSAR Tables 3.10-1 and 2, FPL has purchased Class 1E equipment with qualifications exceeding the SER commitments as far as the state-of-the-art knowledge was available at the time of the purchase order.

In order to comply with the minimum accepted seismic acceleration as stipulated by 10 CFR 100, Appendix A, St. Lucie Unit 2 is designed for a maximum horizontal ground surface acceleration of 0.10 g. This conservative surface design acceleration exceeds the maximum acceleration appropriate for the maximum earthquake which has occurred in the site's seismotectonic province during the past 200 years. The maximum vertical acceleration for the postulated SSE is the same as the peak horizontal acceleration.

The NRC issued GL 87-02 to answer Unresolved Safety Issue (USI) A-46 regarding seismic qualifications of electrical and mechanical components. The GL required licensees to verify the adequacy of seismically mounted mechanical and electrical components for plants that were not documented as having met the provisions of IEEE Standard 344-1975. The technical basis for GL 87-02 was NUREG-1211, Enclosure 1, which listed the plants that, as of February 1987, were not documented as meeting the requirements of IEEE Standard 344-1975. St. Lucie Unit 2 was not listed in Enclosure 1 to NUREG-1211 since the St. Lucie Unit 2 Safety Evaluation Report (NUREG-0843, including supplements) concluded in Section 3.10 that the provisions of

IEEE 344-1975 had been met and that an appropriate seismic and dynamic qualification program had been implemented.

In addition to the licensing basis described in the UFSAR, the seismic and dynamic qualification of mechanical and electrical equipment was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Sections 2.3 and 2.4 of the SER discuss seismic and dynamic qualification of mechanical and electrical equipment that are within the scope of License Renewal. Programs used to manage the aging effects associated with seismic and dynamic qualification of mechanical and electrical equipment are discussed in SER Section 3.0 and Chapter 18 of the UFSAR.

2.2.5.2 Technical Evaluation

2.2.5.2.1 Introduction

This section addresses the impact of the EPU on the qualification of equipment to withstand seismic events and the dynamic effects associated with pipe whip and jet impingement forces.

2.2.5.2.2 Description of Analyses and Evaluations

The impact on seismic design, seismic inputs, and seismic loads was evaluated in order to determine the impact of the EPU on the seismic qualification of essential equipment and supports.

The impact on high energy/moderate energy line break locations, and on the protection features currently in place for protection of essential equipment from the dynamic effects of pipe whip and jet impingement, was addressed in order to determine the impact of the EPU on qualification of equipment to withstand the dynamic effects associated with pipe-whip and jet impingement.

2.2.5.2.3 Impact on Renewed Plant Operation Licensing Evaluations and License Renewal Programs

As discussed above, seismic and dynamic qualification of mechanical and electrical equipment is within the scope of License Renewal. The effects of seismic and dynamic qualification of mechanical and electrical equipment under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, EPU does

not it introduce any new system or component functions nor does it change the functions of existing components such that License Renewal system boundaries are affected.

2.2.5.2.4 Results

Seismic design is not impacted by the EPU since seismic requirements remain unchanged. There is no change to seismic inputs (i.e., amplified response spectra) or seismic loads resulting from the EPU. Therefore, the seismic qualification of essential equipment and supports remains unaffected by the EPU.

As addressed in LR [Section 2.2.1](#) and LR [Section 2.5.1.3](#), the EPU does not result in any new or revised high energy/moderate energy line break locations, and does not affect the protection features currently in place for protection of essential equipment from the dynamic effects of pipe whip and jet impingement (e.g. jet impingement shields). Therefore, the qualification of equipment to withstand the dynamic effects associated with pipe-whip and jet impingement forces is not affected by the EPU.

Since the EPU does not affect the seismic qualification of essential equipment and supports, and does not affect the qualification of equipment to withstand the dynamic effects associated with pipe-whip and jet impingement forces, conformance with GDCs -1, -2, -4, -14, and -30, conformance with 10 CFR 100, Appendix A, and conformance with 10 CFR 50, Appendix B, continue to be met. Also, the EPU does not affect the acceptance criteria given in UFSAR Tables 3.9.6, 3.9.7 and 3.9.13 through 3.9.21.

Evaluations related to seismic and dynamic effects of the EPU are addressed in the following LR Sections:

- LR [Section 2.2.1](#), Pipe Rupture Locations and Associated Dynamic Effects,
- LR [Section 2.2.2](#), Pressure-Retaining Components and Component Supports,
- LR [Section 2.3.1](#), Environmental Qualification of Electrical Equipment, and
- LR [Section 2.5.1.3](#), Pipe Failures.

2.2.5.3 Conclusion

FPL has reviewed the evaluations of the effects of the proposed EPU on the qualification of mechanical and electrical equipment and concludes that they have (1) adequately addressed the effects of the proposed EPU on this equipment and (2) demonstrated that the equipment will continue to meet its current licensing basis with respect to the requirements of GDCs -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, FPL finds the proposed EPU acceptable with respect to the qualification of the mechanical and electrical equipment.

2.2.6 NSSS Design Transients

2.2.6.1 Regulatory Evaluation

Nuclear Steam Supply System (NSSS) design transients are developed for use in the analyses of the cyclic behavior of the NSSS structure system and components (SSCs). To provide the necessary high degree of integrity for them, the transient parameters selected for component fatigue analyses are based on conservative estimates of the magnitude and frequency of the transients resulting from various plant-operating conditions. The Florida Power and Light (FPL) review focused primarily on the effects of the proposed extended power uprate (EPU) on NSSS design parameters that are used in transient analyses, and how those differences in design parameters affected the current NSSS design transients.

FPL's acceptance criteria for this review are based on:

- General Design Criterion (GDC) -1 insofar as it relates to safety-related components being designed, fabricated, erected, constructed, tested and inspected in accordance with the requirements of applicable codes and standards commensurate with the importance of the safety-function to be performed,
- GDC-2 insofar as it relates to safety-related mechanical components of systems being designed to withstand seismic events without loss of capability to perform their safety function,
- GDC-14 insofar as it relates to the reactor coolant pressure boundary (RCPB) being designed so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture, and
- GDC-15 insofar as it relates to the mechanical components of the reactor coolant system (RCS) being designed with sufficient margin to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including anticipated operational occurrences (AOOs).

Specific review criteria are contained in the Standard Review Plan (SRP), Section 3.9.1 and other guidance provided in Matrix 2 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

Specific GDCs for the NSSS design transients are as follows:

- GDC-1 is described in UFSAR Section 3.1.1 Criterion 1 - Quality Standards and Records.

Structures, systems and components important to safety shall be designed, fabricated, erected and tested to quality standards commensurate with the importance of the safety functions to be performed. Where generally recognized codes and standards are used, they

shall be identified and shall be supplemented or modified as necessary to assure a quality product in keeping with the required safety function. A quality assurance program shall be established and implemented in order to provide adequate assurance that these structures, systems, and components will satisfactorily perform their safety functions. Appropriate records of the design, fabrication, erection and testing of structures, systems and components important to safety shall be maintained by or under the control of the nuclear power unit licensee throughout the life of the unit.

SSCs of the facility are classified according to their relative importance to safety. Those items vital to safety such that their failure might cause or result in an uncontrolled release of an excessive amount of radioactive material are designated seismic Class I. They and items of lesser importance to safety, are designed, fabricated, erected and tested according to the provisions of recognized codes and quality standards. Discussions of the applicable codes, standards, records and the quality assurance program used to implement and audit the construction and operation processes were originally presented in UFSAR Sections 17.1 and 17.2; however, this information is now provided in FPL Quality Assurance Topical Report, FPL-1. A complete set of facility structural, arrangement and system drawings will be maintained under the control of FPL throughout the life of the plant. Quality assurance written data and comprehensive test and operating procedures are likewise assembled and maintained by FPL. The classification of safety related structures, systems and components is discussed in UFSAR Section 3.2.

- GDC-2 is described in UFSAR Section 3.1.2 Criterion 2 – Design Bases For Protection Against Natural Phenomena.

Structures, systems and components important to safety shall be designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunamis and seiches without loss of capability to perform their safety functions. The design bases for these structures, systems and components shall reflect: (1) appropriate consideration of the most severe of natural phenomena that have been historically reported for the site and surrounding area, with sufficient margin for the limited accuracy, quantity, and period of time which the historical data have been accumulated, (2) appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena and (3) the importance of the safety functions to be performed.

SSCs important to safety are designed to withstand the effects of natural phenomena without loss of capability to perform their safety functions. Natural phenomena factored into the design of plant structures, systems and components important to safety are determined from recorded data for the site vicinity with appropriate margin to account for uncertainties in historical data.

The most severe natural phenomena postulated to occur at the site in terms of induced stresses is the safe shutdown earthquake (SSE). Those SSCs vital for the mitigation and control of accident conditions are designed to withstand the effects of a loss of coolant accident (LOCA) coincident with the effects of the SSE. SSCs vital to the safe shutdown of the plant are designed to withstand the effects of any one of the most severe natural phenomena, including flooding, hurricanes, tornadoes and the SSE.

Design criteria for wind and tornado, flood and earthquake are discussed in UFSAR Sections 3.3, 3.4 and 3.7 respectively.

- GDC-14 is described in UFSAR Section 3.1.14 Criterion 14 – Reactor Coolant Pressure Boundary.

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.

RCS components are designed in accordance with the ASME Code Section III. Quality control, inspection, and testing as required by this standard and allowable reactor pressure temperature operations ensure the integrity of the RCS.

The RCPB is designed to accommodate the system pressures and temperatures achieved under all expected modes of unit operation, including all anticipated transients, and maintain the stresses within applicable limits.

The RCPB has provisions for in-service inspection as described in UFSAR Section 5.3, to ensure the structural and leak tight integrity of the boundary.

- GDC-15 is described in UFSAR Section 3.1.15 Criterion 15 – Reactor Coolant System Design.

The reactor coolant system and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operations including anticipated operational occurrences.

The operating conditions for normal steady state and transient plant operations are established conservatively (see UFSAR Section 4.4.3). Normal operating limits are selected so that an adequate margin exists between operating and design limits. The plant control systems are designed to ensure that plant variables are maintained well within the established operating limits. The plant transient response characteristics and pressure and temperature distributions during normal operations are considered in the design as well as the accuracy and response of the instruments and controls. These design techniques ensure that a satisfactory margin is maintained between the plant's normal operating conditions, including design transients, and the design limits for the RCPB.

The plant control systems function to minimize deviations from normal operating limits in the event of most AOOs (ANSI N18.2 Condition II Occurrences). Where control systems response would be inadequate or fail upon demand, the reactor protective system and the engineered safety features system function to mitigate the consequences of such events.

The reactor protective system and the engineered safety features system function to mitigate the consequences of accidents (ANSI N18.2 Condition III or IV occurrences). Analyses show that the design limits for the reactor coolant pressure boundary are not exceeded in the event of any ANSI N18.2 Condition II, III or IV occurrences. See UFSAR Section 5.2 and UFSAR Chapter 7 for further information.

UFSAR Sections 3.9.1 and 3.9.3 describe the design transients used in plant analyses.

In addition to the licensing basis described in the UFSAR, the NSSS and associated auxiliary components was evaluated for the continued acceptability and applicability of the design basis transient for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Metal fatigue is a time-limited aging analysis (TLAA) and is discussed in SER Section 4.3 and Chapter 18 of the UFSAR. SER Section 3.1.0.6 describes the Fatigue Monitoring Program as an aging management program designed to track cyclic and transient occurrences to ensure that RCPB components remain within the ASME Code, Section III fatigue limits.

2.2.6.2 Technical Evaluation

2.2.6.2.1 Introduction

As discussed in Chapter 5 of the UFSAR, the SSCs important to safety in the RCS and its auxiliary systems are designed to withstand the effects of the cyclic loads from RCS NSSS temperature and pressure changes. Such cyclic loading is the result of normal unit load transients, i.e., design basis transients. This evaluation compares the design parameters developed for the EPU to the design parameters used in the current design basis transients. Where revisions were necessary, comparative analyses were performed and the transients revised, as needed, to reflect the operating conditions for the EPU. The selected transients are representative of plant transients which, when used as a basis for component fatigue analysis, would provide confidence that the component is appropriate for its application over the 60-year operating license period of the plant.

Revised NSSS design transients have been determined for the EPU. These revised transients were used in the NSSS component structural and fatigue evaluations at EPU conditions. The results of the component structural and fatigue evaluations are provided in LR [Section 2.2](#), Mechanical and Civil Engineering, for each NSSS component.

2.2.6.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters

NSSS design transients were based on the NSSS design parameters developed for the EPU, as presented in LR [Section 1.1](#), Nuclear Steam Supply System Parameters. The design parameters upon which the original applicable NSSS design transients are based were compared to the design parameters for the EPU, and shown to be similar for the temperature values of the RCS.

Assumptions

The EPU hot leg temperature will change from 594°F to 604°F at full load. Additionally, the cold leg temperature will increase slightly, from 550°F, to 551°F, at full load. It is also assumed that control systems will function as designed.

Acceptance Criteria

The current design transients were evaluated and analyzed to determine if they continue to bound the operating parameters associated with the EPU. If the operating parameters changed due to EPU conditions, the revised parameters have been identified in the footnotes to LR [Tables 2.2.6-1](#), NSSS Design Transients – Reactor Vessel, Reactor Coolant Pumps, and Pressurizer, [2.2.6-2](#), NSSS Design Transients – RCS Piping, and [2.2.6-3](#), NSSS Design Transients – Steam Generators, and their impacts have been evaluated and analyzed in the appropriate component sections of LR [Section 2.2](#).

2.2.6.2.3 Description of Analyses and Evaluations

The design parameters for the EPU were compared to the design parameters used in the current design transients. Where there were sufficient differences between the two sets of operating conditions, evaluations and analyses were performed, and the parameters used in the transients were revised to reflect the operating conditions for EPU.

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

A list of NSSS design transients with their associated frequencies of occurrence is provided in LR [Tables 2.2.6-1](#) through [2.2.6-3](#). The transients listed and their associated frequencies of occurrence are unchanged from those in the current design basis list. The revised design transient parameters are determined at EPU conditions for use in the component stress and fatigue analyses as discussed in LR [Section 2.2](#), Mechanical and Civil Engineering. Consistent with the current NSSS design transients, the revised NSSS design transient parameters for EPU are conservative representations of transients that, when used as a basis for component fatigue analyses, provide confidence that the component is appropriate for its application over the period of extended operation.

2.2.6.2.5 Results

The NSSS design transients are inputs to the NSSS primary and secondary side component structural and fatigue analyses and evaluations. The final acceptance was determined by the component stress and fatigue analyses discussed in LR [Section 2.2](#) Mechanical and Civil Engineering, individually for each component.

A list of the NSSS design transients applicable to the EPU, with their associated design value frequencies of occurrence are shown in LR [Tables 2.2.6-1](#) through [2.2.6-3](#). The types of transients listed and their associated frequencies of occurrence are the same as those in the current design basis transient list. The design transient parameters that required revision are also noted in LR [Tables 2.2.6-1](#) through [2.2.6-3](#).

Consistent with the current NSSS design transients, the revised NSSS design transient parameters are conservative and provide confidence that the component will continue to function as designed.

Revised NSSS design transient parameters have been determined for the EPU. These revised transient parameters were used in the NSSS component structural and fatigue evaluations at the EPU conditions. The results of the component structural and fatigue evaluations are provided in LR [Section 2.2](#).

2.2.6.3 Conclusion

FPL has reviewed the evaluation of the effects of the proposed EPU on the NSSS design transients. FPL concludes that the required design transient parameter changes have been adequately addressed. FPL further concludes that the revised NSSS design transient parameters have been incorporated into the transient analysis of the safety-related NSSS systems and components and that St. Lucie Unit 2 will continue to meet its current licensing basis requirements with respect to the requirements of GDC-1, -2, -14, and -15. Therefore, FPL finds the EPU acceptable with respect to the NSSS design transients.

Table 2.2.6-1
NSSS Design Transients – Reactor Vessel⁽¹⁾, Reactor Coolant Pumps, and Pressurizer

Transient Description	Number of Occurrences⁽²⁾	Transient Parameters Required Revision due to the EPU
Plant Heatup	500	No
Plant Cooldown	500	No
Plant Loading at 5% of Full Power per Minute	15,000	No
Plant Unloading at 5% of Full Power per Minute	15,000	Yes ⁽⁴⁾
Step Load Increase of 10% of Full Power per Minute	2,000	No
Step Load Decrease of 10% of Full Power per Minute	2,000	No
Normal Plant Variation	10 ⁶	No
Reactor Trip	400	No
Loss of Primary System Flow	40	No
Loss of Load	40	No
Operational Basis Earthquake	200	No
Safe Shutdown Earthquake (SSE) plus Normal Operation	1	No
SSE plus Normal Operation plus Pipe Rupture	1	No
Loss of Secondary Pressure	5	No
Hydrostatic test, 3125 psia, 100°F-400°F	10	No
Leak Test, 2250 psia, 100°F-400°F	200 ⁽³⁾	No
Notes: 1. Includes the reactor vessel head. 2. The number of occurrences and type of transients are the same as the existing design basis, unless otherwise noted. 3. The replacement reactor vessel head and the replacement control element drive mechanisms are designed to 320 cycles for this transient. 4. Revision to NSSS parameter T _{cold} change from 550°F to 551°F		

Table 2.2.6-2
NSSS Design Transients – RCS Piping

Transient Description	Number of Occurrences⁽¹⁾	Transient Parameters Required Revision due to the EPU
Plant Heatup	500	No
Plant Cooldown	500	No
Plant Loading at 5% of Full Power per Minute	15,000	No
Plant Unloading at 5% of Full Power per Minute	15,000	Yes ⁽²⁾
Step Load Increase of 10% of Full Power per Minute	2,000	No
Step Load Decrease of 10% of Full Power per Minute	2,000	No
Normal Plant Variation	10 ⁶	No
Reactor Trip	400	No
Loss of Primary System Flow	40	No
Loss of Load ⁽²⁾	40	No
Operational Basis Earthquake	200	No
Loss of Secondary Pressure	5	No
Safe Shutdown Earthquake (SSE) plus Normal Operation at Full Power	1	No
SSE plus Normal Operation at Full Power plus Pipe Rupture	1	No
Hydrostatic Test, 3125 psia, 160°F-400°F	10	No
Leak Test, 2250 psia, 160°F-400°F	200	No
Notes: 1. The number of occurrences and type of transients are the same as the existing design basis, unless otherwise noted. 2. Revision to NSSS parameter T _{cold} change from 550°F to 551°F		

**Table 2.2.6-3
NSSS Design Transients – Steam Generators**

Transient Description	Number of Occurrences⁽¹⁾	Transient Parameters Required Revision due to the EPU
Plant Heatup	500	No
Plant Cooldown	500	No
Plant Loading at 5% of Full Power per Minute	15,000	Yes ⁽²⁾
Plant Unloading at 5% of Full Power per Minute	15,000	Yes ⁽³⁾
Step Load Increase of 10% of Full Power per Minute	2,000	Yes ⁽³⁾
Step Load Decrease of 10% of Full Power per Minute	2,000	Yes ⁽³⁾
Cold Feedwater during Hot Standby	15,000	No
Normal Plant Variation	10 ⁶	No
Pump Starting and Stopping	4,000	No
Reactor Trip	400	Yes ^(c)
Loss of Reactor Coolant Flow	40	Yes ^(c)
Loss of Turbine Generator Load	40	Yes ^(c)
Operation Basis Earthquake	200	No
Loss of Feedwater Flow	8	No
Loss of Secondary Pressure	5	No
Feedwater Line Break (FWLB) Pipe Rupture	1	No
Safe Shutdown Earthquake (SSE) plus Normal Operation	1	No
SSE plus Normal Operation plus RCS Pipe Rupture	1	No
SSE plus Normal Operation plus Main Steam Line Break (MSLB) Pipe Rupture	1	No
SSE plus Normal Operation plus FWLB Pipe Rupture	1	No
Hydrostatic Test, 3125 psia, 70°F-400°F	10	No
Secondary Side Hydrostatic Test, 1250 psia, 70°F-400°F	10	No

Table 2.2.6-3 (Continued)
NSSS Design Transients – Steam Generators

Transient Description	Number of Occurrences⁽¹⁾	Transient Parameters Required Revision due to the EPU
Leak Test, 2250 psia, 100°F-400°F	200	No
Secondary Side Leak Test – 1000 psia, 70°F-200°F	200	No
Notes: 1. The number of occurrences and type of transients are the same as the existing design basis, unless otherwise noted. 2. Revision to NSSS parameter T_{cold} change from 550°F to 551°F 3. At the time the replacement steam generators (SGs) were installed, the NSSS SG design transients were updated to reflect the new operating conditions based on the replacement SG parameters. To allot for EPU, the NSSS SG design transients were revised to incorporate the original design basis SG parameters in order to reflect the original design basis that is found in the other NSSS primary components transients.		

2.3 Electrical Engineering

2.3.1 Environmental Qualification of Electrical Equipment

2.3.1.1 Regulatory Evaluation

Environmental qualification (EQ) of electrical equipment involves demonstrating that the equipment is capable of performing its safety function under significant environmental stresses which could result from design basis accidents (DBAs).

The Florida Power and Light (FPL) review focused on the effects of the proposed extended power uprate (EPU) on the environmental conditions that the electrical equipment will be exposed to during normal operation, anticipated operational occurrences, and accidents. The FPL 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 Standard Review Plan (SRP) Section 3.11.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

Safety-related equipment must be capable of maintaining functional operability under conditions postulated to occur during its installed life. This requirement is embodied in 10 CFR 50.49, Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants, 10 CFR 50 Appendix B, Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants, and 10 CFR 50 Appendix A, General Design Criteria for Nuclear Power Plants, Criteria -1, -2, -4, -23 and -50.

The St. Lucie Unit 2 construction permit was issued on May 2, 1977. Originally St. Lucie Unit 2 was committed to meet IEEE 323-1971, but revised that commitment to comply with IEEE 323-1974 guidelines wherever practical for equipment qualification.

The NRC subsequently issued more definitive criteria in NUREG-0588, Interim Staff Position on Environmental Qualification (EQ) of Safety-Related Electrical Equipment, which contains two sets of criteria:

- Category I, for plants whose construction permit was issued after July 1, 1974, incorporates and supplements IEEE Standard 323-1974, and
- Category II, for plants whose construction permit was issued before July 1, 1974, incorporates and supplements IEEE Standard 323-1971.

Because the construction permit was issued on May 2, 1977, NUREG-0588 Category I Criteria are applicable.

EQ of safety-related equipment located in a mild environment is ensured by conformance to the general quality and surveillance requirements identified in 10 CFR Part 50, Appendix B, and Regulatory Guide 1.33, Quality Assurance Program Requirements (Operation), as implemented in the FPL quality assurance topical report.

On September 29, 2008, via Amendment No. 152 to the Renewed Facility Operating License, the NRC approved adoption of the alternative source term (AST) as allowed by 10 CFR 50.67 and described in NRC Regulatory Guide (RG) 1.183. According to the guidance given in RG 1.183, FPL elected to retain the use of TID-14844, the source terms used to establish EQ program radiological environments.

Additional details that define the licensing basis for safety-related electrical equipment qualification are described in UFSAR Sections 3.11 and 18.2.5. The EQ program ensures the continued qualification of equipment that must function during and following design conditions postulated for design basis accidents and the post-accident duration.

In addition to the licensing basis described in the UFSAR, the EQ of electrical equipment was evaluated for License Renewal. For License Renewal, electrical and I&C systems were broken down into commodity groups and then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.5 of the SER identifies electrical components that are within the scope of License Renewal. The EQ Program is a time-limited aging analysis (TLAA) and is discussed in SER Section 4.4 and UFSAR Chapter 18.

2.3.1.2 Technical Evaluation

2.3.1.2.1 Introduction

This section provides the EPU evaluations, addressing the following areas:

- Reactor containment building,
- Post accident operability time (PAOT),
- Reactor auxiliary building, and
- Trestle area.

2.3.1.2.2 Description of Analyses and Evaluations

The evaluation of the EQ of safety-related electrical equipment involves the comparison of the EPU environmental parameters to those of the current values. If the EPU values exceed the current values, then the environments are compared against the test conditions used to qualify the equipment.

The list of electrical equipment for EQ is obtained from the EQ-list. The equipment is listed by unit EQ tag number, manufacturer, model number and Document Package (Doc Pac) number.

A comparison of current temperature and pressure conditions with EPU loss-of-coolant-accident (LOCA)/main steamline break (MSLB) accident conditions inside containment and high energy line break (HELB) accident conditions outside containment was performed. This comparison was used to evaluate the potential impact the EPU conditions have on the qualified life of the components during normal operation, and the DBA, with respect to the accident peak temperature and pressure, and their ability to withstand these conditions for the long term PAOT of 180 days.

Similarly, a comparison was performed, by area, of the current and EPU radiation environments associated with normal plant operation and following a LOCA, including the total integrated dose (normal 60 year operation plus accident) expected in each area.

The transient temperatures associated with anticipated operational occurrences (AOOs) such as reactor trip, safety injection and containment isolation were considered. The average operational temperature for the area, if it were to be considered over 60 years, would not be changed by the short temperature spikes associated with AOOs and the average temperature would be bounded with margin by the area normal design temperature used for the equipment qualification.

2.3.1.2.2.1 Reactor Containment Building Environmental Parameters and Evaluation

Normal Conditions – Temperature:

There is no change in the maximum normal operating temperature (120°F) inside containment as a result of the EPU operation. Therefore, the qualified life of equipment that is based on this temperature is not changed by the EPU operation. Refer to LR [Section 2.7.7](#), Other Ventilation Systems (Containment).

Normal Conditions – Pressure:

There is no change in normal pressure and therefore no effect on the environmental qualification of the equipment as a result of EPU operation. Refer to LR [Section 2.7.7](#), Other Ventilation Systems (Containment).

Normal Conditions – Humidity:

There is no change in the normal operating relative humidity as a result of the EPU.

Normal Conditions – Radiation:

The normal operation radiation doses used for radiological EQ at current conditions are based on design considerations and source terms corresponding to a core power level of 2700 MWt, 1 percent fuel defects, and a one-year fuel cycle length. Integrated doses are based on 60 years of normal operation.

The impact of EPU on the normal operation radiation environment used for EQ is determined by using recent survey data that reflect operation at full power, with an 18-month fuel cycle, and by using the assessment provided in LR [Section 2.10.1](#), Occupational and Public Radiation Doses, regarding impact of the EPU on normal operation radiation levels. This assessment is used to verify or update as necessary, the dose rate values currently used to develop the 60-year integrated dose, taking into consideration operation at the current power level for the past years of operation and operation at the EPU power level for the years remaining under the operating

license. A 10 percent margin is included to address possible uncertainty in survey measurements.

Refer to section entitled – Summary Impact of EPU on Equipment Qualification (below), for a discussion on the EPU normal operation radiation environment inside containment and the total integrated dose used to evaluate EQ.

Accident Conditions – Temperature:

Containment temperature analyses were performed for EPU conditions. The peak EPU LOCA and MSLB temperatures are bounded by the current peak EQ temperature profile as shown on [Figure 2.3.1-1](#) and remain below the EQ envelope during the onset of the PAOT period with the exception of a small portion of the curve which from time 1E3 to 1E4 seconds is approximately 20 degrees above the EQ profile. This small departure is not detrimental to the qualification of the equipment since there is sufficient overall margin between the expected temperature profile and the design temperature profile. Refer to LR [Section 2.6.1](#), Primary Containment Functional Design, for a discussion of the containment LOCA analysis.

The peak accident temperature for the EPU operation is bounded by the peak EQ temperature. Therefore, the equipment is qualified for the EPU accident transient conditions.

Based on this review, it is concluded that there is no impact on the temperature qualification of equipment.

Accident Conditions – Pressure:

The peak containment design pressure is the pressure which the vapor space or containment atmosphere should not exceed. Refer to LR [Section 2.6.1](#).

The EPU pressure profile comparison is presented in [Figure 2.3.1-2](#), where it is shown that the current EQ LOCA and MSLB accident pressure profile bounds the EPU accident pressure profile. There is no effect on the qualification of the equipment as the peak tested conditions still envelope current EQ LOCA/MSLB accident pressure profile and, thereby, the peak EPU pressure profile.

Accident Conditions – Humidity:

The current accident humidity is 100 percent. The EPU relative humidity level remains unchanged from the current accident humidity due to EPU.

Accident condition – pH:

The post-recirculation containment sump pH ranges from approximately 7.0 to 8.1 and remains within the EQ specification without affecting the EQ of the equipment.

Accident condition – Submergence:

Following EPU, the submergence elevation showed a slight decrease (approximately 1.2 inches) to the flood level. Based on a review of equipment inside containment, there is no impact.

Accident Conditions – Radiation:

The accident radiation doses used for radiological EQ current conditions are based on the TID-14844, nuclide release assumptions; i.e., following a LOCA, 100 percent of the core noble gases, 50 percent of the core halogen, and 1 percent of the core remainder are instantaneously released from the fuel into the containment.

It is noted that St. Lucie Unit 2 is approved for the use of AST as outlined in 10 CFR 50.67 and Regulatory Guide 1.183 for post-accident dose assessments associated with the offsite locations and on-site locations that require continuous occupancy, such as the control room (CR). However, and in accordance with current licensing basis, the EPU assessment for the post-LOCA integrated doses for EQ purposes is based on TID-14844 source terms. This approach is acceptable based on Section 1.3.5 of Regulatory Guide 1.183, which indicates that though EQ analyses impacted by plant modifications should be updated to address the impact of the modification, no plant modification is required to address the impact of the difference in source term characteristics (i.e., AST vs. TID-14844) on EQ doses.

The current accident gamma dose estimates utilized for equipment qualification for locations inside containment are based on a core power level of 3000 MWt, a 12-month fuel cycle, and with the exception of a few selected components, an integration period of one year. The radiation environments were estimated based on guidance set forth in NUREG-0737 and Regulatory Guide 1.89 Revision 0.

The current 1-year post-accident in-containment beta radiation dose is based on the Division of Operating reactors (DOR) Guidelines, i.e., an unshielded beta dose of $2.0\text{E}+08$ rads, and on the detailed calculations documented in Appendix D of NUREG-0588, i.e., a beta dose of $1.4\text{E}+08$ rads.

The EPU will increase the radioactivity level in the core by the percentage of the uprate. The radiation source terms in equipment/structures containing radioactive fluids, and the corresponding radiation zone doses, will increase accordingly. Additional factors that impact the equilibrium core inventory and consequently, the estimated dose, are fuel enrichment and burnup.

The EPU equilibrium core inventory utilized for this assessment reflects expected fuel management schemes at EPU conditions that span a range of fuel enrichment from 1.5 weight percent (w/o) to 5.0 w/o U-235, and utilizes a more realistic prediction of the mix of assemblies relative to enrichment than that assumed for the dose consequence analyses discussed in LR [Section 2.9.2](#), Radiological Consequences Analyses Using Alternative Source Terms. A list of the dose-significant nuclide core inventory developed using ORIGEN 2.1 is presented in LR [Table 2.9.1-3](#). Note that the EPU EQ assessment uses the entire complement of isotopes from the ORIGEN 2.1 output.

The impact of the EPU on the accident environmental gamma dose estimates is developed using scaling techniques that reflect a comparison of accident source terms developed based on the core inventory utilized in the original analyses of record, to the corresponding source terms developed using the EPU core inventory which is based on a core power level of 3030 MWt (includes 0.3 percent margin for power uncertainty) and an 18-month fuel cycle. Since the relative abundance of each isotope and the average gamma energy of each isotope are the key

parameters that affect direct exposure, having a scaling factor that addresses the change in these parameters is sufficient to assess the radiological impact of the EPU. Consideration is given to the fact that dose scaling factors will vary with radiation source, time after accident, as well as shielding; therefore bounding values are utilized for each integration period. Additional information relative to the approach used in development of scaling factors is provided in LR [Section 2.10.1](#).

The estimated increase in radiation levels reflects, in addition to the EPU power level and 18-month fuel cycle, the use of current computer codes, methodology, and nuclear data in developing the uprated core inventory (vs. the methodology, computer tools, and nuclear data used in the development of the original licensing basis core inventory). As a result, the calculated EPU dose scaling factor values are different from the core power ratio.

The EPU beta dose inside containment is developed based on source term guidance provided in NUREG-0737 (i.e., instantaneous homogeneous mix of 100 percent of the core noble gases, and 50 percent of the core halogens in containment atmosphere). For purposes of model simplicity, no removal mechanism (such as sprays, plateout, etc.) is credited other than decay.

Summary Impact of EPU on Equipment Qualification

With the exception of radiation, pressure, and temperature accident conditions, normal service conditions and operational occurrences (that is, for pressure and humidity) do not change inside containment for EPU. The radiation environments are increased to reflect the core power increase as a result of an EPU. The normal containment temperature has increased by less than 3°F, and remains below the maximum allowable temperature of 120°F. The change in normal operating pressure range remains bounded by the existing conditions.

The EPU containment analysis of DBAs shown as LR [Figure 2.3.1-1](#) demonstrates that the peak accident temperature for the EPU operation is bounded by the current EQ profile for the equipment qualification. Therefore, the equipment is qualified for the EPU accident transient conditions.

LR [Figure 2.3.1-1](#) shows PAOT at 24 hours is not impacted. Long term PAOT is evaluated further in LR [Section 2.3.1.2.2.2](#) and has been evaluated for temperature impact.

Pressure effects are generally stress-related rather than age degradation-related. Overlaying of the pressure curves in LR [Figure 2.3.1-2](#) graphically illustrates the accident pressure curves overlay on the current EQ profile.

The peak EPU LOCA/MSLB temperature is bounded by the peak EQ LOCA/MSLB accident temperature profile ([Figure 2.3.1-1](#)) that graphically shows the accident temperature curve overlays and PAOT at 24 hours, with the exception of a small portion of the curve which from time 1E+03 to 1E+04 seconds is approximately 20 degrees above the EQ profile. This small departure is not detrimental to the qualification of the equipment since there is sufficient overall margin between the expected temperature profile and the design temperature profile.

The normal operation and accident radiation doses inside containment have increased due to the EPU. For each radiation zone in containment the normal operation dose is combined with the accident dose to determine the total integrated dose used for this evaluation.

For the most limiting radiation zone in containment, the total integrated dose under EPU operation based on 60 years of normal operation, use of an 18-month fuel cycle and a conservatively assumed one year accident duration is $1.67\text{E}+7$ rads gamma plus $1.25\text{E}+08$ rads beta for a total integrated dose of $1.42\text{E}+08$ rads.

The impact of EPU on the EQ for radiological conditions is determined through comparison of the EPU environmental radiation values against the qualification values found in the EQ Doc Pacs.

Using the information available in the Doc Pacs, any EQ equipment that could not be qualified by direct comparison to the beta radiation was assessed for potential beta dose reduction. The total integrated dose (TID), gamma plus beta, used the reduced beta plus gamma for comparison. Factors included consideration if a component was sealed, equipment shielding considerations, the availability of specific calculations or the actual distance from the radiation source.

The results of the radiation comparisons show that all the equipment in the EQ program will continue to be qualified at the EPU conditions and thus will continue to meet the current licensing basis with respect to the requirements of 10 CFR 50.49.

The peak temperature values for the DBAs bound the temperature transients of the AOOs. Therefore, EPU will have no impact on the temperature transients associated with AOOs.

The environmental condition parameters not related to aging, but instead related to performance such as relative humidity, chemical spray pH, and submergence have not changed significantly and do not impact EQ.

The equipment qualification includes maintenance of the components within their qualified life. For some components, the qualified life is based on the maximum design temperatures for normal operation. The EPU normal operation has no measurable change in this temperature (the maximum allowed normal bulk average temperature is not changing); therefore, EPU does not change the qualified life. For components with heat rises when energized, the EPU operation does not change the heat rise or the percentage of operating time with heat rise.

See LR [Table 2.3.1-1](#) for a summary of results of the EPU impact on environmental qualification of electrical equipment.

2.3.1.2.2.2 Post Accident Operating Environmental Parameters and Evaluations

LR [Figure 2.3.1-1](#) compares the current containment EQ profiles with the EPU accident profiles for LOCA and MSLB peak temperature and the transient at 24 hours and subsequent temperature profile leading to the long term PAOT; LR [Figure 2.3.1-2](#) compares the current containment EQ profile with the profile for LOCA and MSLB peak pressure and the transient at 24 hours with subsequent pressure profile leading to a long term PAOT.

As shown on LR [Figures 2.3.1-1](#) and [2.3.1-2](#), the EPU LOCA and MSLB results remain below the EQ envelop following the peak temperature and pressure plateaus during and following the onset of the PAOT period. The EPU accident does not impact the required PAOT of 180 days. Therefore, the PAOT of the EQ components remains valid for the EPU operation.

2.3.1.2.2.3 Reactor Auxiliary Building (RAB) Environmental Parameters and Evaluations

Normal Conditions – Temperature:

The normal operating temperature for the RAB is 104°F. There is no change in the maximum normal design temperature as a result of the EPU.

Normal Conditions – Pressure:

There are no heating, ventilation, and air conditioning (HVAC) changes being made in the RAB as part of EPU, however control room HVAC changes are planned. These changes do not affect design flows, system balance and resultant pressures; therefore, the pressure is not affected and the RAB pressure is not impacted by EPU.

Normal Conditions – Humidity:

The normal humidity in the RAB is approximately 50 percent and is not impacted by EPU.

Normal Conditions – Radiation:

As previously discussed, the impact of EPU on the normal operation radiation environment in the RAB is determined by using recent survey data that reflect current operation at full power with an 18-month fuel cycle. The assessment is used to verify or update as necessary the dose rate values currently used to develop the 60-year integrated dose.

EQ is not affected by the normal operating radiation environment for EPU. See total integrated dose discussion for the RAB in the accident radiation section below and the use of normal radiation conditions.

Normal Conditions – pH:

There is no chemical spray in the RAB so this is not applicable in the RAB and is unaffected by EPU.

Accident Conditions – Temperature:

The accident analyses of the HELBs in the RAB for EQ have not changed as a result of the EPU; no new conditions are identified due to the EPU.

An evaluation was performed for the ECCS pump room areas to address worst-case post-LOCA room heat-up due to operation of post-accident equipment at EPU conditions. The maximum temperature in these areas is less than 120°F. There is no impact to EQ resulting from the EPU operation.

Accident Conditions – Pressure:

The pressure in the RAB has not changed as a result of the EPU.

Accident Conditions – Radiation:

As previously discussed, the impact of the EPU on the accident environmental gamma dose estimates is developed using scaling techniques that reflect a comparison of accident source terms developed based on the core inventory used in the original analyses of record, to the corresponding source terms developed using the EPU core inventory. The EPU dose

contribution due to radiation sources carrying sump water reflects a reduction due to the increase in the EPU sump water volume by a factor of 1.23 from that used in the pre-EPU analyses.

The results of a comparison of the EPU total integrated dose radiation zone values in the RAB based on 60 years of normal operation, use of an 18-month fuel cycle and a conservatively assumed 1-year accident duration is against the qualification values determined that the environmental qualification of equipment currently in the EQ program is not impacted due to EPU.

Implementation of the EPU has been determined to increase post-accident radiological doses for EQ zones within the RAB. With EPU implementation, two previously mild EQ zones on the 43-foot elevation of the RAB in the vicinity of the shield building ventilation system HEPA and charcoal filters were predicted to have post-accident doses exceeding the threshold for a harsh environment ($1.0\text{E}+05$ rads). Walkdowns and evaluations of electrical equipment located in these zones concluded that the following electrical equipment required further evaluation:

- LT-07-13A (Wide Range Containment Sump Level Transmitter),
- LT-07-13B (Wide Range Containment Sump Level Transmitter),
- LT-07-14A (Narrow Range Containment Sump Level Transmitter),
- HVE-9B Fan Motor,
- HVE-9B Hydramotor Damper Actuator,
- Damper D-16 Limit Switch (Open),
- Damper D-16 Limit Switch (Close), and
- FT-25-21B1 (Flow transmitter for HVE-9B Hydramotor Damper Actuator).

FPL performed component-specific radiological dose analyses for these components to determine if any further action was necessary (e.g., shielding, component qualification). The resultant radiological doses were determined to be below the threshold level of $1.0\text{E}+05$ rads, thus demonstrating that they would remain in a mild radiological environment and that no further action was necessary.

Accident Conditions – Humidity:

The humidity in the RAB is not changed by EPU. There is no EPU impact to EQ.

Accident Conditions – Flooding:

The EPU does not affect the current evaluation of flooding in any of the areas. There is no EPU impact to EQ.

Accident Conditions – pH:

The pH is not applicable in the RAB and is not affected by EPU. There is no impact to EQ in the RAB due to EPU.

2.3.1.2.2.4 Trestle Area Environmental Parameters and Evaluations

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. There is no chemical spray in the trestle area.

Normal Conditions – Temperature:

The normal operating temperature for equipment qualified life is the design temperature of 104°F; there is no change in temperature as a result of EPU.

Normal Conditions – Pressure:

Being open to the atmosphere, the pressure in the trestle area is atmospheric. There is no change in pressure as a result of EPU.

Normal Conditions – Humidity:

There is no change in the humidity (100 percent) as a result of EPU.

Normal Conditions – Radiation:

The radiation dose for normal operation is 1.50E+02 rads and has not changed as a result of EPU.

Normal Conditions – pH:

pH is not applicable in the trestle area.

Accident Conditions – Temperature:

Trestle area temperature analyses were performed for EPU conditions. The limiting HELB remains the failure of a main steam line. Environmental conditions for the limiting HELB have been analyzed; components located in the trestle area remain qualified for EPU conditions.

Accident Conditions – Pressure:

The pressure in the trestle area is atmospheric (the structure is open to the atmosphere; and, although there is a HELB, the pressure at any EQ component is basically atmospheric) and is not affected or changed by EPU operation.

Accident Conditions – Radiation:

The total integrated dose has not changed significantly due to EPU. Normal 60 year dose has not changed (1.50E+02 rads) and the accident dose has changed minimally (from 6.20E+02 rads to 6.45E+02 rads). There is no impact on equipment qualification as a result of these changes.

Accident Conditions – Humidity:

The accident humidity of 100 percent in the trestle area is not changed by EPU operation.

Accident Conditions – Flooding:

Submergence (flooding) is not applicable for the trestle area.

Accident Conditions – pH:

pH is not applicable in the trestle area.

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

As discussed above, the EQ Program is within the scope of License Renewal. Operation of the electrical components under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. Except as noted in Section 2.3.1.2.4, 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.

2.3.1.2.4 Results

Radiation dose values increase for EPU operation.

As a result of EPU, localized areas located on the 43 foot elevation RAB HVAC area have changed from a mild environment to a harsh environment. This change resulted in the components listed in LR [Section 2.3.1.2.2.3](#) requiring component-specific dose calculations to investigate whether or not shielding was required to reduce their exposure levels below the threshold limit of $1.0\text{E}+05$ rads. The component-specific doses were all below $1.0\text{E}+05$ rads.

All EQ equipment in the EQ program has been evaluated and is qualified for the increased total integrated dose both inside and outside containment with the exception of the RDF Corporation resistance temperature detectors (RTDs) TE-07-3A and TE-07-3B, the radiation margin for these devices was less than that recommended by the IEEE 323 Standard of 10 percent. These containment temperature RTDs will be replaced with RTDs that are qualified to higher dose levels and meet the margin requirements of IEEE 323 -1974.

The containment accident temperature and pressure profile are bounded by the existing equipment qualification profile. All equipment inside containment is qualified for the accident temperatures and pressures resulting from operation under EPU conditions.

The HELBs, which are the bases for equipment qualification outside containment, do not change as a result of EPU operation. All equipment outside containment is qualified for the appropriate EPU accident temperatures.

The qualified life of the equipment is not changed since the normal operating temperatures are not exceeded for EPU. The time-limited aging analysis (TLAA) of the EQ of electrical equipment remains valid for EPU radiation and temperature conditions.

2.3.1.3 Conclusion

FPL has performed an assessment of the effects of the proposed EPU on the EQ of electrical equipment and concludes that it has adequately addressed the effects of the proposed EPU on

the environmental conditions for the qualification of, electrical equipment. FPL further concludes that the equipment will continue to meet the current licensing basis requirements with respect to 10 CFR 50.49 following implementation of the proposed EPU. FPL finds the proposed EPU acceptable with respect to the EQ of the electrical equipment.

Table 2.3.1-1
Summary of Results of EPU Impact on Environmental Qualification of Electrical Equipment

Parameter	Reactor Containment Building	Reactor Auxiliary Building	Steam Trestle
Normal Conditions			
Temperature	No change to maximum normal operating temperature (120°F)	No change to maximum normal operating temperature (104°F)	No change to qualified life design temperature (104°F)
Pressure	• EPU pressure range is bounded by current conditions	No change	No change (pressure is 0 psig since open to atmosphere)
Humidity	No change in normal operating relative humidity	No change	No change (100% RH)
pH	N/A	N/A	N/A
Radiation	• EQ not affected by the normal operation radiation environment (See discussion under Accident Conditions)	• EQ not affected by the normal operation radiation environment (See discussion under Accident Conditions)	No change
Accident Conditions			
Temperature	Bounded by current peak EQ temp profile	The accident analyses of the HELBs in the RAB for EQ have not changed as a result of the EPU; no new conditions are identified due to the EPU	The pre-EPU accident temperature in the trestle area of 320°F is the localized temperature effects of a HELB, does not affect the area and is not changed by EPU operation
Pressure	Bounded by current pressure profile	No Change	No Change
Humidity	Current relative humidity is 100%; unchanged by EPU	No Change	No Change
pH	• pH range unchanged • No EQ impact from change		N/A N/A
Submergence/ Flooding	• Submergence level decreased • No impact to equipment due to equipment elevations		N/A N/A
Radiation	• Calculated using bounding scaling factors • Total integrated dose increases for EPU • Based on assessments, all equipment will continue to be qualified at EPU conditions		The total integrated dose has not changed significantly due to EPU. Normal 60 year dose has not changed (1.50E+02 rads) and the accident dose has changed minimally (from 6.20E+02 rads to 6.45E+02 rads). There is no impact on equipment qualification as a result of these changes.

Figure 2.3.1-1
Containment LOCA and MSLB Accident Temperature Profiles Vs. Plant EQ Profile

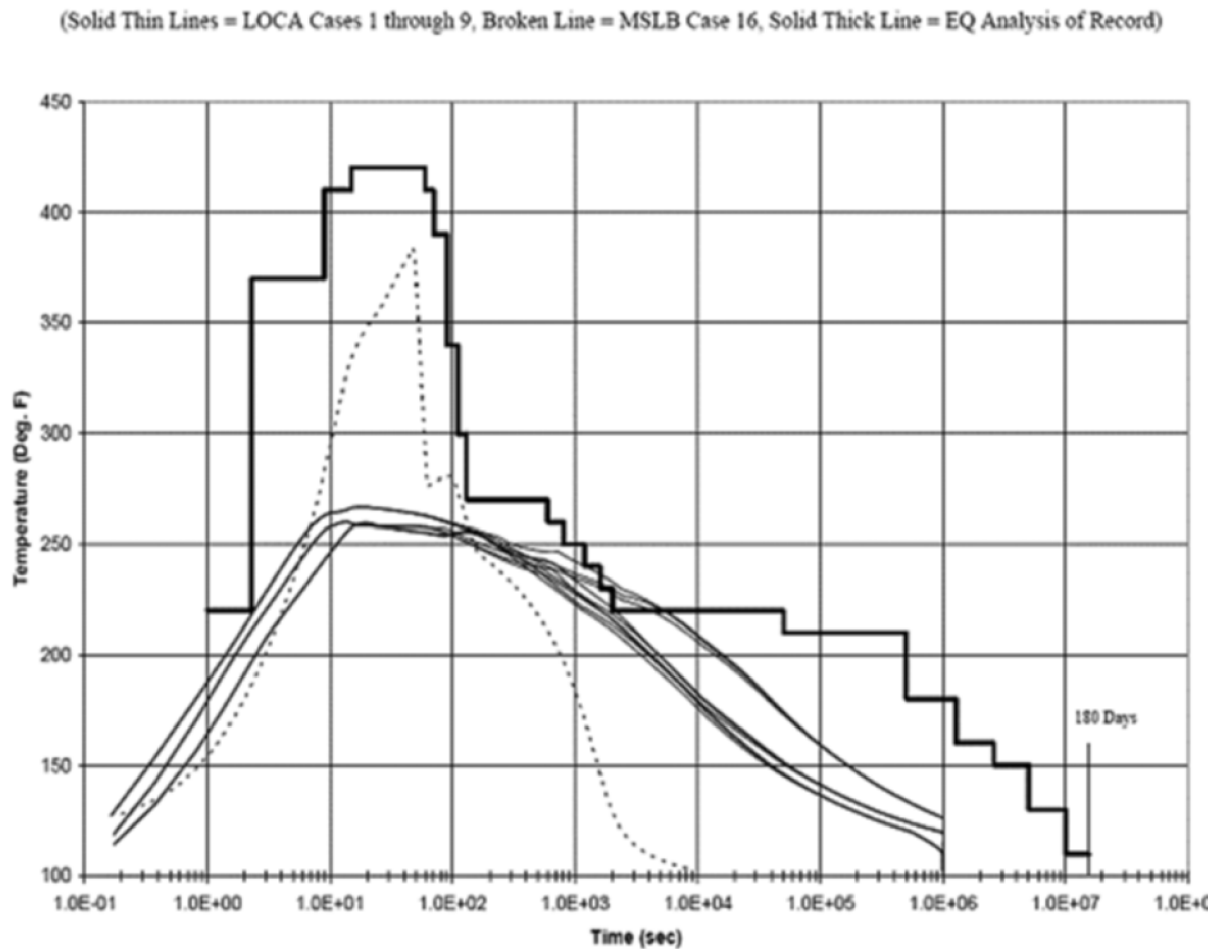
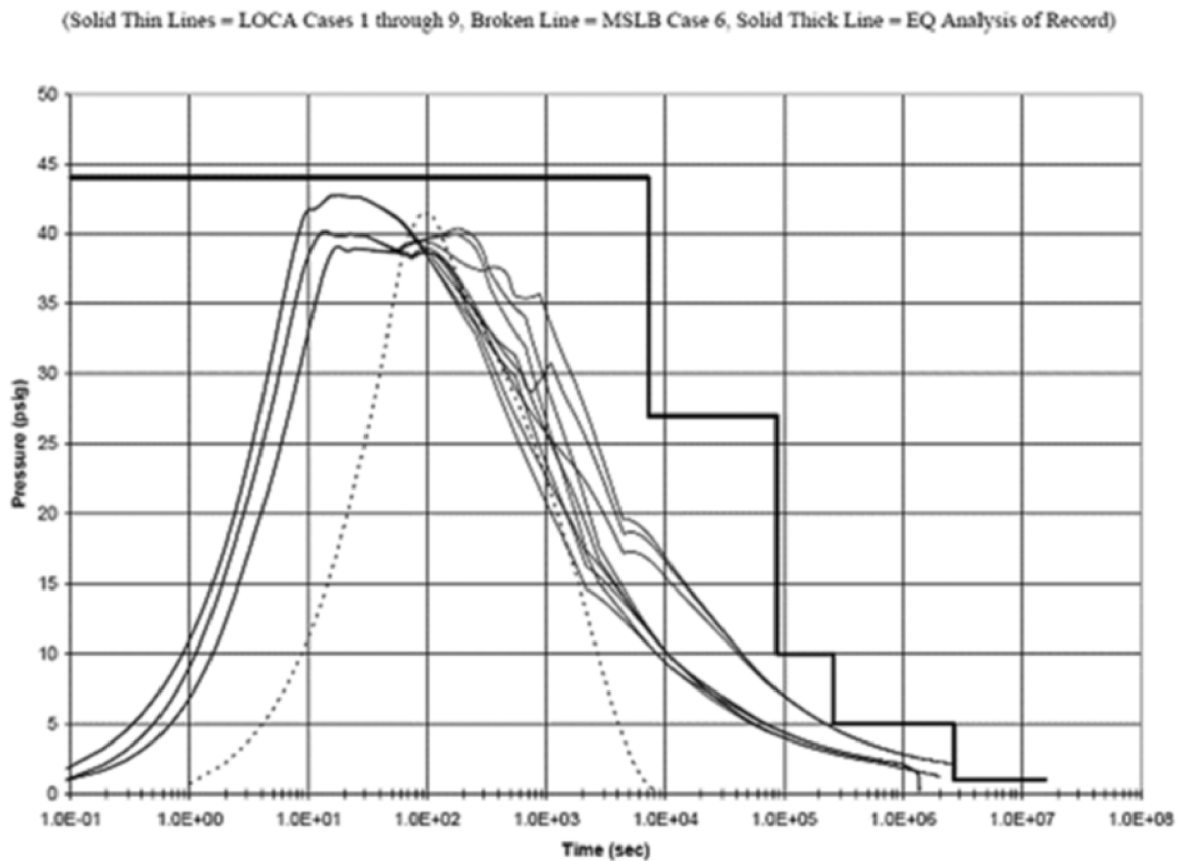


Figure 2.3.1-2
Containment LOCA and MSLB Accident Pressure Profiles vs. Plant EQ Profile



2.3.2 Offsite Power System

2.3.2.1 Regulatory Evaluation

The offsite power system includes two or more physically independent circuits capable of operating independently of the onsite standby power sources. The Florida Power and Light (FPL) review covered the descriptive information, analyses, and referenced documents for the offsite power system; and the stability studies for the electrical transmission grid. The FPL 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 General Design Criterion (GDC)-17.

Specific review criteria are contained in Standard Review Plan (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 Unit 2 Current Licensing Basis

As noted in Updated Final Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDC for Offsite Power System is as follows:

- GDC-17 is described in UFSAR Section 3.1.17 Criterion 17 - Electrical Power Systems.

An onsite electrical power system and an offsite electrical power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

The onsite electrical power sources, including the batteries, and the onsite electrical distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

Electrical power from the transmission network to the switchyard shall be supplied by physically independent transmission lines (not necessarily on separate rights-of-way) designed and located so as to suitably minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite electrical power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not

exceeded. One of these circuits shall be designed to be available within a few seconds following a loss of coolant accident to assure that core cooling, containment integrity, and other vital safety functions are maintained.

Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electrical power supplies.

Offsite power is transmitted to the plant switchyard by three physically independent 230 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 or of a unit generator, there is a "fast dead bus" automatic transfer to the startup transformers thus providing continuity of power.

In the event of a loss of the offsite power sources, two emergency onsite diesel generator sets and redundant sets of station batteries provide the necessary ac and dc power for safe shutdown or, in the event of an accident, provide the necessary power to restrict the consequences to within acceptable limits. The onsite emergency ac and dc power systems consist of redundant and independent power sources and distribution systems such that a single failure does not prevent the systems from performing their safety function.

Refer to UFSAR Sections 8.2 and 8.3 for further discussion of offsite power sources and onsite power sources respectively.

The functions of the Offsite Power Systems are:

- a. to provide startup auxiliary power;
- b. To provide alternate power sources for the auxiliary loads, and
- c. To provide a preferred power source for the safety related electrical equipment during an emergency.

St. Lucie Unit 1 UFSAR Section 8.2.2.3 provides the transient stability study performed for the dual-unit St. Lucie site, the results of which conclude that the transmission system and the unit response is stable for all of the contingency events simulated. None of the outage events modeled cause transmission voltage or line loadings to exceed ratings.

In addition to the licensing basis described in the UFSAR, the offsite power system was evaluated for License Renewal. For License Renewal, electrical and instrumentation and controls (I&C) systems were broken down into commodity groups and then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.5 of the SER identifies that components of the offsite power system are within the scope of License Renewal. The programs used to manage the aging effects associated with the offsite power system are discussed in SER Section 3.6 and UFSAR Chapter 18.

2.3.2.2 Technical Evaluation

2.3.2.2.1 Introduction

The offsite power system and its components are discussed in the UFSAR Sections 8.2 and 8.3. The offsite transmission system and 230 kV switchyard are common to St. Lucie Unit 1 and 2.

The offsite transmission system is designed to provide reliable facilities to:

- Accept the electrical output of the plant, and
- 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. Each line is carried on a separate transmission tower and running parallel to each other. These lines run to the Midway substation, traversing the Indian River and an overland section. Each circuit is sized for handling 100 percent of one unit's output. The 230 kV system is protected from lightning and switching surges by overhead electrostatic shield wires and surge protection equipment. One of the three 230 kV transmission lines can supply all of the plant auxiliary power.

The system stability analysis assessed the response of the transmission system to the loss of the largest generator, the loss of largest load, and the loss of most critical transmission circuit. The analyses conclude that the transmission system, as well as the St. Lucie Unit 2 response, is stable for all of the contingency events stipulated in the USFAR Section 8.2.2.1.

The five bay 230 kV (nominal) switchyard 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) 2A and 2B, where it is stepped up to 230 kV nominal and enters the 230 kV switchyard through the overhead tie-lines.

The east pull-off tower in Bay 2 supplies power via a single overhead tie-line to SUTs 1A and 2A, located in the Unit 1 transformer yard. The east pull-off tower in Bay 4 supplies power via three overhead tie-lines to SUTs 1B and 2B, located in the Unit 2 transformer yard. Either set of 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 (2-secondary winding).

2.3.2.2.2 Description of Analyses and Evaluations

The offsite power system and its components were evaluated to ensure they are capable of performing their intended function at EPU conditions. The evaluation was based on the system's required design functions and attributes, and upon a comparison between the existing equipment

ratings and the anticipated operating requirements at EPU conditions. In addition, grid stability is evaluated and current licensing basis is assessed with respect to the requirements of GDC-17.

Refer to LR [Section 2.3.3](#) for the main transformers and startup transformers evaluation.

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

As discussed above, the offsite power system is within the scope of License Renewal. Operation of the offsite power system under EPU conditions has been evaluated to determine if there any new aging effects requiring management or if any existing aging management programs are affected. 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.

2.3.2.2.4 Results

2.3.2.2.4.1 Grid Stability

The offsite transmission system is discussed in UFSAR Section 8.2.1. A system impact study was performed to evaluate the impact of the EPU on the reliability of the local 230 kV and Florida Reliability Coordinating Council bulk electric power systems. The study was performed in accordance with FPL and Florida Reliability Coordinating Council requirements and North American Electric Reliability Corporation's Planning Standards.

Thermal, voltage, stability, and short-circuit simulations, with and without EPU, were compared to determine any detrimental impact of the proposed EPU. Several analyses were performed in the study, including thermal, power flow, transient stability and short circuit cases. Extreme contingencies (i.e., loss of entire generation units) were evaluated and found to be acceptable.

Key results provided in the study are as follows:

- Identification of any circuit breaker short circuit capability limit exceeded as a result of EPU;
- Identification of any thermal overload or voltage limit violation resulting from EPU; and
- Identification of any instability or inadequately damped response to system disturbances resulting from the impact of EPU on the interconnection.

The EPU for both units meet the reactive capability requirements:

- Fault current levels did not exceed the rating of any of the circuit breakers in the switchyard as a result of the EPU.
- If only St. Lucie Unit 1 were to be uprated, then upgrading of the existing facilities or construction of new facilities would not be required; however, since uprates are planned for both St. Lucie units the integration of the EPU as an FPL network resource requires an increase in the thermal rating of the existing St. Lucie-Midway #1, St. Lucie-Midway #2, and

St. Lucie-Midway #3 230 kV lines. Therefore, the three St. Lucie Midway line ratings will be increased from 2380A to 2790A.

- Results of the dynamic simulations indicate acceptable performance for the most extreme North American Electric Reliability Corporation Category D event at Midway substation. The most severe fault at Midway substation is on the Midway 500/230 kV auto with delayed clearing for breaker failure. Similar to the existing performance without the upgrades, St. Lucie Units 1 and 2 lost synchronism and tripped after the fault was cleared; however, the transmission system remained stable. This performance is acceptable for the North American Electric Reliability Corporation Category D extreme event.
- The analysis indicated that the EPU project for both units will not adversely affect the Southern to Florida import capability in the 2012 timeframe.

The grid stability analysis and system impact study are provided in Appendix C to Attachment 5 of the EPU license amendment request.

2.3.2.2.4.2 Offsite Power System Components

Transmission Lines

Transmission lines are discussed in UFSAR Sections 8.2.1.1 and 8.2.2.1. The transmission system consists of three separate 230 kV transmission lines connecting the St. Lucie switchyard to the system transmission grid at Midway substation. The transmission system has been evaluated for EPU conditions. The evaluation determined that modifications are required to upgrade the 230 kV transmission lines connected to the St. Lucie switchyard. The required modifications are installation of spacers between the existing bundled phase conductors, fiber optic overhead ground wire on all three lines, replacement of associated disconnect switches and a new power system stabilizer. The proposed modifications will ensure that the transmission lines' design functions will be maintained following implementation of the EPU.

Switchyard Connections

The 230 kV switchyard equipment has been evaluated. The evaluation determined that modifications are required to upgrade switchyard equipment. The required modifications include replacement of wavetraps with overhead fiber optic protection schemes, replacement of disconnect switches, and upgrade or replacement of associated jumpers, buses and equipment connections. The evaluation concluded that the proposed modifications to the 230 kV switchyard equipment will ensure that the design function of the switchyard equipment is maintained following implementation of EPU.

Main Transformers Tie-Line

The existing tie-lines between the 230kV switchyard and the main transformers 2A and 2B high voltage side have been evaluated for EPU conditions. The evaluation determined that the existing tie-lines are adequate to meet the generator EPU rating. The tie-lines are protected by a differential protection scheme with inputs from current transformers located at the main transformers high side and in switchyard breakers. The evaluation also confirmed that existing tie-lines differential protection schemes are adequate for EPU loads.

Startup Transformers Tie-Lines

The existing tie-lines between the 230kV switchyard and the startup transformers high voltage side provide separate offsite power sources from switchyard Bay 2 and Bay 4 to startup transformers 1A, 2A and 1B, 2B, respectively. The startup transformers tie-lines have been evaluated for EPU conditions. The evaluation determined that the existing tie-lines are adequate to meet EPU plant auxiliary loads. The tie-lines are protected by a differential protection scheme with inputs from current transformers located at the startup transformers high side and at the associated switchyard breakers. The evaluation indicates that the increase in plant auxiliary loads at EPU conditions does not affect the existing startup transformers tie-lines protection design.

2.3.2.2.4.3 Summary

As a result of the evaluation for EPU, it has been determined that the offsite power system will continue to have sufficient capacity and capability to supply power to plant auxiliary power system for station startup, shutdown or at any time that auxiliary power is unavailable from the unit auxiliary transformers in accordance with the current licensing basis. This result considers the effect of modifications in associated equipment. FPL further concludes that the impact of the proposed EPU does not degrade grid stability.

2.3.2.3 Conclusion

FPL has reviewed the effects of the proposed EPU on the offsite power system and concludes that the offsite power system will continue to meet its current licensing basis with respect to the requirements of GDC-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. FPL further concludes that the impact of the proposed EPU does not degrade grid stability. Therefore, FPL finds the proposed EPU acceptable with respect to the offsite power system.

2.3.3 AC Onsite Power System

2.3.3.1 Regulatory Evaluation

The alternating current (ac) onsite power system includes those standby power sources, distribution systems, and auxiliary supporting systems that supply power to safety-related equipment. The Florida Power and Light (FPL) review covered the descriptive information, analyses, and referenced documents for the ac onsite power system.

The 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.

Specific review criteria are contained in Standard Review Plan (SRP) Sections 8.1 and 8.3.1 and guidance is provided in Matrix 3 of RS-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDC for the ac onsite power system:

- GDC-17 is described in UFSAR Section 3.1.17 Criterion 17-Electrical Power Systems.

An onsite electrical power system and an offsite electrical power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

The onsite electrical power sources, including the batteries, and the onsite electrical distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

Electrical power from the transmission network to the switchyard shall be supplied by physically independent transmission lines (not necessarily on separate rights-of-way) designed and located so as to suitably minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. Two physically independent circuits from the switchyard to the onsite electrical distribution system shall be provided. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power sources and the other offsite electrical power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a loss of coolant accident to

assure that core cooling, containment integrity, and other vital safety functions are maintained.

Offsite power is transmitted to the plant switchyard by three physically independent 230 kV transmission lines. During normal plant operation, the unit auxiliary power is normally supplied from the main generator through the plant auxiliary transformers. Upon loss of power from main generator via the auxiliary transformers or of a unit generator, there is a fast dead bus automatic transfer to the start-up transformers, thus providing continuity of power.

In the event of a loss of the offsite power sources, two emergency onsite diesel generator sets and redundant sets of station batteries provide the necessary ac and dc power for safe shutdown or, in the event of an accident, provide the necessary power to restrict the consequences to within acceptable limits. The onsite emergency ac and dc power systems consist of redundant and independent power sources and distribution systems, such that a single failure does not prevent the systems from performing their safety function.

Refer to UFSAR Sections 8.2 and 8.3 for further discussion of offsite power sources and onsite power sources respectively.

The normal source of auxiliary ac power for plant start-up or shutdown is from the incoming off-site transmission lines through the plant switchyard and start-up transformers.

Each of the startup transformers and each emergency diesel generator has sufficient capacity to supply the safety-related loads for safe plant shutdown or to mitigate the consequences of a design basis accident.

In addition to the licensing bases described in the UFSAR, the ac onsite power system was evaluated for License Renewal. For License Renewal, electrical and instrumentation and controls (I&C) systems were broken down into commodity groups and then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.5 of the SER identifies that components of the ac onsite power system are within the scope of License Renewal. The programs used to manage the aging effects associated with the ac onsite power system are discussed in SER Section 3.6 and UFSAR Chapter 18.

2.3.3.2 Technical Evaluation

2.3.3.2.1 Introduction

The ac onsite power system and its components are discussed in UFSAR Sections 8.1, 8.2 and 8.3. The ac onsite power system consists of station service transformers (SST), the 6900 V, 4160 V, 480 V, 120 V systems, emergency diesel generators (EDG), associated buses, non-segregated phase bus ducts, cables, electrical penetrations (where applicable), circuit breakers and protective relays. In addition, the main generator, isolated phase bus ducts (IPB), main transformers (MT), unit auxiliary transformers (UAT), and startup transformers (SUT) are included in the ac onsite power system evaluations.

The function of the main generator is to provide a means of converting the mechanical energy of the main turbine into a supply of regulated and usable electricity. The generator output is delivered at 22 kV to the MTs 2A and 2B and UATs 2A and 2B through IPB ducts.

The function of the IPB ducts is to conduct electrical power from the main generator to the MTs 2A and 2B and UATs 2A and 2B.

The function of the two three-phase, two winding MTs 2A and 2B is to provide a means to transmit the generator output power to the switchyard by stepping up the generator voltage from 22 kV (nominal) to the switchyard voltage of 230 kV (nominal).

The function of the two three-phase, three winding UATs 2A and 2B is to step down the main generator's output at 22 kV to 6.9 kV and 4.16 kV to supply the onsite ac electrical distribution system normal loads during normal power operation.

The function of the two three-phase, three winding SUTs 2A and 2B is to step down the offsite voltage from 230 kV to 6.9 kV and 4.16 kV and power the plant auxiliary loads required for startup, normal operation, normal shutdown and emergency shutdown for each unit and when UATs 2A and 2B are not available.

The function of the 6.9 kV system is to supply power to non-safety-related loads. The function of the 4.16 kV system is to provide power to safety-related and non-safety-related loads.

The function of the 480 V system is to step down the 4.16 kV through load centers, to supply non-safety-related and safety-related buses (including motor control centers (MCC)), and through step-down transformers to rectifiers/inverters to supply 120 VAC instrumentation and direct current (dc) controls and 120/208 V power panels. The normal supply to non-safety-related 480 V buses 2A1 and 2B1 is from 4.16 kV buses 2A2 and 2B2, respectively, which are powered from UATs or SUTs. The emergency portion of the 480 volt system is arranged into redundant load groups A and B served by 480 volt buses 2A2 and 2A5, 2B2 and 2B5 respectively with a swing load group AB served by 480 volt bus 2AB. Power is transmitted from the 4.16 kV emergency buses through the SST to 480 volt buses 2A2, 2A5, 2B2 and 2B5. The swing bus 2AB may be tied to either one of the redundant emergency 480 volt buses but never both at the same time.

The function of the station blackout (SBO) cross-tie is to connect the safety-related swing switchgears 1AB and 2AB of the two units during an SBO event. This cross-tie can be used when an actual SBO condition exists and will be implemented under procedural controls to assure that the EDG capability will not be exceeded. Further, the present St. Lucie design has the capability of electrically connecting the two units' 4.16 kV buses 1A2 and 2A2 (1B2 and 2B2) through 4.16 kV bus 2A4 (2B4). Refer to LR [Section 2.3.5](#), Station Blackout, for the station SBO evaluation.

The function of the two EDGs 2A and 2B is to supply emergency ac onsite power in the event of a complete loss of normal offsite power, i.e., loss of offsite power (LOOP). The system is capable of performing this function with or without a coincident loss-of-coolant accident (LOCA).

The function of the 120/208 V power system is to supply power for normal lighting and other plant loads that do not require a regulated power source. Some of the 120/208 volt panels feed safety-related loads such as engineered safety features process monitoring instrumentation as

well as some non-safety-related loads requiring regulated power. In such cases, the stepdown transformer is fed from an emergency diesel generator backed MCC to supply a Class 1E power panel.

The function of the 120 VAC instrument power system is to provide regulated, redundant Class 1E power to essential instrumentation and control loads. The function of the separate 120 volt vital ac system is to provide uninterruptable power to non-emergency instrumentation and control loads.

2.3.3.2.2 Description of Analysis and Evaluations

The ac onsite power system and its components were evaluated to ensure they are capable of performing their intended functions at EPU conditions. The evaluation is based on the system's required design functions and attributes, and upon comparison between the existing equipment ratings and anticipated operating requirements at EPU conditions. The EPU conditions require that the equipment operate at service conditions different than the currently evaluated operating conditions. To determine the impact of EPU operation on the ac onsite power system, a baseline for bus loading was developed to represent the existing plant loading conditions. New load flow/short circuit current analyses were performed that include load changes as a result of EPU conditions. The results of these analyses are used to ensure that the system and equipment are capable of performing their intended functions and form the bases for the ac onsite power system evaluations.

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

As discussed above, the ac onsite power system is within the scope of License Renewal. Operation of the ac onsite power system under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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

2.3.3.2.4 Results

As a result of EPU studies, several modifications are planned to improve electrical bus margins. These modifications will compensate for increases in electrical loading, such as, an increase in size of the IPB duct cooling fan motors or an increase in EPU load requirements for the various pump motors. The major modifications are briefly described below:

- Trip 4.16 kV motors for the heater drain (HD), condensate pumps (CND), and main feedwater (FW) pumps during a safety injection actuation system (SIAS) event,
- The new MT cooling loads will also be tripped during a SIAS event, and

- The new IPBD cooling fan motors are increasing from 25 horsepower (hp) to 100 hp and will have their electrical feeds moved from an MCC to the same load centers that feed the transformer cooling package. These loads also will be tripped during a SIAS event.

Main Generator

The main generator is discussed in UFSAR Section 8.2.1.3. The existing generator rating is 1000 MVA, 22 kV, 850 MW, 0.85 power factor, 60 Hz, 1800 rpm @ 60 psig hydrogen pressure. In order to support unit operation at EPU conditions, a generator evaluation was performed. The evaluation determined that the existing main generator must be modified. The required generator changes include rewinding of the rotor and stator and modifying the associated hydrogen cooling system. The revised generator nameplate rating is 1200 MVA, 22 kV, 1080 MW, 0.90 power factor, 60 Hz, 1800 rpm @ 75 psig hydrogen pressure. The maximum generator output at EPU conditions is 1069.8 MW @ 0.897 power factor lagging. The generator capability curves show that the modified main generator is capable of continuous operation at this level and adequate to support unit operation at EPU conditions including machine leading and lagging reactive power requirements, as indicated in LR [Table 2.3.3-1](#).

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.

Isolated Phase Bus Duct

The IPB duct is discussed in UFSAR Section 8.2.1.3. The existing IPB duct main bus and main transformer tap bus continuous current design ratings are 28 kA and 14 kA forced cooled, respectively. The EPU evaluation determined that the IPB duct main bus and main transformer tap bus will be upgraded to 33.2 kA and 16.6 kA (by replacing the existing isolated phase coolers), respectively, which bounds unit operations at worst-case EPU loading conditions, as indicated in LR [Table 2.3.3-1](#).

The existing IPB duct tap buses to UAT and potential transformer (PT) are rated 2.5 kA self-cooled. The evaluation also demonstrates that the continuous current rating of the tap buses bounds the anticipated worst-case bus loading at EPU conditions.

The evaluation indicates that the IPB main bus short circuit design ratings are adequate for EPU conditions. However, IPB MT, UAT and PT tap buses short circuit design ratings are less than the anticipated worst-case fault current levels for both pre-EPU and EPU conditions. This is a current plant design issue. Further analysis has shown that only the UAT taps require modification. The modifications to resolve over duty condition on IPB UAT tap buses will be implemented prior to EPU.

The IPB duct upgrade modification will include replacement of the existing isolated phase cooler. The evaluation confirms after considering the modifications that the IPB duct main and tap bus continuous and short circuit ratings are adequate to support unit operation at EPU conditions.

Main Transformers 2A and 2B

The generator step up MTs 2A and 2B are discussed in UFSAR Section 8.2.1.3. The MTs are rated 475 MVA each, forced oil and air (FOA) at 65°C, connected in parallel, with separate cooling equipment. The 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, a transformer study was performed to determine required modifications to upgrade the MT rating. The required modifications include replacement of step up MTs 2A and 2B with new higher rated transformers. The new transformers will be rated 635 MVA each, FOA at 55°C temperature rise, which envelopes the anticipated worst-case generator step up transformer loading at EPU conditions. The modifications will be implemented prior to EPU.

The existing MT protection requires revised relay setpoints to support operation at EPU conditions.

Unit Auxiliary Transformers 2A and 2B

The existing three-winding UATs 2A and 2B are discussed in UFSAR Section 8.2.1.4 and 8.3.1.1.1. Each transformer FOA design rating at 65°C is 39.2 MVA @ 22 kV high voltage (HV) winding, 23.52 MVA @ 6.9 kV low voltage (LV) winding, and 15.68 MVA @ 4.16 kV LV winding. The EPU evaluation determined that the existing UAT 65°C design ratings for the HV and both LV windings envelope the anticipated worst-case loading on the UATs at EPU conditions, therefore, the UATs are adequate to support unit operation at EPU conditions.

The existing UAT protection relay setpoints are not affected and are adequate at EPU conditions.

Startup Transformers 2A and 2B

The existing three-winding SUTs 2A and 2B are discussed in UFSAR Section 8.2.1.5.

Each SUT, 2A and 2B, is rated 21/28/35/39.2 MVA: SUT 2A - oil air/forced, air/forced oil and air at 55°C forced oil and air at 65°C (OA/FA/FOA at 55°C/FOA at 65°C); SUT 2B - oil air/forced oil air (one cooling bank)/forced oil air at 55°C (both cooling banks)/forced oil air at 65°C (both cooling banks) (OA/FOA/FOA at 55°C/FOA at 65°C), double secondary winding, 230/6.9/4.16 KV. The SUT 2A 6.9 KV secondary is rated 12.6/16.8/21.0/23.6 MVA and 4.16 KV secondary is rated 8.4/11.2/14.0/15.7 MVA, OA/FA/FOA at 55°C /FOA at 65°C. The SUT 2B 6.9 KV secondary is rated 12.6/16.8/21.0/23.52 MVA and 4.16 KV secondary is rated 8.4/11.2/14.0/15.68 MVA, OA/FOA (one cooling bank)/FOA (both cooling banks) at 55°C /FOA at 65°C (both cooling banks).

The EPU evaluation determined that the existing SUT 65°C design ratings for the HV and both LV windings envelope the anticipated worst-case loading on the SUTs at EPU conditions, therefore, the SUTs are adequate to support unit operation at EPU conditions.

The existing startup transformer protection relay setpoints are not affected and are adequate at EPU conditions.

6.9 kV System

The 6.9 kV system is discussed in UFSAR Section 8.3.1.1.1(a). Two 6.9 kV buses 2A1 and 2B1 are provided, each supplied from a unit auxiliary or alternatively from a startup transformer. Each

6.9 kV bus serves two reactor coolant pump motors and one steam generator main FW pump motor. The 6.9 kV buses are non-safety-related, or normal buses, since they serve equipment that is not required to function for safe plant shutdown or for design basis accidents. The evaluation of the 6.9 kV system, switchgear buses, circuit breakers, non-segregated phase bus ducts and affected motors at EPU conditions confirms the following:

6.9 kV Switchgear Buses, Circuit Breakers and Non-segregated Phase Bus Ducts

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, as indicated in LR [Tables 2.3.3-2](#) and [2.3.3-3](#). 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 buses, circuit breakers and non-segregated phase bus ducts are within the equipment design ratings.

The 6.9 kV FW pump motors are affected by operation at EPU conditions. 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, as indicated in LR [Table 2.3.3-3](#). Therefore, the EPU loading requirements of motors, motor feeder breakers are bounded by equipment design ratings.

The calculated worst-case short circuit momentary currents at the affected 6.9 kV switchgear buses during operation at EPU conditions are less than the equipment short circuit ratings, as indicated in LR [Table 2.3.3-4](#). The affected 6.9 kV switchgear circuit breaker short circuit interrupting currents are less than the equipment short circuit ratings, as indicated in LR [Table 2.3.3-5](#). The EPU short circuit current requirements of switchgear buses and circuit breakers remain bounded by equipment design ratings.

Therefore, the 6.9kV system switchgear buses, circuit breakers, and non-segregated phase bus ducts are adequately sized to support operation at EPU conditions.

System 6.9 kV Voltage Level

The FW pump motors are affected by operation at EPU conditions. The calculated worst-case minimum and maximum steady-state running motor terminal voltages have been evaluated in the load flow, short circuit, and motor starting analysis. The evaluation indicates that the minimum and maximum steady-state motor terminal voltages are within the allowable minimum and maximum design values at existing and EPU conditions.

6.9 kV Motor Load Requirements

The existing FW pump motors are affected by operation at EPU conditions. The motor load brake horsepower requirements remain within the 7000 hp nameplate rating. The steady-state full load current requirements for the motors, as shown in LR [Table 2.3.3-3](#), are bounded by the full load current design ratings. Therefore, steady-state running current loads on the 6.9 kV motors affected by operation at EPU conditions are within the design ratings of the motors at EPU conditions.

The allowable current loading for existing FW pump motor cables is not adversely affected by operation at EPU conditions.

The protective relay setpoints of the FW pump motors were established based upon the full load current values for the motors. These values are above the EPU load conditions. Therefore, there are no changes to the existing protective relay setpoints for the 6.9 kV motors at EPU conditions. The FW system is addressed in LR [Section 2.5.5.4](#).

4.16 kV System

The 4.16 kV system is discussed in UFSAR Section 8.3.1.1.1(b). The evaluation of the 4.16 kV system, switchgear buses, circuit breakers, non-segregated phase bus ducts and affected motors at EPU conditions confirms the following:

4.16 kV Switchgear Buses, Circuit Breakers and Non-segregated Phase Bus Ducts

The 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, as indicated in LR [Table 2.3.3-6](#). 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 buses, circuit breakers and non-segregated phase bus ducts are within the equipment design ratings.

The CND pump motors, HD pump motors and turbine cooling water (TCW) pump motors are affected by operation at EPU conditions. The calculated worst-case full load current for the pump motors during operation at EPU conditions are less than the motor rated maximum full load currents, as indicated in LR [Table 2.3.3-7](#). Therefore, the EPU loading requirements of motors, motor feeder breakers are bounded by equipment design ratings.

The calculated worst-case short circuit momentary currents at the affected 4.16 kV switchgear buses during operation at EPU conditions are less than the equipment short circuit ratings, as indicated in LR [Table 2.3.3-6](#). The affected 4.16 kV switchgear circuit breaker short circuit interrupting currents are less than the equipment short circuit ratings, as indicated in LR [Table 2.3.3-8](#). The EPU short circuit current requirements of switchgear buses and circuit breakers remain bounded by equipment design ratings.

Therefore, the 4.16 kV system switchgear buses, circuit breakers, and non-segregated phase bus ducts are adequately sized to support operation at EPU conditions.

4.16 kV System Voltage Level

The CND pump motors, HD pump motors, and TCW pump motors are affected by operation at EPU conditions. The calculated worst-case minimum and maximum steady-state running motor terminal voltages are shown in LR [Table 2.3.3-9](#). The table indicates that the minimum and maximum steady-state motor terminal voltages are within the allowable minimum and maximum design values. Therefore, the motor terminal voltages are within the allowable voltage range at EPU conditions.

The evaluation demonstrates that there are no adverse voltage effects on the safety-related 4.16 kV system buses protected by degraded voltage relays. Therefore, the degraded voltage relay setpoints are not affected by operation at EPU conditions.

4.16 kV Motor Load Requirements

The existing CND pump motors, HD pump motors and TCW pump motors are affected by operation at EPU conditions. The motor load brake horsepower requirements remain within the nameplate ratings. The steady-state full load current requirements for the affected motors, as shown in LR [Table 2.3.3-7](#) are bounded by the full load current design ratings. Therefore, steady-state running current loads on the 4.16 kV motors affected by operation at EPU conditions is within the design ratings of the motors at EPU conditions.

The allowable current loading for existing CND pump motor, HD pump motor, and TCW pump motor cables are not adversely affected by operation at EPU condition.

The protective relay setpoints of the CND pump motors, HD pump motors, and TCW pump motors were established based upon the full load current values for the motors. These values are above the EPU load conditions. Therefore, there are no changes to the existing protective relay setpoints for the 4.16 kV motors at EPU conditions. The condensate system is addressed in LR [Section 2.5.5.4](#).

480 V System

The 480 V system is discussed in UFSAR Section 8.3.1.1.1(c). The 480 V system is comprised of nine 480V load center buses 2A1, 2B1, 2A5, 2A2, 2B2, 2B5, 2A3, 2B3 and 2AB supplied from the 4.16 kV system through 4160V/480V station service transformers (SSTs) which are normally powered from the UATs or SUTs.

The 480 V System load changes under EPU conditions are as follows:

- The horsepower of the high pressure seal oil backup pump motor on non-safety-related MCC 2B1, powered from 480V load center 2B1 is being increased from 20 hp to 40 hp,
- The 25 hp IPB duct cooler fan motors will be replaced by 100 hp fan motors and will be removed from MCCs 2A1 and 2B1 and repowered from 480V load centers buses 2A1 and 2B1, and
- The turbine generator bearing oil lift pump motor on non-safety-related MCC 2B1, powered from 480V load center 2B1 is being increased from 15 hp to 20 hp.

The evaluation of the 480 V system, affected SSTs, load center buses and circuit breakers, and MCCs at EPU conditions confirms the following:

4160 V-480 V Station Service Transformers

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, high pressure (HP) seal oil back-up pump motor, and turbine generator bearing oil lift pump motor modifications. The evaluation indicates that the affected SST design ratings envelope the load requirements under EPU conditions.

480 V Load Center Buses and Breakers

The impact of the system changes described above on the 480 V load center buses under EPU conditions has been evaluated. As indicated in LR [Table 2.3.3-10](#), the calculated worst-case

steady-state continuous current and short circuit momentary duty at the 480 V load center buses are enveloped by the equipment design ratings under existing and EPU conditions.

The impact of the system changes described above on the short circuit interrupting duty of the 480 V load center circuit breakers under EPU conditions has been evaluated. As indicated in LR [Table 2.3.3-11](#), the calculated worst-case short circuit interrupting duties on the circuit breakers under EPU conditions are enveloped by the equipment design ratings, with exception of the circuit breaker 2-40703 on load center 2AB, which is rated 22kA (maximum fault current 24kA). This condition will be remedied prior to EPU.

480 V Motor Control Centers

The impact of the EPU on the affected MCC steady-state continuous load currents is a decrease in load on MCC buses 2A1 and 2B1. The load flow calculations determined that the steady-state load current requirements for the affected MCC buses and circuit breakers are enveloped by the MCC bus and circuit breaker design ratings.

The 480 V MCC circuit breakers are rated 22 kA, 25 kA or 30 kA (symmetrical) interrupting ratings. The short circuit calculations determined that the fault duties on the circuit breakers are enveloped by the equipment design ratings.

Therefore, the evaluations determined that the 480 V load center and MCC buses and circuit breakers are adequately sized, for steady-state continuous current loading and short circuit duty, to support plant operation at EPU conditions.

480 V System Voltage Level

The evaluation demonstrates that there are no adverse voltage effects on the safety-related 480V load center buses 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 all 480 V load centers and MCCs do not exceed the maximum allowable design value range.

480 V Motor Load Requirements

The new IPB duct cooler fan motors, rated 100 hp, will be powered from the 480 V load centers 2A1 and 2B1. The HP seal oil backup pump motors rated 20 hp will be replaced by new 40 hp motors on MCC 2B1. As determined in the load flow calculations, the steady-state full load current requirements for the motors are bounded by the full load current design ratings at EPU conditions. The turbine generator bearing oil lift pump motors will be upgraded from 15 hp to 20 hp, powered from MCC 2B1. The turbine generator bearing oil lift pump motors operate during the Mode 5 (light load) condition. Therefore, the pump motor 5 hp load increase will provide additional voltage margin and has no impact on the Mode 1 or SIAS condition of operation.

Emergency Diesel Generators

The EDGs are discussed in UFSAR Section 8.3.1.1.1(f). The continuous rating of the EDGs is 3669.4 kW with additional short term ratings 3934.3 kW (2000 hour) and 4108.6 kW (30 minutes)

at 104°F. EDG loading has increased as a result of EPU. Calculations have been performed to assess the impact of the EPU loads on the EDGs. The results of the calculations indicate that EDG ratings are not exceeded by the cumulative loads applied and that the output voltage and frequency can be expected to meet specified requirements when loads are added, either as part of the load blocks or individually. In addition, the results of the calculations verify that the EDGs meet the load requirements of Technical Specifications. No modification of the EDGs is required to accommodate the increased loads. Since the EDG loading is bounded, the existing protective relay settings are not impacted by EPU.

Refer to LR [Section 2.5.7.1](#), Emergency Diesel Engine Fuel Oil Storage and Transfer System, for the emergency diesel engine fuel oil storage and transfer system evaluation.

120 VAC and 120/208V Power Systems

The 120 VAC instrument power system and 120/208 V power system are discussed in UFSAR Sections 8.3.1.1.1(d) and 8.3.1.1.1(e). The evaluation determined that no load changes to the 120 VAC Class 1E instrument power system and 120/208 V Class 1E power system are required to support EPU.

The anticipated modifications as required due to EPU conditions that may affect the 120 VAC non-Class 1E and 120/208 V 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 VAC non-Class 1E and 120/208V non-Class 1E power systems is expected to be small. Therefore, these systems will not be adversely affected by EPU conditions, and equipment ratings are expected to remain bounded by the existing analysis.

GDC-17 Requirements

The load flow and short circuit current analysis calculations indicate that the ac onsite power system equipment voltages and fault duties are not adversely affected by EPU conditions. The loading requirements of the evaluated equipment are bounded by equipment design ratings. Therefore, the ac onsite power system will continue to meet the licensing basis with respect to the requirements of GDC-17, and perform its intended functions during anticipated operational occurrences and accident conditions following implementation of the proposed EPU.

2.3.3.3 Conclusion

FPL has reviewed the assessment related to the effects of the proposed EPU on the ac onsite power system and concludes that it has adequately accounted for the proposed EPU effects on the systems functional design. FPL further concludes that the ac onsite power system will continue to meet the current licensing basis with respect to the requirements of GDC-17 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to the ac onsite power system.

Table 2.3.3-1
EPU Maximum Generator Output and Main Isolated Phase Bus and
Transformer Tap Bus Continuous Current Loading

Unit Operation	Generator Output				IPB Bus				
					Main Bus		Main Transformer Tap Bus		
					EPU Load	EPU Design Rating	Tap Bus 1A Load	Tap Bus 1B Load	EPU Design Rating
	MW	MVAR	MVA	PF %	kA				
Lagging	1069.8	529	1193.28	89.7	30.88	33.2	15.44	15.44	16.60
Leading	1069.8	290	1108.41	96.5	30.50		15.25	15.25	

Table 2.3.3-2
6.9 KV SWITCHGEAR BUS STEADY-STATE MAXIMUM CURRENT
(Supply From UAT)

Bus	Rating (A)	Existing		EPU		Notes
		Bus Voltage (V)	Load (A)	Bus Voltage (V)	Load (A)	
2A1	2000	6799	1246	6819	1254	1,2
2B1	2000	6802	1246	6833	1240	1,2

Notes:

1. The calculated continuous current values and bus voltages for the switchgear are obtained from the worst-case existing and EPU value from the load flow/short circuit analysis.
2. Under EPU conditions, train A (i.e., bus 2A1) experiences a larger load increase than train B (i.e., bus 2B1). However the load increase on train B is not clearly represented in the above table. This is due to an increase in the resultant bus 2B1 voltage under EPU condition, as shown in the above table. Because buses 2A1 and 2B1 loads consists of mostly constant-KVA (i.e., motor) loads, an increase in bus voltage results in a decrease in bus continuous current. The bus voltage increase was a result of utilizing a higher source (i.e., main generator) voltage under EPU than what was used under existing conditions.

Table 2.3.3-3
Affected 6.9 kV Circuit Breaker and Motor Steady-State Maximum Continuous Current

Breaker	Breaker Rating (A)	Motor	Motor Rating (hp)	Motor Rated Full Load Current (A)	Maximum Existing Load (A)	Maximum EPU Load (A)
2A1-3	1200	Feedwater 2A	7000	530	515	513
2B1-3	1200	Feedwater 2B	7000	530	515	512

Table 2.3.3-4
6.9 kV Switchgear Bus Short Circuit Momentary Current
(Asymmetrical)

Bus	Bus Bracing (kA)	Maximum Existing Duty (kA)	Maximum EPU Duty (kA)
2A1	70	60.0	60.1
2B1	70	60.5	60.7

Table 2.3.3-5
6.9 kV Switchgear Circuit Breaker Maximum
Short Circuit Interrupting Current
(Symmetrical)

Circuit Breakers on Bus	Design Rating Adjusted (A)	Maximum Existing Duty Adjusted (A)	Design Rating EPU Load Adjusted (A)	Maximum EPU Duty Adjusted (A)
2A1	39,457	35,894	39,457	35,967
2B1	39,457	36,405	39,457	36,548

Table 2.3.3-6
4.16 kV Switchgear Bus Steady-State Load
& Momentary Short Circuit Current

Bus	Existing		EPU		Ratings	
	Load (A)	Momentary (kA)	Load (A)	Momentary (kA)	Load (A)	Momentary (kA)
2A2	1677	61	1726	61	3000	80
2A3 (SA)	433	54	433	55	1200	80
2B2	1616	60	1663	60	3000	80
2B3 (SB)	423	54	422	54	1200	80
2A4	1661	56	1715	56	3000	80
2B4	1591	58	1641	58	3000	80

Table 2.3.3-7
Affected 4.16 kV Circuit Breaker and
Motor Steady-State Current

Breaker on Bus	Breaker Rating (A)	Motor	Motor Rating (hp)	Full Load Current (A)	Maximum Existing Load (A)	Maximum EPU Load (A)
2A2	1200	HD Pump 2A	1250	160	141	152
2B2	1200	HD Pump 2B	1250	160	141	148
2A2	1200	TCW Pump 2A	250	36	30	31
2B2	1200	TCW Pump 2B	250	36	30	31
2A2	1200	Condensate Pump 2A	4000	488	415	445
2B2	1200	Condensate Pump 2B	4000	488	415	444

Table 2.3.3-8
4.16 kV Switchgear Circuit Breaker Short Circuit Interrupting Current
(Symmetrical)

Circuit Breakers on Bus	Existing		EPU	
	Design Rating Adjusted (A)	Maximum Duty Adjusted (A)	Design Rating Adjusted (A)	Maximum Duty Adjusted (A)
2A2	46,913	35,387	46,913	35,428
2A3 (SA)	46,913	33,282	46,913	33,314
2B2	46,913	35,269	46,913	35,316
2B3 (SB)	46,913	32,891	46,913	32,928
2AB (SAB)	46,913	31,055	46,913	31,081
2A4	46,913	33,206	46,913	33,035
2B4	46,913	34,931	46,913	34,743

Table 2.3.3-9
4.16 kV System Minimum and Maximum Voltage
at Affected Motor Terminals

Motor	Rating (hp)	Minimum Voltage			Maximum Voltage		
		Existing (V)	EPU (V)	Design (V)	Existing (V)	EPU (V)	Design (V)
TCW pump 2A	250	4093	4107	3600	4411	4283	4400
TCW pump 2B	250	4100	4114	3600	4418	4290	4400
HD pump 2A	1250	4093	4107	3600	4411	4282	4400
HD pump 2B	1250	4099	4114	3600	4418	4289	4400
Condensate pump 2A	4000	4090	4104	3600	4409	4280	4400
Condensate pump 2B	4000	4096	4111	3600	4416	4286	4400

Table 2.3.3-10
480 V Load Center Bus Steady-State Continuous and
Momentary Short Circuit Current

Bus	Continuous Load			Short Circuit Momentary (Asymmetrical)		
	Existing Load (A)	EPU Load (A)	Rating (A)	Maximum Existing Duty (A)	Maximum EPU Duty (A)	Rating (Bus Bracing) (A)
2A1(1)	1,450	1,538	2,500	33,131	37,757	66,500
2A1(2)	1,376	1,341	1,600	18,582	18,618	66,500
2A2(1) (SA)	1,563	1,561	2,500	36,585	36,542	66,500
2A2(2) (SA)	836	836	1,600	18,307	18,284	66,500
2A3	183	183	1,000	19,044	19,023	22,000
2AB (SAB)	147	147	1,600	32,369	32,330	66,500
2B1(1)	1,355	1,442	2,500	31,328	31,970	66,500
2B1(2)	1,355	1,322	1,600	17,817	17,876	66,500
2B2(1) (SB)	1,370	1,368	2,500	38,485	38,447	66,500
2B2(2) (SB)	649	649	1,600	18,683	18,663	66,500
2B3	184	184	1,000	19,070	19,052	22,000
2A-5(1) (SA)	593	592	2,500	33,320	33,283	66,500
2A-5(2) (SA)	364	365	1,600	17,477	17,456	66,500
2B-5(1) (SB)	636	635	2,500	32,908	32,877	66,500
2B-5(2) (SB)	408	408	1,600	17,224	17,434	66,500

Table 2.3.3-11
480 V Load Center Circuit Breaker Short Circuit Interrupting Current
(Symmetrical)

Circuit Breakers on Bus	Design Rating Adjusted (kA)	Existing Maximum Duty Adjusted (kA)	EPU Maximum Duty Adjusted (kA)
2A1(1)	30	25	25
	65	25	25
2A1(2)	30	14	14
2A2(1) (SA)	30	27	27
	50	27	27
	65	27	27
2A2(2) (SA)	30	13	13
2A3	30	15	15
2AB (SAB)	22	24	24
	30	24	24
	50	24	24
2B1(1)	30	24	24
	65	24	24
2B1(2)	30	13	13
2B2(1) (SB)	30	29	29
	50	29	29
	65	29	29
2B2(2) (SB)	30	14	14
2B3	30	15	15
2A-5(1) (SA)	30	25	25
	65	25	25
2A-5(2) (SA)	30	13	13
2B-5(1) (SB)	30	25	25
	65	25	25
2B-5(2) (SB)	30	13	13

2.3.4 DC Onsite Power System

2.3.4.1 Regulatory Evaluation

The direct current (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 Florida Power and Light (FPL) review covered the information, analyses, and referenced documents for the dc onsite power system.

The NRC acceptance criterion for this review is 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.

Specific review criteria are contained in NRC Standard Review Plan (SRP) Sections 8.1 and 8.3.2.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

The specific GDC for the dc onsite power system:

- GDC-17 is described in UFSAR Section 3.1.17, Electrical Power Systems.

An onsite electrical power system and an offsite electrical power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

The onsite electrical power sources, including the batteries, and the onsite electrical distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electrical power sources.

In the event of a loss of the offsite power sources, two emergency onsite diesel generator sets and redundant sets of station batteries provide the necessary ac and dc power for safe shutdown or, in the event of an accident, provide the necessary power to restrict the consequences to within acceptable limits. The onsite emergency ac and dc power systems consist of redundant and independent power sources and distribution systems such that a single failure does not prevent the systems from performing their safety function.

The two systems that supply the 125V dc power to redundant Class 1E load groups from the two separate 125V dc buses are electrically independent and physically separated from each other. Each of the two systems has adequate capacity to supply the 125V dc power for the safety related loads required for safe shutdown of the plant. Refer to UFSAR Section 8.3.2 for further discussion of the onsite dc power system.

In Generic Letter (GL) 91-06, dated April 29, 1991, the NRC staff identified actions to be taken related to Generic Issue A-30, Adequacy of Safety Related DC Power Supplies. FPL responded via letter from W. H. Bohlke (FPL) to the NRC Document Control Desk, dated October 28, 1991, Subject: Generic Letter 91-06 Responses. In a letter from J. A. Norris (NRC) to J. H. Goldberg (FPL), dated January 22, 1992, the NRC indicated that St. Lucie Unit 2 met the reporting requirements of GL 91-06.

In addition to the licensing basis described in the UFSAR, the dc onsite power system was evaluated for License Renewal. For License Renewal, electrical and instrumentation and controls (I&C) systems were broken down into commodity groups and then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.5.1.1.2 of the SER identifies that components of the dc onsite power system are within the scope of License Renewal. The programs used to manage the aging effects associated with the dc onsite power system are discussed in SER Section 3.6 and UFSAR Chapter 18.

2.3.4.2 Technical Evaluation

2.3.4.2.1 Introduction

There are two Class 1E 125V dc buses for each train (2A, 2AA, and 2B, 2BB), one 125V dc swing bus (2AB), and two 125V dc non-safety buses (2C and 2D).

The dc system has the following key design attributes:

- The Class 1E dc system is divided into redundant trains (A and B) that include two buses for each train (2A, 2AA, and 2B, 2BB) along with the swing bus (2AB). One battery and two battery chargers serve each train's bus with a swing bus and charger. At each bus, both chargers are working continuously while the swing charger is in standby. The 2AB swing bus is normally tied to the 2A bus. There are also non-Class 1E loads supplied (via isolation devices).
- The Class 1E 2A and 2B batteries are 60 cells with capacity of 2400 amp-hours each at 300 A 8-hour discharge rate. Each battery's capacity permits four hours of emergency operation without assistance from a battery charger. Each stationary battery supplies power for 125V dc safety loads that include control power for Class 1E 4160V and 480 V ac switchgear and inverters for critical 60 cycle instrument power along with some non-Class 1E loads.
- The two batteries provide two separate sources of dc power for engineered safety features equipment; train A equipment supplied from battery 2A and train B equipment is supplied from battery 2B.

- There are two 100 percent capacity, continuously operating static battery chargers for each Class 1E 125V dc bus; battery chargers 2A and 2AA for train A and chargers 2B and 2BB for train B. A fifth battery charger on the AB bus (2AB) provides backup for any of the operating battery chargers.
- The non-Class 1E 125V dc system consists of two batteries 2C and 2D, two battery chargers (one for each battery) and a distribution bus for each battery.

2.3.4.2.2 Description of Analysis and Evaluations

The 125V dc system and its components were evaluated to ensure they are capable of performing their intended function at EPU conditions. The evaluation is based on the system's required design functions and attributes and, upon a comparison between the existing dc equipment ratings and the anticipated operating requirements at EPU conditions.

The evaluations of the Station Blackout (SBO) and 10 CFR 50, Appendix R programs are performed in LR [Sections 2.3.5](#) and [2.5.1.4](#), respectively. Refer to LR [Sections 2.3.5](#) and [2.5.1.4](#) for additional discussions.

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

As discussed above, the dc onsite power system is within the scope of License Renewal. Operation of the dc onsite power system under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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.

2.3.4.2.4 Results

The safety-related and non-safety-related portions of the 125V dc systems were evaluated to determine potential impacts due to EPU conditions.

There are plant modifications planned to be implemented that will affect the safety-related portions of the 125V dc system:

- Repowering of the isolated phase bus (IPB) duct cooler fan motors directly from the 480V ac load center buses. This modification changes the power sources for IPB duct cooling fan motors from 480V ac MCCs to 480V ac load centers. The circuit breakers for the 480V ac load centers utilize dc control power, which will increase the loading of the 2A and 2B batteries.
- AC buses margin improvement modifications - These modifications trip IPB duct cooling fan motors, main transformer cooling equipment, condensate, feedwater and heater drain pump motors on the safety injection actuation signal (SIAS) event. The control circuit for all these breakers utilizes dc control power, which will increase the loading of the 2A and 2B batteries.

The EPU load increases on the 2A and 2B batteries were compared with the first minute's loading (most conservative approach) under the SBO coping and SIAS scenarios and a percent increase was calculated. The most limiting case (i.e., the case with the least amount of available margin) was the SBO coping case. However, the EPU dc load increases on the 2A and 2B batteries affect only the SIAS scenarios. Therefore, the SBO coping battery 2A and 2B margins have not been changed as a result of the EPU. For the most limiting case (i.e., the case with least amount of available margin) for battery 2A under the SIAS scenarios, the additional first minute loading associated with the EPU (10.0A) represents a 1.6 percent load increase, with a pre-EPU margin of 28.8 percent. For battery 2B under the SIAS scenarios, the additional first minute loading associated with the EPU (10A) represents a 1.6 percent load increase, with a pre-EPU margin of 25.9 percent.

Based on the battery load review, it is reasonable to conclude that the 125V dc system continues to have adequate 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.

The evaluations of the SBO and 10 CFR 50, Appendix R programs did not result in any 125V dc system load changes. Refer to LR [Sections 2.3.5](#) and [2.5.1.4](#) for additional discussions.

2.3.4.3 Conclusion

FPL has reviewed the assessment of the effects of the proposed EPU on the dc onsite power system for St. Lucie Unit 2 and concludes that it has adequately accounted for the effects of the proposed EPU on the system's functional design. FPL further concludes that the dc onsite power system will continue to meet its current licensing basis with respect to the requirements of GDC-17 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, FPL finds the proposed EPU acceptable with respect to the dc onsite power system.

2.3.5 Station Blackout

2.3.5.1 Regulatory Evaluation

Station blackout (SBO) refers to a complete loss of alternating current (ac) electric power to the essential and nonessential switchgear buses in a nuclear power plant. SBO involves the loss of offsite power (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 buses fed by station batteries through inverters or the loss of power from "Alternate AC Sources" (AACs). The Florida Power and Light (FPL) 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.

Specific review criteria are contained in Standard Review Plan (SRP) Sections 8.1 and Appendix B to SRP Section 8.2; and other guidance provided in Matrix 3 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

10 CFR 50.63 exempts certain plants from the requirements to submit information in response to the SBO rule, if the capability to withstand SBO was specifically addressed in the operating license proceeding and was specifically approved by the NRC. St. Lucie Unit 2 meets this requirement because the issue of SBO was considered by the Atomic Safety Licensing Appeal Board (ALAB-603) and a plant-specific analysis (UFSAR Section 15.10) was performed by FPL which demonstrated that the plant could successfully withstand a complete loss of ac power for at least 4 hours. In the context of the SBO rule this would constitute a coping analysis independent of ac power.

The determination of the 4-hour SBO duration was based on a probabilistic/statistical calculation which combined the probabilities of LOOP and loss of both emergency diesel generators (EDGs), and the probabilities of not being able to restore either of these sources of AC power within 4 hours. The probability values used in this calculation were based on historical experience data at the St. Lucie site.

UFSAR Section 15.10 states that the SBO event is part of the plant's design basis.

As discussed above an analysis was performed as requested by the NRC in response to the decision of ALAB-603.

The results of this analysis show that:

1. Natural circulation and core cooling can be maintained;

2. The reactor core remains in a subcritical condition;
3. There is no fuel failure;
4. The reactor coolant system (RCS) coolant pressure remains within limits; and,
5. The resulting radiological doses are within limits.

The NRC Safety Evaluation Report (SER) as documented in letter from J. A. Norris (NRC), St. Lucie, Units 1 and 2 - 10 CFR 50.63 Station Blackout (TAC NOS. 68608 and 68609), to J. H. Goldberg (FPL), dated September 12, 1991 ([Reference 1](#)) and supplemental SER as documented in letter from J. A. Norris (NRC), St. Lucie, Units 1 and 2 – Response to 10 CFR 50.63, Station Blackout, (TAC Nos. M68608 and M68609) to J. H. Goldberg, dated June 11, 1992; ([Reference 2](#)) concluded in part that the St. Lucie Unit 2 method of coping with an SBO is acceptable.

The NRC SER ([Reference 1](#)) also addressed the following issues:

- Condensate inventory for decay heat removal,
- SBO coping duration, and
- Use of the St. Lucie Unit 1 EDGs via the ac intertie between St. Lucie Units 1 and 2 to provide additional support for coping with an SBO at St. Lucie Unit 2.

Maintenance of the reliability of the St. Lucie Unit 2 EDGs at 0.974 or greater.

UFSAR Section 15.10 contains additional information pertaining to SBO relative to accident analysis.

UFSAR Section 8.3.1 discusses ac power systems. This section describes the cross-tie which connects the safety-related swing switchgear of St. Lucie Units 1 and 2. In the unlikely event of a total loss of ac power at St. Lucie Unit 2 and a loss of one EDG on St. Lucie Unit 1, power supplied from Unit 1 to Unit 2 via the cross-tie can be used to augment the DC coping program, i.e., to power battery chargers, uninterruptible power supplies (UPS), and other selected equipment until conclusion of the SBO. The cross-tie may also be used to transfer off-site power, if available, from Unit 1 to Unit 2.

UFSAR Section 8.3.1.1.2p also addresses SBO. This section states that the St. Lucie design has the capability of electrically connecting the two units 4.16 kV buses 1A2 and 2A2 (1B2 and 2B2) through 4.16 kV bus 2A4 (2B4). This tie may be used in case of an SBO on St. Lucie Unit 2 and both EDGs available on St. Lucie Unit 1.

The review requirements associated with Note 1 as described in Matrix 3 of Section 2.1 of RS-001 are addressed in LR [Section 2.3.5.2](#).

In addition to the licensing bases described in the UFSAR, the systems required to mitigate an SBO event were evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License

Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.5 of the SER identifies that the systems required to mitigate an SBO event are within the scope of License Renewal. The programs used to manage the aging effects associated with the systems required to mitigate an SBO event are discussed in SER Section 3.6 and UFSAR Chapter 18.

2.3.5.2 Technical Evaluation

2.3.5.2.1 Introduction

An SBO is initiated by a LOOP with the subsequent failure of both EDGs to start. Heat losses from the pressurizer, combined with inventory losses via primary safety valve leakage, controlled bleedoff from the reactor coolant pumps (RCPs) and other sources, cause the primary system to gradually depressurize. During an SBO, no source of makeup water (charging pumps or high pressure safety injection (HPSI)) is available. Similarly, no heat source (pressurizer heaters) can offset heat loss through the pressurizer walls.

If the total loss of power continues for a significant duration, the primary system will reach saturation. The amount of voiding will increase, eventually interrupting natural circulation. Continued inventory losses may eventually uncover the core. The purpose of a SBO analysis is to ensure that natural circulation is maintained for at least four hours.

The decay heat used for the SBO analysis at EPU conditions is based on the ANSI/ANS-5.1 1979 decay heat curve, plus a 2 sigma uncertainty.

2.3.5.2.2 Description of Analyses and Evaluations

The following topics, addressed in the St. Lucie Unit 2 SBO current licensing basis, are evaluated for impact of the EPU:

1. SBO Coping Duration,
2. SBO Analysis, Including Condensate Inventory for Decay Heat Removal,
3. Class 1E Battery Capacity,
4. Control Room Habitability,
5. Radiological Release Due to SBO,
6. Emergency Diesel Generator Reliability Program, and
7. Plant Procedures.

The following topics related to SBO are also addressed:

8. Modifications Required in Support of the EPU, and
9. Impact of Renewed Plant Operating Evaluations and License Renewal Programs.

2.3.5.2.3 Results

1. SBO Coping Duration

The NRC SER ([Reference 1](#)) states the following:

The methodology for the determination of the SBO duration is not identical to the methodology prescribed by the corresponding guidance for the SBO rule (Position 3.1 of RG 1.155 or Section 3.0 of NUMARC 87-00). However, the two methodologies are considered to be essentially equivalent since they are derived from the same fundamental basis and differ only in format. The determination of the 4-hour SBO coping duration was based on a probabilistic/statistical calculation which combined the probabilities of loss of offsite power and both emergency diesel generators, and the probabilities of not being able to restore either of these sources of AC power within 4 hours. The probability values used in this calculation were based on historical experience data at the St. Lucie site.

The EPU does not affect the methodology used to determine the SBO coping duration, and does not affect the probability values used in the probabilistic/statistical calculation. Therefore, the EPU does not affect the coping duration of 4 hours.

2. Station Blackout Analysis, including Condensate Inventory for Decay Heat Removal

The SBO event was analyzed using the detailed digital computer code RETRAN ([Reference 3](#)). This code is NRC approved and simulates the neutron kinetics, RCPs, pressurizer, pressurizer power operated relief valves (PORVs), pressurizer safety valves (PSVs), pressurizer spray, steam generator (SG), and SG safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

The RETRAN digital computer code was used to evaluate the total condensate storage tank (CST) volume required, RCS inventory, and auxiliary feedwater (AFW) flow in accordance with the UFSAR.

A. SBO Analysis

As noted above, the SBO analysis at pre-EPU conditions is described in UFSAR Section 15.10. The analysis results show that:

- Natural circulation and core cooling can be maintained for a 4 hour duration,
- The reactor core remains in a subcritical condition,
- There is no fuel failure,
- The RCS pressure remains within limits, and
- The resulting radiological doses are within limits.

An SBO analysis at EPU conditions has been performed. The following addresses impact of the EPU on the pre-EPU SBO analysis in UFSAR Section 15.10, and identifies key elements/results of the SBO analysis at EPU conditions.

a. Identification of Event and Causes (UFSAR Section 15.10.1)

UFSAR Section 15.10.1 discusses the identification and causes of the SBO event. The EPU does not affect the identification of the SBO event or its causes as discussed in UFSAR Section 15.10.1.

b. Sequence of Events and Systems Operation (UFSAR Section 15.10.2)

The SBO sequence of events for EPU conditions is shown in LR [Table 2.3.5-1](#).

The safety functions necessary to maintain the plant in hot shutdown include reactivity control, reactor heat removal, primary system integrity, and secondary system integrity. Regarding primary system integrity, the pre-EPU analysis shows that a pressurizer PORV opens to limit RCS pressure increase and the safety injection tanks (SITs) provide borated water to the RCS, increasing RCS inventory and helping to maintain subcooling in the hot leg. However, as discussed below, the analysis at EPU conditions shows that the primary system pressure remains below the opening setpoint of the PORVs, and the primary system pressure remains above the maximum SIT discharge pressure.

The EPU does not affect the discussions of reactivity control, reactor heat removal, and secondary system integrity contained in UFSAR Section 15.10.2.

Impact of the EPU on the evaluation of control room habitability is addressed in Topic 4 below.

UFSAR Section 15.10.2 describes corrective actions that would be used to restore ac power to the plant prior to the end of the 4 hour coping duration. The EPU does not affect these corrective actions.

c. Emergency DC Battery – Profile During SBO (UFSAR Section 15.10.3)

Impact of the EPU on the Class 1E battery capacity during an SBO is addressed in Topic 3 below.

UFSAR Section 15.10.3 identifies the equipment/instrumentation required to remain functional during an SBO. The SBO analysis considered the instrumentation/equipment outlined in UFSAR Section 15.10.3 with the exception of the SITs and the PORVs. As discussed below, the analysis at EPU conditions shows that the primary system pressure remains below the opening setpoint of the pressurizer PORVs, and the primary system pressure remains above the maximum SIT discharge pressure. Despite not being used, the PORVs and associated instrumentation and the SITs are required to remain in operation during the transient. The instrumentation and equipment provided in UFSAR Section 15.10.3 were confirmed to be the only items required to remain functional during an SBO, thus establishing concurrence between the EPU analysis and the information provided in the UFSAR.

d. Analysis of Effects and Consequences (UFSAR Section 15.10.4)

Mathematical models

As addressed above, the response to an SBO at EPU conditions was simulated using the RETRAN computer program ([Reference 3](#)).

Input parameters and initial conditions

The initial conditions assumed for this event at EPU conditions are shown in LR [Table 2.3.5-2](#).

The EPU does not affect the disposition of normally operating systems given in UFSAR Table 15.10-3.

With exception of the SITs, the EPU does not affect the utilization of safety systems for SBO given in UFSAR Table 15.10-4. This table shows that the SITs are available and are actuated, but not required, at pre-EPU conditions. However, as discussed below, the analysis at EPU conditions shows that the primary system pressure remains above the maximum SIT discharge pressure, and therefore, the SITs would not actuate at EPU conditions.

Results

Dynamic behavior of key parameters following an SBO at EPU conditions is presented in LR [Figures 2.3.5-1 to 2.3.5-9](#).

Departure from nucleate boiling is not analyzed in the SBO event at EPU conditions as it is bounded by the complete loss of flow event (refer to LR [Section 2.8.5.3.1](#), Loss of Forced Reactor Coolant Flow) at EPU conditions.

The major contributors to reactor coolant inventory loss are the opening of the PSVs and PORVs, and RCP seal leakage. The analysis of the SBO event at EPU conditions demonstrates that the pressurizer pressure remains below the opening setpoint of both the PSVs and the PORVs, thereby minimizing any reactor coolant inventory loss via these valves. The major contributor to reactor coolant inventory loss during the SBO event at EPU conditions is RCP seal leakage.

At EPU conditions, the primary system pressure remains above the maximum SIT discharge pressure (650 psig per Technical Specification 3.5.1) for the duration of the coping period.

The turbine driven auxiliary feedwater (TDAFW) pump is credited with supporting the decay and sensible heat removal from the core during the duration of an SBO event. The TDAFW pump receives an actuation signal on low SG level and is credited with delivering 500 gpm to the two SGs within 330 seconds after actuation; feedwater continues throughout the coping period of four hours. The analysis at EPU conditions has determined that the TDAFW pump will maintain sufficient AFW flow to the SGs for the full four hour coping period at EPU conditions.

The core is demonstrated to be maintained in a subcritical post-trip condition for the SBO event at EPU conditions by the fact that the core reactivity never exceeds a total reactivity of -3290 pcm.

e. Conclusions (UFSAR Section 15.10.5)

The maximum RCS pressure is 2389 psia (including RCP and elevation heads). This is well below 110 percent of design pressure.

The evaluation indicates that, at the end of a four hour SBO event, natural circulation and core cooling are maintained, sufficient liquid inventory remains in the vessel to ensure that the core does not uncover, and no fuel failure occurs at EPU conditions.

The core is demonstrated to be maintained in a subcritical post-trip condition for the SBO event at EPU conditions by the fact that the core reactivity never exceeds a total reactivity of -3290 pcm.

Radiological release due to the EPU is addressed in Topic 5 below.

B. Condensate Inventory for Decay Heat Removal

A conservative value of the required condensate inventory to accommodate an SBO event under EPU conditions has been determined to be 100,000 gallons.

Per Technical Specification 3.7.1.3, the minimum contained volume of the CST is 307,000 gallons. An analysis demonstrated that the minimum required CST volume to support cooldown to shutdown cooling entry temperature is 154,000 gallons (130,500 gallons in the CST are reserved for St. Lucie Unit 1 and 13,433 gallons are unusable). Therefore, the available condensate inventory reserved for St. Lucie Unit 2 exceeds the required condensate inventory to accommodate an SBO under EPU conditions. No modifications to the CST are required.

3. Class 1E Battery Capacity

As addressed in LR [Section 2.3.4](#), DC Onsite Power System, there are two 125 VDC buses for the Class 1E DC System (2A and 2B) and one 125 VDC swing bus (2AB). The Class 1E 2A and 2B batteries are 60 cells with a capacity of 2400 amp-hours each at 300 amp 8 hour discharge rate.

An evaluation of the effects of the EPU on the 125 VDC Systems for the four hour SBO coping duty cycle demonstrated that all loads are electrical devices (such as breakers, relays, inverters, motor-operated valves) that remain unchanged after EPU implementation, and that SBO strategies also remain unchanged. The evaluation concludes that the EPU has no effect on the 125 VDC Systems.

4. Control Room Habitability

UFSAR Section 15.10.2 states the following:

The loss of ac power will result in a loss of control room air conditioning. The low initial temperature of the control room and the surrounding heat sinks (floor, walls, etc.) and the

greatly reduced internal heat load due to a loss of power both serve to moderate the temperature rise resulting from the loss of cooling. In addition, certain manual operations can be performed, such as opening roof top dampers and exterior doors to establish natural circulation cooling paths. The limited duration of the blackout helps to ensure that the control room remains habitable and that the equipment required for hot standby remains operable during this period.

The source of internal heat loads in the control room during an SBO is DC-powered equipment and safety-related instrumentation powered by the inverters. As addressed above, the EPU has no effect on the 125 VDC systems, and therefore, the EPU does not affect the heat loads in the control room during an SBO. Accordingly, the EPU does not affect the evaluation of control room habitability contained in UFSAR Section 15.10.

5. Radiological Release Due to EPU

The conservatively calculated doses at the exclusion area boundary (EAB), low population zone (LPZ), and the control room due to an SBO are within the applicable guidelines.

6. EDG Reliability Program

As addressed in UFSAR Section 8.3.1.1.2(m), the Emergency Diesel Generator Reliability Program meets the guidelines of RG 1.155 Position 1.2, Reliability Program. This program is unaffected by the EPU.

7. Plant Procedures

Comparison of the pre-EPU plant procedures applicable to SBO with the SBO analysis at EPU conditions shows that no new operator actions are required, and therefore no procedure changes are required. Comparison of the operator action times for operating the atmospheric dump valves (ADV) at pre-EPU conditions with the operator action times at EPU conditions (refer to LR [Table 2.3.5-1](#)) shows that these action times are not affected by the EPU.

Plant procedures include instructions for restoring ac power to St. Lucie Unit 2 using the SBO crosstie from St. Lucie Unit 1 to St. Lucie Unit 2. The EPU does not affect these instructions.

8. Modifications Required in Support of the EPU

For modifications in support of the EPU, there is no adverse impact on the capability to cope with an SBO at EPU conditions.

9. Impact of Renewed Plant Operating Evaluations and License Renewal Programs

As discussed above, the systems required to mitigate an SBO event are within the scope of License Renewal. Operation of the systems required to mitigate an SBO event under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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.

2.3.5.3 Conclusion

FPL has reviewed the effects 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. FPL concludes that they have adequately evaluated the effects of the proposed EPU on SBO and demonstrated that the plant will continue to meet the requirements of the plant's licensing basis following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to SBO.

2.3.5.4 References

1. J. A. Norris (NRC), "St. Lucie, Units 1 and 2 - 10 CFR 50.63 Station Blackout (TAC NOS. 68608 and 68609)," to J. H. Goldberg, (FPL) dated September 12, 1991.
2. J. A. Norris (NRC), "St. Lucie, Units 1 and 2 – Response to 10 CFR 50.63, Station Blackout," (TAC Nos. M68608 and M68609) to J. H. Goldberg, (FPL) dated June 11, 1992.
3. WCAP-15234-A (Non-Proprietary), "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analysis," May 1999.

Table 2.3.5-1
Station Blackout Sequence of Events At EPU Conditions

Time (sec)	Event	Setpoint/ Value
0 - 20	Steady state period	---
20.0	Loss of all onsite and offsite ac power and loss of main feedwater	---
21.6	Reactor trip signal on low RCS flow	91.9 percent
22.3	Maximum core power	102.3%
25.1	Maximum RCS pressure	2389 psia
25.5	Maximum pressurizer pressure	2363 psia
26.8	Main steam isolation valves (MSIVs) close (Note 1)	---
27.7	Main steam safety valves open	1000 psia
33.3	Maximum secondary system pressure	1012 psia
1262	Auxiliary feedwater actuation signal	5% of narrow range span
1592	Auxiliary feedwater reaches the steam generators	500 gpm total
1820	1. Operator opens and controls ADVs 2. Main steam safety valves close 3. Total main steam safety valve release	900 psia 995 psia 213,400 lbm
8620	Operators act to reduce steam pressure to cool the primary RCS via ADV control	---
11335	Voiding occurs in reactor vessel upper head	---
11335	Minimum hot leg subcooling margin	26.1 °F
14420	1. Operator restores ac power 2. Total atmospheric dump valve release	429,600 lbm
1. MSIV closure time is conservative, based on maximizing heat load to be removed for the SBO event.		

Table 2.3.5-2
Assumed Initial Conditions for Station Blackout Analysis at EPU Conditions

Parameter	Assumed Value
Initial core power level	3030 MWt
Core inlet coolant temperature: High T _{avg} nominal value Low T _{avg} nominal value	578.5 °F 563 °F
Core volumetric loop flow	187500 gpm
Pressurizer pressure	2250 psia
Initial pressurizer water volume	63% level
SG water level	65% of narrow range span
Moderator temperature coefficient	$-0.9110^{-4} \Delta\rho / ^\circ\text{F}$
CEA Worth for Trip	$-5.2010^{-2} \Delta\rho$
Primary coolant leakage	16 gpm

Figure 2.3.5-1
Station Blackout Event at EPU Conditions Core Power vs. Time

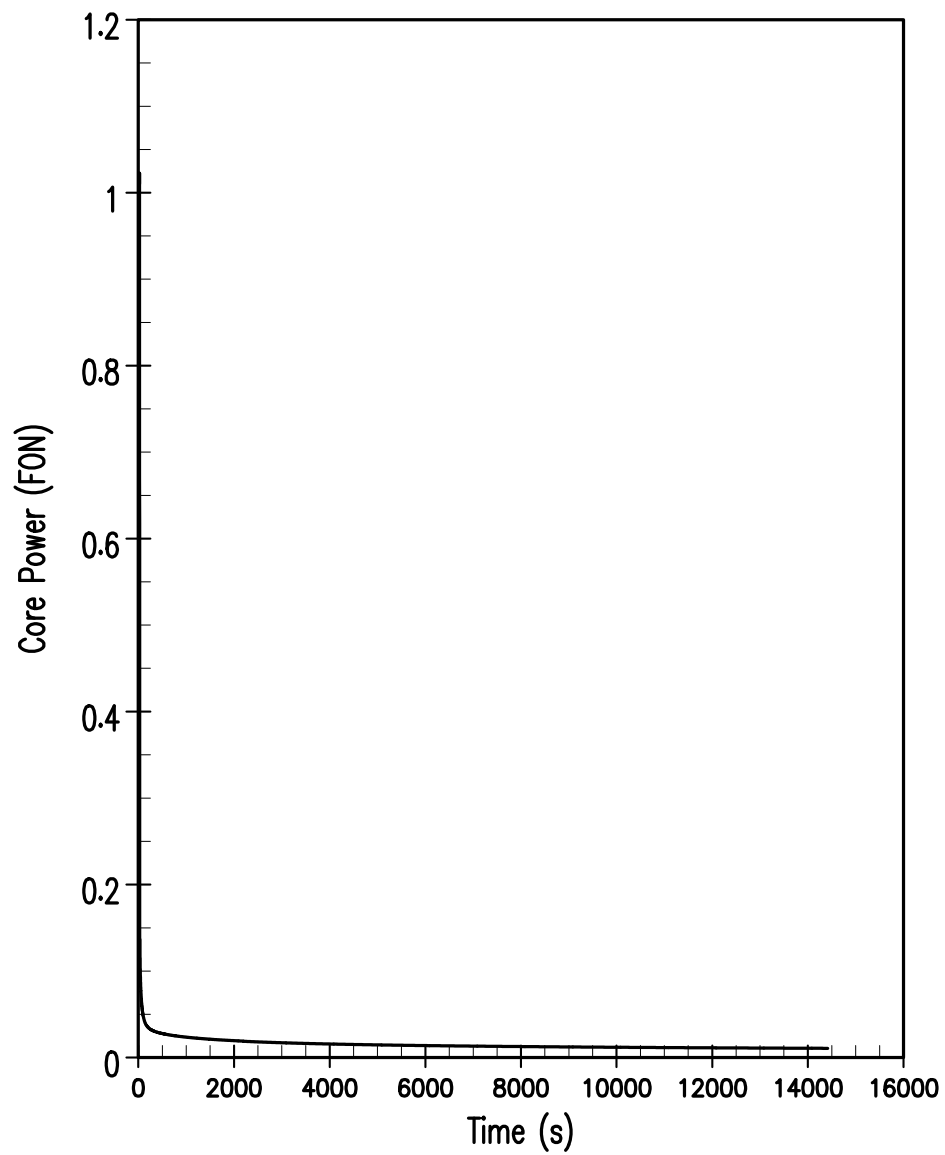


Figure 2.3.5-2
Station Blackout Event at EPU Conditions Core Avg. Heat Flux vs. Time

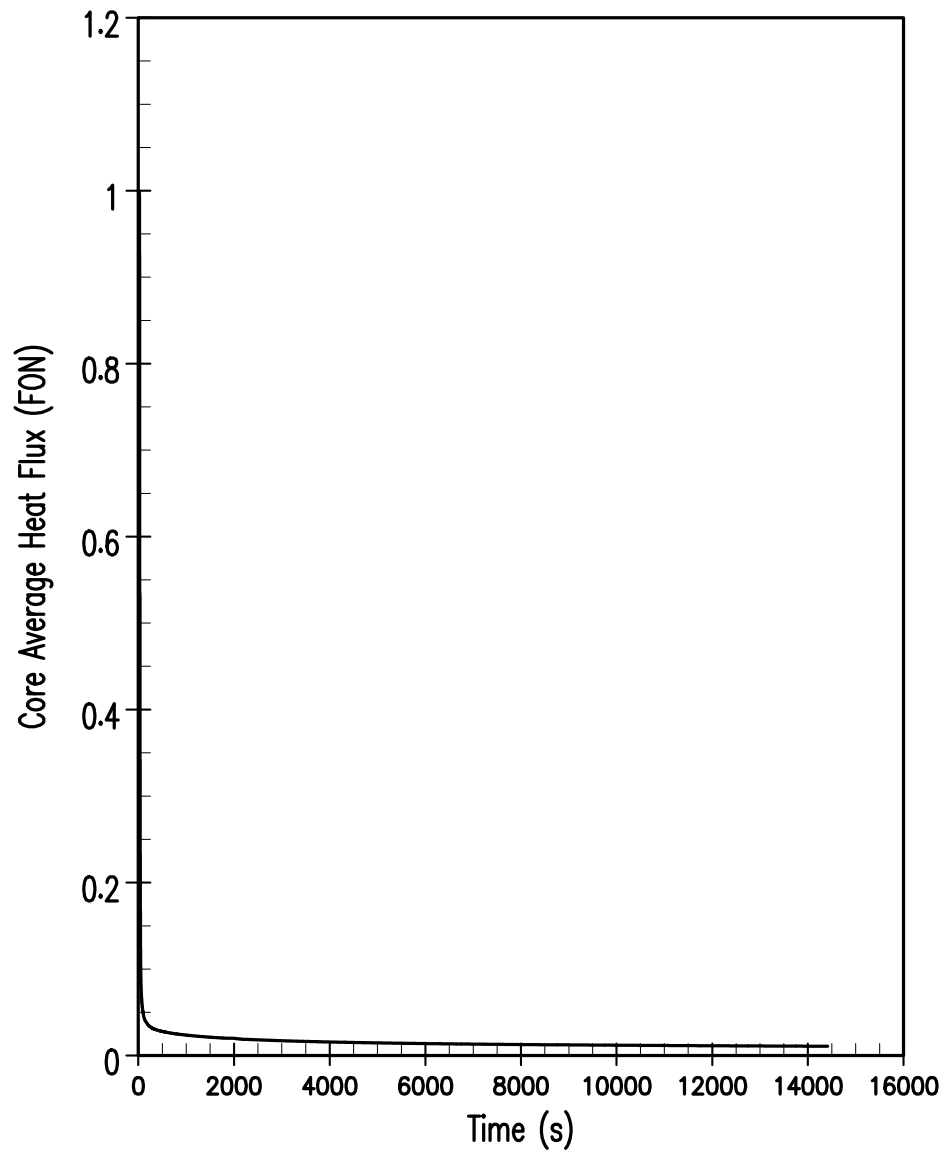


Figure 2.3.5-3
Station Blackout Event at EPU Conditions Pressurizer Pressure vs. Time

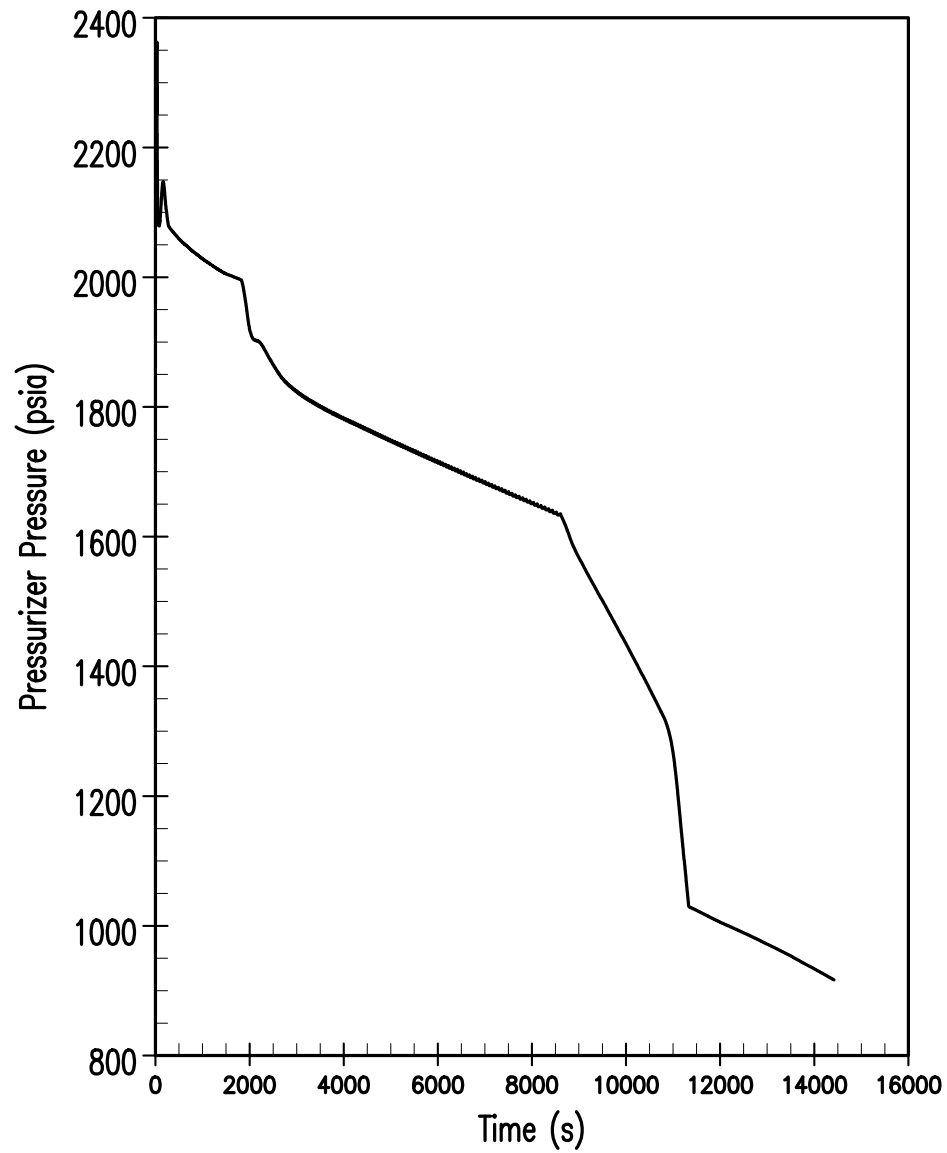


Figure 2.3.5-4
Station Blackout Event at EPU Conditions RCS Temperatures vs. Time

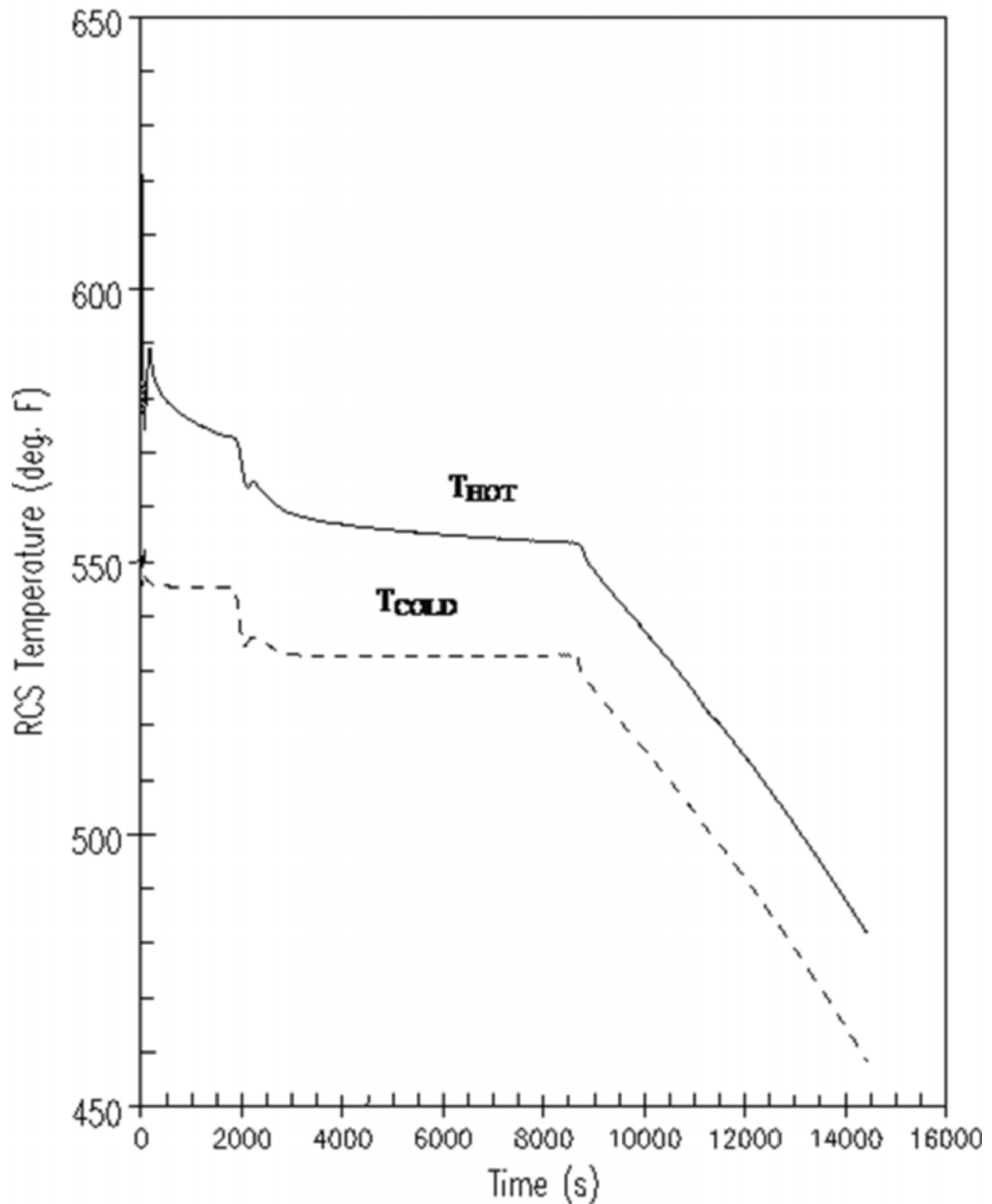


Figure 2.3.5-5
Station Blackout Event at EPU Conditions Pressurizer Water Volume vs. Time

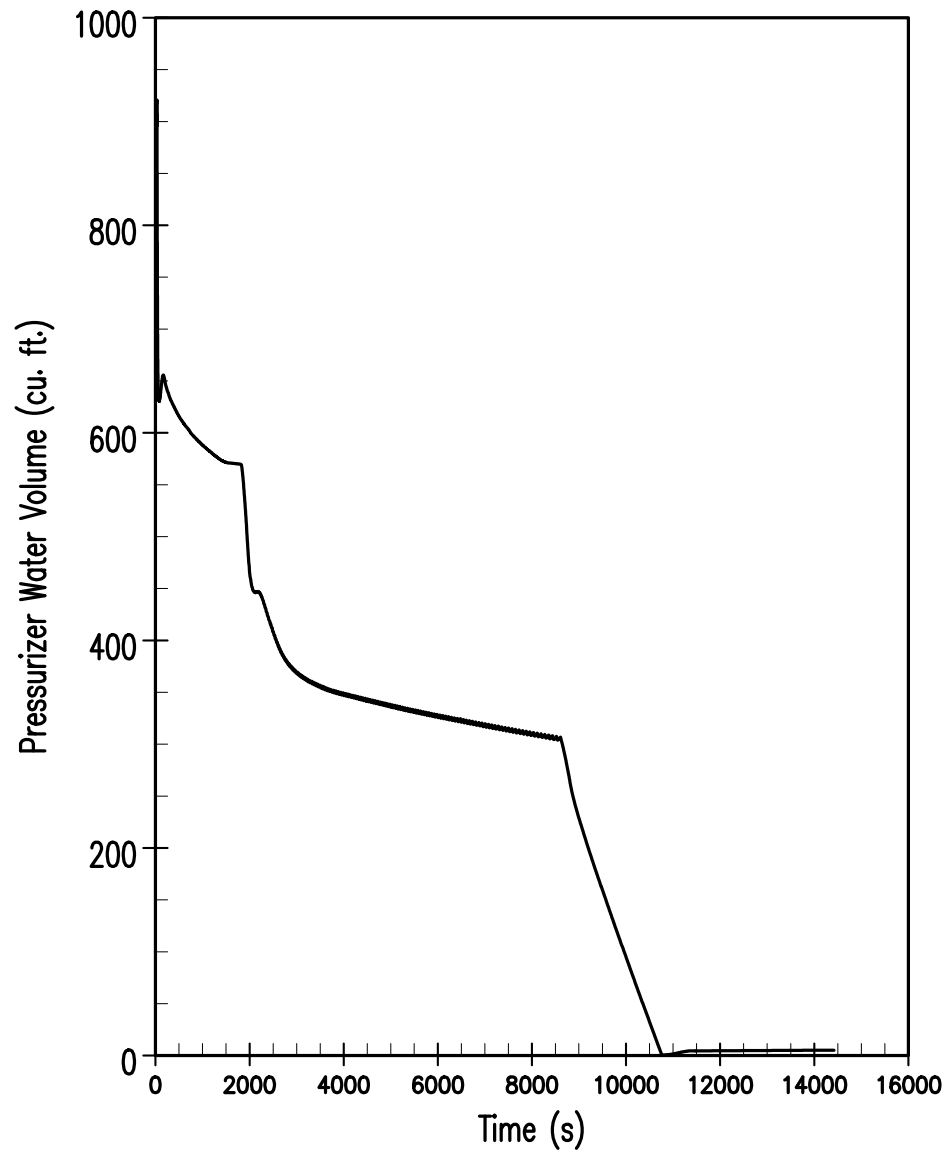


Figure 2.3.5-6
Station Blackout Event at EPU Conditions Reactor Coolant Flow vs. Time

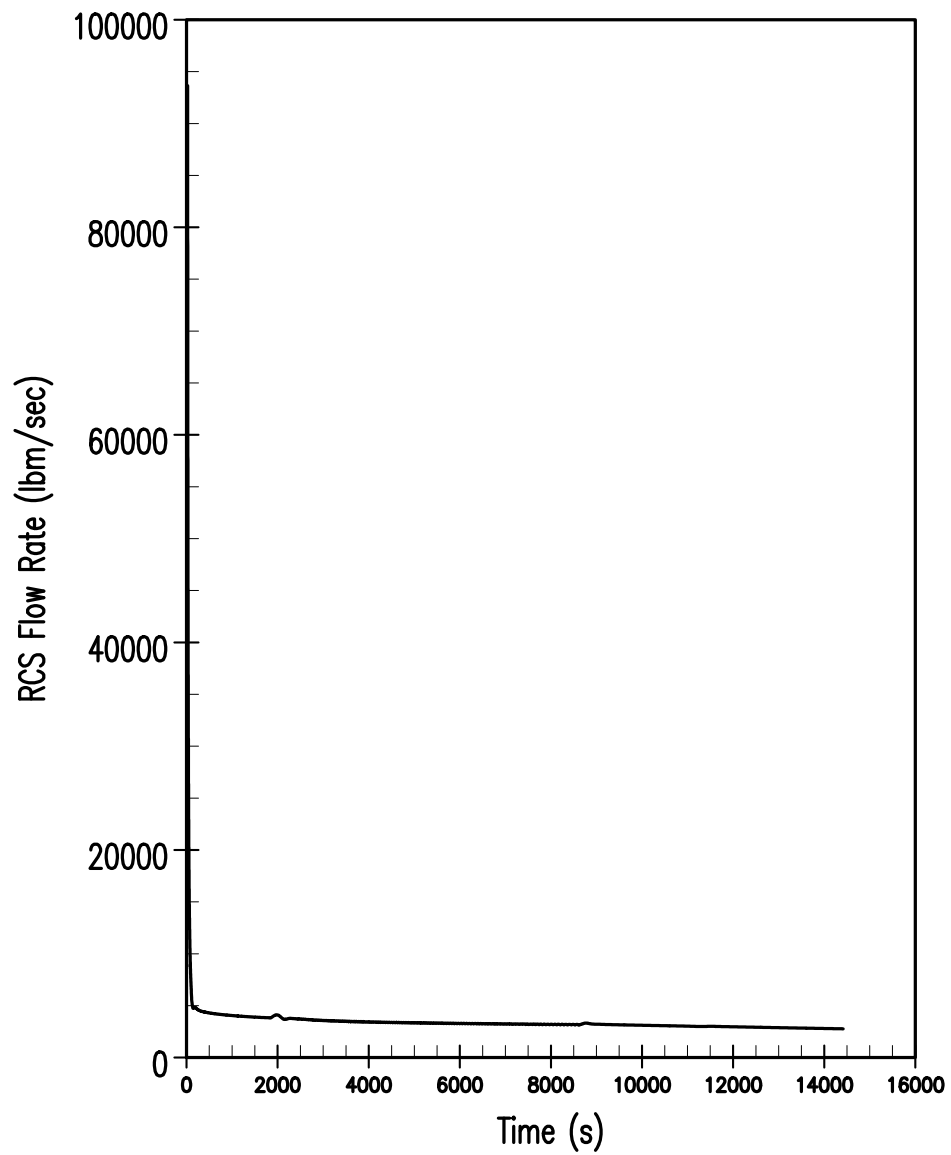


Figure 2.3.5-7
Station Blackout Event at EPU Conditions Steam Generator Pressure vs. Time

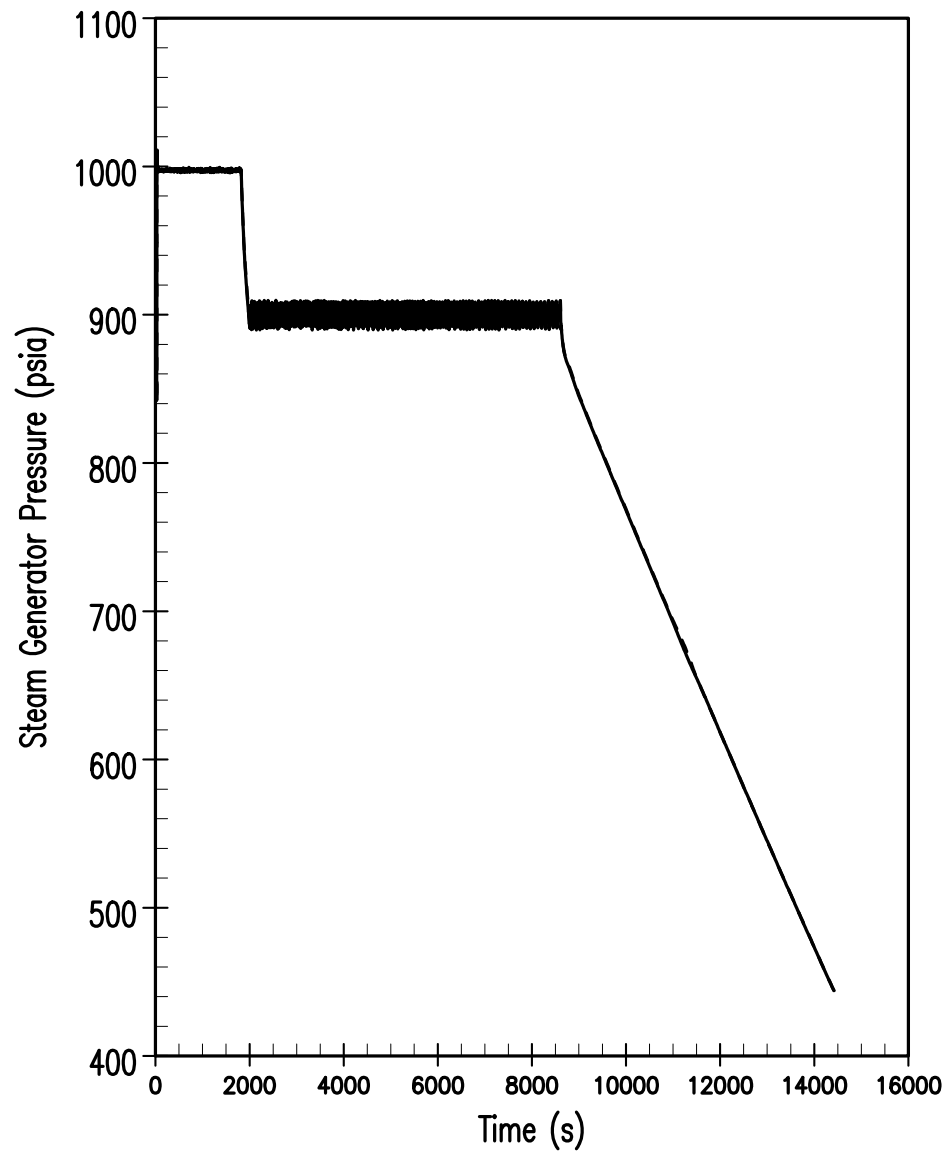


Figure 2.3.5-8
Station Blackout Event at EPU Conditions Steam Generator Water Mass vs. Time

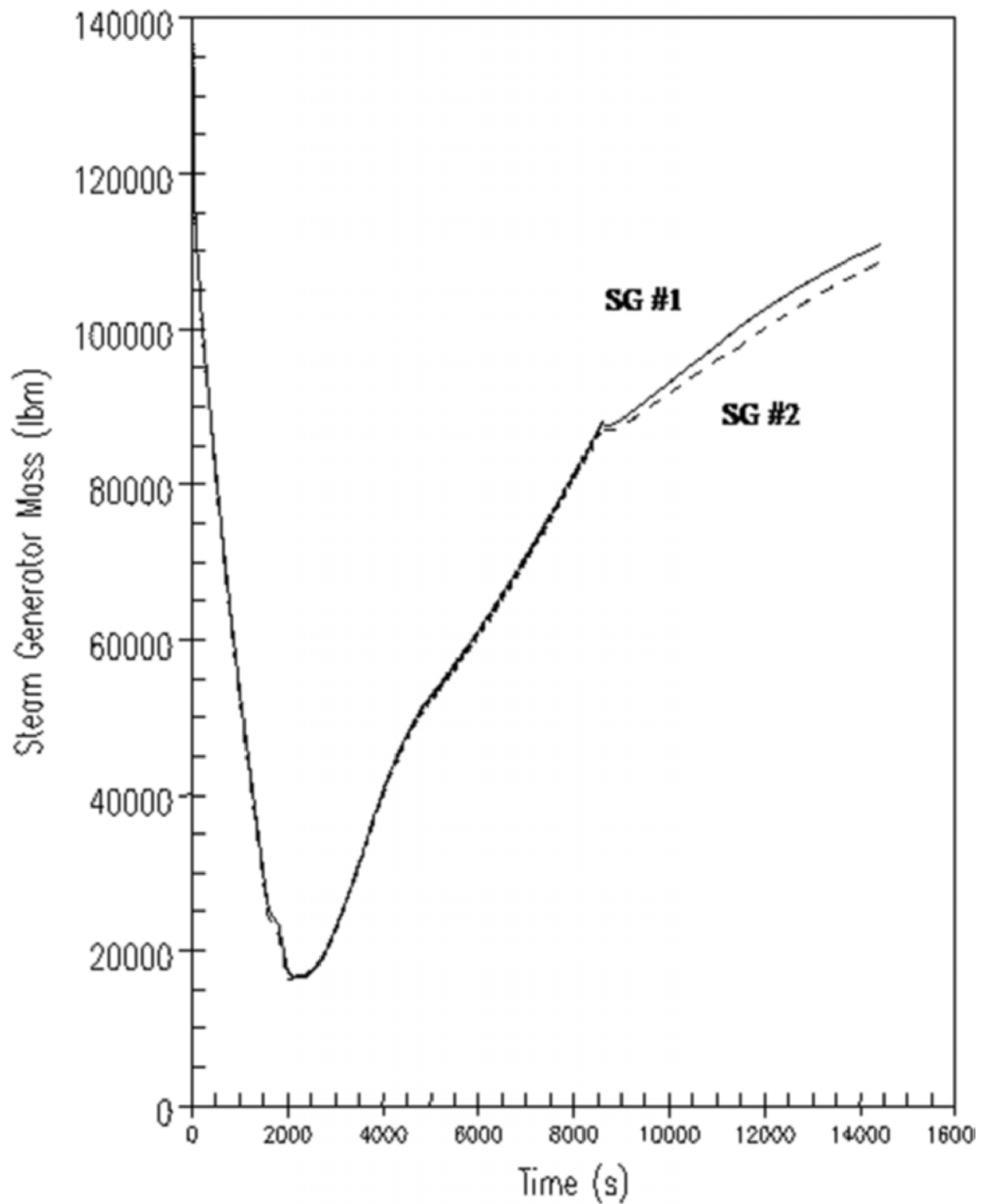
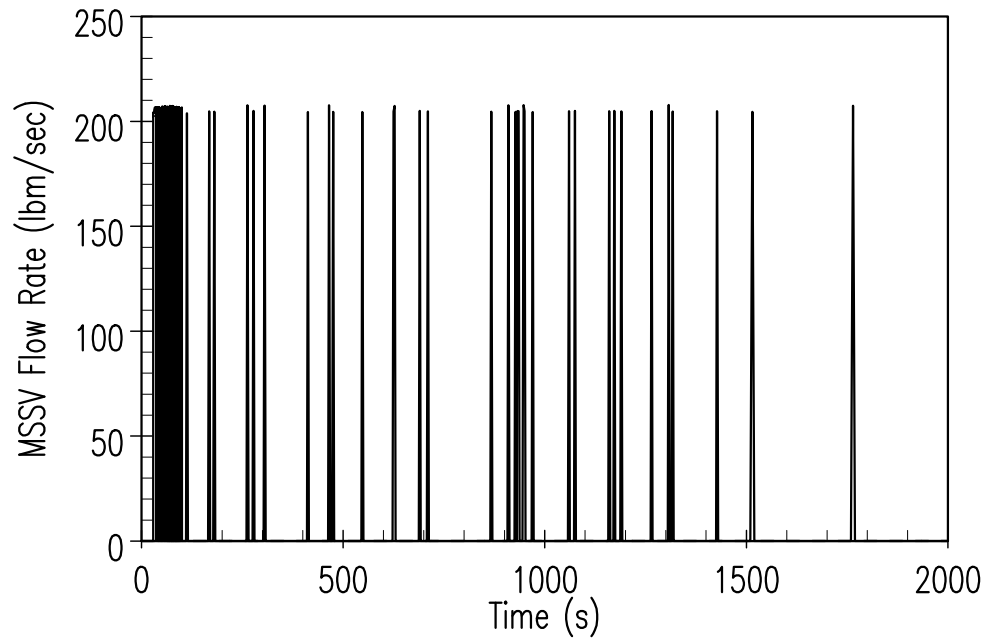


Figure 2.3.5-9
Station Blackout Event at EPU Conditions Main Steam Safety Valves Flow vs. Time



2.4 Instrumentation and Controls

2.4.1 Reactor Protection, Safety Features Actuation, and Control Systems

2.4.1.1 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.

Florida Power and Light (FPL) has 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 extended power uprate (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. FPL's review was also conducted to ensure that failures of the systems do not affect safety functions.

The 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:

- General Design Criterion (GDC)-1, insofar as it requires that structures, systems and components (SSCs) important-to-safety are designed, fabricated, erected, and tested to quality standards commensurate with their importance to functions to be performed;
- GDC-4, insofar as it requires that SSCs be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents;
- GDC-13, insofar as it requires that instrumentation is provided to monitor variables and systems over their anticipated ranges for normal operation, anticipated operational occurrences, and for accident conditions as appropriate to ensure safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary (RCPB), and the containment and its associated systems. Appropriate controls should be provided to maintain these variables and systems within prescribed operating ranges.
- GDC-19, insofar as it requires that a control room is provided from which actions can be taken to operate the nuclear unit safely under normal conditions, and maintain it in a safe condition under accident conditions, including loss-of-coolant accidents (LOCAs);
- GDC-20, insofar as it requires protection systems be designed (1) to initiate automatically the operation of appropriate systems including the reactivity control systems, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and to initiate the operation of important-to-safety systems and components;

- GDC-21 insofar as it requires protection systems be designed for high functional reliability and in-service testability commensurate with the safety functions to be performed. Redundancy and independence designed into the protection system shall be sufficient to assure that (1) no single failure results in loss of the protection function and (2) removal from service of any component or channel does not result in loss of the required minimum redundancy unless the acceptable reliability of operation of the protection system can be otherwise demonstrated;
- GDC-22 insofar as it requires protection systems be designed to assure that the effects of natural phenomena, and of normal operating, maintenance, testing, and postulated accident conditions on redundant channels do not result in loss of the protection function, or shall be demonstrated to be acceptable on some other defined basis;
- GDC-23 insofar as it requires protection systems be designed to fail into a safe state or into a state demonstrated to be acceptable on some other defined basis if conditions such as disconnection of the system, loss of energy (e.g., electric power, instrument air), or postulated adverse environments (e.g., extreme heat or cold, fire, pressure, steam, water, and radiation) are experienced;
- GDC-24, insofar as it requires that the protection system is separated from the control systems to the extent that a system satisfying all reliability, redundancy, and independence requirements of the protection systems is left intact in the event of a failure of any single control system component or channel, or failure or removal from service of any single control system component or channel that is common to the control and protection systems. Interconnection of the protection and control systems will be limited so as to ensure that safety is not significantly impaired.

Specific review criteria are contained in SRP Sections 7.0, 7.2, 7.3, 7.4, 7.7 and 7.8.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design basis of St. Lucie Unit 2 conforms to the NRC General Design Criteria for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDCs for the reactor protection, safety features actuation and control systems are as follows:

- GDC-1 is described in UFSAR Section 3.1.1 Criterion 1 – Quality Standards and Records.

Structures, systems and components important to safety shall be designed, fabricated, erected and tested to quality standards commensurate with the importance of the safety functions to be performed. Where generally recognized codes and standards are used, they shall be identified and shall be supplemented or modified as necessary to assure a quality product in keeping with the required safety function. A quality assurance program shall be established and implemented in order to provide adequate assurance that these structures, systems, and components will satisfactorily perform their safety functions. Appropriate records of the design, fabrication, erection and testing of structures, systems and

components important to safety shall be maintained by or under the control of the nuclear power unit licensee throughout the life of the unit.

SSCs of the facility are classified according to their relative importance to safety. Those items vital to safety such that their failure might cause or result in an uncontrolled release of an excessive amount of radioactive material are designated as seismic Category I. They, and items of lesser importance to safety, are designed, fabricated, erected and tested according to the provisions of recognized codes and quality standards. Discussions of the applicable codes, standards, records and the quality assurance program used to implement and audit the construction and operation processes were originally presented in UFSAR Section 17.2; however, this information is now provided in FPL Quality Assurance Topical Report, FPL-1. A complete set of facility structural, arrangement and system drawings is maintained under the control of FPL throughout the life of the plant. Quality assurance written data and comprehensive test and operating procedures are likewise assembled and maintained by FPL. The classification of seismic Category I structures and safety related systems and components is discussed in UFSAR Section 3.2.

- GDC-4 is described in UFSAR Section 3.1.4 Criterion 4 – Environmental and Missile Design Bases.

Structures, systems and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and approved by the Commission demonstrates that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

SSCs important to safety are designed to accommodate the effects of, and to be compatible with the pressure, temperature, humidity, and radiation conditions associated with normal operation, maintenance, testing, and postulated accidents including a LOCA, in the area in which they are located.

- GDC-13 is described in UFSAR Section 3.1.13 Criterion 13 – Instrumentation and Control.

Instrumentation shall be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary, and the containment and its associated systems. Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges.

Instrumentation is provided, as required, to monitor and maintain significant process variables which can affect the fission process, the integrity of the reactor core, the RCPB, and the

containment and its associated systems. Controls are provided for the purpose of maintaining these variables within the limits prescribed for safe operation.

The principal variables and systems monitored include neutron flux level (reactor power); reactor coolant temperature, flow, and pressure; pressurizer level; steam generator (SG) level and pressure; and containment pressure and temperature.

The following is provided to monitor and maintain control over the fission process during both transient and steady state periods over the lifetime of the core:

- a. Twelve independent channels of excore nuclear instrumentation are used to monitor the fission process. There are four wide range channels, four safety channels, two control channels and two startup channels.
- b. Two independent control element assembly (CEAs) position indicating systems;
- c. A method of determining soluble poison concentration by sampling and analysis of reactor coolant water;
- d. Manual control of reactor power by means of CEAs;
- e. Manual regulation of coolant boron concentration.

Incore instrumentation provides information on core power distribution and for calibration of excore flux detectors.

Instrumentation is provided to measure variables such as temperatures, pressures, flows and levels in various plant systems and is used to maintain these variables within prescribed limits.

The reactor protective system (RPS) is designed to monitor the reactor operating conditions and to affect a reliable and rapid reactor trip if any one or a combination of conditions deviate from a pre-selected operating range.

The containment pressure, temperature and radiation instrumentation is designed to function during normal operation and the postulated accidents.

The instrumentation and control systems are described in detail in UFSAR Chapter 7.

- GDC-19 is described in UFSAR Section 3.1.19 Criterion 19 – Control Room.

A control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in safe condition under accident conditions, including loss of coolant accidents. Adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent to any part of the body, for the duration of the accident.

Equipment in appropriate locations outside the control room shall be provided (1) with a design capability for prompt hot shutdown of the reactor, including necessary instrumentation and controls to maintain the unit in a safe condition during hot shutdown, and (2) with a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

The control stations, switches, controllers and indicators necessary to operate or shut down the unit and maintain safe control of the facility are located in the control room.

The design of the control room permits safe occupancy during design basis accident conditions. The control room is isolated from the outside atmosphere during the initial period following the occurrence of an accident. The control room ventilation system recirculates control room air through HEPA and charcoal filters as discussed in UFSAR Section 9.4.1 and UFSAR Section 6.4. Radiation detectors and alarms are provided. Emergency lighting is provided as discussed in UFSAR Section 9.5.3.

Alternate local controls and local instruments are available for equipment required to bring the plant to and maintain a hot standby condition. It is also possible to attain a cold shutdown condition from locations outside of the control room through the use of suitable procedures.

- GDC-20 is described in UFSAR Section 3.1.20 Criterion 20 – Protection System Functions.

The protection system shall be designed (1) to initiate automatically the operation of appropriate systems including the reactivity control systems, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and to initiate the operation of systems and components important to safety.

The RPS monitors reactor operating conditions and automatically initiates a reactor trip when the monitored variable or combination of variables exceeds a prescribed operating range. The reactor trip setpoints are selected to ensure that anticipated operational occurrences do not cause acceptable fuel design limits to be violated. Specific reactor trips are described in UFSAR Section 7.2.

Reactor trip is accomplished by de-energizing the control element drive mechanism holding latch coils through the interruption of the control element drive mechanism (CEDM) power supply. The CEAs are thus released to drop into the core reducing reactor power.

The ESFAS monitors potential accident conditions and automatically initiates ESF and their supporting systems when the monitored variables reach prescribed setpoints. The parameters which automatically actuate ESF are described in UFSAR Section 7.3. Manual actuation capability is provided to the operator.

- GDC-21 is described in UFSAR Section 3.1.21 Criterion 21 – Protection System Reliability and Testability.

The protection system shall be designed for high functional reliability and inservice testability commensurate with the safety functions to be performed. Redundancy and independence designed into the protection system shall be sufficient to assure that (1) no single failure results in loss of the protection function and (2) removal from service of any component or channel does not result in loss of the required minimum redundancy unless the acceptable reliability of operation of the protection system can be otherwise demonstrated. The protection system shall be designed to permit periodic testing of its functioning when the reactor is in operation, including a capability to test channels independently to determine failures and losses of redundancy that may have occurred.

The protection systems are designed to provide high functional reliability and in-service testability by designing to the requirements of IEEE 279 - 1971 and IEEE 338 - 1971. The systems are designed such that the single failure criterion and performance requirements are met with three channels in service.

A coincidence of exceeding the trip setpoint on two or more channels of a trip parameter generates a trip signal. Four measurement channels with electrical and physical separation are provided for each parameter. To enhance plant availability, a fourth channel is provided as a spare and allows bypassing of one channel while maintaining the requisite two-out-of-three system.

Each channel of the protection system, including the sensors up to the final actuation device is capable of being checked during reactor operation. Those channels that can affect plant operation are tested during scheduled reactor shutdown. Measurement sensors of each channel used in protection systems are checked by observing outputs of similar channels which are presented on indicators and recorders in the control room. Trip units and logic are tested by inserting a signal into the measurement channel ahead of the readout and, upon application of a trip level input, observing that a signal is passed through the trip units and the logic to the logic output relays. The logic output relays are tested individually for initiation of trip action.

Protection system reliability and testability are discussed in UFSAR Sections 7.2 and 7.3.

- GDC-22 is described in UFSAR Section 3.1.22 Criterion 22 – Protection System Independence.

The protection system shall be designed to assure that the effects of natural phenomena, and of normal operating, maintenance, testing and postulated accident conditions on redundant channels do not result in loss of the protection function, or shall be demonstrated to be acceptable on some other defined basis. Design techniques, such as functional diversity or diversity in component design and principles of operation, shall be used to the extent practical to prevent loss of the protection function.

The protection systems conform to the provisions of IEEE 279 – 1971, as explained in UFSAR Section 7.2.2.3. Four independent measurement channels complete with sensors, sensor power supplies, signal conditioning units and bistable trip units are provided for each parameter monitored by the protection systems. The measurement channels are provided with a high degree of independence by separate connections of the channel sensors to the process systems. Power to the channels is provided by independent vital power supply buses.

- GDC-23 is described in UFSAR Section 3.1.23 Criterion 23 – Protection System Failure Modes.

The protection system shall be designed to fail into a safe state or into a state demonstrated to be acceptable on some other defined basis if conditions such as disconnection of the system, loss of energy (e.g., electric power, instrument air) or postulated adverse environments (e.g., extreme heat or cold, fire, pressure, steam, water, and radiation) are experienced.

Protective system trip channels are designed to fail into a safe state or into a state established as acceptable in the event of loss of power supply or disconnection of the system. A loss of power to

the CEDM holding coils results in gravity insertion of the CEAs into the core. Redundancy, channel independence and separation incorporated in the protective system design minimize the possibility of the loss of a protection function under adverse environmental conditions. Refer to UFSAR Sections 7.2 and 7.3.

- GDC-24 is described in UFSAR Section 3.1.24 Criterion 24 – Separation of Protection and Control Systems.

The protection system shall be separated from control systems to the extent that failure of any single control system component or channel, or failure or removal from service of any single protection system component or channel which is common to the control and protection systems leaves intact a system satisfying all reliability, redundancy, and independence requirements of the protection system. Interconnection of the protection and control systems shall be limited so as to assure that safety is not significantly impaired.

The protection systems are separated from the control instrumentation systems so that failure or removal from service of any control instrumentation system component or channel does not inhibit the function of the protection system. Separation of protection and control systems is discussed in UFSAR Section 7.2.2.3.

UFSAR Section 7.2 describes the design criteria for the RPS, provides a description of the RPS operation, reactor trips and analysis including control and protection system interaction.

UFSAR Section 7.3 describes the design criteria for the ESFAS, provides a description of its operation, signals, analysis, redundancy and diversity.

UFSAR Section 7.4 describes the instrumentation and control systems that are required to establish and maintain a safe shutdown condition for the reactor.

UFSAR Section 7.5 identifies the instrumentation subject to the requirement of Regulatory Guide (RG) 1.97, post accident monitoring, analysis, detection of inadequate core cooling and safety related display instrumentation.

UFSAR Section 7.6 includes a description of systems required for safety which have not been discussed in UFSAR Sections 7.2 through 7.5.

UFSAR Section 7.7 describes the instrumentation and control systems, whose functions are not essential for the safety of the plant, and includes all of the plant instrumentation and control equipment not addressed in UFSAR Sections 7.2 through 7.6.

In addition to the licensing basis described in the UFSAR, the reactor protection, safety features actuation and control systems were evaluated for License Renewal. For License Renewal, electrical and I&C systems were broken down into commodity groups and then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.5 of the SER identifies that components of the reactor protection, safety features actuation and control systems are within the scope of License Renewal. The programs used to manage the aging effects associated with the reactor protection, safety features actuation and control systems are discussed in SER Section 3.6 and UFSAR Chapter 18.

2.4.1.2 Technical Evaluation

2.4.1.2.1 Introduction

The EPU has a direct impact on the reactor control system due to the increase in reactor thermal power. The EPU has only potential indirect impact on the RPS and ESFAS setpoints. The RPS and the ESFAS Technical Specification (TS) functions were evaluated for the EPU in order to confirm or modify the setpoints listed in the TS, Table 2.2-1 and Table 3.3-4.

2.4.1.2.2 Input Parameters, Assumptions and Acceptance Criteria

The primary design parameters associated with the EPU are identified in LR [Section 1.1](#), Nuclear Steam Supply Parameters. The initial best estimate nominal operating parameters for analysis of control systems are identified in LR [Table 2.4.1-1](#).

2.4.1.2.3 Description of Analyses and Evaluations

The effects of the EPU have been evaluated for normal operation, operational transients, and accident conditions described in the UFSAR. These analyses used the most conservative (where appropriate) of Nuclear Steam Supply System (NSSS) design values from LR [Section 1.1](#), Nuclear Steam Supply System Parameters, [Table 1.1-1](#).

LR [Section 2.8.5.0](#), Accident and Transient Analyses, discusses the RPS and ESFAS limiting trip setpoints assumed in the accident analyses and the time delays assumed for each trip function. Acceptability of the RPS and ESFAS trip functions, including the setpoints and response times, are addressed in the 2.8.5 series of LRs, as applicable.

As discussed in LR [Section 2.13](#), Risk Evaluation, a risk informed change to the low steam generator water level trip setpoint will be made to address the potential loss of heat removal capability during a total loss of feedwater (TLOFW) event. The setpoint will be changed from ≥ 20.5 percent to ≥ 35 percent water level for each SG. The intent of this action, in conjunction with procedural changes, is to increase the inventory in the SG following TLOFW events to increase the time available for the operator to implement once-through-cooling. No other changes are required to the NSSS instrumentation ranges, scaling and setpoints used in the RPS/ESFAS.

Total loop uncertainty (TLU) calculations for each instrument channel for the low steam generator water level trip function, as well as the remaining RPS/ESFAS functions, were updated as necessary to reflect EPU conditions and to ensure consistency with surveillance test procedures. These loop uncertainty calculations are consistent with the latest setpoint methodology, which is based on the ANS/ISA-67.04.01 methodology and are discussed in LR Appendix E.

An uncertainty allowance (UA) is defined as the margin set aside in the determination of the analytical limit (AL) to accommodate loop uncertainty. The UA and the TS trip setpoint are combined in the safety analysis to establish the AL. When necessary, the UA was increased from the current plant value to ensure each UA remained bounding with respect to the updated EPU TLU value.

The updated EPU TLU calculations include bistable trip unit setting tolerance (ST) as a random effect, which is statistically combined with other independent random effects using a standard “square root sum of the squares” method. The surveillance procedure “As-Left” acceptance criterion, synonymous with bistable ST, is also treated as a bias. Therefore, the acceptance criterion utilized in the EPU review of the RPS and ESFAS setpoints is defined as:

$$TLU + ST \leq UA$$

The EPU safety analyses were performed using updated ALs that contain allowances equal to or exceeding the UA. No changes were necessary for any RPS and ESFAS TS setpoints beyond the low steam generator level RPS trip setpoint.

The results of the NSSS operational transient analyses are described in LR [Section 2.4.2](#), Plant Operability. These analyses included changes to specific NSSS control system setpoints. These analyses determined that with the exception of the following items listed, the NSSS instrumentation ranges, scaling, and setpoints used in the reactor control instrumentation remained adequate for EPU as discussed in LR [Section 2.4.1.2.3.3](#).

- Main steam header pressure instrumentation for steam bypass control,
- Main steam flow instrumentation,
- Main feedwater flow instrumentation, and
- Turbine first stage pressure instrumentation.

Operation of the plant at EPU conditions has minimal effect on balance-of-plant (BOP) system instrumentation and control devices. Based on EPU operating conditions for the power conversion and auxiliary systems, most process control valves and instrumentation have sufficient range/adjustment capability for use at the EPU conditions.

The evaluation methodology used to evaluate the BOP system instrumentation includes the following basic steps:

- Perform system analysis to determine how the EPU conditions/ranges/setpoints compare to the current operating conditions/ranges/setpoints for the BOP systems;
- For those systems (subsystems) that are impacted by the EPU, determine the major process instrumentation or board-mounted instruments from the piping and instrument diagrams (P&IDs) and instrument calibration procedures and tabulate the current and EPU process data;
- Analyze the affected instruments to determine EPU instrument impact;
- For those instruments affected by the EPU, recommend new scaling, setpoints, ranges, or a suitable replacement (if required).

BOP system instrumentation evaluated included the following fluid systems:

- Main steam system (UFSAR Section 10.3),
- Condensate and feedwater system (UFSAR Section 10.4),

- Heater drain system (UFSAR Section 10.4),
- Circulating water system (UFSAR Section 10.4),
- Component cooling water system (UFSAR Sections 9.2 and 7.4),
- Turbine cooling water system (UFSAR Section 9.2),
- Steam dump and bypass system (UFSAR Sections 7.7, 10.3 and 10.4),
- Turbine generator system (UFSAR Section 10.2),
- Extraction steam system (UFSAR Section 10.1),
- Steam generator blowdown system (UFSAR Section 10.4), and
- Fuel pool system (UFSAR Section 9.1), and
- Intake cooling water (service water) and ultimate heat sink system (UFSAR Section 9.2).

The EPU evaluation of BOP instrumentation and controls demonstrated that, except as noted below, the design of BOP instruments, ranges, and setpoints remain acceptable for EPU operation.

UFSAR Table 7.4-2 identifies indicators located at the hot shutdown panel in the reactor auxiliary building for monitoring SG pressure and level. The existing indicator spans are unaffected at EPU conditions.

UFSAR Table 7.4-1 identifies instruments required to monitor safe shutdown for the component cooling water system, intake cooling water system, auxiliary feedwater system and atmospheric dump system. The existing indicator spans are unaffected at EPU conditions.

BOP monitored variables required in accordance with RG 1.97 are identified in UFSAR Section 7.5 and summarized in UFSAR Table 7.5-1. The existing indicator spans for these variables remain bounding at EPU conditions. The following BOP RG 1.97 variables potentially affected by the EPU were analyzed and found to be acceptable:

- Steam generator pressure,
- Auxiliary feedwater pump discharge flow,
- Auxiliary feedwater pump discharge pressure,
- Condensate storage tank level, and
- Component cooling water header flow.

2.4.1.2.3.1 Reactor Protection

The design bases and description of the RPS is listed in UFSAR Section 7.2.1, Reactor Trip System (RTS), and includes a listing of the reactor trips, purpose of each trip, and any associated protection and control permissives. The RPS automatically trips the reactor to protect against:

1. Reactor Coolant System (RCS) damage caused by high system pressure,
2. fuel rod cladding damage caused by a departure from nucleate boiling, and
3. fuel centerline melt caused by excessive local power production.

The basic reactor trip philosophy is to define a region of power and coolant temperature, core power distribution and pressure conditions allowed by the primary trip functions (variable high power trip, thermal margin/low pressure trip and local power density trip). The allowable operating region within these trip settings is provided to prevent any combination of power, temperature, and pressure that would result in a departure from nucleate boiling (DNB) or fuel center line melt with all reactor coolant pumps in operation.

Additional primary trip functions occur on high pressurizer pressure, low reactor coolant flow, low steam generator pressure, low steam generator water level, high steam generator pressure difference, high containment pressure, loss of turbine – low hydraulic fluid pressure, low component cooling water flow to the reactor coolant pumps, and high rate of change of power. A manual trip is provided to back up the primary trip functions for specific accident conditions and mechanical failures.

The variable high power, thermal margin/low pressure, local power density and high steam generator pressure difference (asymmetric steam generator transient) trip functions are implemented in the core protection calculators (CPCs). The CPCs are analog predecessors of the digital CPC System in use at newer CE plants. They do not use microprocessors or software.

As a result of the evaluations discussed in LR [Section 2.4.1.2.3](#), no RPS instrumentation or setpoint changes were necessary to ensure the RPS will continue to satisfy its design functions at EPU conditions. However, based on risk insights, a change to the low steam generator water level trip setpoint from ≥ 20.5 percent to ≥ 35 percent water level for each steam generator is being proposed.

2.4.1.2.3.2 Engineered Safety Feature Actuation System

The ESFAS functions provide protection against equipment damage and the release of radioactive materials in the event of a LOCA or a secondary line break accident and to maintain the reactor in a shutdown condition following an accident. They also provide sufficient core cooling to limit the extent of fuel and fuel cladding damage and to ensure the integrity of the containment structure. These functions rely on the ESFAS and associated instrumentation and controls.

As a result of the evaluations discussed in LR [Section 2.4.1.2.3](#), there are no ESFAS instrumentation and setpoint changes necessary to ensure that the ESFAS will continue to satisfy its design functions at EPU conditions.

2.4.1.2.3.3 Control Systems

The various reactor control systems are described in UFSAR Section 7.7, Control Systems Not Required for Safety. The reactor control systems are designed to limit nuclear plant transients for prescribed load perturbations, under automatic control, within prescribed limits to preclude the possibility of a reactor trip in the course of these transients. During steady-state operation, the primary function of the reactor control is to allow operator adjustment of reactivity to maintain a programmed average reactor coolant temperature that rises in proportion to load. Complete supervision of both the nuclear and turbine generator plants is accomplished from the control room.

UFSAR Sections 7.7 and 1.2.2.4 describe the NSSS control systems functional requirements. Therefore, the current design basis operational transients described are:

- A step increase in steam flow of 10 percent, with the steam flow initially between 15 and 90 percent,
- A step decrease in steam flow of 10 percent, with the steam flow initially between 100 and 25 percent,
- Ramp changes in steam flow at a rate of 5 percent per minute within the range of 15 to 100 percent, and
- A load rejection of up to 29 percent with steam bypass control system (SBCS).

The analyses evaluating the response to design basis operational transients at EPU conditions are described in LR [Section 2.4.2](#). The acceptable response to the design basis operation transients are based on the changes described for the reactor regulating system, feedwater regulating system and steam bypass control system being implemented.

Turbine First Stage Pressure Instrumentation

When the turbine generator is on line, turbine first stage pressure increases essentially linearly from 0 percent - 100 percent turbine load and provides a close correlation of secondary power to reactor power. This allows turbine first stage pressure to be used as a reliable input demand signal or permissive to the various reactor control systems between 0 percent and 100 percent reactor power. The current 0 percent - 100 percent turbine load turbine first stage pressure correlates to 0 – 515.4 psig. The current high pressure (HP) turbine has a governing stage and the governing stage exit pressure is the first stage pressure. For EPU, a new HP turbine is being installed which 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 nominal first stage turbine pressure of 0 – 788.6 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.

Reactor Regulating System Changes

The reactor regulating system responds to changes in RCS temperature and secondary load as sensed by the RCS measured T_{avg} 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 – 100 percent power turbine first stage pressure range of 0 – 788.6 psig corresponds to the new T_{avg} range of 532 – 577.3 °F.

Pressurizer Level Control System Changes

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 full power T_{avg} temperature 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 corresponding to a T_{avg} temperature of 572.3 °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. The pressurizer level program low limit and high limit in terms of level do not change for EPU. The evaluation of the reactor regulating system and pressurizer level control system is described in LR [Section 2.4.2](#).

Feedwater Regulating System Changes

The feedwater regulating system, which is a subsystem of the distributed control system (DCS), maintains steam generator water level within acceptable limits by positioning the main feedwater regulating valves and feedwater bypass valves. In addition, in the event of a reactor trip or turbine trip, the feedwater regulating valves are closed and the DCS controls steam generator level via the feedwater bypass valves. For EPU, the feedwater regulating valves are being modified. Therefore, changes to the feedwater regulating and feedwater 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. The evaluation of the feedwater regulating system is described in LR [Section 2.4.2](#).

Steam Bypass Control System (SBCS) Changes

The SBCS is comprised of five valves, one bypass valve and four dump valves, all of 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 are being 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 evaluation of the steam bypass control system is described in LR

Section 2.4.2.

Moisture Separator Reheater (MSR) and Feedwater Heater 5A/B Level Controls

The existing pneumatic controls for MSR and high pressure feedwater heater 5 level control are being replaced with electronic instruments. The existing backup level switch control functions will not be changing.

Leading Edge Flow Meter (LEFM)

The existing feedwater flow is measured using venturi based differential pressure signals as part of the DCS. To support EPU, the existing DCS is being modified to use newly installed LEFMs which provide alternate feedwater flow inputs. See LR **Section 2.4.4**, Measurement Uncertainty Recapture Power Uprate, for additional details

Condensate and Feedwater System

The condensate and feedwater system evaluation is described in LR **Section 2.5.5.4**, Feedwater and Condensate. As a result of this evaluation, the following modifications will be implemented to regain operating margin when the power uprate occurs on the main feedwater system:

- Feedwater 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 feedwater pumps.
- Feedwater Flow – The range of the various feedwater 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. All associated indicators, recorders, computer points, and alarm setpoints will be rescaled as necessary.

Main Steam System

The main steam system evaluation is described in LR **Section 2.5.5.1**, Main Steam. As a result of this evaluation, the following modifications will be implemented.

- Main Steam Flow – 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. All associated indicators, recorders, computer points, and alarm setpoints will be rescaled as necessary.

Turbine Cooling Water System

As a result of the turbine cooling water system evaluation, the following modification will be implemented:

- Replace isolated phase bus air coolers flow indicator,
- Replace turbine generator outboard and inboard exciter coolers, and
- Replace generator hydrogen coolers.

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. The new digital control system will be designed to meet applicable cyber security requirements.

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

As discussed above, the reactor protection, safety features actuation and control systems are within the scope of License Renewal. Operation of the reactor protection, safety features actuation and control systems under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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.

2.4.1.2.5 Results

The changes to the instrumentation and controls for EPU are the result of accident and transient analyses and system evaluations to verify the systems and controls will continue to provide the required indication, protection actions, and plant response as originally designed. The changes ensure the DNB values remain within acceptable limits and the RCS pressure boundary and the main steam pressure boundary are maintained within the design values. No RPS or ESFAS instrumentation or setpoint changes were necessary to ensure they will continue to satisfy their design functions at EPU conditions. However, due to risk insights, a change to the RPS low steam generator water level trip setpoint from ≥ 20.5 percent to ≥ 35 percent water level for each steam generator is being proposed. There are no new protection systems required to support EPU. The identified instrumentation recalibration and instrument rescaling will ensure the instrumentation continues to allow monitoring plant process parameters during normal, transient and accident conditions and provide protective functions as required. The identified changes to the reactor regulating system, the SBCS and the feedwater regulating system are designed to improve the transient response of these control systems, and are shown to be acceptable in LR [Section 2.4.2](#).

2.4.1.3 Conclusion

FPL has reviewed the effects of the proposed EPU on the functional design of the reactor trip system, ESFAS, safe shutdown system and control systems. FPL concludes that the review 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. FPL further concludes that the systems will continue to meet the requirements of 10 CFR 50.55a(a)(1), 10 CFR 50.55a(h), and GDCs -1, -4, -13, -19, -20, -21, -22, -23 and -24. Therefore, FPL finds the proposed EPU acceptable with respect to instrumentation and controls.

Table 2.4.1-1
Best-Estimate Nominal Operating Parameters

Operating Parameter	Best-Estimate Value
Core Power (MWth)	3020.0
Reactor Coolant Pump Power (MWth)	14.2
Pressurizer System Pressure (psia)	2250.0
Pressurizer Level at Full Power (%)	63.0
Full Power Hot Leg Temperature (°F)	602.6
Full Power Cold Leg Temperature (°F)	551.0
Zero Power Cold Leg Temperature (°F)	532.0
Full Power Steam Generator Pressure (psia)	882.0
Full Power Feedwater Temperature (°F)	436.0

2.4.2 Plant Operability

2.4.2.1 Regulatory Evaluation

The nuclear steam supply system (NSSS) Instrument & Control (I&C) systems are required to respond to the initiation of plant operational transients without initiating a reactor trip or engineered safety feature (ESF) actuation signal (ESFAS). Nuclear Regulatory Commission (NRC) review standard RS-001 does not explicitly reference the Standard Review Plan (SRP) or other guidance documentation for license basis reviews regarding plant operability. Florida Power and Light (FPL) conducted an evaluation of the nuclear steam supply system (NSSS) I&C systems response to operational transients at EPU conditions to ensure that the responses remain acceptable.

The acceptance criteria are based on:

- General Design Criterion (GDC)-13, insofar as it requires that instrumentation be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary (RCPB), and the containment and its associated systems. Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC GDC for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDC for Plant Operability is as follows:

- GDC-13 is described in UFSAR Section 3.1.13 Criterion 13 - Instrumentation and Control.

Instrumentation shall be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary, and the containment and its associated systems. Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges.

Instrumentation is provided, as required, to monitor and maintain significant process variables which can affect the fission process, the integrity of the reactor core, the RCPB and the containment and its associated systems. Controls are provided for the purpose of maintaining these variables within the limits prescribed for safe operation.

The principal variables and systems monitored include neutron level (reactor power); reactor coolant temperature, flow, and pressure; pressurizer level; steam generator (SG) level and pressure; and containment pressure and temperature.

The following instrumentation is provided to monitor and maintain control over the fission process during both transient and steady state periods over the lifetime of the core:

- Twelve independent channels of nuclear instrumentation are used to monitor the fission process. There are four startup channels, four safety channels, two Appendix R channels and two control channels.
- Two independent control element assembly (CEA) position indicating systems;
- A method of determining soluble poison concentration by sampling and analysis of reactor coolant water;
- Manual and automatic control of reactor power by means of CEA's; and
- Manual regulation of coolant boron concentrations.

In-core instrumentation is provided to supplement information on core power distribution and to provide for calibration of out-of-core flux detectors.

Instrumentation measures temperatures, pressures, flows, and levels in the main steam system and auxiliary systems and is used to maintain these variables within prescribed limits.

The reactor protective system is designed to monitor the reactor operating conditions and to affect reliable and rapid reactor trip if any one or a combination of conditions deviate from a preselected operating range.

The containment pressure, temperature, and radiation instrumentation is designed to function during normal operation and postulated accidents.

The instrumentation and control systems are described in detail in UFSAR Chapter 7.

Reactivity is controlled by adjustments of CEAs for rapid reactivity changes or by adjustment of boric acid concentration for slow reactivity changes. The boric acid is used to compensate for slow load changes and for such long term effects as fuel burnup and changes in fission product concentration.

UFSAR sections that address the design features and functions of the NSSS instrumentation and control systems include:

- UFSAR Section 7.5 describes non-safety and safety related display instrumentation. The safety related (Class 1E) display instrumentation provides timely information to the operator so that the operator may initiate appropriate safety actions if and when required. Non-safety instrumentation is used for normal operation and, although not required, may be available for operator information. UFSAR Table 7.5-1 lists the safety display instrumentation.
- UFSAR Section 7.7.1.1.2 states that the reactor coolant pressure control system maintains system pressure within specified limits by the use of pressurizer heaters and spray valves. The control and alarm setpoints are shown on UFSAR Figure 5.4-12.

- UFSAR Section 7.7.1.1.3 states that the pressurizer level control system minimizes changes in RCS water inventory by the use of charging pumps and letdown control valves in the chemical and volume control system as described in UFSAR Section 9.3.4.
- UFSAR Section 7.7.1.1.4 states that the feedwater regulating system which is a subsystem of the distributed control system (DCS), maintains SG water level within acceptable limits by positioning the main feedwater regulating valves which control the feedwater to each SG.
- UFSAR section 7.7.1.1.5 states that the steam dump and bypass control system is a subsystem of the DCS. As described in UFSAR Section 10.4.4, it is designed to provide a means of manually controlling reactor coolant temperature during plant startup and for removing NSSS stored energy, decay heat, and pump energy during shutdown cooling. In addition, the system can automatically accommodate a load rejection of up to 29 percent without opening the pressurizer relief valves or the main steam safety valves (MSSVs) or causing a reactor trip.

In addition to the licensing bases basis described in the UFSAR, plant operability as it relates to I&C systems was evaluated for License Renewal. For License Renewal, electrical and I&C systems were broken down into commodity groups and then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.5.1 of the SER identifies that components of the I&C systems are within the scope of License Renewal. The programs used to manage the aging effects associated with the I&C systems are discussed in SER Section 3.6 and UFSAR Chapter 18.

2.4.2.2 Technical Evaluation

2.4.2.2.1 Introduction

UFSAR Sections 1.2.2.4 and 7.7.1 describe the plant's ability to sustain the following operational transients:

- A step increase in steam flow of 10 percent, with the steam flow initially between 15 and 90 percent,
- A step decrease in steam flow of 10 percent, with the steam flow initially between 100 and 25 percent,
- Ramp changes in steam flow at a rate of 5 percent per minute within the range of 15 to 100 percent,
- A load rejection of up to 29 percent with steam bypass control system (SBCS), and
- A turbine/reactor trip.

Analyses of the design basis transients were performed using the EPU NSSS control system settings and setpoints to demonstrate adequate margin exists to relevant reactor trip and ESF actuation setpoints over the entire range of EPU operating conditions.

The analyses were performed using the Westinghouse CENTS computer code ([Reference 1](#)). This computer code is a system-level program that models the overall NSSS, including the detailed modeling of the control and protection systems. The CENTS code is not a part of the current licensing basis, but is an NRC approved code that is acceptable for this purpose and referencing in licensing applications for Combustion Engineering designed pressurized water reactors.

A CENTS model base deck was developed for EPU conditions. The transients specified above were analyzed to show that the plant response is acceptable. The transients evaluated included transients starting from 90 percent power level which reflects the current licensed power of 2700 MWt. This was done in order to ensure that like comparisons were made between the current and EPU power levels. Details of the analyses are described below.

2.4.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The following changes were made in the analyses for EPU:

- The analysis used increased SBCS valve capacities with linear valve Cv curves and a two second quick open stroke time due to the EPU as described in LR [Section 2.5.5.3](#), Turbine Bypass.
- The analysis assumed changes to the condensate and feedwater system due to the EPU as described in LR [Section 2.5.5.4](#), Condensate and Feedwater.
- The EPU analysis derived NSSS control system settings were used for an evaluation of the margin to trip or to initiate an ESFAS. The changes to the NSSS control system settings are also described in LR [Section 2.4.1](#), Reactor Protection, Safety Features Actuation and Control Systems. The NSSS control systems requiring setting changes are listed below:
 - Main steam flow and feedwater flow instrument range,
 - The SBCS main steam header pressure instrumentation range with a corresponding change to SBCS proportional control setpoint,
 - The SBCS valve demand programs,
 - The SBCS quick open settings for change in main steam flow,
 - The reactor regulating system reactor coolant system (RCS) reference temperature for 100 percent power,
 - The pressurizer level control program for the higher RCS average temperature program,
 - The feedwater regulating system valve demand program,
 - The feedwater regulating system turbine trip override settings. This includes the closure rate of the SG feedwater flow control valves and the 5 percent flow setting for the 15 percent feedwater valves.

The following assumptions were made for the operational transients analyzed:

- All applicable NSSS control systems, except CEA control, were assumed to be operational and in the automatic mode of control (that is, SBCS, pressurizer level control, SG level

control, and pressurizer pressure control). CEA control is assumed to always be in manual mode.

- The best-estimate full-power operating conditions for EPU were assumed. The plant parameters (that is, RCS T_{avg} , pressurizer pressure, pressurizer level, SG level) were assumed to be at the nominal EPU NSSS control system setpoints.
- Best-estimate at the beginning-of-cycle (BOC) core conditions (that is, CEA worth, moderator temperature coefficient (MTC), doppler power defect, etc.) are used. The BOC values used are conservative for margin to trip analysis.
- The atmospheric dump valves were assumed to be closed in manual control for all of the operational transients.
- The operator is assumed to take manual action to start or stop a condensate pump, heater drain pumps and a feedwater pump during power ramps.
- The analysis used the post-EPU reactor protection system (RPS) and ESFAS setpoints. The RPS and ESFAS setpoints used are:

High pressurizer pressure reactor trip:	2360.0 psia
Pressurizer minimum thermal margin low pressure reactor trip:	1900.0 psia
Low pressurizer pressure safety injection (SI):	1740.0 psia
Low SG pressure reactor trip:	626.0 psia
Low SG pressure main steam isolation signal:	600.0 psia
Low SG narrow range level reactor trip:	35.5 percent
Low SG narrow range level auxiliary feedwater actuation signal (AFAS):	19.5 percent

The acceptance criterion for the analyses is that the operational transients should not result in a reactor trip or an ESF actuation.

2.4.2.2.3 Description of Analyses and Evaluations

Design operational transients were performed using the derived NSSS control system settings and an increase in the condenser SBCS valve capacities. With the increased condenser SBCS valve capacities and revised NSSS control system settings, these analyses achieved acceptable results. The required changes to the NSSS control system settings are described in LR [Section 2.4.1](#), Reactor Protection, Safety Features Actuation and Control Systems. The required changes to the SBCS valves are described in LR [Section 2.5.5.3](#), Turbine Bypass.

A step increase in steam flow of 10 percent, with the steam flow initially between 15 and 90 percent

A 10 percent step increase in steam flow was evaluated from initial power levels of 25 percent, 50 percent, 80 percent and 90 percent. No operator actions were assumed and CEA control was in manual.

A step decrease in steam flow of 10 percent, with the steam flow initially between 100 and 25 percent

A 10 percent step decrease in steam flow was evaluated from initial power levels of 25 percent, 50 percent, 90 percent and 100 percent. No operator actions were assumed and CEA control was in manual.

Ramp changes in steam flow at a rate of 5 percent per minute within the range of 15 to 100 percent

A ramp change in steam flow from 100 percent to 15 percent power was evaluated. The operator was assumed to reduce power using manual CEA control starting at the initiation of the transient to match steam demand. It was also assumed that the operator stopped one main feedwater pump at about 50 percent power, a condensate pump at about 45 percent power and both heater drain pumps at approximately 35 percent power.

A ramp change in steam flow from 15 percent to 100 percent power was evaluated. The operator was assumed to increase power using manual CEA control starting at the initiation of the transient to match steam demand. It was also assumed that the operator started a condensate pump at approximately 50 percent power, a main feedwater pump one minute later and the heater drain pumps at approximately 80 percent power.

A load rejection of up to 29 percent with SBCS

A 30 percent step decrease in steam flow with SBCS was evaluated from initial power levels of 75 percent, 90 percent and 100 percent. The 30 percent step decrease in steam flow bounds the identified 29 percent step decrease requirement. No operator actions were assumed and CEA control was in manual.

Turbine Trip and Reactor Trip

In addition to the design operational transients, a manual reactor trip transient was evaluated from power levels of 90 percent and 100 percent. Also, turbine trip with reactor trip was evaluated from power levels of 25 percent, 50 percent, 75 percent, 90 percent and 100 percent.

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

As discussed above, the plant operability as it relates to I&C systems is within the scope of License Renewal. Operation of the I&C systems under EPU conditions have been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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.

2.4.2.2.5 Results

These analyses show that the proposed changes to the affected NSSS control systems discussed in LR [Section 2.4.2.2.2](#), Input Parameters, Assumptions, and Acceptance Criteria, above, will enable the plant to continue to satisfy the requirements of the design operational transients listed below.

A step increase in steam flow of 10 percent, with the steam flow initially between 15 and 90 percent

A 10 percent step increase in steam flow was evaluated from initial power levels of 25 percent, 50 percent, 80 percent and 90 percent. The minimum pressurizer pressure was 2154 psia, which is 414 psia above the safety injection actuation signal (SIAS) setpoint. The minimum SG pressure was 781 psia which is 155 psi above the SG low pressure setpoint. The results indicate that no reactor trip or ESFAS setpoints were challenged and the NSSS control system response was stable. Therefore, the response to a step increase in steam flow of 10 percent for EPU is acceptable.

A step decrease in steam flow of 10 percent, with the steam flow initially between 100 and 25 percent

A 10 percent step decrease in steam flow was evaluated from initial power levels of 25 percent, 50 percent, 90 percent and 100 percent. The maximum pressurizer pressure was 2326 psia, which is 34 psi below the reactor trip setpoint. The maximum pressurizer pressure occurred at 100 percent power level (EPU condition) which is an increase of 5 psia above the 90 percent initial power level case. The SBCS valves open to limit the increase in secondary pressure. The maximum SG pressure was 956 psia which is 44 psi below the nominal MSSV lift setpoint of 1000 psia. The results indicate that no reactor trip or ESFAS setpoints were challenged and the NSSS control system response was stable. Therefore, the response to a step decrease in steam flow of 10 percent for EPU is acceptable.

Ramp changes in steam flow at a rate of 5 percent per minute within the range of 15 to 100 percent

Ramp changes in steam flow from 100 percent to 15 percent power and from 15 percent to 100 percent power were evaluated. The results obtained were bounded by the 10 percent step increase and decrease in steam flow transients. The results indicate that no reactor trip or ESFAS setpoints were challenged and the NSSS control system response was stable. Therefore, the response to ramp changes in steam flow at a rate of 5 percent per minute for EPU is acceptable.

A load rejection of up to 29 percent with SBCS

A 30 percent step decrease in steam flow was evaluated from initial power levels of 75 percent, 90 percent and 100 percent. The maximum pressurizer pressure was 2327 psia which is 33 psi below the reactor trip setpoint. The maximum pressurizer pressure occurred at 100 percent power level (EPU condition) which is an increase of 5 psia above the 90 percent initial power level case. The SBCS valves open to limit the increase in secondary pressure. The maximum steam generator pressure was 953 psia which is 47 psi below the nominal MSSV lift setpoint of 1000 psia. The results indicate that no reactor trip or ESFAS setpoints were challenged and the

NSSS control system response was stable. Therefore, the response to a load rejection of up to 29 percent with SBCS for EPU is acceptable.

Turbine Trip and Reactor Trip

The transient due to a manual reactor trip was evaluated from power levels of 90 percent and 100 percent. Also, turbine trip with reactor trip was evaluated from power levels of 25 percent, 50 percent, 75 percent, 90 percent and 100 percent. For these transients, the SBCS valves open to limit the increase in secondary pressure. For a reactor trip from 100 percent power level (EPU condition), the maximum SG pressure was 997 psia which is an increase of 23 psia from the 90 percent initial power level case. For a turbine trip with reactor from 100 percent power level (EPU condition), the maximum SG pressure was 999 psia which is an increase of 23 psia from the 90 percent initial power level case. The pressurizer did not drain and the minimum pressurizer pressure calculated was above the SIAS setpoint. Therefore, the response to a turbine trip or reactor trip for EPU is acceptable.

2.4.2.3 Conclusion

FPL has reviewed the effects of the proposed EPU on the plant response to operational transients. FPL concludes that the changes necessary to achieve satisfactory results at the proposed EPU are consistent with the plant's design basis, and will continue to meet the current licensing basis with respect to the requirements of GDC-13. Therefore, FPL finds the proposed EPU acceptable with respect to plant operability (margin to trip).

2.4.2.4 References

1. Topical Report WCAP-15996-P-A, Revision 1, Technical Description Manual for the CENTS Code, March 2005.

2.4.3 Pressurizer Component Sizing

2.4.3.1 Regulatory Evaluation

The pressurizer pressure control system (consisting of the pressurizer heaters, spray, and power operated relief valves (PORVs)) provides the means of controlling the pressurizer pressure to less than the design basis setpoint value during steady-state operation and to minimize the pressurizer pressure excursions during design basis operational transients. Florida Power and Light (FPL) conducted a review of the pressurizer pressure control system for the EPU to ensure that the system is adequately designed so that they continue to meet its design basis operational functions and if any changes are required for the extended power uprate (EPU).

The acceptance criteria related to the quality of design of the pressurizer pressure control system are based on:

- 10 CFR 50.55a(a)(1), insofar as it requires that safety-related structures, systems, and components (SSCs) be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed;
- 10 CFR 50.55a(h)(2), insofar as it requires that protection systems must be consistent with the plant's current licensing basis;
- General Design Criterion (GDC)-1, insofar as it requires that safety-related SSCs are designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed;
- GDC-13, insofar as it requires that instrumentation be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to ensure safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary (RCPB), and the containment and its associated systems. Appropriate controls should be provided to maintain these variables and systems within prescribed operating ranges.
- GDC-19, insofar as it requires that a control room be provided from which actions can be taken to operate the nuclear unit safely under normal conditions and to maintain it in a safe condition under accident conditions, including loss-of-coolant accidents (LOCAs);
- GDC-24, insofar as it requires that the protection system be separated from the control systems to the extent that failure of any single control system component or channel, or failure or removal from service of any single control system component or channel that is common to the control and protection systems leaves intact a system satisfying all reliability, redundancy, and independence requirements of the protection systems. Interconnection of the protection and control systems will be limited so as to ensure that safety is not significantly impaired.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms to the NRC General Design Criteria (GDC) for Nuclear Power Plants as

specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDCs for pressurizer component sizing are as follows:

- GDC-1 is described in UFSAR Section 3.1.1 Criterion 1 – Quality Standards and Records.

Structures, systems and components important to safety shall be designed, fabricated, erected and tested to quality standards commensurate with the importance of the safety functions to be performed. Where generally recognized codes and standards are used, they shall be identified and evaluated to determine their applicability, adequacy and sufficiency and shall be supplemented or modified as necessary to assure a quality product in keeping with the required safety function. A quality assurance program shall be established and implemented in order to provide adequate assurance that these structures, systems, and components will satisfactorily perform their safety functions. Appropriate records of the design, fabrication, erection and testing of structures, systems and components important to safety shall be maintained by or under the control of the nuclear power unit licensee throughout the life of the unit.

- GDC-13 is described in UFSAR Section 3.1.13 Criterion 13 – Instrumentation and Control.

Instrumentation shall be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary, and the containment and its associated systems. Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges.

UFSAR Section 7.7.1.1 describes control systems, including the reactor coolant pressure control system and the pressurizer level control system.

- GDC-19 is described in UFSAR section 3.1.19 Criterion 19 – Control Room.

A control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in safe condition under accident conditions, including loss of coolant accidents. Adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent for the duration of the accident.

Equipment in appropriate locations outside the control room shall be provided (1) with a design capability for prompt hot shutdown of the reactor, including necessary instrumentations and controls to maintain the unit in a safe condition during hot shutdown, and (2) with a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

Control stations, switches, controllers and indicators necessary to operate or shutdown the unit and maintain safe control of the facility are located in the control room.

- GDC-24 is described in UFSAR Section 3.1.24 Criterion 24 – Separation of Protection and Control Systems.

The protection system shall be separated from control systems to the extent that failure of any single control system component or channel, or failure or removal from service of any single protection system component or channel which is common to the control and protection systems leaves intact a system satisfying all reliability, redundancy, and independence requirements of the protection system. Interconnection of the protection and control systems shall be limited so as to assure that safety is not significantly impaired.

The pressurizer is a vertically mounted, bottom supported, seismic Category I, stainless steel clad, cylindrical pressure vessel. Replaceable direct immersion electric heaters are vertically mounted in the bottom head. The pressurizer is equipped with nozzles for spray line, surge line, safety valves, relief valves and pressure, temperature and water level instrumentation. Principal design parameters are listed in Table 5.4-6 of the UFSAR.

The water level in the pressurizer is programmed as a function of average reactor coolant temperature with high or low water level error signals resulting in control actions. The pressurizer surge line is sized to accommodate the flow rates associated with reactor coolant system (RCS) expansion and contraction due to design basis transients.

The pressurizer spray is supplied from each of the reactor coolant pumps (RCPs) associated with steam generator 2B. Automatic spray control valves control the amount of spray as a function of pressurizer pressure; both of the spray control valves function in response to the signal from the controller. These valves are sized to use the differential pressure between the RCP discharge and the pressurizer to pass the amount of spray required to prevent the pressurizer steam pressure from opening the PORVs during normal load following transients.

UFSAR Section 5.4.10.3 states that analyses performed in accordance with the requirements of ASME Code, Section III, Code Class 1, demonstrate the pressurizer is adequate for all normal operating and transient conditions expected during the life of the plant.

LR [Section 2.2.2.7](#) addresses the evaluation of the pressurizer and supports as pressure retaining components. LR [Section 2.5.2](#) addresses the pressurizer relief tank. LR [Section 2.8.4.2](#) evaluates over pressure protection at power. LR [Section 2.8.4.3](#) addresses overpressure protection during low temperature operation.

In addition to the licensing basis described in the UFSAR, the pressurizer components were evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.1.2 of the SER identifies that components of the pressurizer components are within the scope of License Renewal. Programs used to manage the aging effects associated with the pressurizer components are discussed in SER Section 3.1.2 and Chapter 18 of the UFSAR.

2.4.3.2 Technical Evaluation

2.4.3.2.1 Introduction

The following pressurizer components were evaluated for the EPU to ensure that the nuclear steam supply system (NSSS) pressure control system is adequate for the increased pressures and temperatures for the uprate parameters contained in LR [Section 1.1](#), Nuclear Steam Supply System Parameters.

- Pressurizer power-operated relief valves,
- Pressurizer spray valves, and
- Pressurizer heaters.

To support the EPU, new control system settings will be implemented as described in LR [Section 2.4.1](#), Reactor Protection, Safety Features Actuation, and Control Systems. The pressurizer safety valves (PSVs) are discussed in LR [Section 2.8.4.2](#), Overpressure Protection During Power Operation. The PORVs are also used for low temperature overpressure protection (LTOP). Refer to LR [Section 2.8.4.3](#) for the EPU review of PORV operations for LTOP.

The components comprising the pressurizer pressure control system are discussed in UFSAR Sections 5.4.10, 5.4.13 and 7.7.1.1.2. Based on those discussions, the following bases are used to evaluate the sizing acceptability of the various components of the pressurizer pressure control system.

2.4.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Pressurizer PORVs

The PORVs are designed to pass the maximum steam release associated with a continuous control element assembly (CEA) withdrawal event starting from low pressure conditions. UFSAR Section 5.4.13 states that the PORVs design is based on the design transient control rod withdrawal accident. The total relief capacity shall also be large enough so that the PSVs do not open during a loss of load from full power.

The CEA withdrawal and the loss of load event analyses were performed following the general guidelines and methodology presently in use for UFSAR Chapter 15 accident transient analyses and for plant operational transient evaluations. These analyses were performed using the design parameters and assumptions listed below:

- (2) Crosby valves - Model DS-C-72025-1 with an orifice bore of 2.135 in., a flow area of 3.58 in sq. Note: the relieving capacity of only one valve was used for the safety analyses,
- Design temperature of 675°F,
- Design pressure of 2500 psia,
- Design capacity minimum of 395,000 lbs/hr of saturated steam,
- Set pressure of 2370 psia,

- Valve design backpressure of 500 psia, and
- PORV total stroke time of 1.3 seconds consists of 0.15 seconds for solenoid delay and 1.15 seconds for stroke time.

These analyses of PORV performance at power are predicated on a pressurizer steam space being available, so that the discharge through the PORVs will be saturated steam.

Pressurizer Spray Valves

The design criteria for sizing the maximum pressurizer spray flow is to provide cooling water to the pressurizer in order to mitigate pressure excursions, while avoiding reactor trips and PORV actuation, during ramp and step load following transients. The limiting pressure excursion events for the spray valves are a loss of load event and normal pressure variations of +/- 100 psi.

The spray valve transient evaluations are a part of the overall EPU safety and control system analyses. These analyses were performed using the CENTS code as well as the following design parameters and assumptions listed below:

- (2) full capacity valves with a design flow of 450 gpm,
- Design pressure of 2500 psia,
- Design temperature of 650°F,
- Flow driven by RCS pressure drop from RCP discharge to pressurizer dome,
- Pressure control system modulates spray valve position from full closed to full open to maintain pressure, and
- Auxiliary spray supplied by chemical and volume control system (CVCS) is provided to the pressurizer downstream of the spray valves before the spray nozzle.

Pressurizer Heaters

The design criterion for sizing the pressurizer heaters is that the heatup rate of the pressurizer with water level at the hot zero power (HZP) level must match the heatup rate of the RCS with four RCPs running and 2/3 of the core generating decay heat following a refueling outage. Matching the heatup rates of the pressurizer and the RCS allows for an orderly plant heatup and pressurization.

The NSSS control system transient evaluations were performed using CENTS following the guidelines and methodology presently found in UFSAR Chapter 7. The evaluations were performed using the design parameters and assumptions listed below:

- Single unit direct immersion type with a total capacity of 1500 kW,
- Minimum required heater capacity of 300 kW in two groups,
- Approximately 20% of the heaters are connected to proportional controllers to account for steady state heat losses and to maintain steam pressure, and
- The remaining heaters are backup heaters energized on the low pressurizer pressure signal.

2.4.3.2.3 Description of Analyses and Evaluations

Pressurizer PORVs

The uncontrolled CEA rod withdrawal at power event currently shown in UFSAR has a maximum system pressure of approximately the 2370 psia setpoint of the PORVs.

The CEA withdrawal event at full power and a loss of load event at full power were reanalyzed at EPU conditions to assure that the transient results are still within the original PORV operational constraint of precluding safety valve actuation. Discussion of the CEA withdrawal at power event can be found in LR [Section 2.8.5.4.2](#), Uncontrolled Control Rod Assembly Withdrawal at Power. Evaluation of loss of load event can be found in LR [Section 2.8.5.2.1](#), Loss of External Load, Turbine Trip, and Loss of Condenser Vacuum.

Pressurizer Spray Valves

An evaluation was performed to determine whether the design operation of spray valves was adequate to meet the operating requirements for EPU. The NSSS pressure excursion performance was reviewed for the loss of load event, and for ramp and step load transients for proper system performance.

Specifically, a step load change from 100 percent to 90 percent was evaluated to determine spray valve operation during this representative operating transient.

In the loss of load event analysis for PORV capacity evaluation, the performance of the spray valves was reviewed to determine their contribution in mitigating the pressure transient.

Pressurizer Heaters

An evaluation was performed to determine if the required heater capacity was affected by the EPU conditions. The heatup time from cold shutdown to hot standby is not affected by the uprate.

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

As discussed above, the pressurizer components are within the scope of License Renewal. Operation of the pressurizer components under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.4.3.2.5 Results

The evaluations verify that the pressurizer pressure control system operating the pressurizer heaters and the spray control valves in conjunction with the pressurizer water level control

system operating the letdown and charging equipment maintain control of the RCS level during all of the normal operating transients without causing any plant trips, such as high and low pressure trips as well as any pressurizer level trips. These analyses also demonstrate that sufficient steam space is maintained to avoid PORV opening under water solid conditions.

Pressurizer PORVs

The current UFSAR Chapter 15 analyses and the EPU UFSAR Chapter 15 results both do not take credit for PORV actuation to mitigate the consequences of any accident.

The uncontrolled CEA rod withdrawal event currently shown in the UFSAR has a maximum system pressure of 2363 psia, which is just below the PORV setpoint of 2370 psia. This transient was re-analyzed and the resulting pressure was 2485 psia without taking credit for the PORVs. If the PORV had been modeled, the PORV opening setpoint of 2370 psia would have relieved the pressure well before the PSV minimum setpoint of 2450 psia is reached.

The total PORV relief capacity is large enough so that the PSVs do not open during a loss of load at full power. Note, this is for one PORV operational since the other PORV has its block valve closed. The analysis results show a maximum pressure of 2433 psia which is below the PSV minimum setpoint of 2450 psia.

Pressurizer PORVs are not subjected to water-solid conditions during non-LOCA transients. LR [Section 2.8.5.2.2](#), Loss of Non-emergency AC Power to the Station Auxiliaries, and LR [Section 2.8.5.2.3](#), Loss of Normal Feedwater Flow, show that water-solid conditions in the pressurizer do not occur under those transients. LR [Section 2.8.5.0](#) addresses the ability of the RETRAN computer code that was used for these analyses to accurately determine the occurrence of water-solid conditions. LR [Section 2.4.1](#), Reactor Protection, Safety Features Actuation, and Control Systems describes the ability of the pressurizer level control system to maintain the level low enough that a sufficient steam volume is maintained to ensure the pressurizer does not go solid during non-LOCA transient conditions.

In addition, the analyses for NSSS control system setpoint evaluation at EPU do not require any mitigating support from PORV actuation. The operational analyses demonstrated that the transient results showed a maximum peak pressurizer pressure which is less than the pressurizer PORV actuation setpoint of 2370 psia.

Pressurizer Spray Valves

The pressurizer spray valves will control RCS pressure to prevent a reactor trip and PORV actuation, during ramp and step load following transients. The system response to operational transients was evaluated and is acceptable demonstrating that the spray valve performance is acceptable for EPU.

A spray valve actuation transient was reviewed that demonstrated the performance of the spray valves. It showed that for a step load change from 100 percent to 90 percent, the pressure increase was limited to 2326 psia with maximum flow thru the spray valves for approximately 8 seconds at 16 seconds into the transient.

In addition, for the loss of load PORV capacity calculation, the spray valves were also required to mitigate the pressure increase. The spray valves started to open 2.1 seconds into the transient,

reaching full open at 6.3 seconds and the pressure increase was terminated at 6.2 seconds, below the safety valve setpoint.

Pressurizer Heaters

The plant operability analyses described in LR [Section 2.4.2](#), Plant Operability, demonstrates that the pressurizer pressure is maintained above the low pressurizer pressure reactor trip setpoint during the design basis operational transients. Therefore, for EPU, the current heater capacity remains sufficient to maintain the pressurizer pressure at its setpoint during steady-state operation and to minimize pressure excursions during design basis operational transients.

2.4.3.3 Conclusion

FPL has evaluated the effects of the proposed EPU on the functional design of the NSSS pressurizer pressure control systems. FPL concludes that the evaluation adequately addresses the effects of the proposed EPU on these systems and that the other changes that are necessary to the reactor control systems to achieve the proposed EPU, are consistent with the pressurizer pressure control systems' design basis. FPL further concludes that the pressurizer pressure control systems will continue to meet its current licensing basis requirements with respect to 10 CFR 50.55a(a)(1) and 10 CFR 50.55a(h), and GDC-1, GDC-13, GDC-19, and GDC-24. Therefore, FPL finds the proposed EPU acceptable with respect to the pressurizer pressure control systems.

2.4.4 Measurement Uncertainty Recapture Power Uprate

2.4.4.1 Regulatory Evaluation

NRC Review Standard RS-001, Review Standard for Extended Power Uprates, is specific to extended power uprate (EPU). As such, it does not include review and acceptance criteria applicable to Measurement Uncertainty Recapture (MUR). To facilitate the Nuclear Regulatory Commission (NRC) review process, the content and format of this Licensing Report (LR) section has been structured to be consistent with the guidelines in NRC Regulatory Issue Summary (RIS) 2002-03, Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications ([Reference 1](#)). Since this MUR is an integral part of a larger EPU, some MUR content is contained in other LR sections. This LR section provides reference to associated content, where applicable.

2.4.4.2 Technical Evaluation

2.4.4.2.1 Introduction

Like most nuclear units, St. Lucie Unit 2 was originally designed with feedwater (FW) flow and temperature instrumentation consisting of venturis, differential pressure transmitters and resistance temperature detectors (RTDs) for each FW header. Since then, improvements have occurred in FW flow and temperature measurement instrumentation and the associated power calorimetric uncertainty values. Based on the installation of new FW flow / FW temperature instrumentation and the associated reduction in reactor core power uncertainty values, FPL is proposing to increase the core rated thermal power by 1.7 percent (MUR only). The proposed increase in the rated thermal power is being implemented as an integral part of an overall EPU, which will increase the licensed rated thermal power from 2700 MWt to 3020 MWt.

Modifications required for the MUR portion of the proposed uprate include installation of the Cameron/Caldon Leading Edge Flow Meter (LEFM) CheckPlus system. Existing FW flow and temperature instrumentation will be retained and used for comparison monitoring of the LEFM system and as a backup FW mass flow measurement when needed.

2.4.4.2.2 Summary of St. Lucie Unit 2 Measurement Uncertainty Recapture Evaluation

I. Feedwater Flow Measurement Technique and Power Measurement Uncertainty (RIS 2002-03 Section I)

I.1 Feedwater Flow Measurement Devices

The FW flow measurement system to be installed is a Cameron/Caldon LEFM CheckPlus ultrasonic 8-path transit time flowmeter. The design of this advanced flow measurement system is addressed in detail by the manufacturer in Topical Reports ER-80P, ER-160P and ER-157P ([References 2, 3, and 5](#), respectively). The referenced topical reports and NRC approvals are as follows:

- ER-80P, Improving Thermal Power Accuracy and Plant Safety While Increasing Operating Power Level Using the LEFM Check System, dated March 1997;

- ER-160P, Supplement to Topical Report ER-80P: Basis for a Power Uprate with the LEFM Check System, dated May 2000;
- ER-157P, Supplement to Topical Report ER-80P: Basis for a Power Uprate with the LEFM Check or CheckPlus System, dated October 2001.

The NRC has previously approved the Topical Reports referenced above in safety evaluation reports (SERs) ([References 7, 8, and 9](#), respectively) on the following dates:

- ER-80P, NRC SER, dated March 8, 1999,
- ER-160P, NRC SER, dated January 19, 2001,
- ER-157P, NRC SER, dated December 20, 2001.

The LEFM CheckPlus system consists of one flow element (spool piece) installed in each of the two FW flow headers. The “A” header spool piece is to be installed a minimum of 8 diameters upstream from the existing FW venturi and a minimum of 19 diameters downstream from the nearest 90° bend. The “B” header spool piece is to be installed a minimum of 14 diameters upstream from the existing FW venturi and a minimum of 9 diameters downstream from the nearest 90° bend. The resulting piping configurations were explicitly modeled as part of the LEFM meter factor and accuracy assessment testing performed at Alden Research Laboratories. The planned installation location of each flow element conforms to the applicable requirements in Cameron Topical Reports ER-80P and ER-157P.

The LEFM CheckPlus system is to be permanently installed in accordance with the requirements of ER-80P, ER-157P and FPL procedures. It will be used for continuous calorimetric power determination by providing FW mass flow and FW temperature input data to the distributed control system (DCS), which is the computer system used for automated performance of the 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 (Cameron Report ER-740, Bounding Uncertainty Analysis for Thermal Power Determination at St. Lucie Units 1 & 2 Using the LEFM CheckPlus system). ER-740 (Cameron proprietary document) is provided in Appendix F to Attachment 5 of the EPU LAR. Critical performance parameters, including signal to noise ratio, are continually monitored for every individual meter path and alarm setpoints are established to ensure corresponding assumptions in the uncertainty analysis remain bounding. Signal noise will be minimized via strict adherence with Cameron design requirements. Transducer signal cables are provided by Cameron in accordance with their design requirements. Transducer signal cable length is limited to 100 feet via use of locally mounted transmitters and these signal cables will be routed in dedicated conduit. Processed transducer data from the LEFM transmitters is sent to the LEFM central processing units (CPUs) via RS-485 communication cables. These RS-485 cables are routed in raceway systems designated for low level 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 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 to facilitate side-by-side comparison with data based on conventional instruments. Hard-wired alarms from LEFM to main control room annunciator panels will provide redundant operator notification of degraded system performance or outright system failure. The plant simulator will be modified to mimic the changes made to the DCS calorimetric display screens and to the annunciator panels. The LEFM CheckPlus system will also communicate with the PI system (product of OSIsoft for management of real time data) via a digital communications interface with appropriate cyber-security safeguards. These PI system communication links will provide the same “high-level” data sent to DCS, as well as LEFM performance and diagnostic data that will be used for trending and general equipment performance monitoring.

Each individual LEFM CheckPlus system flow element (spool piece) has been calibrated in a site-specific model test at Alden Research Laboratories with traceability to National Standards. A copy of the Alden Research Laboratories certified calibration report is contained in the Design Basis Uncertainty Analysis for the system. The LEFM CheckPlus system will be installed and commissioned in accordance with FPL procedures and Cameron installation and test requirements. LEFM commissioning will include verification of ultrasonic signal quality and evaluation of actual plant hydraulic velocity profiles as compared to those documented during the Alden Research Laboratories testing.

I.2 Topical Reports Criteria

In approving Caldon Topical Reports ER-80P and ER-157P, the NRC established four criteria to be addressed by each licensee. The four criteria and a discussion of how each will be satisfied for St. Lucie Unit 2 follows:

Criterion 1

Discuss maintenance and calibration procedures that will be implemented with the incorporation of the LEFM, including processes and contingencies for inoperable LEFM instrumentation and the effect on thermal power measurements and plant operation.

Response to Criterion 1

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 2968 MWt (Note: 2968 MWt is based on 98.3 percent of the proposed licensed power level of 3020 MWt). The incorporation of, and continued adherence to, these requirements will assure that the LEFM system is properly maintained and calibrated. A more detailed discussion of LEFM system maintenance and calibration procedures is provided in Section I.4 below. Contingency plans for operation of the plant with the LEFM CheckPlus system out of service are described in Section I.5 below.

Criterion 2

For plants that currently have LEFMs installed, provide an evaluation of the operational and maintenance history of the installed instrumentation 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.

Response to Criterion 2

This Criterion is not applicable to St. Lucie Unit 2. Although St. Lucie Unit 2 does have an existing LEFM system installed, it is an older generation external (strap-on) system that has never been approved for a measurement uncertainty recapture power uprate. The existing LEFM data is only used on a periodic basis to compensate for the effects of venturi fouling. St. Lucie Unit 2 currently uses venturis, differential pressure transmitters, and RTDs to obtain the daily calorimetric heat balance measurements. The existing strap-on LEFM equipment will be removed and a new LEFM CheckPlus system will be installed as the basis for the measurement uncertainty recapture.

Criterion 3

Confirm that the methodology used to calculate the uncertainty of the LEFM in comparison to the current feedwater 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.

Response to Criterion 3

The methodology used to calculate the uncertainty of calorimetric related process measurement instrument channels is based on FPL Nuclear Engineering Department Discipline Standard IC-3.17, Instrument Setpoint Methodology for Nuclear Power Plants ([Reference 11](#)). This FPL standard is in turn based on ISA Standard ISA-RP67.04.02, Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation and NRC Regulatory Guide (RG) 1.105, Setpoints for Safety-Related Equipment ([Reference 10](#)). The LEFM based total calorimetric power uncertainty is based on Cameron Topical Reports ER-80P and ER-157P, which are in turn also based on ISA Standard ISA-RP67.04.02 ([Reference 12](#)). FPL and Cameron methodologies share a common technical basis, and are therefore consistent with respect to evaluation of uncertainties and statistical combination of uncertainty effects. In accordance with this methodology, individual loop uncertainties are determined for each process parameter used in the calorimetric power calculation. A sensitivity analysis is used to determine the effect of each process parameter uncertainty on the calorimetric power calculation. Uncertainties for parameters that are not statistically independent are arithmetically summed to produce groups that are independent. Independent parameters/groups are then combined using a statistical summation (square root sum of squares) to determine total calorimetric power measurement uncertainty.

Criterion 4

For plants where the ultrasonic meter (including LEFM) was not installed and flow elements calibrated to a site-specific piping configuration (flow profiles and meter factors not representative of the plant specific installation), additional justification should be provided 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, confirm that the piping configuration remains bounding for the original LEFM installation and calibration assumptions.

Response to Criterion 4

Criterion 4 does not apply to St. Lucie Unit 2. The calibration factor for the St. Lucie Unit 2 flow elements has been established by tests of these spools at Alden Research Laboratory in March, 2009. These tests included a full scale model of the St. Lucie Unit 2 hydraulic geometry and piping arrangement. Test data and results for the flow elements are documented in Cameron Engineering Report ER-736, Meter Factor Calculation and Accuracy Assessment for St. Lucie Unit 2 (Reference 6). The calibration factor (also known as the meter factor) used for the St. Lucie Unit 2 flow elements and the uncertainty in the calibration factor for the LEFM CheckPlus system are also based on this Cameron engineering report. ER-736 (Cameron proprietary document) is provided in Appendix F to Attachment 5 of the EPU LAR.

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-736. Final commissioning is expected to be completed at the conclusion of refueling outage SL2-20.

I.3 Rated Thermal Power Uncertainty Calculation

LR Table 2.4.4-1 summarizes the core thermal power measurement uncertainty for St. Lucie Unit 2 and provides a comparison with the uncertainties identified in Topical Report ER-157P for the LEFM CheckPlus system. The uncertainties documented in this table are based on Cameron engineering reports ER-736, Meter Factor Calculation and Accuracy Assessment for St. Lucie Unit 2 and ER-740, Bounding Uncertainty Analysis for Thermal Power Determination at St. Lucie Units 1 & 2 Using the LEFM CheckPlus system. ER-736 and ER-740 (Cameron proprietary documents) are provided in Appendix F to Attachment 5 of the EPU LAR.

In addition to the process inputs provided by the LEFM CheckPlus system, the DCS uses the following process inputs to calculate the contribution of items 6 & 8 from Table 2.4.4-1 (i.e., Steam Enthalpy & Other Gains and Losses) in the determination of core thermal power:

- Steam pressure,
- Blowdown flow,
- Charging flow,
- Letdown flow,
- Blowdown temperature,
- Charging temperature,
- Letdown temperature,
- Reactor coolant pump power,

- Pressurizer heater power.

These process inputs are obtained from analog instrumentation channels that are maintained and calibrated in accordance with required periodic calibration procedures. Applicable uncertainty terms for these calorimetric related process measurement instrument channels are based on surveillance procedure requirements for calibration frequency, setting tolerance and measure & test equipment (M&TE) accuracy. Configuration of the hardware associated with these process measure channels is maintained in accordance with the site configuration management process. See response to Criterion 3 above for additional discussion related to determination and combination of uncertainties associated with calorimetric related process measurement channels.

Uncertainty associated with steam generator (SG) moisture carryover (MCO) has been conservatively addressed in the LEFM based calorimetric uncertainty analysis. Following the steam generator replacement, actual MCO for each replacement SG was measured using a tracer gas test methodology. The measured MCO was 0.032 percent and 0.007 percent for the 2A and 2B SGs respectively. The uncertainty of the MCO test results was calculated by test vendor to be 0.011 percent and 0.005 percent for the 2A and 2B SGs, respectively. The measured MCO values identified above are used in the calorimetric calculations to compute steam enthalpy. In contrast, the maximum MCO specification (i.e., replacement SG vendor warranty) for the replacement SGs is < 0.1 percent. In accordance with standard Cameron methodology, the MCO uncertainty term used in the overall LEFM calorimetric uncertainty analysis was based on an assumed 10 percent variation in the vendor warranty MCO value (i.e., the uncertainty term is based on 0.01 percent). Therefore, the MCO uncertainty term used in the calorimetric uncertainty analysis is greater than the tracer gas test uncertainty (i.e., the average MCO uncertainty of the two SGs is 0.008 percent).

I.4 System Maintenance

Instruments that affect the power calorimetric, including the LEFM CheckPlus system inputs, are monitored by site Engineering Department personnel. Equipment problems for plant systems, including the LEFM CheckPlus system equipment, fall under the site work control process. Conditions that are adverse to quality are documented under the corrective action program. Corrective action procedures, which ensure compliance with the requirements of 10 CFR 50, Appendix B, include instructions for notification of deficiencies and error reporting. The following information addresses specific aspects of calibration and maintenance procedures relating to the LEFM CheckPlus system.

- Calibration and maintenance is performed by Instrumentation and Controls (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.
- Routine preventive maintenance activities will include physical inspections, power supply checks, backup battery replacements, and internal oscillator frequency verification. Ultrasonic signal verification and alignment is performed automatically by the LEFM CheckPlus system. Signal verification is determined by reviewing the signal quality measurements performed and displayed by the LEFM CheckPlus system. Selected I&C

personnel in the Maintenance Department are trained and qualified per the site's Institute for Nuclear Power Operations (INPO) accredited training program before maintenance or calibration is performed and prior to increasing power above 2968 MWt. This training includes lessons learned from industry experience. Initially, formal training by Cameron is to be provided to St. Lucie Station personnel.

- The LEFM CheckPlus system is designed and manufactured in accordance with Cameron's 10 CFR 50, Appendix B, Quality Assurance Program and its Verification and Validation Program. Cameron's Verification and Validation Program fulfills the requirements of ANSI/IEEE-ANS Standard 7-4.3.2, Standard Criteria for Digital Computers in Safety Systems of Nuclear Power Generating Stations (Reference 13) and ASME-NQA-2a, Quality Assurance Requirements for Nuclear Facility Applications (Reference 14). In addition, the program is consistent with guidance for software verification and validation in EPRI TR-103291, Handbook for Verification and Validation of Digital Systems (Reference 15). Specific examples of quality measures undertaken in the design, manufacture, and testing of the Cameron LEFM CheckPlus system are provided in Cameron Technical Report ER-80P, Section 6.4 and Table 6.1.
- Corrective action involving maintenance is to be performed by Maintenance Department I&C personnel, qualified in accordance with the site's training program, and formally trained on the LEFM CheckPlus system.
- Reliability of the LEFM CheckPlus system is to be monitored by site Engineering Department personnel. Equipment problems for plant systems, including the LEFM CheckPlus system equipment, will fall under the site work control process. Conditions that are adverse to quality will be documented under the corrective action program.
- The St. Lucie Unit 2 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 inform FPL of any deficiencies in accordance with Cameron's maintenance agreement and/or 10 CFR Part 21 reporting requirements.

I.5 Out of Service Requirements

UFSAR Section 13.7, Licensee-Controlled Technical Specification Requirements, will be revised to include Limiting Condition for Operation (LCO) and Action Statements for the Cameron LEFM CheckPlus system.

The allowed outage time (AOT) for operation at any power level in excess of 2968 MWt (Note: 2968 MWt is based on 98.3 percent of the proposed licensed power level of 3020 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 bases for the AOT are:

- Alternate plant instruments (FW venturis, differential pressure (DP) transmitters, and RTDs) will be used if the Cameron LEFM CheckPlus system is out of service. The mass flow rate data (based on the venturis, 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 (i.e., the operator will not be presented with an abrupt change in indicated reactor thermal power as a result of the switchover between using the LEFM based mass flow rate and the venturi based mass flow rate in the calorimetric power calculation). Over the subsequent 48 hours, the potential contributors to signal error are venturi nozzle fouling and transmitter drift. Over a 48 hour time period, with the plant at stable full power conditions, the error due to venturi fouling is not significant. Three Rosemount DP transmitters and three Weed RTDs are used for each FW header mass flow rate calculation. Review of plant calibration records shows that drift of these sensors is typically less than 0.25 percent of the calibrated span over 18 months. Therefore, the expected drift over a 48 hour period will not result in any significant error in the mass flow rate calculation. In addition, three DP transmitters are used for each venturi, and three RTDs are also used, making it less likely that the average signal would drift substantially. This redundancy also affords the opportunity to monitor the stability performance of each individual sensor via a cross channel comparison.

- The LEFM system, including the interface to DCS, has been designed to be fault tolerant. The LEFM system includes two physically separate and redundant CPUs, each capable of processing the data from both LEFM spool pieces. Each LEFM CPU will communicate with a dedicated DCS front end Ethernet interface module. The active CPU data source for the DCS calorimetric calculations will be automatically swapped by the DCS when necessary based on quality status flags originating from LEFM and from the Ethernet interface module. 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. Availability of LEFM output data to support the manual calorimetric is independent of DCS availability (i.e., data can be obtained from the display screens on either LEFM CPU located in the main control room). However, as a conservative measure, UFSAR Section 13.7 will restrict plant power to less than or equal to 2968 MWt (based on 98.3 percent of the proposed licensed power level of 3020 MWt) if the automated calorimetric portion of DCS can not be restored within 48 hours.
- Most repairs (physical work only) to the Cameron LEFM CheckPlus system can be made within an eight-hour shift. The proposed AOT of 48 hours will give plant personnel time to plan the work and make repairs within the bounds of the plant work control process. Avoiding an unwarranted power reduction will also facilitate high-confidence post maintenance testing since it will then be possible to verify normal operation of the Cameron LEFM CheckPlus system via comparison with other instruments at the same power level and indications as before the failure.
- Operations personnel will operate the plant based on the calibrated alternate plant instruments when the Cameron LEFM CheckPlus system is not available. The need for any power reduction will generally be avoided since repairs would typically be accomplished prior to the expiration of the 48 hour period. Elimination of unwarranted power maneuvers will reduce challenges to plant operations.
- 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 2968 MWt (based on 98.3 percent

of the proposed licensed power level of 3020 MWt) until the LEFM CheckPlus system is fully functional. This immediate response following a 10 percent power change is prudent since this sort of plant transient may affect venturi fouling or through some other means adversely affect the accuracy of the alternate instruments used for FW mass flow rate determination.

For the Cameron LEFM CheckPlus system out-of-service condition, the 48-hour “clock” starts at the time of the failure. The status of the Cameron LEFM CheckPlus system is automatically monitored by the LEFM software. The status of each flow element will be transmitted to DCS and displayed on a DCS calorimetric screen. Hardwired annunciators will also be provided to ensure control room operators are immediately aware of any change in LEFM status. The Cameron LEFM CheckPlus system will continuously monitor, test, and/or verify the following attributes of system operation:

- Signal to noise ratio,
- Transit time deviation,
- Signal rejection percentage,
- Pressure deviation,
- Temperature deviation,
- Meter velocity profile (i.e., changes to flatness ratio and swirl, verified against specified thresholds).

Multiple layers of redundancy are included in the LEFM CheckPlus design. Therefore, it is far more likely to experience some level of system performance degradation rather than total system failure. Various LEFM system level failure modes and corresponding effects on calorimetric uncertainty have been evaluated and documented in the site-specific uncertainty analysis (Cameron Engineering Report ER-740). UFSAR Section 13.7 is to be revised to include Action Statements for LEFM system level failure modes in accordance with the following:

- As described above, the St. Lucie Unit 2 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. As described in ER-157P, each LEFM CheckPlus meter consists of two 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. UFSAR Section 13.7 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. UFSAR Section 13.7 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, UFSAR Section 13.7 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.

II. Accidents and transients for which the existing analyses of record bound plant operation at the proposed uprated power level (RIS 2002-03 Section II)

III. Accidents and transients for which the existing analyses of record do not bound plant operation at the proposed uprated power level (RIS 2002-03 Section III)

Evaluation

The MUR is an integral part of an EPU. As such, the analyses of record were reevaluated and reanalyzed, as necessary, to support the uprated power level of 3020 MWt, including a measurement uncertainty of 0.3 percent. The analyses were performed consistent with the guidance provided in RS-001. Discussion of the event-specific analyses is provided in LR [Section 2.8.5.0](#) and the 2.8.5 series of LRs. The analysis results demonstrate compliance with the applicable analysis limit(s) at the EPU power level, including a measurement uncertainty of 0.3 percent.

Conclusion

The analyses of record were reevaluated and reanalyzed, as necessary, to support the uprated power level of 3020 MWt plus a measurement uncertainty of 0.3 percent. The analysis results demonstrate compliance with the applicable analysis limit(s) at the EPU power level, including a measurement uncertainty of 0.3 percent.

IV. Mechanical/Structural/Material Component Integrity and Design (RIS 2002-03 Section IV)

Evaluation

The MUR is an integral part of an EPU. As such, the structural integrity of the major plant components was reevaluated and reanalyzed, as necessary, to support the uprated power level of 3020 MWt including a measurement uncertainty of 0.3 percent. The analyses were performed consistent with the guidance provided in RS-001. Discussion of the component-specific analyses is provided in the 2.1 and 2.2 series of LRs. The analysis results demonstrate compliance with the applicable analysis criteria at the EPU power level, including a measurement uncertainty of 0.3 percent.

Conclusion

The structural integrity of the major plant components was reevaluated and reanalyzed, as necessary, to support the uprated power level of 3020 MWt plus a measurement uncertainty of 0.3 percent. The analysis results demonstrate compliance with the applicable analysis criteria at the EPU power level, including a measurement uncertainty of 0.3 percent.

V. Electrical Equipment Design (RIS 2002-03 Section V)

Evaluation

The MUR is an integral part of an EPU. As such, electrical equipment was reevaluated and reanalyzed, as necessary, to support the uprated power level of 3020 MWt, including a measurement uncertainty of 0.3 percent. The analyses were performed consistent with the guidance provided in RS-001. Discussion of the electrical equipment analyses is provided in the 2.3 series of LRs. The analysis results demonstrate compliance with the applicable analysis criteria at the EPU power level, including a measurement uncertainty of 0.3 percent.

Conclusion

The electrical equipment was reevaluated and reanalyzed, as necessary, to support the uprated power level of 3020 MWt, plus a measurement uncertainty of 0.3 percent. The analysis results demonstrate compliance with the applicable analysis criteria at the EPU power level, including a measurement uncertainty of 0.3 percent.

VI. System Design (RIS 2002-03 Section VI)

Evaluation

The MUR is an integral part of an EPU. As such, major plant systems were reevaluated and reanalyzed, as necessary, to support the uprated power level of 3020 MWt, including a measurement uncertainty of 0.3 percent. The analyses were performed consistent with the guidance provided in RS-001. Discussion of the system-specific analyses is provided in the 2.5 series of LRs. The analysis results demonstrate compliance with the applicable analysis criteria at the EPU power level, including a measurement uncertainty of 0.3 percent.

Conclusion

The major plant systems were reevaluated and reanalyzed, as necessary, to support the uprated power level of 3020 MWt, plus a measurement uncertainty of 0.3 percent. The analysis results demonstrate compliance with the applicable analysis criteria at the EPU power level, including a measurement uncertainty of 0.3 percent.

VII. Other (RIS 2002-03 Section VII)

Evaluation

The MUR is an integral part of the EPU. The overall impact of EPU on operator actions, procedures and training is discussed in LR [Section 2.11.1](#), Human Performance. The overall impact of EPU on control room controls, displays (including the safety parameter display system) and alarms is discussed in the 2.4 series of LRs. The impact of the EPU on the plant simulator is also discussed in the 2.4 series of LRs. Modifications necessary to support EPU are summarized

in LR [Section 1.0](#), Introduction to the St. Lucie Unit 2 Extended Power Uprate Licensing Report. The overall impact of EPU on plant effluents, occupational radiation exposure and environmental assessment is discussed in LR [Section 2.10.1](#), Occupational and Public Radiation Doses and LAR Attachment 2, Supplemental Environmental Report. The balance of this section pertains only to the direct impact of the MUR portion of the EPU.

Impact On Operations

Abnormal Operating Procedures

The impact of the MUR on operator actions has been identified and evaluated. Operating procedures are to be revised to address the Limiting Condition for Operation (LCO) and Action Statement requirements applicable to the LEFM CheckPlus system, as described in Subsection I.5 above.

Emergency Operating Procedures

There will be no changes to emergency operating procedures resulting solely from the MUR.

Operation and Maintenance Procedures

Procedure changes pertaining to operation and maintenance of the Cameron LEFM CheckPlus system are discussed in Subsection I.4 above.

Operator Actions

As discussed Subsection I.5 above, new Action Statements pertaining to various LEFM CheckPlus system failure modes and/or degraded conditions are to be added to UFSAR Section 13.7. These Action Statements involve reactor thermal power reductions if the degraded condition is not corrected within the specified AOT of 48 hours. These new operator actions are captured in abnormal operating procedures.

Control Room Controls, Displays and Alarms

Modifications to DCS calorimetric screens and annunciator panels pertaining to operation of the Cameron LEFM CheckPlus system are discussed in Subsection I.1 above.

Plant Simulator

Modifications to the plant simulator pertaining to operation of the Cameron LEFM CheckPlus system are discussed in Subsection I.1 above.

Modifications

Modifications required for the MUR are to be completed prior to increasing reactor thermal power above 2968 MWt (based on 98.3 percent of the proposed licensed power level of 3020 MWt). Additional information pertaining to post modification test requirements and power ascension test sequencing is presented in LR [Section 2.12](#), Power Ascension & Testing Plan.

Procedures Related to Temporary Operation Above Full Steady State Licensed Power Level

Operations Department procedures that provide guidance regarding unintentional and temporary operation above the licensed power limit are to be revised as necessary to reflect a calorimetric uncertainty of 0.3 percent. Per existing procedures, steady state power is maintained between 99.92 percent and 99.97 percent. Existing procedural guidance also prohibits any action that would intentionally raise core thermal power above the licensed power limit for any period of time.

Training

The Operations Department has been integrated into the uprate process. An Operations Department representative was included in the uprate team. The design change process requires Operations Department reviews and signoffs on the design change packages.

The Operations Department staff are to be trained on the modifications, technical specification changes, and procedural changes prior to implementation of the MUR. This will assure that the Operations Department staff receives the required training for continued safe and reliable operations.

Training on operation and maintenance of the Cameron LEFM CheckPlus system, is to be developed and carried out prior to implementation of the MUR. MUR related training for other departments needs is to be developed and carried out as appropriate.

Environmental Impact

There is no environmental impact resulting solely from the MUR.

VIII. Changes to technical specifications, protection system settings, and emergency system settings (RIS 2002-03 Section VIII)

Technical Specifications

The MUR is an integral part of the EPU. As such, the proposed technical specification changes are included in the proposed changes for the EPU. LR Attachment 1 contains a description of the proposed technical specification changes, and Attachment 3 contains marked-up pages of the proposed changes. Changes directly affected by the MUR are:

- Renewed Facility Operating License DPR-67 Maximum Power Level is increased to 3020 MWt, and
- Technical Specification 1.25 Definition of Rated Thermal Power is changed to 3020 MWt.

Protection System Settings

There are no changes to the protection system settings as a result of the MUR.

Emergency System Settings

There are no changes to the emergency system settings as a result of the MUR.

2.4.4.3 References

1. NRC Regulatory Issue Summary (RIS) 2002-03, Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications
2. Cameron Engineering Report ER-80P, Revision 0, Improving Thermal Power Accuracy and Plant Safety While Increasing Operating Power Level Using the LEFM Check System, dated March 1997
3. Cameron Engineering Report ER-160P, Revision 0, Supplement to Topical Report ER-80P: Basis for a Power Uprate with the LEFM Check System, dated May 2000.
4. Cameron Engineering Report ER-157P, Revision 5, Supplement to Topical Report ER-80P: Basis for a Power Uprate with the LEFM Check or CheckPlus System, dated October 2001.
5. Cameron Engineering Report ER-740, Revision 0, Bounding Uncertainty Analysis for Thermal Power Determination at St. Lucie Units 1 & 2 Using the LEFM CheckPlus System
6. Cameron Engineering Report ER-736, Revision 3, Meter Factor Calculation and Accuracy Assessment for St. Lucie Unit 2
7. ER-80P NRC Safety Evaluation Report (SER), dated March 8, 1999
8. ER-160P NRC Safety Evaluation Report (SER), dated January 19, 2001
9. ER-157P NRC Safety Evaluation Report (SER), dated December 20, 2001
10. NRC Regulatory Guide (RG) 1.105, Setpoints for Safety-Related Equipment
11. FPL Nuclear Engineering Department Discipline Standard IC-3.17, Revision 7, Instrument Setpoint Methodology for Nuclear Power Plants
12. ISA Standard ISA-RP67.04.02, Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation
13. ANSI/IEEE-ANS Standard 7-4.3.2, Standard Criteria for Digital Computers in Safety Systems of Nuclear Power Generating Stations
14. ASME-NQA-2a, Quality Assurance Requirements for Nuclear Facility Applications
15. EPRI TR-103291, Handbook for Verification and Validation of Digital Systems

Table 2.4.4-1
Rated Thermal Power Uncertainty Calculation

Parameter	ER-157P	Both LEFMs Normal	One Section of One LEFM in Maintenance	One Section of Both LEFMs in Maintenance
1. Hydraulics (profile factor)	0.25%	0.20% ⁽²⁾	0.40%	0.44%
2. Geometry (spool dimensions, transducer installation, spool thermal expansion)	0.09%	0.14%	0.16%	0.17%
3. Time measurements (transit times and non-fluid delay)	0.045%	0.045%	0.045%	0.045%
4. Feedwater density (correlation, LEFM temperature determination, pressure input)	0.07%	0.07%	0.07%	0.07%
5. Feedwater enthalpy (correlation, LEFM temperature determination, pressure input)	0.08%	0.08%	0.08%	0.08%
6. Steam enthalpy (pressure input)	0.07%	0.0225%	0.0225%	0.0225%
7. Steam enthalpy (moisture uncertainty)	0.21% [0.0%] ⁽¹⁾	0.0087%	0.0087%	0.0087%
8. Other gains and losses (calorimetric related process parameters)	0.07%	0.0356%	0.0356%	0.0356%
9. Total power determination uncertainty	0.39% [0.33%] ⁽¹⁾	0.30%	0.46%	0.50%
1. Per ER-157P, bracketed figures reflect an assumption of no moisture carryover. 2. For more direct comparison with ER-157P, the individual LEFM profile factor uncertainty is 0.21% for loop A and 0.26% for loop B.				

2.5 Plant Systems

2.5.1 Internal Hazards

2.5.1.1 Flooding

2.5.1.1.1 Flood Protection

2.5.1.1.1.1 Regulatory Evaluation

Florida Power & Light Company (FPL) conducted a review in the area of flood protection to ensure that safety-related structures, systems, and components (SSCs) are protected from flooding. The FPL review covered flooding of safety-related SSCs from internal sources, such as those caused by failures of tanks and vessels. The 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 acceptance criterion for flood protection is based on General Design Criterion (GDC)-2.

Specific review criteria are contained in the Standard Review Plan (SRP), Section 3.4.1, and other guidance is provided in Matrix 5 of RS-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to Title 10 of the Code of Federal Regulations (10 CFR) Part 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

- GDC-2 is described in UFSAR Section 3.1.2, Criterion 2 - Design Bases for Protection Against Natural Phenomena.

Structures, systems and components important to safety shall be designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunamis and seiches without loss of capability to perform their safety functions. The design bases for these structures, systems and components shall reflect: (1) appropriate consideration of the most severe of natural phenomena that have been historically reported for the site and surrounding area, with sufficient margin for the limited accuracy, quantity, and period of time which the historical data have been accumulated, (2) appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena and (3) the importance of the safety functions to be performed.

The SSCs important to safety are designed to withstand the effects of natural phenomena without loss of capability to perform their safety functions. Natural phenomena factored into the design of plant SSCs important to safety are determined from recorded data for the site vicinity with appropriate margin to account for uncertainties in historical data.

The most severe natural phenomena postulated to occur at the site in terms of induced stresses is the safe shutdown earthquake (SSE). Those SSCs vital for the mitigation and control of accident conditions are designed to withstand the effects of a loss of coolant accident (LOCA) coincident with the effects of the SSE. The SSCs vital to the safe shutdown of the plant are designed to withstand the effects of any one of the most severe natural phenomena, including flooding, hurricanes, tornadoes and the SSE.

Design criteria for wind and tornado, flood and earthquake are discussed in UFSAR Sections 3.3, 3.4 and 3.7, respectively.

Internal flooding from sources other than high energy line breaks and moderate energy line cracks, including internal flooding due to failure of tanks and process equipment is addressed in UFSAR Section 3.4.3.

In addition to the licensing bases described in the UFSAR, flood protection was evaluated for St. Lucie Unit 2 License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Sections 2.3.3 and 2.4 of the SER identifies that components of flood protection are within the scope of License Renewal. Programs used to manage the aging effects associated with flood protection are discussed in SER Sections 3.3 and 3.4 and UFSAR Chapter 18.

2.5.1.1.1.2 Technical Evaluation

2.5.1.1.1.2.1 Introduction

This section addresses impact of the Extended Power Uprate (EPU) on internal flooding due to internal sources.

Internal flooding is also addressed in LR [Section 2.5.1.1.2](#), Equipment and Floor Drains.

The impact of the EPU on internal flooding due to high energy line breaks (HELBs) / moderate energy line cracks outside containment is addressed in Licensing Report (LR) [Section 2.5.1.3](#), Pipe Failures.

The impact of the EPU on potential flooding from a fire protection system pipe break is addressed in LR [Section 2.5.1.4](#), Fire Protection.

Submergence inside containment is addressed in LR [Section 2.3.1](#), Environmental Qualification of Electrical Equipment.

2.5.1.1.1.2.2 Description of Analyses and Evaluations

The analysis of the failure of all non-seismic Category I tanks and components in the reactor auxiliary building and the resulting flooding of safety-related equipment is addressed in UFSAR Section 3.4.3. This analysis is summarized as follows:

All non-seismic tanks in the reactor auxiliary building were considered and are assumed to rupture during a seismic event. The fluid from these tanks would drain to the emergency core cooling system (ECCS) pump room sumps through isolatable pipes. The most limiting safety-related components in the reactor auxiliary building are the high pressure safety injection (HPSI) pump conduit boxes located in the ECCS pump room. Analysis reveals that it would take 145 minutes to reach the HPSI Pump A conduit box and 102 minutes to reach the HPSI Pump B conduit box. Within 8 minutes of the event four independent Category I level switches will set off alarms in the control room. This gives plant personnel ample time to isolate the ECCS pump room from the fluid draining into it. Isolating the ECCS pump room cubicle will cause the fluid to accumulate on another level, but safety-related equipment will not be affected. The analysis concludes that a potential flooding incident in the reactor auxiliary building cannot impair the ability of redundant equipment to achieve a safe shutdown condition.

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

As discussed above, flood protection is within the scope of License Renewal. Operation of flood protection under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.5.1.1.1.3 Results

The analysis of the failure of all non-seismic Category I tanks and components and the resulting flooding of safety-related equipment at current conditions concluded that a potential flooding incident in the reactor auxiliary building cannot impair the ability of redundant equipment to achieve a safe shutdown condition. The EPU does not increase the size or the amount of fluid in non-Seismic Category I tanks or components located in the reactor auxiliary building. The EPU does not require the addition of any new non-Seismic Category I tanks or components in the reactor auxiliary building. The EPU does not affect the location of existing safety-related equipment in the reactor auxiliary building required for safe shutdown of the plant, nor does it require the addition of any new safety-related equipment in the reactor auxiliary building required for safe shutdown. Therefore, the EPU does not affect the existing analysis of internal flooding in the reactor auxiliary building due to failure of non-seismic Category I tanks or components.

2.5.1.1.1.4 Conclusion

FPL has reviewed the analysis of failure of non-seismic Category I tanks or components in the reactor auxiliary building and concludes that SSCs important to safety will continue to be

protected from flooding and will continue to meet its current licensing basis with respect to the requirements of GDC-2 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to flood protection.

2.5.1.1.2 Equipment and Floor Drains

2.5.1.1.2.1 Regulatory Evaluation

The function of the equipment and floor drains system is to assure that waste liquids, valve and pump leakoffs, and tank drains are directed to the proper area for processing or disposal. The equipment and floor drains system is designed to accommodate the volume of leakage expected, and prevent a backflow of water that might result from maximum flood levels to areas of the plant containing safety-related equipment. The FPL review of the equipment and floor drains system included the collection and disposal of liquid effluents outside containment. The review focused on any changes in fluid volumes or pump capacities that are necessary for the proposed EPU and that are not consistent with previous assumptions with respect to floor drainage considerations.

The NRC acceptance criteria for the equipment and floor drains system are based on General Design Criteria (GDC) -2 and -4 insofar as they require the equipment and floor drains system 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 Standard Review Plan (SRP) 9.3.3, and other guidance is provided in Matrix 5 of RS-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

- GDC-2 is described in UFSAR Section 3.1.2, Criterion 2 - Design Bases for Protection Against Natural Phenomena.

Structures, systems and components important to safety shall be designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunamis and seiches without loss of capability to perform their safety functions. The design bases for these structures, systems and components shall reflect: (1) appropriate consideration of the most severe of natural phenomena that have been historically reported for the site and surrounding area, with sufficient margin for the limited accuracy, quantity, and period of time which the historical data have been accumulated, (2) appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena and (3) the importance of the safety functions to be performed.

The SSCs important to safety are designed to withstand the effects of natural phenomena without loss of capability to perform their safety functions. Natural phenomena factored into the design of plant SSCs important to safety are determined from recorded data for the site vicinity with appropriate margin to account for uncertainties in historical data.

The most severe natural phenomena postulated to occur at the site in terms of induced stresses is the safe shutdown earthquake (SSE). Those SSCs vital for the mitigation and control of accident conditions are designed to withstand the effects of a loss of coolant accident (LOCA) coincident with the effects of the SSE. The SSCs vital to the safe shutdown of the plant are designed to withstand the effects of any one of the most severe natural phenomena, including flooding, hurricanes, tornadoes and the SSE.

Design criteria for wind and tornado, flood and earthquake are discussed in UFSAR Sections 3.3, 3.4 and 3.7, respectively.

- GDC-4 is described in UFSAR Section 3.1.4 Criterion 4 - Environmental and Missile Design Bases.

Structures, systems and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss- of- coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and approved by the Commission demonstrates that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

The SSCs important to safety are designed to accommodate the effects of and to be compatible with the pressure, temperature, humidity, and radiation conditions associated with normal operation, maintenance, testing, and postulated accidents including a LOCA in the area in which they are located.

Refer to UFSAR Sections 3.5, 3.6, 3.7, and 3.11 for details on missile protection, pipe rupture and jet impingement protection, seismic design criteria and environmental qualification, respectively.

Functions and features of the equipment and floor drains systems regarding internal flooding are presented in UFSAR Section 9.3.3, Equipment and Floor Drainage Systems.

The non-safety related equipment and floor drainage system includes all piping from equipment or floor drains to the sump, sump pumps, and piping necessary to carry potentially radioactive and nonradioactive effluents through separate subsystems.

Section 9.3.3 of the NRC Safety Evaluation Report related to the operation of St. Lucie Plant No. 2, (NUREG 0843) indicates that adequate protection against flooding of safety related equipment and protection against the inadvertent release of potentially radioactive liquids to the environment through plant drainage paths is provided.

In addition to the licensing bases described in the UFSAR, the equipment and floor drains system was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in

Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003 . Section 2.3.3 of the SER identifies that components of the equipment and floor drains system are within the scope of License Renewal . Programs used to manage the aging effects associated with the equipment and floor drains system are discussed in SER Section 3.3 and UFSAR Chapter 18.

2.5.1.1.2.2 Technical Evaluation

2.5.1.1.2.2.1 Introduction

This section addresses impact of the EPU on the volume of leakage entering the equipment and floor drainage system and on the potential for internal flooding due to backflow through the equipment and floor drainage systems.

This section also addresses impact of the EPU on the equipment and floor drainage system design to protect against the potential for inadvertent transfer of contaminated fluids to an uncontaminated drainage system.

Collection and disposal of liquid effluents outside of containment is addressed in LR [Section 2.5.6.2](#).

2.5.1.1.2.2.2 Description of Analyses and Evaluations

Seismic Design

As addressed in UFSAR Section 9.3.3.3, the sumps in the ECCS pump room (one sump in each of two compartments) in the reactor auxiliary building have separate level detection instrumentation designed to seismic Category I and Class 1E requirements to enable the operator to identify which sump is filling and to allow the operator to initiate protective action as required. As addressed in UFSAR Section 3.4.3, floor drains entering the ECCS pump room compartments are provided with redundant seismic Category I isolation valves, which are capable of remote-manual operation from the control room. As addressed in UFSAR Sections 3.2 and 6.2.4, the piping and valves for containment isolation of equipment drain lines penetrating the containment are seismic Category I. The remainder of the equipment and floor drainage system in the reactor auxiliary building, reactor building, and fuel handling building serves no safety function, and therefore is not designed to seismic Category I requirements. The EPU does not affect seismic design of components in the equipment and floor drainage system (refer to LR [Section 2.2.5](#)).

Expected Volume of Leakage

UFSAR Section 9.3.3 describes the equipment and floor drainage systems in the following structures:

- Reactor building,
- Reactor auxiliary building, and
- Fuel handling building.

The EPU does not add any new equipment or modify existing equipment (e.g., pumps, strainers) in the above-listed structures that would result in increasing the quantities of liquids currently entering the equipment and floor drainage systems. Therefore, the sizing of the existing equipment and floor drainage systems remains acceptable at EPU conditions.

Backflow Through the Equipment and Floor Drains System

The NRC issued Inspection and Enforcement (IE) Notice 83-44 ([Reference 1](#)) and Supplement 1 ([Reference 2](#)) to address the potential for damage of safety-related equipment as a result of flooding related backflow through equipment and floor drainage system, and related flooding issues. FPL reviewed the impact of these potential flooding problems at St. Lucie Unit 2. According to the review, safety related equipment applicable to IE Notice 83-44 is housed in the safeguards room in the reactor auxiliary building. The two independent floor drainage systems within the St. Lucie Unit 2 safeguards room drain directly into their respective sump tanks, with each sump tank having two dedicated sump pumps responsible for transfer to the equipment drain tank. Each drain system can isolate the safeguards room via a series of valves. No check valves are present in the drain lines to the respective sump tanks. Based on these observations, the review of historical evaluations and inspections, and the current procedures in place that address flooding of the reactor auxiliary building, it was concluded that a similar event as outlined in IE Notice 83-44 could not occur at St. Lucie Unit 2. A check valve on the discharge piping of each of two sump pumps in compartments A and B in the safeguards room in the reactor auxiliary building prevents backflooding of the compartments via the sump pump discharge piping. UFSAR Section 9.3.3.3 states:

There are no lines from the radioactive equipment and floor drainage system that penetrate the reactor auxiliary building below elevation 18.0 ft; the elevation associated with the maximum wave runup. Water is thus precluded from backflowing into the reactor auxiliary building and affecting the operation of safety-related equipment required to bring the plant to a safe cold shutdown.

The EPU does not affect the design of the equipment and floor drainage system in the reactor auxiliary building. Therefore, following implementation of the proposed EPU, the conclusions of the review performed in response to IE Notice 83-44 remain unaffected, and water remains precluded from backflowing into the safeguards room or into the reactor auxiliary building via the equipment and floor drainage system.

Potential for Inadvertent Transfer of Contaminated Fluids to an Uncontaminated Drainage System

UFSAR Section 9.3.3.1 states that the radioactive drainage systems and non-radioactive drainage systems are isolated from each other. Therefore, there is no potential for inadvertent transfer of contaminated fluids to an uncontaminated drainage system at current conditions. The EPU does not affect the design of the equipment and floor drainage system, and therefore there is no potential for inadvertent transfer of contaminated fluids to an uncontaminated drainage system following implementation of the proposed EPU.

2.5.1.1.2.2.3 Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

As discussed above, the floor and equipment drain system is within the scope of License Renewal. Operation of the floor and equipment drain system under EPU conditions has been evaluated to determine if there any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.5.1.1.2.2.4 Results

The sumps in the ECCS pump room in the reactor auxiliary building have separate level detection instrumentation designed to seismic Category I and Class 1E requirements. Floor drains entering the ECCS pump room compartments are provided with redundant seismic Category I isolation valves. The piping and valves for containment isolation of equipment drain lines penetrating the containment are seismic Category I. The EPU does not affect the seismic design of these components in the equipment and floor drainage system. The remainder of the equipment and floor drainage system in the reactor auxiliary building, reactor building, and fuel handling building serves no safety function, and therefore is not designed to seismic Category I requirements.

The EPU does not add any new equipment or modify existing equipment (e.g., pumps, strainers) in the reactor building, reactor auxiliary building, or fuel handling building that would result in increasing the quantities of liquids currently entering the equipment and floor drainage systems. Therefore, the sizing of the existing equipment and floor drainage systems remains acceptable at EPU conditions.

Based on the design of the equipment and floor drains system, the review of historical evaluations and inspections, and the current procedures in place to address flooding of the reactor auxiliary building, it was concluded that a similar event as outlined in IE Notice 83-44 could not occur at St. Lucie Unit 2. Check valves prevent backflooding of the A and B compartments in the safeguards room via the sump pump discharge piping.

Because no lines from the radioactive equipment and floor drainage system penetrate the reactor auxiliary building below elevation 18.0 ft; water from wave runup is precluded from backflowing into the reactor auxiliary building and affecting the operation of safety-related equipment. The EPU does not affect the design of the equipment and floor drainage system in the reactor auxiliary building. Therefore, following implementation of the proposed EPU, the conclusions of the review performed in response to IE Notice 83-44 remain unaffected, and water remains precluded from backflowing into the safeguards room or into the reactor auxiliary building via the equipment and floor drainage system.

The radioactive drainage systems and non-radioactive drainage systems are isolated from each other. Therefore, there is no potential for inadvertent transfer of contaminated fluids to an uncontaminated drainage system at current conditions. The EPU does not affect the design of the equipment and floor drainage system, and therefore there is no change in the potential for inadvertent transfer of contaminated fluids to an uncontaminated drainage system following implementation of the proposed EPU.

2.5.1.1.2.3 Conclusion

FPL has reviewed the effects of the proposed EPU on the equipment and floor drainage system. Since the EPU does not add any new equipment or modify existing equipment in the reactor building, reactor auxiliary building or fuel handling building that would result in increasing quantities of liquids entering the equipment and floor drainage system, FPL concludes that the equipment and floor drainage system has sufficient capacity to: (1) handle the expected leakage, (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 following implementation of the proposed EPU. Based on this, FPL concludes that the equipment and floor drainage system will continue to meet its current licensing basis with respect to the requirements of GDCs -2 and -4 following implementation of the proposed EPU. Therefore FPL finds the proposed EPU acceptable with respect to the equipment and floor drainage system.

2.5.1.1.2.4 References

1. IE Notice 83-44, Potential Damage to Redundant Safety Equipment as a Result of Backflow Through the Equipment and Floor Drain System, July 1, 1983.
2. Supplement 1 to IE Notice 83-044, Potential Damage to Redundant Safety Equipment as a Result of Backflow Through the Equipment and Floor Drain System, August 30, 1990.

2.5.1.1.3 Circulating Water System

2.5.1.1.3.1 Regulatory Evaluation

The circulating water system (CWS) provides a continuous supply of cooling water to the main condenser to remove the heat rejected by the turbine cycle and auxiliary systems. The review of the CWS focused on changes in flooding analyses that are necessary due to increases in fluid volumes or installation of larger capacity pumps or piping needed to accommodate the proposed EPU. FPL's acceptance criteria for the CWS are based on General Design Criteria (GDC)-4 for the effects of flooding of safety-related areas due to leakage from the CWS and the effects of malfunction or failure of a component or piping of the CWS on the functional performance capabilities of safety-related structures, systems, and components.

Specific review criteria are contained in the Standard Review Plan (SRP), Section 10.4.5, and other guidance is provided in Matrix 5 of RS-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

- GDC-4 is described in UFSAR Section 3.1.4 Criterion 4 - Environmental and Missile Design Bases.

Structures, systems and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss- of- coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and approved by the Commission demonstrates that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

SSCs important to safety are designed to accommodate the effects of and to be compatible with the pressure, temperature, humidity, and radiation conditions associated with normal operation, maintenance, testing, and postulated accidents, including a LOCA, in the area in which they are located.

Refer to UFSAR Sections 3.5, 3.6, 3.7, and 3.11 for details on missile protection, pipe rupture and jet impingement protection, seismic design criteria and environmental qualification, respectively.

Evaluation of failures in the circulating water system piping is addressed in UFSAR Section 10.4.5.

In addition to the licensing bases described in the UFSAR, the circulating water system was evaluated for St. Lucie Unit 2 License Renewal. As documented in NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003, the circulating water system was determined to be outside the scope of License Renewal.

2.5.1.1.3.2 Technical Evaluation

2.5.1.1.3.2.1 Introduction

As addressed in LR [Section 2.5.8.1](#), Circulating Water System, the EPU does not add any new components, nor does it introduce any new functions for existing components in the circulating water system. Accordingly, this LR section addresses impact of the EPU on analyses / design features related to internal flooding due to a circulating water system pipe break or expansion joint failure.

2.5.1.1.3.2.2 Description of Analyses and Evaluations

As addressed in UFSAR Section 10.4.5.3:

The circulating water system piping is located entirely underground in the yard except at the main condenser. The main condenser is located in the lowest elevation of the turbine building. There is no safety-related equipment housed in the turbine building, and, thus, a failure in the circulating water piping to the main condenser will not result in potential malfunction of any safety related components.

The turbine building is a totally open structure which houses the secondary side components. Any leakage in the circulating water system would be directed to either the building floor drains or the site storm drainage system. Any leakage local to the condenser will be directed to the condenser sump. Since there is no safety related equipment in this area, an essential leak detection system is not provided for this area.

The EPU does not affect the design or location of the turbine building, circulating water system, or main condenser. As addressed in LR [Section 2.5.8.1](#), the circulating water system flow rate and operating pressures are unchanged at EPU conditions. The EPU does not add any safety-related equipment to the turbine building.

2.5.1.1.3.2.3 Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

As addressed above in LR [Section 2.5.1.1.3.1](#), the circulating water system was determined to be outside the scope of License Renewal; therefore, with respect to the circulating water system, the EPU does not impact any License Renewal evaluations.

2.5.1.1.3.2.4 Results

As discussed in LR [Section 2.5.8.1](#), the circulating water system flow rate and operating pressures are unchanged at EPU conditions. There are no required modifications to the

circulating water system or the turbine building as a result of the EPU that would affect the analyses associated with internal flooding due to a circulating water pipe rupture or expansion joint failure. The EPU does not add any safety-related equipment to the turbine building. Therefore, the EPU does not affect the current analyses and design features related to internal flooding due to a circulating water pipe rupture or expansion joint failure.

2.5.1.1.3.3 Conclusion

FPL has reviewed the protection of safety-related equipment from internal flooding due to a pipe break or expansion joint failure in the circulating water system. FPL concludes that the circulating water system will continue to meet its current licensing basis with respect to the requirements of GDC-4. Since the circulating water system flow and operating pressures will remain unchanged for the EPU, and there are no modifications to the circulating water system or the turbine building resulting from the EPU that would affect the analyses associated with flooding due to a circulating water pipe rupture or expansion joint failure, the proposed EPU is acceptable with respect to flooding from the circulating water system.

2.5.1.2 Missile Protection

2.5.1.2.1 Internally Generated Missiles

2.5.1.2.1.1 Regulatory Evaluation

The Florida Power and Light (FPL) review evaluated missiles that could result from in-plant component overspeed failures and high-pressure system ruptures. FPL's review of potential missile sources covered pressurized components and systems, and high-speed rotating machinery. FPL's review was conducted to ensure that safety-related Systems, Structures, and Components (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, FPL reviewed the non-safety-related SSCs to ensure that their failure will not preclude the intended safety function of the safety-related SSCs. FPL'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 of SSCs important to safety against the effects of internally generated missiles that may result from equipment failures are based on:

- GDC-4 insofar as SSC's important-to-safety are required to be protected against the effects of internally generated missiles that may result from equipment failures in order to maintain their essential safety functions.

Specific review criteria are contained in Standard Review Plan (SRP) Sections 3.5.1.1 and 3.5.1.2.

St. Lucie Unit 2 Current Licensing Basis

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

The specific GDCs pertaining to missile protection are as follows:

- GDC-4 is described in UFSAR Section 3.1.4 Criterion 4 – Environmental and Missile Design Bases.

Structures, systems and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and

approved by the Commission demonstrates that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

Systems and components located both inside and outside the containment have been examined to identify and classify potential missiles. Two categories of systems and components have been reviewed to determine the potential for generating missiles:

- pressurized components, and
- high speed rotating machinery.

UFSAR Section 3.5.1.1 evaluates internally generated missiles from both categories of systems outside containment. UFSAR Table 3.5-1 lists the missiles outside containment generated by high energy systems and UFSAR Table 3.5-2 shows the missiles outside containment generated from failure of overspeed protection.

UFSAR Section 3.5.1.2 evaluates internally generated missiles from both categories of systems inside containment. A tabulation of missiles generated from failures of pressurized components, their source and characteristics, and provided missile protection, is given in UFSAR Table 3.5-4.

UFSAR Section 3.5.1.3 evaluates the potential for damage to safety-related structures, systems and components due to turbine missiles to determine whether additional protection, beyond that inherently provided by existing structural shielding, is required to further reduce the damage probability.

UFSAR Section 3.6 describes the design bases and protective design features that are used to demonstrate that the essential systems and components, and essential structures are adequately protected against the effects of postulated piping failures.

In addition to the licensing basis described in the UFSAR, the potential missile sources were evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3 of the SER identifies that components of the systems that contain potential missile sources are within the scope of License Renewal. Programs used to manage the aging effects associated with the systems that contain potential missile sources are discussed in SER Section 3.0 and Chapter 18 of the UFSAR.

2.5.1.2.1.2 Technical Evaluation

2.5.1.2.1.2.1 Introduction

The impact of EPU on internally generated missiles that could result from in-plant component overspeed failures and high pressure system rupture has been evaluated. The potential missile sources, the missile protection criteria and methods of protection of safety related structures and equipment against missiles are addressed in UFSAR Section 3.5.1.

The purpose of this evaluation is to comply with the GDC-4 of Appendix A to 10 CFR Part 50 for the design of nuclear power plant structures and components. FPL conducted a review of potential internally generated missiles to ensure that safety related structures and equipment are adequately protected from them. UFSAR Section 3.5.1.3 addresses turbine missiles generated as a result of turbine rotor failure. Turbine generated missiles are addressed in LR

[Section 2.5.1.2.2](#), Turbine Generator.

2.5.1.2.1.2.2 Description of Analyses and Evaluations

Missiles which are generated inside or outside containment may cause damage to SSC's that are necessary for the safe shutdown of the reactor or for accident mitigation or may cause damage to SSC's whose failure could result in a significant release of radioactivity. The potential sources of such missiles are valve bonnets and hardware retaining bolts, relief valve parts, instrument wells, pressure containing equipment (such as accumulators and high pressure bottles), high speed rotating machinery, and rotating components such as impellers and fan blades.

The FPL review 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.

As a result of this evaluation it was determined that implementation of EPU does not impact system pressures in a manner that would change the probability of missile generation. As such the existing missile barrier protection measures remain effective for EPU conditions.

Refer to LR [Section 2.2.1](#), Pipe Rupture Locations and Associated Dynamic Effects, for evaluation of pipe rupture locations and associated dynamic effects.

Refer to LR [Section 2.5.1.2.2](#), Turbine Generator, for evaluations of the impact of turbine missiles.

2.5.1.2.1.2.3 Impact on Renewed Plant Operating License Evaluations and License Renewal

As discussed above, the potential missile sources are within the scope of license renewal. Operation of the systems containing potential missiles sources under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, the 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.

2.5.1.2.1.3 Results

UFSAR Sections 3.5.1.1 and 3.5.1.2 discuss potential missile sources and UFSAR Tables 3.5-1 and 3.5-2 identify specific missiles considered. The internal missiles identified in the UFSAR table are associated with the reactor coolant, main steam and equipment associated with various plant safe shutdown systems. Since the operating pressures of these systems are not increasing for the EPU, and since no changes are being made to any missile barriers, there is no adverse effect on the existing missile analysis. For plant areas containing safety-related SSC's, the EPU will not result in any changes to existing missile sources or add any new components that could become a new potential missile source. The EPU will also not result in any system configuration changes that would impact any existing missile barrier considerations.

The results of the evaluations demonstrate that the EPU will not impact safety related SSC's with respect to internally generated missiles and will continue to meet the current licensing basis with respect to the requirements of GDC-4.

The EPU does not add new missile barrier components or modify any existing components that would change the license renewal evaluation boundaries. Therefore, no new aging effects requiring management are identified.

2.5.1.2.1.4 Conclusion

FPL reviewed the changes in system pressures and configurations that are required for the proposed EPU and concludes that safety-related SSCs will continue to be protected from internally generated missiles and will continue to meet its current licensing basis with respect to the requirements of GDC-4 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to internally generated missiles.

2.5.1.2.2 Turbine Generator

2.5.1.2.2.1 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 following review of the turbine generator focuses on the effects of the extended power uprate (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, insofar as it relates to protection of structures, systems, and components (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 Standard Review Plan (SRP) Section 10.2.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conform with the NRC General Design Criteria for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

- GDC-4 is described in UFSAR Section 3.1.4 Criterion 4 – Environmental and Missile Design Bases.

Structures, systems and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and approved by the Commission demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

Refer to UFSAR Section 3.5.1.3 for a discussion of turbine missiles.

In addition to the licensing basis described in the UFSAR, the turbine generator system was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of

St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.4.1 of the SER identifies that components of the turbine generator system are within the scope of License Renewal. Programs used to manage the aging effects associated with the turbine generator system are discussed in SER Section 3.4.1 and Chapter 18 of the UFSAR.

2.5.1.2.2.2 Technical Evaluation

2.5.1.2.2.2.1 Introduction

The current turbine-generator and control systems are described in UFSAR Sections 7.7 and 10.2. The current turbine is a Westinghouse Electric Corporation, tandem-compound, 1800 rpm unit consisting of one double-flow high pressure (HP) rotor in tandem with two double-flow low pressure (LP) rotors. The turbine controls and overspeed protection provisions designed to minimize turbine failure probabilities are described below.

The turbine is equipped with an automatic stop and emergency trip system, which trips the stop and control valves to a closed position in the event of turbine overspeed, low bearing oil pressure, low vacuum or thrust bearing failure. An electric solenoid trip valve is provided for remote manual trips and for various automatic trips. In addition, a turbine trip initiates a main generator lockout to prevent generator damage. The turbine control system is discussed in UFSAR Section 7.7.1.1.10. Upon occurrence of a turbine trip when the reactor power level exceeds 15-percent, a signal is supplied to the reactor protective system to trip the reactor. The logic-circuitry for this trip function is discussed in UFSAR Section 7.2.

Additionally, the turbine generator is currently provided with two overspeed protection systems:

1. Overspeed Protection Controller (OPC) (see UFSAR Figure 10.2-4)

The OPC system is an electro-hydraulic control system that controls turbine overspeed in the event of a complete loss of load and if the turbine reaches or exceeds 103 percent of rated speed. It trips the turbine at 111.5 percent of rated speed.

OPC action also occurs when turbine speed is equal to, or greater than, 103 percent of rated speed. Governor and interceptor valves are closed until the speed drops below 103 percent. In addition, OPC will energize solenoid 20/AST, which will cause all turbine valves to trip if the turbine speed reaches 111.5 percent of rated speed.

2. Mechanical Overspeed Protection System (see UFSAR Figure 10.2-5)

The mechanical overspeed device consists of an eccentric weight mounted in the end of the turbine shaft. The weight is balanced in position by a spring until the turbine reaches a 111 percent overspeed condition. The centrifugal force of the weight then overcomes the spring compression and the weight activates a trigger which trips the overspeed trip valve allowing the autostop pressure to drain, thus tripping all turbine valves.

The OPC system and the mechanical system do not share any sensing devices.

Due to their material state and age, the two existing LP rotors will be replaced with new Siemens supplied replacement rotors prior to the implementation of the EPU. In addition, the HP rotor will

be replaced due to the increased volumetric flow requirements under the proposed uprate condition. These changes will result in a significant overall increase in the compound turbines moment of inertia as compared to the existing unit. However, this change 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.

Based on the complete replacement of all LP and HP rotors in conjunction with the power uprate, the impact of these modifications on the existing turbine controls and overspeed protection systems and the resulting effect on the plant's consideration of turbine missiles must be evaluated. For the EPU, protection against turbine missiles will be evaluated using the probabilistic approach of SRP 3.5.1.3, Revision 3, "Turbine Missiles."

2.5.1.2.2.2.2 Description of Analyses and Evaluations

The impact of the EPU on the normal operation, testing, inspection, and overspeed protection of the turbine with the replacement of all LP and HP rotors has been assessed and found acceptable. The fundamental items listed below were considered in this evaluation:

- 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.
- Although the overspeed controls system will undergo some upgrades to improve its overall reliability and operability, the evaluations for run-away rotor events will be based on the existing system. This is acceptable since the dominant contributors to destructive overspeed (governor valve failures and trip header blockage per WCAP-16501) are outside of the scope of the planned turbine control system upgrades and since the type of control system upgrades currently planned has been previously evaluated by Westinghouse (WCAP-16501) and found to be conservative with respect to original EH fluid system component failure probabilities.
- 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 power uprate. The actual turbine rotor inspection frequency is well within the analyzed inspection interval used by the rotor manufacturer to demonstrate compliance with the guidance of SRP 3.5.1.3.
- Based on maintaining the same turbine control testing program and the conservative use of the existing control system parameters in the following evaluations, the existing 18 month fuel cycle conditional probability of destructive overspeed value of $2.58\text{E-}6$ per year (Probability of Destructive Overspeed following system separation per WCAP-16051) remains unchanged due to the power uprate 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 $5.40\text{E-}02$ per year (WCAP-16051) 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 1.39E-07/year under EPU conditions.

- Material properties of the replacement rotors along with their physical properties have been 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 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, this power increase, the volume inherent in the extraction steam system piping, and the volume increase due to moisture separator reheater and feedwater heater changes will be offset by changes associated with the new replacement turbine rotors. To determine the net effect of these changes, an evaluation was performed 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. This study 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.

While the net impact on the turbines' design overspeed condition was insignificant and allows the same overspeed trip settings as presently in use, the impact of the increased rotor inertia and configuration on the probability of turbine missile generation must be evaluated. To address this issue, an updated missile analysis was completed for the new LP rotors. While the HP rotor is also being replaced, the relatively massive and strong casings for the HP rotor prohibits the generation of external missiles for the new HP rotor as it had for the previous HP rotor and therefore this is not a credible source of missiles. The LP rotors however would be prone to missile ejection under both normal operation (up to and including 120-percent overspeed conditions) and under run-away overspeed conditions (greater than 120-percent based on total failure of the overspeed protection system). This new 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 product of these two probability values for both failure and missile ejection were then summed for the various LP disks for the total of all such disks within the turbine. This resulting probability was then added to the probability of a missile being ejected under run-away overspeed conditions. In this second case, the probability of a missile is based on the probability of reaching this run-away overspeed condition which is tied to the possibility of failing the overspeed protection system. This protective overspeed system is comprised of speed monitoring devices, trip and fast closure of steam stops and control valves. Since the probability of run-away overspeed is not tied to the rotor design, but rather to the control system, this value is not changed as a result of the new LP and HP rotor replacements.

The existing digital electro-hydraulic control system of the turbine monitors its speed and initiates a turbine trip at a preset overspeed to maintain a controlled overspeed condition which limits the maximum overspeed to under 120-percent under all design conditions. The one exception is the complete failure of this control system where the rotor is allowed to accelerate unchecked to its run-away destructive overspeed condition where disk failure could occur at approximately 190-percent of normal speed. Although this existing system will undergo some upgrades in

conjunction with the EPU-related design changes to the turbine, these modifications will only enhance the reliability of the controls system and thereby reduce the probability of reaching a run-away condition. Therefore, the analysis for this run-away condition will remain based on the originally installed system which is considered conservative.

The use of a probabilistic approach to turbine missiles has long been accepted as an appropriate means of justifying the safe design of a nuclear plant's turbine. The total potential probability of turbine missile related damage is typically taken as the product of the individual probabilities of missile generation, missile ejection from the turbine shell, and missile interaction with safety-related plant SSC. The NRC and industry practice prior to the mid-80's was to focus on maintaining a low damage probability by utilizing system separation and structural shielding along with generally accepted generic values for the potential generation and ejection of turbine missiles. Industry research efforts in the 80's along with a better understanding of the influence of rotor materials and water chemistry on rotor failures led to a gradual evolution, where today, preventing missile generation is the primary focus. Current turbine missile evaluations utilize generally accepted generic values for missile-plant interactions and establish the probability values of missile generation and missile ejection as a means to justify plant safety. Therefore, while the overall approach to the turbine missile issue has remained constant, the focus and emphasis of turbine missile analyses have changed over time.

The current licensing basis for turbine missile protection relies on a probabilistic approach that considers risk values based on physical plant design and NRC Regulatory Guide 1.115. While the plant structures and current configuration are unchanged and the basis for original acceptance is maintained, current NRC guidance in this area is to focus more on the prevention of missile generation due to the use of controlled water chemistry and frequent inspections of both the turbine rotors and the valves that are used to control the potential for rotor overspeed. The current NRC Standard Review Plan 3.5.1.3, Rev. 3, Turbine Missiles, recommends the use of a good in-service inspection and test program along with the use of rotor material properties and configurations that minimize crack generation and growth as the best means to achieve adequate protection from turbine missile effects. Given the difficulties in adequately establishing the probability of either missile ejection or the resulting damage from such a missile, the NRC rather relies on the concept of preventing missile formation by requiring that the combined probability of missile generation and ejection from the turbine shell be shown to be less than $1.0\text{E-}5/\text{year}$ in plants like St. Lucie Unit 2, where the turbine is unfavorably oriented relative to the plant structures (i.e., where the containment and most safety-related components are within the low-trajectory hazard zone).

In addition to complying with the turbine valve maintenance recommendations provided in WCAP-16501, FPL utilizes a six month valve test frequency for the overspeed protection system along with a 72-month maximum inspection interval on the turbine rotors and blades to ensure a reasonably low probability of generating turbine missiles. Based on the turbine design, with its new LP and HP rotors, and an analytically conservative 100,000 hour inspection frequency, the probability of generating a missile under the EPU normal operating conditions was established as $2.52\text{E-}8/\text{year}$. When this updated missile generation probability is added to the previously established destructive overspeed missile probability value of $1.39\text{E-}7/\text{year}$ based on a six month valve inspection interval, the total annual probability of generating a turbine missile was found to be equal to $1.65\text{E-}07$. Given that this value is below the NRC recommended threshold value of

1.0E-5 per year, the proposed turbine modifications and subsequent EPU operating conditions will not compromise the adequacy of the protection from the potential dynamic effects of turbine related missiles.

Refer to LR [Section 2.13.1](#), Risk Evaluation of EPU, for the evaluation of the impact of EPU on the Probabilistic Risk Assessment (PRA) related to turbine missiles.

2.5.1.2.2.2.3 Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

As discussed above, the turbine generator system is within the scope of License Renewal. Operation of the turbine generator system under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.5.1.2.2.3 Results

The analyses 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 and on the probability of generating turbine missiles. The EPU analyses results are as follows:

- 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 relatively massive and strong casings for the HP rotor prohibit the generation of external missiles for the new HP rotor as they had for the previous HP rotor and therefore, this is not a credible source of missiles,
- Modifications made will enhance the reliability of the controls system and thereby reduce the probability of reaching a run-away condition,
- The total annual probability of generating a turbine missile was found to be equal to 1.65E-07. Given that this value is below the NRC recommended threshold value of 1.0E-5 per year, the proposed turbine modifications and subsequent EPU operating conditions will not compromise the adequacy of the protection from the potential dynamic effects of turbine related missiles, and
- Replacement rotor designs, as well as increased reliance on the low probability of missile generation, are justifications for adequate plant protection from the potential dynamic effects of turbine missiles rather than the exclusive use of protective barriers.

2.5.1.2.2.4 Conclusion

FPL has reviewed the analyses of the effects of the proposed EPU on the turbine generator and concludes that the analyses have adequately accounted for the effects of changes in plant conditions on turbine overspeed. FPL further concludes that the turbine generator will continue to provide adequate turbine overspeed protection to minimize the probability of generating turbine missiles. The probability of unacceptable damage resulting from turbine missiles meets SRP 3.5.1.3 acceptance criteria and thus satisfies the requirements of GDC-4 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to the turbine generator.

2.5.1.2.2.5 References

1. TP-04124, Missile Probability Analysis for the Siemens 13.9m² Retrofit Design of Low-Pressure Turbine by Siemens AG, Submitted to the Nuclear Regulatory Commission as Topical Report TP-04124-NP-A, For Public Record, June 7, 2004, Siemens Westinghouse Power Corporation.
2. Letter from Mr. Herbert N. Berkow, NRC Director, to Mr. Stan Dembkoski, SWPC Director, dated March 30, 2004, Subject: Final Safety Evaluation Regarding Referencing the Siemens Technical Report No. CT-27332, Revision 2, Missile Probability Analysis for the Siemens 13.9m² Retrofit Design of Low-Pressure Turbine by Siemens AG, TAC No. MB7964.

2.5.1.3 Pipe Failures

2.5.1.3.1 Regulatory Evaluation

Florida Power and Light (FPL) 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 FPL review of pipe failures included high and moderate energy fluid system piping located outside of containment. The FPL 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:

- General Design Criterion (GDC)-4, which requires, in part, that structures, systems, and components (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 Standard Review Plan (SRP) Section 3.6.1.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

- GDC-4 is described in UFSAR Section 3.1.4 Criterion 4 – Environmental and Missile Design Bases.

Structures, systems and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and approved by the Commission demonstrates that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

SSCs important to safety are designed to accommodate the effects of and to be compatible with the pressure, temperature, humidity, and radiation conditions associated with normal operation, maintenance, testing, and postulated accidents including a LOCA, in the area in which they are located.

Non-seismic Category I piping is arranged or restrained so that failure of any non-seismic Category I piping will neither cause a nuclear accident nor prevent essential seismic Category I structures or equipment from mitigating the consequences of such an accident.

Seismic Category I piping is arranged or restrained such that in the event of rupture of a seismic Category I pipe which causes LOCA, resulting pipe movement will not result in loss of containment integrity or adequate engineered safety features systems operation.

Refer to UFSAR Sections 3.6B and 3.11 for details on high energy pipe rupture and environmental qualification.

UFSAR Section 3.6B presents the high energy pipe rupture analysis outside containment. The high energy piping systems that are considered for pipe rupture analysis outside containment are:

- main steam and feedwater,
- chemical and volume control system,
- steam generator blowdown system,
- auxiliary steam system,
- auxiliary feedwater system, and
- steam supply to auxiliary feedwater pump.

The criteria used to locate the break points for high energy piping outside containment are described in UFSAR Section 3.6.2.2.2. The various protective methods used to mitigate the consequences of the postulated pipe failure are given in UFSAR Section 3.6.1.2.3. The environmental effects on safety related equipment and components due to the high energy piping systems pipe ruptures outside containment are discussed in UFSAR Section 3.11.

UFSAR Appendix 3.6F presents results of the analysis performed for moderate energy piping failures outside containment. The flooding resulting from moderate energy piping failures are considered in evaluating the availability of essential systems and components to mitigate the consequences of the piping failure.

In addition to the licensing basis described in the UFSAR, the protective barriers associated with high energy line break (HELB) were evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Sections 2.3 and 2.4 of the SER identify that components of the protective barriers associated with HELB are within the scope of License Renewal. Programs used to manage the aging effects associated with the protective barriers associated with HELB are discussed in SER Section 3.5 and Chapter 18 of the UFSAR.

2.5.1.3.2 Technical Evaluation

2.5.1.3.2.1 Introduction

This LR section addresses impact of the extended power uprate (EPU) on piping system failures outside of the containment. The piping lines investigated could potentially affect safety-related SSCs. The impacts that are addressed are the environmental conditions resulting from HELBs, including area temperatures, pressures, and flooding. The high energy lines are those lines with temperatures greater than 200°F and/or pressures greater than 275 psig (UFSAR Section 3.6). The impact of flooding due to moderate energy line breaks (MELBs) is also addressed. Moderate energy lines are fluid systems which are at 200°F or less and 275 psig or less during normal operating conditions (UFSAR Section 3.6).

The impact of the EPU on pipe whip and jet impingement considerations is discussed in LR [Section 2.2.1](#), Pipe Rupture Locations and Dynamic Effects.

The Equipment Qualification Program (addressed in LR [Section 2.3.1](#)) assures that safety-related equipment will be able to perform its intended function(s) while withstanding the environmental conditions generated by the HELB. The HELB for a particular area or building that creates the highest temperature and/or pressure in the area or building is used in the Equipment Qualification Program.

2.5.1.3.2.2 Description of Analyses and Evaluations

The impact of the EPU on analyses of HELBs outside containment is evaluated.

UFSAR Section 3.6.1 and Appendix 3.6B identify systems/portions of systems in which design basis piping breaks are postulated to occur, as follows:

- main steam,
- main feedwater,
- chemical and volume control,
- steam generator blowdown,
- auxiliary steam,
- auxiliary feedwater, and
- steam supply to auxiliary feedwater pump turbine.

The evaluation addresses impact of the EPU on the environmental conditions used for equipment qualification for HELBs outside the Containment, including impact of the EPU on temperatures and pressures due to HELBs, and impact of the EPU on flooding due to HELBs.

UFSAR Appendix 3.6F presents results of the analysis performed for moderate energy piping failures outside containment at current plant conditions. The flooding resulting from moderate energy piping failures is considered in evaluating the availability of essential systems and components to mitigate the consequences of the piping failure.

The impact of the EPU on current flooding analyses due to moderate energy piping failures outside containment for the following rooms and areas is evaluated:

- emergency core cooling system (ECCS) room in reactor auxiliary building (RAB),
- shutdown cooling heat exchanger room,
- boric acid make-up tank room,
- charging pump room,
- diesel generator building,
- diesel oil tank enclosure,
- intake cooling water pump area,
- component cooling water building,
- letdown heat exchanger room,
- boric acid concentrator room,
- pipe tunnels,
- fuel pool heat exchanger room,
- fuel pool pump room, and
- fuel pool purification pump room.

Some of these compartments and areas contain safety-related equipment required for safe plant shutdown while others communicate through the floor drain system and corridors with the rooms containing safety-related equipment.

In general, no operator action such as closing or opening a valve, stopping or starting a pump is assumed for 30 minutes from the first alarm indication in the control room. Also, floor drainage system, sump pumps, etc, are considered available to mitigate the flooding consequences of the piping failure (unless, for conservatism, the analysis assumes floor drainage components are not available).

2.5.1.3.2.3 Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

As discussed above, the protective barriers associated with HELB are within the scope of License Renewal. Operation of the protective barriers associated with HELB under EPU conditions has been evaluated to determine if there any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.5.1.3.2.4 Results

Identification of high energy lines outside containment does not change as a result of EPU.

The EPU does not result in any new pipe break locations to piping outside containment in the main steam and feedwater systems, the letdown and charging lines in the chemical and volume control system (CVCS), steam generator blowdown system (SGBS), auxiliary steam system, auxiliary feedwater (AFW) system, or in the main steam line which supplies steam to the AFW pump turbine.

At EPU conditions, the environmental conditions resulting from a main steam line break (MSLB) outside containment envelope the environmental conditions from a line break in the following systems/lines outside containment: feedwater system, auxiliary steam system, AFW system, and the main steam line which supplies steam to the AFW pump turbine.

The temperature and pressure effects associated with ruptures outside containment in the letdown line, charging line, and SGBS lines remain unchanged for EPU conditions.

The EPU does not affect the current evaluation of flooding in the auxiliary feedwater pump area due to a HELB. The EPU does not affect the current evaluations of flooding due to MELBs in the areas identified in LR [Section 2.5.1.3.2.2](#) above.

2.5.1.3.2.4.1 Impact of the EPU on Temperatures and Pressures Due to HELBs

Main Steam and Main Feedwater Systems Outside Containment

Pipe failures are considered in each of the two main steam lines commencing at the flued head anchor and terminating at the turbine stop valves. Similarly, the two feedwater lines between the containment penetration flued head anchors and feedwater pumps are considered for pipe rupture analysis.

The main steam and feedwater lines are routed from the reactor containment building to the turbine building via two seismic Category I trestles (each trestle supports one main steam line and its corresponding feedwater line).

As addressed in LR [Section 2.2.1](#), Pipe Rupture Locations and Dynamic Effects, the EPU does not result in any new pipe break locations in the main steam or feedwater systems outside containment.

The temperature and pressure effects associated with a MSLB outside containment are addressed in LR [Section 2.3.1](#), Environmental Qualification of Electrical Equipment.

Chemical and Volume Control System Outside Containment (Letdown and Charging Lines)

The maximum operating fluid conditions of the charging line outside containment are 2377 psig and 120°F. A high energy line break in the charging pump room would not result in a temperature/pressure buildup in the compartment, since the maximum operating temperature of

the fluid is only 120°F and no flashing will occur. Neither the operating conditions in the charging line nor the charging pumps are affected by the EPU.

A break in the non-seismic letdown piping downstream of the letdown control valves will cause a pressure differential switch to sense a higher differential pressure across the regenerative heat exchanger and, upon reaching a setpoint of 275 psid, initiate closing of the inside containment letdown isolation valve. Due to the small increase (i.e., less than 5°F) in the reactor coolant system (RCS) temperature at the reactor inlet (T_{cold}) at EPU conditions, changes in letdown line temperatures at EPU conditions are also small. Accordingly, the temperature and pressure effects associated with a letdown line rupture at current conditions remain unchanged at EPU conditions.

As addressed in LR [Section 2.2.1](#), Pipe Rupture Locations and Dynamic Effects, the EPU does not result in any new pipe break locations in the chemical and volume control system outside containment. No modifications to the CVCS piping outside containment are required as a result of the EPU.

Steam Generator Blowdown System Outside Containment

The steam generator blowdown system (SGBS) lines are routed along the roof of the RAB starting from the control room to the steam generator blowdown treatment facility. For the current analysis of a HELB in the SGBS, a pressure and temperature of 885 psig and 532°F, respectively, are used.

The maximum operating temperature of the SGBS at EPU conditions is 532°F, and the system normal operating pressure at EPU conditions is 888 psia (approximately 873 psig). It is seen that the system maximum operating temperature at EPU conditions is the same as the current analysis temperature (532°F), and the system normal operating pressure at EPU conditions (873 psig) is bounded by the current analysis pressure (885 psig). Therefore, the current analysis of a SGBS line rupture remains bounding at EPU conditions.

As addressed in LR [Section 2.2.1](#), Pipe Rupture Locations and Dynamic Effects, the EPU does not result in any new pipe break locations in the SGBS outside containment. No modifications to the SGBS piping outside containment are required as a result of the EPU.

Auxiliary Steam System

The major portion of auxiliary steam system piping is routed in the turbine building, which contains no safety-related equipment. Portions of the auxiliary steam system are routed from the turbine building to the boric acid concentrator (no longer used) rooms and the waste concentrator (no longer used) room in the RAB. Neither of these rooms contains safety-related equipment.

The maximum operating pressure and temperature of the system is generally 25 psig and 350°F. However, in certain areas temperatures and pressures can reach 532°F and 885 psig (steam generator no-load conditions).

A portion of the auxiliary steam system piping routed on the RAB roof is approximately 12 feet from the control room north outside air intake. The effect of a HELB in this location on control room habitability has been evaluated at current plant conditions. The environmental conditions resulting from a break in the outdoor portion of the auxiliary steam system line routed on the RAB

roof will be up to 350°F in the break vicinity with a pressure of 14.7 psia. A line break in this location will not affect control room habitability.

The environmental conditions resulting from a MSLB at current conditions envelope the environmental conditions resulting from an auxiliary steam system line break; therefore, the auxiliary steam system line break is not considered for environmental analysis. The auxiliary steam system pressure and temperature at the main steam header connection at EPU conditions are 866.5 psia (approximately 852 psig) and 527.5°F, respectively. It is seen that the EPU pressure and temperature are bounded by the current maximum operating pressure and temperature (885 psig and 532°F). Accordingly, the environmental conditions resulting from a MSLB continue to envelope the environmental conditions resulting from an auxiliary steam system line break at EPU conditions. Control room habitability is not affected by an auxiliary steam line rupture at EPU conditions.

As addressed in LR [Section 2.2.1](#), Pipe Rupture Locations and Dynamic Effects, the EPU does not result in any new pipe break locations in the auxiliary steam system. No modifications to the auxiliary steam system piping are required as a result of the EPU.

Auxiliary Feedwater System

The AFW system is located under the steam trestle structure. The system consists of three AFW pumps and their associated piping.

The AFW pump discharge piping design temperature from the AFW pumps to the upstream side of the AFW isolation valves was originally based on the maximum condensate storage tank (CST) temperature of 120°F. However, due to being susceptible to effects of back-leakage from the main feedwater system during normal plant operation, the AFW pump discharge piping from the pump discharge motor operated isolation valves to the downstream AFW isolation valves was reanalyzed for temperatures up to 440°F. This temperature is slightly (i.e., less than one percent) higher than the maximum operating temperature of the feedwater system at EPU conditions. A line break is postulated in this section of AFW motor-driven pumps 2A and 2B discharge piping.

The AFW pump discharge piping from the AFW isolation valves to the FW system connection is designed for a maximum temperature similar to the feedwater lines to which they are connected. Line breaks are postulated in this section of AFW motor-driven pumps 2A and 2B discharge piping.

Based on the above discussion, the environmental conditions resulting from line breaks in the AFW pump discharge piping from the AFW pump discharge motor operated valves to the main feedwater system connection would be similar to the environmental conditions resulting from a main feedwater line break. As addressed above, the environmental conditions resulting from a main steam line break envelope the environmental conditions resulting from a feedwater line break at EPU conditions. Therefore, at EPU conditions, the environmental conditions resulting from a main steam line break envelope the environmental conditions resulting from an AFW line break.

As addressed in LR [Section 2.2.1](#), Pipe Rupture Locations and Dynamic Effects, the EPU does not result in any new pipe break locations in the AFW system outside containment. No modifications to the AFW system piping outside containment are required as a result of the EPU.

Main Steam to Auxiliary Feedwater Pump Turbine

The AFW pump turbine is located under the steam trestle structure. Piping failures are considered in the steam line which supplies the AFW pump turbine. Two steam lines (one branch line from the main steam line from each steam generator) originate at the main steam lines just upstream of the main steam isolation valves and join a common header which terminates at the inlet to the turbine. At current plant conditions, the environmental conditions resulting from postulated piping failures in the steam supply piping to the AFW pump turbine are bounded by the postulated breaks identified in the main steam system.

The AFW pump turbine steam demands do not change for the EPU. Therefore, at EPU conditions, the environmental conditions resulting from postulated piping failures in the steam supply piping to the AFW pump turbine continue to be bounded by the postulated breaks identified in the main steam system.

As addressed in LR [Section 2.2.1](#), Pipe Rupture Locations and Dynamic Effects, the EPU does not result in any new pipe break locations in the main steam system outside containment. No modifications to the main steam piping to the AFW pump turbine are required as a result of the EPU.

2.5.1.3.2.4.2 Impact of the EPU on Flooding Due to a HELB

2.5.1.3.2.4.2a Flooding Due to HELB

Auxiliary Feedwater Pumps Area

The walls around the AFW pumps area are provided with adequate openings and the missile protection plates are 9 inches above the floor level; thus, no water buildup would occur in case of a line break. Likewise no equipment outside the AFW pumps area will be affected. The EPU does not affect the location of the AFW pumps or design of the flood walls surrounding the pumps. Therefore, the EPU does not affect the current evaluation of flooding in the AFW pump area due to a HELB.

As addressed in LR [Section 2.2.1](#), Pipe Rupture Locations and Dynamic Effects, the EPU does not result in any new pipe break locations in the main steam or feedwater systems outside containment, or in the AFW system. No modifications to the AFW system piping outside containment are required as a result of the EPU.

2.5.1.3.2.4.2b Flooding Due to MELBs

This section addresses impact of the EPU on the analyses of flooding due to MELBs contained in UFSAR Appendix 3.6F.

ECCS Room in Reactor Auxiliary Building

The ECCS room, located in the RAB at El. -10 feet, is divided into two compartments A & B, by a partial height wall. Each compartment contains safety-related pumps in one train of the redundant trains. A water tight door separates compartment A from the main corridor; three water tight doors separate compartment B from the main corridor. Two sump pumps in each compartment are capable of removing 50 gpm each.

For flooding analysis, the largest flow crack is assumed to occur during normal cold shutdown mode in the suction line of the low pressure safety injection pump located in compartment A.

A flooding analysis was also performed for ECCS room compartment B, assuming a piping failure in the low pressure safety injection suction line located in compartment B, during normal plant shutdown mode.

The EPU does not affect the operating pressures or flow rates in the shutdown cooling system. Therefore, the EPU does not affect the current analysis results regarding flooding from pipe cracks in the ECCS room in the RAB.

Shutdown Cooling Heat Exchanger Room

The two shutdown cooling heat exchangers, located in the RAB at El. -0.5 feet, are separated by a wall that divides the room into two separate compartments. Both compartments communicate with compartment A of the ECCS room through the floor drainage system. The floor drains from the shutdown cooling heat exchanger compartments to the ECCS sump are normally open. A non-watertight door, with bottom El at 2.0 feet, separates each shutdown cooling heat exchanger compartment from the main corridor.

For flooding analysis of shutdown cooling heat exchanger compartment B, the largest flow crack would be in a 12 inch nominal diameter shutdown cooling line.

The EPU does not affect the flow rates / pressures in the shutdown cooling system. Therefore, the EPU does not affect the current analysis results regarding flooding from pipe cracks in the shutdown cooling heat exchanger room.

Boric Acid Make-up Tank Room

The boric acid make-up tank room, located in the RAB at El. -0.5 feet, contains two boric acid make-up pumps. The room is open to a corridor which in turn is connected to an area containing condensate recovery pumps. The floor drains in these areas are connected to ECCS compartment B Sump.

For flooding analysis, a crack is postulated in a four inch discharge line of boric acid makeup tank 2B.

If the piping failure is located in the upstream side of the manual isolation valve in the discharge line of boric acid makeup tank 2B, the operator cannot isolate the crack. The entire contents of the tank are considered to be drained to ECCS compartment B. The boric acid make-up system will remain at present operating conditions. The EPU impact on the boric acid makeup tank minimum volume is insignificant. Therefore, the EPU does not affect the current analysis results regarding flooding from pipe cracks in the boric acid make-up tank room.

Charging Pump Room

The three charging pumps are located in the RAB at El. -0.5 feet. The charging pump room is divided into three separate compartments by 6.5 ft high walls. Each charging pump is located in a separate compartment. Doors are provided between the charging pump room and the pipe tunnel at El. +0.5 feet and the RAB main corridor. Each compartment has a 6 inch high curb at the entrance.

For flooding analysis, the largest flow crack would be in the four inch charging pump 2C suction line. The flooding analyses are the same for each of the charging pump compartments.

The volume control tank (VCT) (from which the charging pumps take suction) operating conditions are not affected by the EPU. Therefore, the EPU does not affect the current analysis results regarding flooding from pipe cracks in the charging pump room.

Diesel Generator Building

There are two diesel generators installed in separate rooms in the diesel generator building.

For flooding analysis, the largest flow crack would be in a 2 inch nominal diameter service water system line. The service water system serves no safety function since it is not required to achieve safe plant shutdown or to mitigate the consequences of a design basis accident.

The EPU does not affect the service water system. Therefore, the EPU does not affect the current analysis results regarding flooding from pipe cracks in the diesel generator building.

Diesel Oil Tank Enclosure

There are two diesel oil storage tanks with their pumps located in two separate compartments in the diesel oil tank enclosure.

For flooding analysis the highest flow crack would be in the 3 inch nominal diameter diesel oil pump suction line.

The existing diesel fuel oil storage tanks remain adequate at EPU conditions. Therefore, the EPU does not affect the current analysis results regarding flooding in the diesel oil tank enclosure.

Intake Cooling Water Pump Area

There are three intake cooling water (ICW) pumps located in the ICW water pump area.

For flooding analysis the largest flow crack would be in the 30 inch diameter ICW pump discharge line.

As addressed in LR [Section 2.5.4.2](#), Station Service Water System, the EPU does not affect the ICW pump head performance. Therefore, the EPU does not affect the current analysis results regarding flooding from pipe cracks in the ICW pump area.

Component Cooling Water Building

The component cooling water (CCW) building contains three CCW water pumps and two heat exchangers. The pumps and heat exchangers are mounted on pedestals at approximately El. 24.0 feet.

For flooding analysis, the largest flow crack would be in the 30 inch ICW system inlet line to the CCW heat exchanger.

As addressed in LR [Section 2.5.4.2](#), Station Service Water System, the EPU does not affect the ICW pump head performance or flow rates to the CCW heat exchanger. Therefore, the EPU does not affect the current analysis results regarding flooding from pipe cracks in the component cooling water building.

Letdown Heat Exchanger Room

The letdown heat exchanger room, located in the RAB at El. 19.5 feet, contains the letdown heat exchanger and associated piping and valves. A door connects this room with the corridor. This room contains no equipment needed for safe plant shutdown, but the room is connected with ECCS compartment A through the floor drainage system.

For flooding analysis, the largest flood crack is in the letdown heat exchanger CCW outlet line.

As addressed in LR [Section 2.5.4.3](#), Reactor Auxiliary Cooling Water System, the EPU does not affect the CCW system operating pressures or flow rates. Therefore, the EPU does not affect the current analysis results regarding flooding from pipe cracks in the letdown heat exchanger room.

Boric Acid Concentrator Room

Two boric acid concentrator rooms and one waste concentrator room are located in RAB at El. 19.5 feet. Each room is connected with the corridor at El. 19.5 feet via a door. The boric acid concentrator (no longer used) and waste concentrator (no longer used) are not safety-related. However, these rooms are connected through the drainage system with ECCS compartment A.

The flooding analysis was performed for a postulated crack in the boric acid concentrator CCW line.

As addressed in LR [Section 2.5.4.3](#), Reactor Auxiliary Cooling Water System, the EPU does not affect the CCW system operating pressures or flow rates. Therefore, the EPU does not affect the current analysis results regarding flooding from pipe cracks in the boric acid concentrator room.

Pipe Tunnels

The upper pipe tunnel is located at El 19.5 feet and the lower pipe tunnel has bi-level floors at El -0.5 feet and at El 0.5 feet. An opening in the floor of the upper tunnel connects the lower tunnel. A door is provided between the lower tunnel and the charging pump room. Another door is provided between the lower tunnel and the corridor which is between the ECCS room and shutdown cooling heat exchanger room. The lower tunnel communicates through the drainage system with ECCS compartments A and B.

The worst postulated crack in the lower pipe tunnel is located in a 24 inch nominal diameter containment spray pump suction line from the refueling water tank. The largest flow crack in the tunnel at El. 19.5 feet would be in a 20 inch nominal diameter CCW line.

The EPU does not affect the containment spray system operating pressures or flow rates. As addressed in LR [Section 2.5.4.3](#), Reactor Auxiliary Cooling Water System, the EPU does not affect the CCW system operating pressures or flow rates. Therefore, the EPU does not affect the current analysis results regarding flooding from pipe cracks in the pipe tunnels.

Fuel Pool Heat Exchanger Room

The fuel pool heat exchanger room, located in the fuel handling building at El. 19.5 feet, contains the fuel pool heat exchanger and associated piping and valves.

For flooding analysis, the largest flow crack would be in the 12 inch nominal diameter CCW line from the fuel pool heat exchanger to return header B.

As addressed in LR **Section 2.5.4.3**, Reactor Auxiliary Cooling Water System, the EPU does not affect the CCW system operating pressures or flow rates. Therefore, the EPU does not affect the current analysis results regarding flooding from pipe cracks in the fuel pool heat exchanger room.

Fuel Pool Pump Room

The fuel pool pump room, located in the fuel handling building at El. 19.5 feet, contains two fuel pool cooling pumps. One door with a six inch curb connects this room with the fuel pool purification filter room. There is a 6 inch high curb between this room and the corridor. This corridor also has a 6 inch high curb to separate the fuel pool heat exchanger room.

For flooding analysis, the largest flow crack would be in the fuel pool cooling pump 12 inch nominal diameter suction line.

The fuel pool cooling and cleanup system is not affected by the EPU. Therefore, the EPU does not affect the current analysis results regarding flooding from pipe cracks in the fuel pool pump room.

Fuel Pool Purification Pump Room

The fuel pool purification pump room, located in the fuel handling building at El 19.5 feet, contains the fuel pool purification pumps. One door connects this room with the fuel pool purification filter room. A wall with top elevation at 26.27 feet provides separation from the fuel pool pump room.

For flooding analysis, the largest flow crack is the fuel pool ion exchanger outlet line.

The fuel pool cooling and cleanup system (which includes the fuel pool purification components) is not affected by the EPU. Therefore, the EPU does not affect the current analysis results regarding flooding from pipe cracks in the fuel pool purification pump room.

2.5.1.3.3 Conclusion

FPL has reviewed the changes that are necessary for the proposed EPU and FPL'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 its current licensing basis with respect to the requirements of GDC-4 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to protection against postulated piping failures in fluid systems outside containment.

2.5.1.4 Fire Protection

2.5.1.4.1 Regulatory Evaluation

The purpose of the fire protection program (FPP) is to provide assurance, through a defense-in-depth design, that a fire will not prevent the performance of necessary safe plant shutdown functions and will not significantly increase the risk of radioactive releases to the environment. The Florida Power and Light (FPL) review focused on the effects of the increased decay heat on the plant's safe shutdown analysis (SSA) 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 FPP are based on:

- 10 CFR 50.48 and associated Appendix R to 10 CFR Part 50, insofar as they require the development of an FPP to ensure, among other things, the capability to safely shut down the plant in the event of a fire;
- 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; and
- 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.

Specific review criteria are contained in Standard Review Plan (SRP) Section 9.5.1, as supplemented by the guidance provided in Attachment 1 to Matrix 5 of Section 2.1 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

The specific GDCs for the Fire Protection System are as follows:

- GDC-3 is described in UFSAR Section 3.1.3 Criterion 3 – Fire Protection.

Structures, systems and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat resistant materials shall be used wherever practical throughout the unit, particularly in locations such as the containment and control room. Fire detection and fighting systems of appropriate capacity and capability shall be provided and designed to minimize the adverse effects of fires on structures, systems and components important to safety. Fire fighting systems shall be designed to assure that their rupture or

inadvertent operation does not significantly impair the safety capability of these structures, systems and components.

Noncombustible and fire resistant materials are used wherever practical throughout the facility, particularly in areas containing critical portions of the plant, such as containment structure, control room, and components of systems important to safety. These systems are designed and located to minimize the effects of fires or explosions on their redundant components. Facilities for the storage of combustible material are designed to minimize both the probability and the effects of a fire.

Equipment and facilities for fire detection, alarm and extinguishment are provided to protect both plant and personnel from fire or explosion and the resultant release of toxic vapors. Both wet and dry type fire fighting equipments are provided.

Normal fire protection is provided by deluge systems, hose lines and portable extinguishers, and preaction type sprinkler systems. The fire protection system is designed such that a failure of any component of the system:

- will not cause a significant release of radioactivity to the environment, and
- will not impair the ability of redundant equipment to safely shutdown and isolate the reactor or limit the release of radioactivity to the environment in the event of a loss-of-coolant accident (LOCA).

All equipment is accessible for periodic inspection. The fire protection system is described in Section 9.5.1 of the UFSAR.

- GDC-5 is described in UFSAR Section 3.1.5 Criterion 5 – Sharing of Structures, Systems, or Components.

Structures, systems and components important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units.

As stated in UFSAR Appendix 9.5A, Fire Protection Program Report, the FPP implements the philosophy of defense-in-depth protection against fire hazards and effects of fire on safe shutdown equipment. The FPP described in this report ensures that in the event of a fire the reactor can be safely shut down and radioactive releases to the environment are minimized. The FPP methodology provided ensures:

- prevention of fires from occurring,
- detection and mitigation of fires that do occur, and
- safe shutdown design, such that were a fire to start and burn for an extended period in spite of prevention/detection/ mitigation measures, capability for safe plant shutdown is retained.

The information presented in UFSAR Appendix 9.5A demonstrates how the design meets 10 CFR 50 Appendix A, General Design Criterion 3, Fire Protection. Moreover, UFSAR Appendix 9.5A outlines how GDC-3 is met using the guidelines contained in Appendix A to branch technical position (BTP) APCSB 9.5-1 and in 10 CFR 50 Appendix R.

As stated in UFSAR Appendix 9.5A Section 2.3.3, St. Lucie Unit 2 conforms to the requirements of 10 CFR 50 Appendix R with exceptions which have been reviewed and approved by NRC or evaluated as acceptable.

UFSAR Appendix 9.5A Section 2.4 demonstrates conformance to the BTP APCSB 9.5-1 Appendix A Guidelines, or describes alternative approaches.

The alternate shutdown methodology is discussed in UFSAR Appendix 9.5A Section 5.0.

The fire protection license condition given in Paragraph 3.E of Renewed Facility Operating License No. NPF-16, dated August 16, 2007, as described in part as follows:

FPL shall implement and maintain in effect all provisions of the approved fire protection program as described in the Updated Final Safety Analysis Report for the facility and as approved in the NRC Safety Evaluation Report (SER), Supplement 3, dated April 1983, and supplemented by NRC letter dated December 5, 1986, subject to the following provision:

FPL may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

Technical Specification 6.8.1.f requires that written procedures be established, implemented, and maintained covering the FPP implementation.

A Fire Protection Plan has been developed which establishes the fire protection policy for the protection of SSCs important to safety and the procedures, equipment and personnel required to implement the program. The Fire Protection Plan addresses fire protection policy for the protection of support facilities and non-safety related structures, systems and components. The Fire Protection Plan was developed and is maintained to satisfy 10 CFR 50, Appendix A - Criterion 3, as required by 10 CFR 50.48(a).

In addition to the licensing basis described in the UFSAR, the fire protection system and fire rated assemblies were evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003.

Sections 2.3.3.6 and 2.4.2.6 of the SER identifies that components of the fire protection system and fire rated assemblies are within the scope of License Renewal. Programs used to manage the aging effects associated with the fire protection system and fire rated assemblies are discussed in SER Sections 3.3.6 and 3.5.2 and Chapter 18 of the UFSAR.

2.5.1.4.2 Technical Evaluation

2.5.1.4.2.1 Introduction

The purpose of the FPP is to provide assurance, through defense-in-depth design, that a fire will not prevent the performance of necessary safe shutdown functions or significantly increase the

risk of radioactive release to the environment during a postulated fire. This section addresses the impact of the extended power uprate (EPU) on the FPP.

2.5.1.4.2.2 Description of Analyses and Evaluations

The impact of the EPU on the following fire protection topics is evaluated:

- Fire protection program report (FPPR) elements,
- Safe shutdown analysis, and
- Other supporting analyses / evaluations.

Since the description and results of the analyses and evaluations associated with these topics are interrelated, these elements of the technical evaluation are addressed in LR [Section 2.5.1.4.2.3](#), Results.

The above-listed fire protection topics are evaluated apart from plant modifications. Plant modifications being implemented in support of the EPU that could potentially impact elements of the FPP include the following:

- Increase main generator hydrogen pressure and hydrogen seal oil pressure,
- Replace the 2A and 2B main transformers to accommodate increased power at EPU conditions,
- Modify the control room air conditioning equipment to allow a higher component cooling water (CCW) inlet temperature,
- Install leading edge flow meter for improved feedwater flow measurement accuracy, and
- Increase margin on the ac electrical busses.

The impact of plant modifications in support of the EPU on the FPP is addressed in accordance with the plant change/modification process.

2.5.1.4.2.3 Results

Fire Protection Program Report Elements

The following program elements contained in the FPPR are evaluated for impact of the EPU:

1. Fire protection systems,
2. Fire hazards analysis,
3. Alternative shutdown capability,
4. Primary coolant system interfaces, and
5. Administrative controls.

1. Fire Protection Systems

The fire protection systems include the site water supply (shared between St. Lucie Units 1 and 2), standpipes and hose stations, fixed suppression systems, portable extinguishers, fire detection systems, lightning protection, emergency lighting systems, communication systems,

local fire department, reactor coolant pump (RCP) oil collection system, and fire rated assemblies – barriers, fire doors, fire dampers, and penetration seals. Hydrogen lines in safety-related areas are designed to prevent a fire from defeating the safety-related function of safety-related systems. The fire protection plant design features will continue to meet their acceptance criteria under EPU conditions.

2. Fire Hazards Analysis

The existing fire hazards analysis provides reasonable assurance that a fire will not cause an unacceptable risk to public health and safety, does not prevent the performance of necessary safe shutdown functions, and does not increase the risk of radioactive release to the environment. There are no changes in the extent or boundaries of the plant fire areas, the location of redundant trains of essential equipment and associated cabling required for safe reactor shutdown, the architectural design and location of both external and internal walls, and the degree of accessibility to a fire by station fire brigade and/or outside fire department personnel as a result of the EPU. The EPU does not affect the bases for an approved deviation from 10 CFR 50 Appendix R requirements.

The impact of EPU modifications on plant core damage frequency (CDF) and large early release frequency (LERF) due to fire is addressed in LR [Section 2.13](#), Risk Evaluation.

3. Alternative Shutdown Capability

As addressed in the FPPR, alternative shutdown capability is designed to ensure that, in the unlikely event that a fire in the control room or cable spread room causes the control room to be uninhabitable or equipment in either room to be inoperable, the plant can safely be taken to cold shutdown from a remote location. Should evacuation of the control room be required, plant shutdown will be accomplished and monitored from the hot shutdown control panel (HSCP) with local operation of selected cold shutdown equipment. Before leaving the control room, operators will trip the reactor, RCPs, main steam isolation valves, and the turbine. Alternative shutdown is accomplished in accordance with plant procedures.

Apart from plant modifications in support of the EPU, the EPU does not affect any components or circuits that provide power, control, or indication to components required for alternative safe shutdown. The EPU does not introduce any additional plant equipment failure modes that will impact the ability to achieve any of the alternative shutdown functions. The EPU does not affect the current alternative shutdown capability used to bring the plant to cold shutdown for a fire in the control room or cable spread room.

As addressed in the FPPR, alternative shutdown capability is provided as follows:

- Once the HSCP is activated, the instrumentation and controls provided thereon, enable the plant operator to maintain the unit at hot standby conditions. Reactor coolant system (RCS) conditions are monitored by means of the pressurizer pressure and level and RCS cold leg temperature indicators. Removal of residual heat through the secondary system is controlled via the main steam safety valves or the atmospheric dump valves, and auxiliary feedwater (AFW) pump and control valves. Steam generator (SG) pressure and level are monitored at the HSCP.

- Pressurizer level is maintained by isolation of letdown and by use of a charging system pump and valves. Pump suction is manually aligned to the boric acid makeup (BAM) tanks or the refueling water tank (RWT). Cold shutdown boron concentration is assured by injecting the entire contents of a BAM tank into the primary system. This is accomplished during the cooldown process via the “shrink and fill” method. The RWT provides the additional volume makeup required to achieve cold shutdown conditions. Depressurization is accomplished through the use of the auxiliary spray system. After depressurization, the shutdown cooling (SDC) system is manually aligned.
- Power level indicators are provided on the HSCP independent of the control room or cable spread room.

Alternative shutdown methods have the capability of achieving cold shutdown within 72 hours. The basic criterion utilized when analyzing alternative shutdown capability is that only equipment that is physically and electrically independent of the control room and cable spread rooms is available for plant shutdown.

The EPU does not modify the current alternative shutdown methods used for safe shutdown, and does not require any new methods, systems, or equipment to perform the required alternative shutdown functions.

4. Primary Coolant System Interfaces

As addressed in the FPPR, several low pressure systems are connected to the high pressure primary coolant system. In some cases, low pressure system isolation is provided solely by redundant electrically operated valves. The design of these systems must ensure that a fire-induced LOCA cannot result due to a single fire opening all the valves in series at a high/low pressure interface.

The systems of concern and the means by which a fire-induced LOCA is prevented are discussed below:

- a. Letdown isolation,
- b. Primary sampling system,
- c. Reactor coolant gas vent system,
- d. Shutdown cooling isolation, and
- e. Power operated relief valves (PORVs).

The letdown line is provided with three pneumatic valves in series, each of which is capable of isolating the RCS, followed by two additional valves in parallel. All valves fail to a safe position (closed) on loss of air. An analysis of the routing of all cables essential to the operation of these valves demonstrated that no one fire can prevent letdown line isolation.

The RCS is provided with three independent sampling paths. Each line has a solenoid valve inside containment and a pneumatic valve outside containment which fails closed on loss of air or power. One valve per line is powered from the ‘A’ dc bus, while the other is powered from the ‘B’ dc bus. In addition, each line has a restriction orifice designed to limit flow to less than the

makeup capability of one charging pump in the event of any failure in the downstream line. Thus, these passive devices minimize the possibility of a LOCA through these lines.

The reactor coolant gas vent system is provided with redundant solenoid operated valves which fail closed on loss of power. Outboard valves are provided with isolation switches (for alternative shutdown) or have their power cables routed in dedicated conduits from the control room to penetration rooms, minimizing the potential for spurious actuation due to fire-induced hot shorts. These design features minimize the potential for a fire-induced LOCA for any fires in the reactor auxiliary building (RAB). In the reactor containment, the power circuits of the outboard valves are routed utilizing dedicated armored cables, therefore minimizing the potential for spurious actuation(s).

The RCS is isolated from the low pressure safety injection system by means of redundant locked-closed motor operated valves. Each line has two valves in series, one valve powered by the SA Train and one by the SB Train. Each of these valves is controlled by independent interlocks which prevent valve opening when RCS pressure is 275 psia or above. Two of these valves, SDC isolation valves V3480 and V3652, are protected from spurious actuation by having their power cables routed in dedicated conduits (RAB only). In containment, these two valve circuits are routed in dedicated conduits or otherwise protected from hot shorts. Thus, a fire-induced LOCA is prevented. The cross-tie valve is normally open and is powered by the SAB Train.

The pressurizer is provided with redundant PORVs. These are solenoid-operated valves which are designed to fail closed on loss of power. For additional protection each PORV has a motor operated valve located upstream for isolation. For diversity, the PORVs are dc powered while the isolation valves are ac powered. The complete system has been analyzed for potential fire-induced faults and protected accordingly. This protection covers various design features, such as dedicated conduit and a qualified 3 hour fire barrier in the RAB, and dedicated armored cable and fused indication circuits in the reactor containment building. These protection features assure that the potential for multiple spurious actuations leading to a loss of primary system integrity have been minimized in all areas where the cables are routed.

All circuits located in the control room controlling the operation of the PORVs are housed in cabinets and control boards. No power cables are in the control room boards and cabinets. Cables are limited to 120V ac or 125V dc control circuits, which are protected by electrical interrupting devices (i.e., breakers, fuses), and instrumentation cables. Low-level instrumentation cables do not require protective devices because the energy released by an electrical fault is low and within the cables continuous energy carrying capability. Thus, the credibility of a self-generated cabinet or board fire is minimized. The entire control room, adjacent areas, and inside the reactor turbine generator boards are provided with smoke detection. Standpipe hose stations are provided at entries, in addition to portable dry chemical, carbon dioxide, and pressurized water fire extinguishers. The control room is continuously manned by senior operations personnel. Still, should a fire occur in the control room or cable spread room, a local disconnect switch is provided for each PORV in the respective division electrical penetration room. Manual operation of this switch will remove control power to the local contactor, therefore assuring that no fire-induced failure of the control circuits can energize (open) a PORV.

Based on the above, the combination of physical separation, system design, and fire protection provisions provide assurance that no single fire will cause a LOCA. Under EPU conditions, there are no electrical changes, modifications, or additions that will affect the current analysis.

5. Administrative Controls

Administrative controls are addressed in the FPPR and include the following topics: fire brigade, fire prevention activities, fire protection systems and barriers, inspection and testing requirements, and fire protection system operability and surveillance requirements. The above topics are unaffected by the EPU. There are no changes to the FPP, fire brigade, fire prevention activities, fire protection systems and barriers, inspection and testing requirements, or fire protection system operability and surveillance requirements as a result of the EPU.

Safe Shutdown Analysis

The 10 CFR 50 Appendix R SSA is one of the defense-in-depth protections against fire hazards. The SSA assures that for a single fire in any area, the ability to safely shut down the unit is not impaired. The SSA addresses the postulated fire damage for each fire area, identifies fire-induced failures that affect the plant, and the post-fire operator actions that can be used to compensate for these failures. Loss of offsite power following a fire is accounted for in the analysis.

Plant-specific operating procedures have been developed from the SSA to provide plant operators with the entry conditions and manual actions required for plant shutdown following a fire.

The following topics addressed in the FPPR and Appendix R SSA are evaluated for impact of the EPU:

1. Cold shutdown time following reactor trip,
2. Safe shutdown time line,
3. Cold shutdown repairs,
4. Initial conditions for fire area analysis,
5. Essential equipment list,
6. Essential cable list,
7. Circuit breaker coordination,
8. Multiple high impedance faults,
9. Associated circuits,
10. Cable failure analyses, and

11. Operator actions and manual action timing.

1. Cold Shutdown Time Following Reactor Trip

An analysis was performed at EPU conditions to demonstrate that the unit can be placed in cold shutdown as required by 10 CFR 50 Appendix R. Based on the requirements of 10 CFR 50 Appendix R, the analysis for EPU determines how long it will take to reach cold shutdown. The analysis assumes natural circulation (no RCPs) and that only one atmospheric dump valve (ADV) and one SG are available for cooldown. The EPU affects plant cooldown times, since core power increases, and therefore decay heat increases. As addressed in LR [Section 2.8.4.4](#), the results of the EPU analysis demonstrate that the unit can be placed in cold shutdown status (RCS temperature less than or equal to 200°F) within 72 hours after reactor trip following a fire at EPU conditions. Moreover, the analysis shows that the unit can be placed in cold shutdown using only one SDC system train.

2. Safe Shutdown Time Line

For selected fire areas, it may take up to one hour to establish RCS makeup via charging flow (two hours will be used as a conservative estimate). Based on this, it is assumed that a cooldown could not start for at least two hours after a fire. Since at the time of restoration of charging it may take some time to re-establish conditions to start a cooldown, an additional two hours will be added before start of cooldown. Based on the above assumptions, cooldown is assumed to be initiated 4 hours following the plant being tripped.

The analysis assumes that one SG, one ADV, and one AFW pump are available to cool the plant from hot standby conditions to hot shutdown conditions, where cooldown to cold shutdown can be initiated. Once the plant reaches hot shutdown, the plant is assumed to remain in this mode until the reactor vessel upper head temperature reaches the saturation temperature corresponding to the operating pressure limit of the SDC system. The analysis for determining the time to reach cold shutdown assumes that only one shutdown heat exchanger is available to cool the plant. No credit is taken for any additional heat being removed by the ADV. In both the cooldown to hot shutdown conditions and the cooldown to cold shutdown, the liquid and metal masses of the primary and secondary plant are included as part of the heat capacity with no heat being lost to the environment. These assumptions increase the time required to reach cold shutdown.

The EPU affects plant cooldown times, since core power increases, and therefore decay heat increases. Based on the above analyses, the requirement to achieve cold shutdown conditions within 72 hours after reactor shutdown continues to be met for EPU conditions with increased heat loads. Also, it is concluded that fuel design limits would not be exceeded and there would be no adverse consequences on the reactor pressure vessel integrity or the attached piping. The EPU does not impact plant procedures required to achieve and maintain cold shutdown.

3. Cold Shutdown Repairs

FPL takes credit for limited repairs (i.e., inserting fuses) to cold shutdown equipment. The EPU does not impact plant procedures or resources required for the above limited repairs to achieve and maintain cold shutdown.

4. Initial Conditions for Fire Area Analysis

The following initial conditions were used in the existing fire area analysis and remain unchanged under EPU conditions:

- a. The fire event is assumed to occur during Mode 1 – 100 percent power operation,
- b. Loss of offsite power or offsite power availability is assumed (whichever results in the most limiting conditions) during the fire event,
- c. Accidents (e.g., LOCA, main steam line break, high energy line break) or natural events (e.g., earthquake, tornado) are not assumed coincident with the fire event, and
- d. Manual reactor trip is assumed to be accomplished prior to control room evacuation in the event of a control room or cable spreading room fire.

5. Essential Equipment List

The existing essential equipment list was developed by reviewing the plant flow diagrams and determining flow paths to support the above listed safe shutdown goals. Based on the requirement that onsite power could be used for initial post fire safe shutdown, only systems and equipment supported by onsite power were reviewed. Typically, safety-related systems which perform the required functions were used, since they lend themselves to the required separation and redundancy which would allow one train to be free from fire damage. Flow diagrams were reviewed and a list of electrically powered equipment along with other major equipment was created. Along with this equipment, the instruments required for these functions and the power supplies for the equipment and instruments on the list were added. Apart from plant modifications in support of the EPU, the EPU does not affect the safe shutdown systems / components, including cables, credited with achieving safe and/or alternative shutdown. Therefore, the essential equipment list remains unchanged for EPU conditions.

6. Essential Cable List

After the essential equipment list was created, cables required to allow essential equipment function were determined by review of the appropriate control wiring drawings, one-line drawings, and power and distribution motor data drawings. This determination included cables required for equipment function, as well as cables that could prevent equipment function or cause equipment mal-operation. This list of cables forms the essential cable list. Apart from plant modifications in support of the EPU, the EPU does not affect the safe shutdown systems / components, including cables, credited with achieving safe and/or alternative shutdown. Therefore, the essential cable list remains unchanged for EPU conditions.

7. Circuit Breaker Coordination

A review of the coordination of protective devices demonstrates that circuit breaker coordination is achieved by properly coordinating electrical protective devices, such as breakers and fuses, such that a short or fault is cleared by the electrical protective device without affecting other safe shutdown circuits. Under EPU conditions, protection devices for safe shutdown equipment are

not changed or modified, and therefore the existing calculation in unaffected and coordination of protective devices is maintained.

8. Multiple High Impedance Faults

Multiple high impedance faults from multiple circuits that trip the bus and panel feeder breaker instead of the individual circuit breakers can potentially affect the operation of safe shutdown loads on the bus. The effects of multiple high impedance faults on associated circuits for the ac and dc electrical systems were analyzed. Under EPU conditions, there is no addition of loads or modification or wiring that will increase the possibility of occurrence of multiple high impedance faults.

9. Associated Circuits

The design of associated circuits (as defined for fire protection) is as follows.

Associated circuits are those that:

1. Have a physical separation less than that required by Section III.G.2 of 10 CFR 50 Appendix R, and;
2. Have one of the following:
 - A. A common power source with the shutdown equipment (redundant or alternative) and the power source is not electrically protected from the circuit of concern by coordinated breakers, fuses, or similar devices, or
 - B. A connection to circuits of equipment whose spurious operation would adversely affect the shutdown capability, or
 - C. A common enclosure with the shutdown cables and,
 - (a) Are not electrically protected by circuit breakers, fuses or similar devices, or
 - (b) Will allow propagation of the fire into the common enclosure.

Circuits that do not meet the separation criteria of Section III.G.2 of 10 CFR 50 Appendix R and have a common power source with safe shutdown equipment are provided with circuit breakers, fuses, or similar devices.

For circuits that do not meet the separation criteria of Section III.G.2 of 10 CFR 50 Appendix R and have a common enclosure, propagation of a fire into the common enclosure is prevented by the provision of fire stops at fire boundaries and by the use of IEEE 383 or equivalent cable.

The EPU does not introduce additional cables, and does not change, modify, or add protective circuit devices or fire barriers; therefore the existing analysis for associated circuits remains unchanged.

10. Cable Failure Analyses

The analysis of the effect on the safe shutdown of the plant in the event of a fire for any particular cable is contained in the SSA. The SSA identifies the cable function with respect to the equipment that it controls/powers in addition to identifying the failures expected based on the cable failure mode field. The potential adverse effect of such failures is listed along with the justifications that it does not impact the safe shutdown or that manual actions are required to mitigate the potential failures of the cable.

The EPU does not add, change or modify any fire zone/areas or NRC-approved 10 CFR 50 Appendix R deviations. Apart from plant modifications in support of the EPU, the EPU does not affect the circuit failure analyses.

11. Operator Actions and Manual Action Timing

Following a fire, equipment normally used to bring the plant to cold shutdown conditions may be inoperable. The operator actions identified in the SSA serve as the technical bases for plant procedures which include operator manual actions for fire safe shutdown scenarios. Manual actions are executed from the control room, outside the control room, inside the reactor containment building, and inside the fire area (for equipment that does not suffer fire damage). Manual actions used for safe shutdown are those that support the process of safe shutdown, or preempt or mitigate equipment mal-operation.

Manual actions from the control room are assumed to be executed at the initiation of the fire event, or later as required. Manual actions (Modes 1, 2, & 3) from outside the control room are executed after an assumed delay from initiation of the fire event, which includes the time for accessing equipment and performing the action, as follows: outside the control room – 30 minutes, inside the reactor containment building – 60 minutes, and inside the fire area – 60 minutes. Cold shutdown (Modes 4 and 5) does not typically require accounting of time required for operator action.

Based on guidance in NRC Generic Letter 86-10, Implementation of Fire Protection Requirements, an analysis to justify the allowable time to perform manual actions for a control room fire was done to determine the effects on safe shutdown of delay times for certain systems and actions.

There are required actions for other systems which were not included in the above analysis.

- Charging Line Isolation and Excess Charging (Multiple Spurious Operations)

Due to the potential of multiple spurious operations, 30 minutes is assumed as the time allowed to isolate the charging line and stop excess flow due to extra charging pumps operating.

- Boric Acid Makeup Pump Shutdown and Chemical and Volume Control System Alignment (Multiple Spurious Operations)

Due to the potential of multiple spurious operations 30 minutes has been allotted to secure a spuriously started BAM pump or secure the flow path to the volume control tank (VCT).

- Intake Cooling Water (ICW) and Component Cooling Water System Timing

The function of containment cooling is a long term function which does not require immediate actions. Therefore, for most locations a time of 60 minutes has been assigned to the restoration of the CCW and ICW systems for containment cooling. There are cases where this time may be exceeded. Most containment actions are for cold shutdown and are not time critical. Therefore, delay of the restart of CCW and ICW can be accepted when there are no time critical actions within the containment.

With only one CCW pump running, it is possible that the CCW pump may run out if all CCW flow paths are open. A run out condition could potentially shorten pump life due to cavitation within the pump, but that effect would take a long time to cause a pump failure. Therefore, a time of 60 minutes has been assigned to the manual realignment of the CCW system to prevent run out for a single operating CCW pump.

There is a possibility that a second ICW or CCW pump would spuriously start. From a system hydraulic point of view this is not a problem. This second pump might be on the same electrical train as the running pump, leaving two pumps on the same train. With regard to immediate emergency diesel generator (EDG) loading, this is not a problem. However, for long term EDG loading, as well as providing flexibility for loading other nonessential, but desirable, loads on the EDG, a time of 30 minutes has been established to secure a spuriously started ICW or CCW pump, if it is operating on the same electrical train as the desired pump.

- Main Feedwater Isolation/Termination

Under certain conditions it is possible that the main feedwater system may provide excess flow to the SGs and cause excessive RCS cooldown and/or SG overfill. An action time of 10 minutes has been assigned for actions to mitigate this condition.

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.

Other Supporting Analyses/Evaluations

The EPU impact on the following evaluations is discussed below:

1. Instrument sensing lines, and
2. Heating ventilation and air conditioning (HVAC) considerations.

1. Instrument Sensing Lines

Instrument sensing lines are potentially susceptible to fire-induced effects. Process fluid contained in sensing lines could heat up and expand as a result of fire and cause spurious instrument operation that could impact either indication or control functions. As such, sensing lines associated with instruments utilized for post fire shutdown have been evaluated. The EPU does not introduce any new components or modify existing components that would affect

instruments and/or sensing lines required for safe shutdown. The current analyses for instruments and sensing lines remain valid under EPU conditions.

2. Heating Ventilation and Air Conditioning Considerations

HVAC is important in providing the capability to safely shutdown the unit in the event of a fire. HVAC is important from the standpoint of providing sufficient ventilation for equipment cooling considerations. In addition, there are selected manual HVAC actions that are necessary to ensure ventilation system fire dampers close to provide the required fire barrier protection for redundant safe shutdown equipment. Finally, HVAC system support is necessary to remove smoke from buildings, rooms and/or enclosures for post-fire habitability and to aid in the performance of required operator manual actions.

Evaluations of HVAC requirements for post-fire safe shutdown were performed, defining the important HVAC functions and manual actions required for safe shutdown equipment cooling, fire damper closure, and post-fire smoke removal at current plant conditions. The EPU does not adversely impact the current evaluations of HVAC requirements for post-fire safe shutdown. The impact of plant modifications in support of the EPU on post-fire safe shutdown HVAC considerations is addressed in accordance with the plant change / modification process.

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

As discussed above, the fire protection system and fire rated assemblies are within the scope of License Renewal. Operation of the fire protection system and fire rated assemblies under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.5.1.4.4 Conclusion

FPL has reviewed the fire-related safe shutdown assessment and concludes that the assessment 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. FPL further concludes that the FPP will continue to meet its current licensing basis with respect to the requirements of 10 CFR 50.48, 10 CFR 50 Appendix R, and GDCs -3 and -5 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to fire protection.

2.5.2 Pressurizer Relief Tank

2.5.2.1 Regulatory Evaluation

The pressurizer relief tank (PRT), referred to as the quench tank (QT) at St. Lucie Unit 2, is a pressure vessel provided to condense and cool the discharge from the pressurizer safety and relief valves. The tank is designed with a capacity to absorb discharge fluid from the pressurizer relief valve during a specified step-load decrease. The QT system is not safety-related and is not designed to accept a continuous discharge from the pressurizer.

Florida Power and Light (FPL) conducted a review of the QT to ensure that operation of the tank is consistent with transient analyses of related systems at the proposed extended power uprate EPU level, and that failure or malfunction of the QT system will not adversely affect safety-related structures, systems, and components (SSCs).

FPL's review focused on any design changes related to the QT 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 valves (PORVs) 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 QT are based on:

- GDC-2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes, and
- 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 Standard Review Plan (SRP) Section 5.4.11 and other guidance provided in Matrix 5 of RS-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to Title 10 of the Code of Federal Regulations (10 CFR) Part 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976.

St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

- GDC-2 is described in UFSAR Section 3.1.2 Criterion 2– Design Bases for Protection against Natural Phenomena.

Structures, systems and components important to safety shall be designed to withstand the effects of natural phenomena such as earthquakes, tornadoes, hurricanes, floods, tsunami and seiches without loss of capability to perform their safety functions. The design bases for

these structures, systems and components shall reflect: (1) appropriate consideration of the most severe of natural phenomena that have been historically reported for the site and surrounding area, with sufficient margin for the limited accuracy, quantity, and period of time which the historical data have been accumulated, (2) appropriate combinations of the effects of normal and accident conditions with the effects of the natural phenomena and (3) the importance of the safety functions to be performed.

The structures, systems and components important to safety are designed to withstand the effects of natural phenomena without loss of capability to perform their safety functions. Natural phenomena factored into the design of plant structures, systems and components important to safety are determined from recorded data for the site vicinity with appropriate margin to account for uncertainties in historical data.

The most severe natural phenomena postulated to occur at the site in terms of induced stresses is the safe shutdown earthquake (SSE). Those structures, systems, and components vital for the mitigation and control of accident conditions are designed to withstand the effects of a loss-of-coolant accident (LOCA) coincident with the effects of the SSE. Structures, systems and components vital to the safe shutdown of the plant are designed to withstand the effects of any one of the most severe natural phenomena, including flooding, hurricanes, tornadoes and the SSE (refer to UFSAR Chapter 2).

Design criteria for wind and tornado, flood and earthquake are discussed in UFSAR Sections 3.3, 3.4 and 3.7, respectively.

- GDC-4 is described in UFSAR Section 3.1.4 Criterion 4 – Environmental and Missile Design Bases.

Structures, systems and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and approved by the Commission demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

SSCs important to safety are designed to accommodate the effects of and to be compatible with the pressure, temperature, humidity, and radiation conditions associated with normal operation, maintenance, testing, and postulated accidents including a LOCA, in the area in which they are located.

Non-Seismic Category I Piping is arranged or restrained so that failure of any non-seismic Category I piping will neither cause a nuclear accident nor prevent essential seismic Category I structures or equipment from mitigating the consequences of such an accident.

Seismic Category I piping is arranged or restrained such that in the event of rupture of a seismic Category I pipe which causes LOCA, resulting pipe movement will not result in loss of containment integrity or adequate engineered safety features systems operation.

The structures inside the containment vessel are designed to sustain dynamic loads which could result from failure of major equipment and piping, such as jet thrust, jet impingement and local pressure transients, where containment integrity is needed to cope with the conditions.

Refer to UFSAR Sections 3.5, 3.6, 3.7, and 3.11 for details.

The QT is designed to receive and condense the normal discharges from the pressurizer safety and power operated relief valves and to prevent the discharge from being released to containment.

The QT is capable of containing the 567 lbm steam calculated to be discharged by the pressurizer safety valves during the worst case anticipated operating occurrence (loss of load event) followed by 575 lbm steam calculated to be discharged by the power operated relief valves during control element assembly (CEA) withdrawal accident as the plant returns to power following the loss of load trip.

The QT is mounted on a structural steel frame which is designed to seismic Category I requirements. The pressure relief discharge system is designated Quality Group D and non-seismic per ANSI N18.2. Furthermore, the piping system from the pressurizer in the QT, although designated non-seismic, has been seismically analyzed to ensure that it withstands safe shutdown earthquake loadings without failure.

The QT design parameters are given in UFSAR Table 5.4-7. The QT, shown on UFSAR Figure 5.4-13, is an austenitic stainless steel vessel suitable for prolonged contact with borated water. The QT is located in the containment at elevation 62 ft which is lower than the pressurizer safety or power operated relief valves to ensure that any leakage or discharge from the valves drains to the QT. Nozzles are provided for the safety/relief valve discharge line, vent, drain, instrumentation, makeup water and a manway and rupture disc. The tank prevents the steam released from the pressurizer safety/relief valves from being released to the containment atmosphere. The steam is discharged under water by the sparger and condensed. A relief valve and a rupture disc venting to the containment atmosphere are provided for overpressure protection. The rupture disc is also provided with a stainless steel vacuum support. The QT is equipped with water level, pressure and temperature instrumentation.

The QT normal water volume of 127 cubic feet covers the sparger and is sufficient to condense the steam released from the pressurizer safety and power operated relief valves as a result of the design basis transient.

The QT is designed and fabricated to the requirements of the ASME Code, Section III, Code Class 3. Although the QT is designated non-seismic, seismic Category I supports have been provided. Furthermore, the piping system from the pressurizer to the QT, although designated non-seismic, has been seismically analyzed to ensure that it withstands safe shutdown earthquake loadings without failure. Besides these evaluations, the QT sparger is analyzed for both seismic forces and blowdown forces. These additional evaluations ensure that the QT would withstand these accident related conditions. The QT rupture disc minimum capacity is

greater than the combined maximum capacities of the pressurizer power operated relief and safety valves at the maximum allowed ASME Code QT pressure. Thus the build-up backpressure does not exceed the valve design backpressure for the pressurizer safety valves. Criteria for design against pipe whip are discussed in UFSAR Section 3.6. Compliance with Regulatory Guide 1.67, Installation of Overpressure Protection Devices, October, 1973 (R0) is discussed in UFSAR Section 3.9.3.

Failure of any of these components in no way compromises the integrity of the reactor coolant pressure boundary or safe shutdown of the plant.

In addition to the licensing basis described in the UFSAR, the QT was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3 of the SER identifies those systems that are in the scope of License Renewal. The QT is not within the scope of License Renewal.

2.5.2.2 Technical Evaluation

2.5.2.2.1 Introduction

The original QT sizing analysis (primarily hand calculations) used early design values for the Doppler coefficient, moderator temperature coefficient, and CEA withdrawal reactivity. The steam releases to the QT were determined for two safety analysis events assuming actuation of only the pressurizer and main steam safety valves and a reactor trip based on high pressurizer pressure. These event analyses assumed zero primary letdown and no use of the pressurizer sprays.

The historical analysis, which combines the steam releases for two separate events, is overly conservative. It is sufficient to verify that the capacity of the QT to condense the steam releases for the bounding loss of load or uncontrolled rod withdrawal event analyses is adequate when each event is considered separately. Treating each event separately is acceptable when it is considered that each event (the loss of load event and the uncontrolled rod withdrawal event) are terminated by a reactor trip. This evaluation method is in accordance with the SRP Section 5.4.11.

2.5.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The historical analyses performed to support the design specification for the QT considered the need to condense 610 pounds of steam for the loss of load event plus 830 pounds of steam for the uncontrolled rod withdrawal event. This total mass of 1440 pounds of steam could be successfully condensed without challenging the QT rupture disk.

Unless the steam flow of the historical analysis for the QT and associated piping, valves, and other components is challenged by EPU, the sizing of the piping, relief valve, and safety valve components will be unaffected by EPU.

2.5.2.2.3 Description of Analyses and Evaluations

A loss of load analysis was conducted, as well as, an evaluation of the limiting steam release for an uncontrolled rod withdrawal event. The uncontrolled rod withdrawal event, re-evaluated the analysis of record (AOR) using limiting EPU design values for the Doppler coefficient, moderator temperature coefficient, and CEA withdrawal reactivity. The events analyzed for EPU assumed only actuation of the pressurizer and main steam safety valves and a reactor trip based on high pressurizer pressure.

Discussion of the methodology used in the analysis of the loss of load and uncontrolled rod withdrawal events can be found in LR [Section 2.8.5](#), Accident and Transient Analysis.

Each of these steam releases was compared to the original design basis mass of 1440 pounds of steam to determine if the steam could be successfully condensed without challenging the QT rupture disk.

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

As discussed above, the QT is not within the scope of License Renewal. Operation of the QT under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.5.2.2.5 Results

The bounding steam release for the loss of load event analysis was determined to be 795 pounds of steam for EPU. The bounding steam release for the uncontrolled rod withdrawal event analysis was determined to be 450 pounds of steam for EPU. Each of these steam releases is less than the design basis mass of 1440 pounds of steam that could be successfully condensed without challenging the QT rupture disk or the historical design basis of the QT associated components.

The capacity of the QT to condense the steam releases for the bounding loss of load EPU event and the bounding uncontrolled rod withdrawal EPU event analyses is such that the steam releases can be successfully condensed without challenging the QT rupture disk. Therefore, there is no need to change the QT water level or temperature limits.

2.5.2.3 Conclusion

FPL has reviewed the pressurizer discharge to the PRT (QT) as a result of the proposed EPU and concludes that: (1) the steam releases can be successfully condensed without challenging

the QT rupture disk and (2) Safety-related SSCs will continue to be protected against failure of the PRT consistent with GDCs -2 and -4. FPL 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

2.5.3.1.1 Regulatory Evaluation

The Florida Power and Light (FPL) review for fission product control systems and structures covered the basis for developing the mathematical model for design basis loss of coolant accident (LOCA) dose computations, the values of key parameters, the applicability of important modeling assumptions, and the functional capability of ventilation systems used to control fission product releases. The FPL review primarily focused on any adverse effects that the EPU may have on the assumptions used in the analyses for the control of fission products. These analyses are presented in LR [Section 2.9.2](#). The NRC acceptance criteria for this review are based on GDC-41, insofar as it relates to the containment atmosphere cleanup system to be provided to reduce the concentration of fission products released to the environment following postulated accidents.

Specific review criteria are contained in Standard Review Plan (SRP) Section 6.5.3 and guidance provided in Matrix 5 of RS-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

- GDC-41 is described in UFSAR Section 3.1.41 Criterion 41–Containment Atmosphere Cleanup.

Systems to control fission products, hydrogen, oxygen, and other substances which may be released into the reactor containment shall be provided as necessary to reduce, consistent with the functioning of other associated systems, the concentration and quantity of fission products released to the environment following postulated accidents, and to control the concentration of hydrogen or oxygen and other substances in the containment atmosphere following postulated accidents to assure that containment integrity is maintained.

Each system shall have suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities to assure that for on-site electrical power system operation (assuming off-site power is not available) and for off-site electrical power system operation (assuming on-site power is not available) its safety function can be accomplished, assuming a single failure.

On September 29, 2008, the NRC approved FPL's license amendment request regarding full-scope implementation of the alternative source term (AST) for St. Lucie Unit 2 and issued Amendment No. 152 to the St. Lucie Unit 2 Operating License ([Reference 1](#)). UFSAR Section 15.6.5, Loss-of-Coolant-Accidents, was revised to incorporate the radiological consequence analysis associated with a LOCA utilizing the alternative source term methodology.

The revised LOCA dose consequence analysis is consistent with the guidance provided in Regulatory Guide (RG) 1.183, Appendix A, Assumptions for Evaluating the Radiological Consequences of a LWR Loss-of-Coolant Accident, as discussed in UFSAR Section 15.0.15, Radiological Consequences. FPL performed analyses for the full implementation of the AST, in accordance with the guidance in RG 1.183 and SRP Section 15.0.1. The AST analyses performed use assumptions and models defined in RG 1.183 to provide appropriate and prudent safety margins.

Although the hydrogen control and sampling systems provided to prevent the buildup of dangerous concentrations of hydrogen in the containment following a LOCA are discussed in UFSAR Chapter 6 in the context of GDC-41, they are not credited as cleanup systems designed to reduce concentration of fission products in the containment atmosphere. As such, an assessment of the EPU impact on their post-accident performance will not be presented in this section.

Input assumptions as well as values of key parameters used in the dose consequence analysis of a LOCA are provided in UFSAR Table 15.6.5-12. The shield building ventilation system (SBVS) is credited in the dose consequence analysis of a LOCA with 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 UFSAR Section 6.2.3. No exfiltration through the concrete wall of the shield building is expected to occur which is consistent with Regulatory Position 4.3 of RG 1.183. The SBVS is credited as meeting the requirements of RG 1.52, Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Post-Accident Engineered-Safety-Feature Atmosphere Cleanup Systems in Light-Water-Cooled Nuclear Power Plants, and Generic Letter 99-02, Laboratory Testing of Nuclear-Grade Activated Charcoal.

The iodine removal system (IRS) is credited in the dose consequence analysis of a LOCA as shown in UFSAR Table 15.6.5-12.

In addition to the licensing bases described in the UFSAR, the fission product control systems and structures were evaluated for St. Lucie Unit 2 License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Sections 2.3.2.2 - Containment Spray, 2.3.3.15 - Ventilation, and 2.4.1 - Containments of the SER identify that components of the Fission Product Control Systems and Structures are within the scope of License renewal. Programs used to manage the aging effects associated with the fission product control systems and structures are discussed in SER Sections 3.2.2, 3.3.15, and 3.5.1 and UFSAR Chapter 18.

2.5.3.1.2 Technical Evaluation

The IRS is designed to operate in conjunction with the containment spray system (CSS) to remove radioiodines from the containment atmosphere following a loss of coolant accident. It does this by injecting chemicals into the containment spray pump suction lines during

containment spray operations to control pH and for iodine absorption. The IRS is in essence a subsystem of the containment spray system. The CSS removes heat from the containment by spraying a borated water and hydrazine solution through the containment atmosphere. The spray system is automatically initiated by the containment spray actuation signal (CSAS) which requires a coincidence of the safety injection actuation signal (SIAS) and the high-high containment pressure signal. The containment spray system consists of two redundant 100 percent capacity subsystems each consisting of a spray pump, shutdown heat exchanger and spray header. The IRS is described in UFSAR Section 6.5.2.

The SBVS consists of two full capacity redundant fan and filter systems and is designed, consistent with the functioning of other engineered safety features systems, to reduce the concentration and quantity of fission products released to the environment following a LOCA by establishing and maintaining a sub-atmospheric pressure within the shield building annulus to ensure that post-accident activity leakage from the containment is routed through the charcoal filter system. Refer to UFSAR Section 6.2.3 for a discussion of the SBVS.

LR **Section 2.9.2** provides the evaluation of the radiological consequences associated with the LOCA and other accidents. The EPU offsite and control room dose analyses demonstrate the effectiveness of the containment structure, containment spray system and SBVS in mitigating the release of radioactivity to the environment following design basis accidents.

LR **Section 2.7.2** provides the evaluation of the SBVS to reduce the concentration and quantity of fission products released to the environment following a LOCA by establishing and maintaining a sub-atmospheric pressure within the shield building to ensure that post-accident activity leakage from the containment vessel is routed through the charcoal filter system.

LR **Section 2.6.1** provides the evaluation of the containment structure, including access openings and penetrations which are designed to accommodate, without exceeding the design leak rate, the transient peak pressure and temperature associated with a LOCA up to and including a double ended rupture of the largest reactor coolant pipe. The containment encloses the reactor system and is the final barrier to protect the public against the release of significant amounts of radioactive fission products in the event of an accident. The containment vessel, shield building, and the associated engineered safety features systems are designed to safely sustain all internal and external environmental conditions that may reasonably be expected to occur during the life of the plant, including both short and long term effects following a LOCA. LR **Section 2.6.1** also discusses the containment heat removal system described in UFSAR Section 6.2.2 which consists of the containment spray system and the containment cooling system. The containment spray system and the containment cooling system are each designed with the capacity to reduce containment pressure and temperature following a LOCA and maintain them at acceptably low levels.

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

As discussed above, the fission product control systems and structures are within the scope of License Renewal. Operation of the fission product control systems and structures under EPU conditions has been evaluated to determine if there any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.5.3.1.4 Results

LR [Section 2.9.2](#) discusses the basis for developing the LOCA dose model, key parameters and assumptions, the functional capability of engineered safety systems used to control fission product releases, and the results of EPU LOCA radiological consequences analysis. The calculation concludes that the control room and off-site doses due to the LOCA remain within the applicable regulatory criteria. Therefore the containment, containment spray system, shield building and SBVS remain effective in limiting the doses to control room occupants and individuals at the exclusion area boundary and low population zone.

Operation at EPU conditions does not impact the ability of the CSS including the IRS, and the SBVS to perform their functions with the required safety margins.

LR [Section 2.7.2](#) concludes that the SBVS continues to provide adequate fission product removal in post accident environments following implementation of the proposed EPU.

LR [Section 2.6.1](#) concludes that the CSS including the IRS continues to provide the required removal of containment heat and iodine in post accident environments following implementation of the proposed EPU.

EPU activities do not add any new components nor do they introduce any new functions to existing components of the fission product control systems that would change the license renewal system evaluation boundaries. Operating at EPU conditions does not add any new or previously unevaluated materials to the system. System and component internal and external environments remain within the parameters previously evaluated.

2.5.3.1.5 Conclusion

FPL has reviewed the effects of the proposed EPU on fission product control systems and structures. FPL concludes that it has adequately accounted for the increase in fission products and changes in expected environmental conditions that would result from the proposed EPU. FPL further concludes that the fission product control systems and structures will continue to provide adequate fission product removal in post accident environments following implementation of the proposed EPU. Based on this, FPL also concludes that the fission product control systems and structures will continue to meet its current licensing basis with respect to the requirements of GDC-41. Therefore, FPL finds the proposed EPU acceptable with respect to the fission product control systems and structures.

2.5.3.1.6 References

1. Letter from Brenda Mozafari (NRC) to J.A. Stall (FPL) "St. Lucie Plant No. 2-Issuance of Amendment Regarding Alternative Source Term, (TAC NO. MD6202)" dated September 29, 2008.

2.5.3.2 Main Condenser Evacuation System

2.5.3.2.1 Regulatory Evaluation

The main condenser evacuation system (MCES) consists of two subsystems:

- the “hogging” or startup system which initially establishes main condenser vacuum, and
- the system which maintains condenser vacuum once it has been established.

The Florida Power and Light (FPL) 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:

- GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents, and
- 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.

St. Lucie Unit 2 Current Licensing Basis

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

- GDC-60 is described in UFSAR Section 3.1.60, Criterion 60 – Control of Releases of Radioactive Material to the Environment.

The nuclear power unit design shall include means to control suitably the release of radioactive materials in gaseous and liquid effluents and to handle radioactive solid wastes produced during normal reactor operation, including anticipated operational occurrences. Sufficient holdup capacity shall be provided for retention of gaseous and liquid effluents containing radioactive materials, particularly where unfavorable site environmental conditions can be expected to impose unusual operational limitations upon the release of such effluents to the environment.

- GDC-64 is described in UFSAR Section 3.1.64 Criterion 64 - Monitoring Radioactivity Releases.

Means shall be provided for monitoring the reactor containment atmosphere, spaces containing components for recirculation of loss of coolant accident fluids, effluent discharge paths, and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences, and from postulated accidents.

Radioactive waste management and monitoring is discussed in UFSAR Chapter 11. Area and airborne monitoring is discussed in UFSAR Section 12.3.4.

As described in UFSAR Section 10.4.2, the MCES or air evacuation system (AES) consists of two hogging ejectors, a steam jet air ejector with associated inter -and aftercondensers, manifolds, valves and piping. The system is designed to establish and maintain condenser vacuum during start-up and normal operation.

During startup, the two hogging ejectors evacuate a combined turbine and main condenser (empty hot well) steam space of 142,000 cubic feet within a period of 60 minutes and thereafter maintain a condenser pressure of five inches Hg absolute. The hogging ejectors discharge to atmosphere and are not monitored for radioactivity.

The steam jet air ejector is designed to achieve a condenser vacuum of about 3.6 inches Hg absolute during normal operation. Noncondensable gases from the steam jet air ejector are monitored for radioactivity prior to being discharged. The presence of radioactivity would indicate a reactor coolant-to-secondary system leak in the steam generators. Refer to UFSAR Section 11.5.2.2.7 for a description of the condenser air ejector monitor.

In addition to the licensing basis described in the UFSAR, the MCES was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3 of the SER identifies those systems that are within the scope of License Renewal. The MCES is not within the scope of License Renewal.

2.5.3.2.2 Technical Evaluation

2.5.3.2.2.1 Introduction

The MCES is discussed in the UFSAR Section 10.4.2 and is designed to remove non-condensable gases and inleakage air from the condenser during plant startup, cooldown, and normal operation.

The “hogging” or startup function of the MCES is accomplished by a priming ejector and two hogging ejectors, which initially establish main condenser vacuum. The priming ejector removes air in the condenser water boxes to draw a vacuum for the circulating water, and the two hogging ejectors evacuate the steam space of the main condenser.

The MCES function of maintaining condenser vacuum after startup is accomplished by a two-stage, twin element steam jet air ejectors and four auxiliary priming ejectors (two per condenser). The steam jet air ejectors, along with associated inter- and after-condensers, removes air in-leakage and non-condensable gases from the condenser steam space

The MCES has sufficient capacity to facilitate removal of non-condensable gases and air-inleakage to the condenser during plant startup and maintain condenser vacuum during normal operation.

2.5.3.2.2.2 Description of Analyses and Evaluations

The hogging ejectors and steam jet air ejectors are capable of removing non-condensable gases and air in-leakage from the condenser shell (steam space) to maintain vacuum.

During start-up, the two hogging ejectors evacuate a combined turbine and main condenser (empty hot well) steam space of 142,000 cubic feet within a period of 60 minutes. As start-up progresses, condenser evacuation is maintained by the two-stage, twin element, steam jet air ejector. The two stage, twin-element steam jet air ejectors have a rated capacity of 50 cfm (25 cfm each element). The non-condensable gases removed by the steam jet air ejector are screened for radioactivity by a radiation monitor.

The main function of this condenser air ejector radiation monitor is to detect any radioactivity in the non-condensable gases, which would indicate a reactor coolant-to-secondary system leak in the steam generators. The design of the MCES does not require modification for the EPU and, therefore, St. Lucie Unit 2 will continue to effectively control radioactive material and monitor radioactive material releases. Refer to LR [Section 2.10.1](#), Occupational and Public Radiation Doses, for the evaluation of plant radioactive monitoring and control of releases of radioactive materials to the environment in compliance with GDCs -60 and -64.

The condenser will not be adversely affected by air in-leakage as a result of the EPU since air in-leakage is entirely related to the physical design of the condenser and its state of integrity. The amount of non-condensable gases in the condenser shell will not significantly increase at EPU conditions such that the design functions of the condenser evacuation system are impacted. Although there is expected to be a slight increase of non-condensables resulting from increased backpressure, decomposition of water treatment chemicals and corrosion under EPU, the quantity of these non-condensables compared with air inleakage is small. Therefore, the steam jet air ejectors have been evaluated by comparing the installed capacity against the Heat Exchanger Institute (HEI) recommended values. The HEI recommended minimum venting capacity for the steam jet air ejectors is 40.0 SCFM at 1 in. HgA and 71.5°F. Refer to LR [Section 2.5.5.2](#), Main Condenser, for additional discussion related to the condenser.

The priming ejectors and auxiliary priming ejectors are capable of removing non-condensable gases and air released from the circulating water from the condenser water boxes to draw a vacuum, maintain vacuum, and prevent air pocket formation in the condenser water boxes. The discharge of these air ejectors is not monitored for radioactivity. There are two auxiliary priming ejectors per condenser, each of which is capable of evacuating fluid at a rate of 200 lb/hr. The increased heat rejection to the condenser at EPU conditions will increase the air release rate from the circulating water, increasing the load on the auxiliary priming ejectors. Therefore, the capacity of the auxiliary priming ejectors was evaluated against the air release rates under EPU operating conditions.

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

As discussed above, the MCES is not within the scope of License Renewal. Operation of the MCES under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.5.3.2.2.4 Results

The plant start-up air removal, or “hogging” function is unaffected by uprate because the physical volume of the steam space is not changing.

The current total design steam flow rate to each condenser shell is 3,312,285 lb/hr and the EPU steam flow rate to each condenser shell is 3,710,632 lb/hr. The HEI Standards for Steam Surface Condensers, 10th Edition (2006) gives a recommended minimum venting capacity of 40.0 SCFM at 1 in. HgA and 71.5°F for an effective steam flow range of 3,000,001 to 4,000,000 lb/hr for two condenser shells. Current steam jet air ejector capacity of 50 CFM meets these standards for both pre-EPU and EPU conditions.

The priming ejectors are unaffected by EPU because the required volume of air to be removed from the water boxes upon startup is not changing.

The total air release rate from circulating water will increase from a current rate of approximately 474 lb/hr (118 lb/hr per ejector) to a rate of approximately 516 lb/hr (129 lb/hr per ejector), maximum, under EPU operation. The higher EPU air release rate remains less than the design capacity of the auxiliary priming ejectors (200 lb/hr per ejector). Therefore, the existing auxiliary priming ejectors are adequate for EPU, without modifications.

The design of the MCES does not require modification in support of the implementation of the EPU. Therefore, the EPU does not impact the ability to control radioactive material or the monitoring of radioactive material releases. The impact of EPU on radiological effluent releases and compliance with 10 CFR 50, Appendix I, is discussed in LR [Section 2.10.1](#), Occupational and Public Radiation Doses.

2.5.3.2.3 Conclusion

FPL has reviewed the effect of the proposed changes to the MCES and concludes that it has adequately evaluated these changes. FPL further 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. FPL also concludes that the MCES will continue meet its current licensing basis with respect to the requirements of GDCs -60 and -64. Therefore, the proposed EPU is acceptable with respect to the MCES.

2.5.3.3 Turbine Gland Sealing System

2.5.3.3.1 Regulatory Evaluation

The turbine gland sealing system is provided to control the release of radioactive material from steam in the turbine to the environment. Florida Power and Light (FPL) 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:

- GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents,
- 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 Standard Review Plan (SRP) Section 10.4.3.

St. Lucie Unit 2 Current Licensing Basis

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

The specific GDC for the turbine gland sealing system are as follows:

- GDC-60 is described in UFSAR Section 3.1.60, Criterion 60 – Control of Releases of Radioactive Materials to the Environment.

The nuclear power unit design shall include means to control suitably the release of radioactive materials in gaseous and liquid effluents and to handle radioactive solid wastes produced during normal reactor operation, including anticipated operational occurrences. Sufficient holdup capacity shall be provided for retention of gaseous and liquid effluents containing radioactive materials, particularly where unfavorable site environmental conditions can be expected to impose unusual operational limitations upon the release of such effluents to the environment.

- GDC-64 is described in UFSAR Section 3.1.64, Criterion 64 – Monitoring Radioactive Releases.

Means shall be provided for monitoring the reactor containment atmosphere, spaces containing components for recirculation of loss of coolant accident fluids, effluent discharge paths, and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences, and from postulated accidents.

Radioactive waste management and monitoring is discussed in UFSAR Chapter 11. Area and airborne monitoring is discussed in UFSAR Section 12.3.4.

The turbine gland sealing system is described in UFSAR Section 10.4.3:

The turbine gland sealing system is designed to prevent atmospheric air leakage into the turbine casings and main condenser, and steam leakage out of the casings of the turbine generator.

The turbine gland sealing system controls the steam pressure to the turbine glands in order to maintain adequate sealing under all conditions of turbine operation. The system consists of individually controlled diaphragm-operated valves, relief valves, and a gland steam condenser.

Gland steam is supplied from the main steam system. At high plant loads, the spillage from the high pressure turbine element glands provides more steam than the low pressure turbine element glands require. The excess steam is relieved to the turbine condenser through a pressure regulating valve. The leak-off steam and air mixture then flows to the gland steam condenser which is maintained at a pressure slightly below atmospheric so as to prevent escape of steam from the ends of glands. The gland steam condenser returns seal leakage to the main condenser as condensate.

Each of the low pressure turbine glands has a gland steam supply regulator. Both high pressure turbine glands are supplied from one regulator. A spillover valve in the high pressure turbine gland seal provides pressure regulation for the dumping of excess turbine gland leakage to the main condenser.

Condensate from the hotwell is pumped by two of the three condensate pumps through the steam jet air ejector inter- and after- condensers, and the gland steam condenser.

Noncondensable gases from the gland steam condenser may be monitored for radioactivity at the same discharge point as the main condenser evacuation system.

Radiation monitoring is provided on the noncondensable gas exhaust header as discussed in UFSAR Section 11.4.2.5.

In addition to the licensing basis described in the UFSAR, the turbine gland sealing steam system was evaluated for License Renewal. As documented in NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003; the turbine gland sealing steam system was determined to be outside the scope of License Renewal.

2.5.3.3.2 Technical Evaluation

2.5.3.3.2.1 Introduction

The turbine gland sealing system prevents air leakage into the turbine casing and prevents steam leakage from the turbine casing into the turbine building. In the postulated event of a steam generator tube failure, the turbine gland sealing system prevents the spread of contaminants into the turbine building. The turbine rotor is designed with labyrinth type glands/seals which provide a high resistance to steam or air flow along the shaft. Gland sealing steam is provided to the gland seal chamber to maintain a slight positive pressure under all operating conditions.

Gland steam is supplied from the main steam header. Each of the LP turbine glands has a gland steam supply regulator. Both HP turbine glands are supplied from one regulator. A spillover valve in the HP turbine gland seal will provide pressure regulation for the dumping of excess turbine gland leakage to the main condenser during high plant loads.

2.5.3.3.2.2 Description of Analyses and Evaluations

This LR section addresses the affects of the EPU on the turbine gland sealing system. The ability of the gland sealing system to continue to control the release of radioactive effluents from the turbine to the environment has been evaluated. Both the HP turbine and the LP turbine will be upgraded for the EPU. All components of this system are evaluated on the upgraded HP and LP turbines.

Other evaluations of the turbine gland sealing system, piping and components are addressed in the following LR sections:

- Erosion/corrosion issues – LR [Section 2.1.8](#), Flow Accelerated Corrosion,
- Cooling water to the gland steam condenser – LR [Section 2.5.5.4](#), Condensate and Feedwater Systems, and
- External steam supply for turbine gland sealing – LR [Section 2.5.5.1](#), Main Steam.

2.5.3.3.2.3 Impact on Renewed Plant Operating License Evaluations and Licensing Renewal Programs

As discussed above, the turbine gland sealing steam system was determined to be outside the scope of License Renewal; therefore, with respect to the turbine gland sealing steam system, the EPU does not impact any License Renewal evaluations.

2.5.3.3.2.4 Results

There is no increase in the required external steam supply flow from the main steam system since it is primarily used to supply sealing steam for turbine/plant startup and at reduced power operation. As plant power increases, the amount of main steam flow required for gland sealing decreases. The main steam system is capable of supplying all the necessary steam required for operation of the turbine gland steam seal system after EPU without any modifications as described in LR [Section 2.5.5.1](#), Main Steam.

The spillover system from the HP turbine glands is affected by the geometry of the gland seals rotor diameter in the gland area, and also by the HP exhaust pressure. The HP turbine gland seal configuration and rotor diameters in the gland area will not be changed by the HP turbine upgrade as a result of EPU. The HP turbine gland leakage flow to the spillover system will be increased due to the higher HP exhaust pressures associated with the EPU. Review of the gland system spillover capacity indicates that the existing spillover regulating station and associated piping is marginally sized based on the calculated spillover flow at design seal clearances. The increased flow can lead to flow-induced restriction and higher than normal pressures at the supply zone of the HP turbine glands. Additional capacity will be added to the spillover system as

part of the HP turbine upgrade modification to ensure that there is sufficient margin to keep the supply zone pressure at desired values.

The steam supply to the LP turbine glands are individually controlled to a constant pressure under all operating conditions, thus, the steam supply to the LP turbines is only affected by the geometry of the gland seals and rotor diameter in the gland area. The leakoff flows are not changed by the HP turbine upgrade. The LP rotor diameters and seal configuration in the gland area will not be changed as part of the LP turbine upgrade. The LP turbine gland sealing system is not affected by the proposed EPU.

The gland sealing steam flow and condensate cooling flow to the gland steam condenser both increase at EPU plant operating conditions due to turbine steam conditions. The increase of required gland steam condenser cooling water flow is adequately supplied by the condensate system. Performance analysis of the gland steam condenser with the new load conditions indicates that the gland steam condensers and gland steam condenser air exhausters do not require any modification to operate within design basis at EPU steam conditions.

Non-condensable gases from the gland steam condenser are normally routed to the plant vent stack and monitored for radioactivity by the plant vent stack radiation monitor. Existing stack effluent radiation monitoring equipment that measures effluent levels based on allowable limits will not be impacted by the EPU as discussed in LR [Section 2.10.1](#), Occupational and Public Radiation Doses.

The evaluation of the turbine gland sealing system at EPU conditions as modified demonstrates that St. Lucie Unit 2 will continue to meet the current licensing basis with respect to the requirements of GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents. This design capability remains unchanged by the EPU. The handling, control, and release of radioactive materials are in compliance with 10 CFR 50, Appendix I, as described in the Offsite Dose Calculation Manual.

The evaluation of the turbine gland sealing system at EPU conditions demonstrates that St. Lucie Unit 2 will continue to meet the current licensing basis with respect to the requirements of GDC-64, insofar as it requires that a 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. This design capability remains unchanged by the EPU.

2.5.3.3.3 Conclusion

FPL has reviewed the evaluations related to the effects of the proposed EPU on the turbine gland sealing system. FPL concludes that the evaluations have adequately accounted for the proposed EPU effects on the turbine gland sealing system. The turbine gland sealing system will continue to meet its current licensing basis with respect to maintaining its ability to control releases of radioactive materials to the environment for them to be monitored, consistent with GDCs -60 and -64. Therefore, FPL 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

2.5.4.1.1 Regulatory Evaluation

The spent fuel pool (SFP) provides wet storage of both fresh and irradiated fuel assemblies. The safety function of the spent fuel pool cooling and cleanup system, named the fuel pool system at St. Lucie Unit 2, is to cool the spent fuel assemblies and keep the fuel covered with water during all storage conditions. The Florida Power and Light (FPL) review focused on the effects of extended power uprate (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 the Part 50 Appendix A, General Design Criteria (GDC), specifically:

- GDC-5, insofar as it requires that structures, systems and components [SSCs] important to safety not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions,
- 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
- GDC-61, insofar as it requires that fuel storage systems be designed with residual heat removal (RHR) capability reflecting the importance to safety of decay heat removal, and including measures to prevent a significant loss of fuel pool coolant inventory under accident conditions.

Specific review criteria are contained in Standard Review Plan (SRP) Section 9.1.3, as supplemented or superseded by the guidance provided in Attachment 3 to Matrix 5 of Section 2.1 of Review Standard (RS)-001, Revision 0.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to Title 10 of the Code of Federal Regulations (10 CFR) Part 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

The specific GDCs for the spent fuel pool cooling and cleanup system are as follows:

- GDC-5 is described in UFSAR Section 3.1.5, Criterion 5 – Sharing of Structures, Systems or Components (SSCs).

Structures, systems and components important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units.

The St. Lucie Unit 2 fuel pool system does not share safety-related SSCs with St. Lucie Unit 1.

- GDC-44 is described in UFSAR Section 3.1.44, Criterion 44 – Cooling Water.

A system to transfer heat from structures, systems and components important to safety, to an ultimate heat sink shall be provided. The system safety function shall be to transfer the combined heat load of these structures, systems, and components under normal operating and accident conditions.

Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electrical power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

With respect to removing decay heat from wet spent fuel storage, the cooling water systems that function to remove the combined-heat load from SSCs important to safety under normal operating and accident conditions, are the fuel pool cooling system, component cooling water (CCW) system and the intake cooling water (ICW) system.

The cooling portion of the fuel pool system is designed to remove the decay heat produced in the fuel from a full core placed in the spent fuel pool 120 hours after reactor shutdown, in addition to the decay heat load from twenty one batches previously discharged fuel following 18 month fuel cycles. With two fuel pool pumps operating, and with a maximum CCW temperature of 100°F the maximum spent fuel pool water temperature does not exceed 150°F. With one fuel pool pump operating and one fuel pool heat exchanger in service and with the maximum CCW temperature of 100°F, the maximum spent fuel pool water temperature does not exceed 150°F, when 1883 spent fuel assemblies discharged following > 18 month cycles are in the fuel pool, and the most recent batch of 105 discharged assemblies has cooled for 120 hours. This assumed quantity of stored irradiated fuel exceeds the 1585 assembly licensed storage capacity.

For refueling evolutions that propose to utilize a full core offload, outage-specific calculations are performed to demonstrate that the spent fuel pool bulk water temperature will not exceed the design-basis temperature of 150°F with one fuel pool cooling system pump and one heat exchanger in operation.

The piping, valves, pumps and heat exchangers of the ICW and CCW systems are designed and arranged so that the safety function can be performed assuming a single failure.

Electrical power for the operation of each system may be supplied from offsite or onsite emergency power sources, with distribution arranged such that a single failure will not prevent the system from performing its safety functions.

- GDC-61 is described in UFSAR Section 3.1.61, Criterion 61 – Fuel Storage and Handling and Radioactivity Control.

The fuel storage and handling, radioactive waste, and other systems which may contain radioactivity shall be designed to assure adequate safety under normal and postulated accident conditions. These systems shall be designed (1) with a capability to permit inspection and testing of components important to safety, (2) with suitable shielding for

radiation protection, (3) with appropriate containment, confinement, and filtering systems, (4) with a residual heat removal capability having reliability and testability that reflects the importance to safety or decay heat and other residual heat removal, and (5) to prevent significant reduction in fuel storage coolant inventory under accident conditions.

With respect to inspection and testing, UFSAR Section 3.1.61 states that most of the components and systems in this category are in frequent use and no special testing is required. Those systems and components important to safety which are not normally operating are tested periodically, e.g., temperature alarms in the fuel pool system (UFSAR Section 9.1.3) and radiation alarms in the fuel pool area, and the fuel handling equipment (prior to each refueling).

With respect to preventing significant loss of fuel storage coolant inventory following a single failure or accident condition, UFSAR Section 9.1.3.3 states that the fuel pool system is designed to remove decay heat from a partial core offload of 105 assemblies at 120 hours after reactor shutdown, placed into an otherwise filled spent fuel pool. A minimum decay time of 18 months, based on a nominal cycle length, is assumed for the previously-offloaded fuel. When quantifying the maximum bulk water temperature, analyses also assumed a single active and single passive component failure had occurred; loss of one fuel pool cooling pump (the active component) and a heat exchanger (a passive component) produces limiting results. Considering these conditions, bulk water temperature remains less than 150°F.

A bounding case for the full core offload scenario, coincident with an assumed single failure, considered all 217 assemblies from the core to be placed in the fuel pool racks, filling all available storage cells, beginning 120 hours after reactor shutdown. Minimum decay time of the previously offloaded fuel is taken as 18 months. Fuel now being offloaded from the core is assumed to consist of 73 assemblies irradiated at full power conditions for 4.5 years, 72 assemblies having 3 years of full power irradiation, and 72 assemblies with 1.5 years of full power irradiation. At 165.89°F, bulk temperature for these conditions exceeds the fuel pool's 150°F design basis limit; however, even the higher temperature resulting from this hypothetical limiting condition is substantially below saturation conditions, thus precluding any significant loss of the fuel pool coolant inventory.

Per UFSAR Section 9.1.3.3.1, there are several sources of fresh water on the site that are available to the fuel handling building; namely, refueling water tank, condensate storage tank, city water storage tanks and the primary water tank. The concurrent loss of these sources and the fuel pool cooling system is unlikely. Due to the fuel pool's relatively low coolant inventory boil-off rate, there is sufficient time to establish makeup. A seismic Category I backup salt water supply is available from the ICW intertie. A standpipe on the fuel handling building is provided from grade to the operating deck elevation and hose connections are provided at both ends of the standpipe. Thus, via fire hose, the fuel pool makeup can be readily supplied by the ICW pumps. The ICW system via the hose connections can provide the necessary makeup.

Emergency cooling by sea water will not result in unacceptable corrosion of the fuel cladding or structural components. Integrity of the fuel rod cladding and containment of fuel material and fission products is therefore assured. With regard to stainless steel structural components, it is unlikely that any localized corrosion cracking can result in loss of structural integrity of these components.

As shown in UFSAR Table 9.1-8a, following a full core offload evolution initiated 120 hours after shutdown, the spent fuel pool bulk temperature reaches a maximum of approximately 143°F with two fuel pool cooling pumps in operation. During a full core offload with only one fuel pool cooling pump in operation, spent fuel pool bulk temperature reaches a maximum of nearly 166°F.

In the event of a complete loss of fuel pool cooling, there is sufficient time (greater than 3 hours during a full core offload with only one fuel pool cooling pump in operation) to provide an alternate means of cooling before boiling occurs in the spent fuel pool.

In addition to the licensing basis described in the UFSAR, the fuel pool system was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.3.7 of the SER identifies that components of the fuel pool system are within the scope of License Renewal. Programs used to manage the aging effects associated with the fuel pool system are discussed in SER Section 3.3.7 and Chapter 18 of the UFSAR.

2.5.4.1.2 Technical Evaluations

2.5.4.1.2.1 Background

The fuel pool system is designed to assure adequate cooling of stored fuel during both routine operation and following normal planned offloads. Most aspects of this system will be unchanged by operation at EPU conditions. As is demonstrated below, the fuel pool system will continue to meet the same design basis performance criteria during operation at EPU conditions.

The periodic refueling evolutions involve both partial and full core fuel offloads, depending on plant and system requirements. Operation while at EPU conditions will continue to utilize each method of refueling.

Partial offloads usually transfer only permanently discharged assemblies to the fuel pool racks. Analysis of these evolutions has been performed, and is documented in Section 9.1.3 of the UFSAR. Inputs typically consider a conservatively large number of fuel assemblies to have been placed in the fuel pool, at a bounding time after reactor shutdown, and with each assembly having characteristics that yield high decay heat generation rates. In addition, analyses of partial core offloads consider only one fuel pool system pump and one fuel pool heat exchanger to be in service. The fuel pool bulk temperatures calculated to result from this bounding evolution have been quantified and are demonstrated to remain within design limits.

The time to reach bulk boiling in the fuel pool racks has been quantified, considering the most adverse timing for a possible loss of all forced convection. Results show that for the limiting partial core offload, sufficient time is available to implement remedial measures that preclude damage to fuel.

Refueling evolutions that involve the offload of all fuel from the core have also been examined. Analyses of offload conditions where both fuel pool cooling pumps and both fuel pool heat

exchangers are in operation, as well as situations where only a single train of fuel pool cooling is in service have been considered. These scenarios are discussed, along with their respective results, in UFSAR Section 9.1.3.3. From time-to-time, FPL has performed cycle-specific analyses of the full core offload activity, assuming only one fuel pool cooling system pump is available, prior to undertaking this evolution. These condition-specific analyses have been used to validate operational guidance and to demonstrate that bulk water temperatures remain <150°F throughout the evolution.

An assessment of local temperature conditions in the vicinity of a hypothetical fuel rod having the upper bound surface heat flux has been performed. Analyses show adequate heat transfer is maintained, and departure from nucleate boiling (DNB) does not occur. As is done for partial core offloads, the limiting time-to-boil is established. Results here also demonstrate that sufficient time is available to initiate inventory makeup from backup sources so as to preclude damaging the stored fuel.

During EPU operations, the fuel pool system will continue to consist of a seismic Category I closed loop system, having two half-capacity cooling pumps and two full-capacity heat exchangers. Geometry of the fuel pool, and of the fuel pool system suction and discharge piping, will not change; fuel pool water providing the cooling pump's source of suction will continue to be drawn from near the pool's surface. After passing through the fuel pool heat exchanger, and rejecting heat to the CCW system, discharge flow will still be returned to the fuel pool near the bottom of the racks by means of a distribution header, positioned along the opposite wall from where suction is drawn. No features are being added that would increase the probability of inadvertently draining the fuel pool.

While operating at EPU conditions, the fuel pool system will continue to be manually controlled with the system performance monitored locally. Annunciation of certain system-related off-normal conditions will continue in the control room. A low fuel pool discharge pressure condition, an open pump breaker, pool high temperature, the overload of fuel pool cooling and pool purification pump motors, or an abnormal pool water level condition will be annunciated in the control room. Control room annunciation of off-normal conditions involving CCW flow will also continue.

The proposed increase in core thermal power yields an increase in maximum decay heat loads for the various offload analysis cases, and a corresponding increase in the cooling system heat load. As summarized here, FPL has performed thermal hydraulic analyses of limiting configurations to evaluate the effects of an increased decay heat generation rate on: fuel pool temperature, the time-to-boil following a loss of forced convection, and on localized heat transfer effects for a limiting fuel rod.

2.5.4.1.2.2 Description of Analyses and Evaluations

To examine the impact of post-EPU operations on the unit's design basis, bulk temperature and time-to-boil analyses were performed. The scenarios analyzed are similar, but not identical, to those in the UFSAR. Differences include: (a) offload time is adjusted to accommodate the higher post-EPU decay heat load, (b) the analysis solved for the maximum offload rate that would maintain bulk pool temperature less than 150°F and (c) input assumptions used are typically more conservative than used in pre-EPU analyses. Additionally, the presence of a neutron-absorbing (i.e., MetamicTM) insert, added to every cell in the SFP racks, is considered.

Because of analysis differences and because each core offload evolution is procedurally controlled to limit decay heat in the spent fuel pool, there is no value in a side-by-side comparison of existing and EPU conditions.

Bulk Temperature Analysis

Analysis of fuel pool bulk temperature considered the following offload scenarios:

- **Scenario 1 - Normal Partial Core Offload**

A partial core offload of 105 limiting assemblies initiated at 140 hours after reactor shutdown, during which the maximum temperature of CCW flow supplied to the spent fuel pool heat exchanger is conservatively assumed to be 100°F. All remaining cells of the fuel pool racks were assumed to be filled with conservatively characterized, previously discharged fuel. One fuel pool system cooling pump and one fuel pool heat exchanger are assumed to be in service. Various offload rates were analyzed to determine those which would maintain fuel pool bulk temperature 150°F.

- **Scenario 2 - Normal Full Core Fuel Offload**

A full core fuel offload of 217 assemblies having bounding characteristics is discharged into a fuel pool where storage racks are otherwise filled with highly-burned, previously discharged fuel. Two trains of fuel pool cooling (i.e., 2 fuel pool cooling pumps and 2 fuel pool heat exchangers) are assumed to be in operation. The offload is initiated at 140 hours after reactor shutdown. The CCW temperature to the fuel pool heat exchangers is assumed to be either 95°F or 100°F. Various offload rates were analyzed to determine those which would maintain fuel pool bulk temperature 150°F.

- **Scenario 3 - Full Core Offload, Considering the Failure of a Fuel Pool Cooling Train**

A full core fuel offload into an otherwise filled fuel pool, having conditions and assumptions equivalent to those in Scenario 2, is analyzed to determine the impact of losing one train of fuel pool cooling on the fuel pool temperature rise. The loss of one train of fuel pool cooling is taken at the time of maximum heat load, which is at the end of offload. The calculated temperature increase will be used to set the limit on the maximum pool temperature during offload evolutions, such that a single failure (loss of one fuel pool cooling train) will not result in fuel pool bulk temperature exceeding 150°F.

Bulk Temperature Results

- **Scenario 1 - Normal Partial Core Offload**

The maximum fuel pool bulk temperature calculated for this condition remains <150°F, considering de-fueling rates of up to 7 assemblies per hour, which is in excess of that physically achievable in the plant, when offload is initiated at 140 hours after shutdown.

- **Scenario 2 - Normal Full Core Fuel Offload**

The maximum fuel pool bulk temperature calculated for this condition remains <150°F, considering de-fueling rates of up to 7 assemblies per hour, which is in excess of that physically achievable in the plant, when offload is initiated at 140 hours after shutdown.

- Scenario 3 - Full Core Offload, Considering the Failure of a Fuel Pool Cooling Train

The maximum SFP bulk temperature rise (also called the thermal overshoot) that could result from a worst-case spent fuel pool cooling train failure has been determined to be 27°F for a full core fuel offload initiated 140 hours after reactor shutdown. The procedural upper limit for the spent fuel pool temperature during a full core offload will be set so as to ensure the 150°F limit is not exceeded in the event of a failure of one fuel pool cooling train, after accounting for the maximum thermal overshoot.

Time-to-Boil Analysis

Although a total loss of forced convection is unlikely, if this event were to occur, the bulk water temperature would begin to rise. A loss of forced convection of sufficient duration would lead to bulk boiling in the fuel pool and a loss of the water inventory. For each scenario described above, the time-to-boil following an assumed loss of forced convection has been determined.

For these offload scenarios, assumptions are applied to ensure the calculated time-to-boil is minimized. One assumption constrains the time forced convection is lost to be coincident with the maximum calculated fuel pool bulk temperature. Another assumes minimum water volume, with the initial water level in the fuel pool being no higher than the low level alarm setpoint. These assumptions, and others, lessen thermal capacity of the fuel pool, thereby promoting pool heatup.

Time-to-Boil Results

The limiting result for each scenario is presented in the [Table 2.5.4.1-1](#).

Results demonstrate that sufficient time exists to provide an alternate means of cooling prior to the onset of boiling in the racks. Following the onset of boiling, makeup requirements remain well below the currently available 150 gpm makeup capability.

Local Temperature Analysis

An analysis was performed to determine if decay heat generated by the limiting stored fuel assembly is sufficient to cause localized boiling in the racks, considering fuel present in both the spent fuel pool and the cask pit rack. If the peak cladding temperature of this limiting bundle is less than the saturation temperature of water at local conditions, or if the fuel rod cladding surface heat flux is less than the heat flux required to produce a DNB condition, then sufficient heat transfer is present to ensure no cladding failure due to burnout.

The calculated hydraulic resistance bounds all of the different rack types in the SFP and the cask pit, and is also maximized by using conservative fuel assembly hydraulic resistance parameters. An additional 5% reduction in the calculated permeability, and a 5% increase in the calculated inertial resistance are imposed in the analysis for added conservatism. Bounding fuel assembly decay heat is used in calculating the bounding peak fuel rod cladding temperature for the hottest fuel assembly, which is compared to the local saturation temperature.

The local temperature analyses calculate a bounding peak local water temperature in the storage rack cell containing the hottest fuel assembly, after applying hydraulic resistance values suitable to bound conditions present in the fuel pool and the cask pit rack. The local temperature analysis then calculates a bounding peak fuel cladding temperature for the hottest spent fuel assembly.

All rack storage locations are assumed to contain irradiated fuel, including bundles discharged from a full core offload. As a prerequisite to the local temperature analysis, the maximum temperature of cooling water entering the fuel pool is determined.

The cask area is separated from the main pool by a full-height concrete wall having an open, submerged keyway (or slot), such that the cask pit is hydraulically coupled with the spent fuel pool. Because of this hydraulic coupling, the local temperature analysis assumes a free exchange of water between the two regions.

The decay heat generated by spent fuel assemblies stored in the fuel racks is treated as a volumetric heat source in a porous media region. The decay heat generated by stored fuel is transferred to the water, inducing a buoyancy-driven upward flow through each fuel rack cell. Once the spatial temperature distribution is obtained, the difference between cladding surface temperature and the local water temperature (sometimes referred to as cladding superheat) is calculated considering laminar flow heat transfer principles and Darcy's Law.

The bounding scenario referred to above combines several adverse effects; including the upper bound fuel pool bulk water temperature, a bounding assembly/rack cell hydraulic resistance, an adverse arrangement of fuel having the highest decay heat loads, an upper bound heat flux in the limiting assembly, and superposition of the rack cell minimum saturation pressure and maximum surface heat flux.

Local Temperature Results

Local temperature results, including: 1) peak local water temperature, 2) the peak cladding superheat, and 3) the peak fuel cladding temperature are presented in LR [Table 2.5.4.1-2](#). Saturation temperature of water increases with increasing pressure and consequently, with increasing depth in the fuel pool.

The critical location at which the propensity for local boiling in the racks is assessed has been conservatively defined as at the top of the active fuel when seated in the racks: a depth of approximately 23 feet. At this depth, the saturation temperature of water is approximately 239°F.

For heat distribution scenarios involving clumping the full core fuel offload in both the center of fuel racks and at the center of the cask pit, the calculated peak local water temperature is calculated to be less than the local saturation temperature. 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 DNB. The relevant acceptance criteria are satisfied.

Analytical Methods and Assumptions

As noted, fuel discharge can be of the following types:

- A partial core refueling discharge (e.g., 105 highly-burned assemblies), and
- A full core discharge.

Time-dependent changes in the decay heat generated by irradiated fuel follow a negative exponential relationship. Thus, long-cooled fuel produces substantially less decay heat than does fuel recently offloaded from the core. A determination of total decay heat produced

following an offload evolution separately calculates the decay heat generation rate due to the current offload, and the decay heat generation rate of long-cooled assemblies comprising most of the fuel pool's inventory. Holtec International's LONGOR computer code was used to quantify the decay heat produced by previously offloaded fuel, while their BULKTEM program was used to calculate the decay heat produced by the current offload. Both of these programs incorporate the Oak Ridge National Lab (ORNL) ORIGEN2 computer code for performing decay heat calculations, and have been used previously by FPL in the UFSAR and other regulatory submittals to NRC.

Analyses of the fuel pool system and stored irradiated fuel considering operation at EPU conditions utilized the analysis methods and conservative assumptions summarized below. Although EPU parameter values differ from UFSAR values, methods similar to those described in UFSAR Section 9.1.3.3 were used to perform the fuel pool analyses.

- Maximizing Heat into the Fuel Pool
 - Thermal power is 3050 MWt, which is higher than the EPU value of 3020 MWt.
 - All irradiated fuel stored in the fuel pool is burned at EPU conditions, to a high exposure. Prospectively, EPU fuel burnup at final discharge is taken as the design maximum value; also, high values of accumulated burnup are applied to once-burned and twice-burned assemblies discharged as part of the full core fuel offload.
 - Batch sizes are greater and initial enrichment of future fuel reloads are less than those applicable to planned EPU conditions, effectively bounding the heat generation rate. As an example, fuel having a combination of a 3.5 weight percent (w/o) initial U^{235} enrichment and a discharge burnup of 55,000 MWD/MTU is unlikely to be present in the fuel pool. However, this combination of parameter values was used to maximize decay heat loads and bulk temperature, bounding any other fuel present up to 55,000 MWD/MTU.
 - In-core hold times prior to initiating transfer of irradiated fuel to the fuel pool racks are assumed to be relatively short compared to operational experience.
- Minimizing the Fuel Pool's Heat Capacity
 - Mass, volume and density assumptions applicable to storage racks, and the contained stored fuel, have been applied to maximize the volume of displaced water.
- Minimizing Heat Transfer from the Fuel Pool
 - CCW flow to the fuel pool heat exchanger is taken as a value below the lower bound of its procedurally-described acceptable range of values.
 - Fouling of the heat exchanger surfaces and levels of tube plugging are assumed to exceed St. Lucie Unit 2's operational experience, when quantifying thermal and hydraulic performance.
 - Thermal performance of the fuel pool system heat exchanger assumed a CCW inlet temperature to the heat exchanger to be at its maximum design value. This yields a slight de-rate of the heat exchanger performance, compared to the higher density water and higher heat capacity present at more typical operating temperatures.

- Even though St. Lucie Unit 2 has two separate trains of spent fuel pool cooling, each with an independent fuel pool cooling pump and heat exchanger, per pump flow is arbitrarily taken as a reduced value when two fuel pool system pumps are assumed to be operating. This reduces the assumed fuel pool water flow rate, thereby increasing fuel pool bulk water temperature.
- Ambient air temperature in the vicinity of the fuel pool is assumed to be 110°F to minimize passive heat losses.
- Passive losses (i.e., heat conduction through walls and floor slab, or losses from the surface) are neglected in local temperature analysis, which has the effect of maximizing local temperatures.
- Maximizing Local Temperature Conditions
 - The plenum gaps underneath the racks (i.e., between the floor and the rack's base plate) are modeled as less than the actual gap. This assumption ensures the effects of flow restrictions around bearing pads and the rack pedestals are bounded.
 - Rack-to-wall gaps are credited for downcomer flow, whereas no downcomer flow between the rack modules is assumed to exist (the actual rack-to-rack gaps are neglected). This increases flow resistance, and bounds any variations in the as-installed rack configuration.
 - Conservatively high axial and radial peaking factors are applied in the determination of the limiting local heat flux. Also, all the hottest fuel assemblies of the assumed core discharge are positioned together, near the center of the fuel pool, or in the cask pit rack (both scenarios are considered). Both the treatment of peaking factors and the positioning of hot fuel contribute to maximizing the local temperature.
 - The resistance effects of MetamicTM inserts on flow, in both the viscous and inertial terms, have been included. Maximizing the viscous resistance, as is done here, is achieved through dimensional assumptions that minimize the cell hydraulic diameter. Inertial effects are bounded by assuming the MetamicTM insert head piece blocks 2/3 of the cell flow area at the top of the insert above the fuel assembly, which increases the inertial resistance.

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

As discussed above, the fuel pool system is within the scope of License Renewal. Operation of the fuel pool system under EPU conditions has been evaluated to determine if there are any new aging effects requiring management, or if any existing aging management programs are affected. The EPU analyses have covered the addition of a new neutron absorption material (MetamicTM inserts) to the rack storage cells. Refer to LR [Section 2.8.6.2](#), Spent Fuel Storage, for discussion on management of MetamicTM inserts.

The EPU does not result in exceeding any operating or environmental parameters previously evaluated for components included within the scope of license renewal. Thus, no changes are necessary to any existing aging management programs. Furthermore, EPU does not change the functions of existing components such that license renewal system boundaries are affected.

2.5.4.1.2.4 Results

Summary of Thermal Analyses

Spent fuel pool decay heat calculations have been performed consistent with the guidance provided in Section 9.1.3 of the USNRC Standard Review Plan, and in the applicable sections of RS-001, Review Standard for Extended Power Uprates, Revision 0. Calculations performed utilized conservative inputs and considered combinations of operating pumps, along with a variety of event initiation times, fuel discharge rates and cooling water temperatures.

Results demonstrate that the design basis temperature limits are met for both partial and full core fuel offload evolutions, considering a single active failure. Thermal overshoot values have been determined for use in developing operational guidance for controlling full core fuel offload evolutions.

The local water temperature of the fuel pool cell containing the limiting fuel assembly is less than the saturation temperature. Cladding temperature at the point of maximum heat flux also remains less than the local saturation temperature. Thus, heat transfer is adequate to preclude a departure from nucleate boiling.

The time to onset of boiling in the fuel pool, following a loss of all forced convection at the time fuel pool temperature has reached its maximum, is sufficiently long (e.g., >5 hours) so as to permit the prior establishment of an alternate means of cooling. Requirements for inventory makeup, to maintain fuel pool level following the onset of boiling, are within the capability of installed plant systems.

The fuel pool system piping and valves are acceptable for EPU without changes or modifications.

The evaluation of the fuel pool system capabilities at EPU conditions demonstrates that St. Lucie Unit 2 will continue to meet the current licensing basis with respect to the requirements of GDC-44. The fuel pool system provides this capability under both normal operating and accident conditions to transfer decay heat to the unit heat sink, assuming a single failure. With the implementation of EPU, the system continues to retain the capability to perform this function.

The evaluation of the fuel pool system at EPU conditions demonstrates that St. Lucie Unit 2 will continue to meet the current licensing basis with respect to the requirements of GDC-61, insofar as it provides features that facilitate periodic inspection and testing, and residual heat removal capability and with design features to prevent significant reduction in fuel storage coolant inventory under accident conditions. These design capabilities remain unchanged by the EPU.

2.5.4.1.3 Conclusion

FPL has reviewed the assessment related to the fuel pool system and concludes that it has adequately accounted for the effects of the proposed EPU on the fuel pool cooling function of the system. Based on this review, FPL concludes that the fuel pool 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, FPL finds the proposed EPU acceptable with respect to the fuel pool system.

Table 2.5.4.1-1
Time-to-Boil Spent Fuel Pool

Offload Scenario	Minimum Time-to-Boil (hrs)	Maximum Boil-off Rate (gpm)
Scenario 1	10.6	44.7
Scenario 2	6.2	75.1
Scenario 3	6.2	75.1

Table 2.5.4.1-2
Peak Temperatures in Fuel Pool

Parameter	Value (°F)⁽¹⁾	Value (°F)⁽²⁾
Local water temperature	172	200
Cladding superheat	33	33
Local fuel cladding temperature	205	233
Notes: 1. Hot fuel placed in spent fuel pool 2. Hot fuel placed in cask pit		

2.5.4.2 Station Service Water System

2.5.4.2.1 Regulatory Evaluation

The station service water system, referred to as the intake cooling water (ICW) system, provides essential cooling to safety-related equipment and may also provide cooling to non-safety-related auxiliary components that are used for normal plant operation. The Florida Power and Light (FPL) 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 loss-of-coolant accident (LOCA) with the loss-of-offsite power (LOOP)). FPL's review focused on the additional heat load that would result from the proposed EPU.

The NRC's acceptance criteria are based on:

- GDC-4, insofar as it requires that structures, systems, and components (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;
- 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
- 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 Standard Review Plan (SRP) Section 9.2.1, as supplemented by NRC Generic Letters (GL) 89-13 and GL 96-06.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

The specific GDCs for the ICW system are as follows:

- GDC-4 is described in UFSAR Section 3.1.4 Criterion 4 – Environmental and Missile Design Bases.

Structures, systems and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss- of- coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in

nuclear power units may be excluded from the design basis when analysis reviewed and approved by the Commission demonstrates that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

SSCs important to safety are designed to accommodate the effects of and to be compatible with the pressure, temperature, humidity, and radiation conditions associated with normal operation, maintenance, testing, and postulated accidents including a LOCA, in the area in which they are located.

- GDC-5 is described in UFSAR Section 3.1.5 Criterion 5 - Sharing of Structures, Systems or Components.

Structures, systems and components important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units.

The ultimate heat sink is a safety-related SSC that supplies emergency cooling water to both St. Lucie Units 1 and 2. See LR [Section 2.5.4.4](#), Ultimate Heat Sink.

- GDC-44 is described in UFSAR Section 3.1.44 Criterion 44 - Cooling Water.

A system to transfer heat from structures, systems and components important to safety, to an ultimate heat sink shall be provided. The system safety function shall be to transfer the combined heat load of these structures, systems, and components under normal operating and accident conditions.

Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

The cooling water systems which function to remove the combined heat load from SSCs important to safety under normal operating and accident conditions, are the component cooling water (CCW) system and the intake cooling water (ICW) system.

The ICW system is an open loop system which removes heat from the CCW system and transfers it to the ultimate heat sink as described in UFSAR Section 9.2.1. The system consists of three pumps with piping, valves, and instrumentation arranged in two essential headers, one to each CCW heat exchanger, and branches to two non-essential headers, which supply water to the turbine cooling water and open blowdown cooling system heat exchangers, which are isolated automatically upon receiving safety injection actuation signal. Only one essential header is needed to remove the heat generated under post-LOCA conditions.

The intake cooling water pumps normally take water from the Atlantic Ocean through the circulating water intake conduits and canal. In the event of interruption of water from this source, water is taken through the emergency cooling water canal from Big Mud Creek. The ultimate heat sink is discussed in UFSAR Section 9.2.5.

In addition to the licensing basis described in the UFSAR, the ICW system was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.3.9 of the SER identifies that components of the ICW system are within the scope of License Renewal. Programs used to manage the aging effects associated with the ICW system are discussed in SER Section 3.3.9 and Chapter 18 of the UFSAR.

2.5.4.2.2 Technical Evaluation

2.5.4.2.2.1 Introduction

The ICW system's primary source of cooling water is from the Atlantic Ocean through the circulating water intake conduits and canal. The system is designed to provide adequate cooling to safety-related and non-safety-related loads during normal operation and to safety-related loads during abnormal and accident conditions. The ICW system was designed to ensure adequate heat removal with a maximum seawater temperature of 95°F.

2.5.4.2.2.2 Description of Analyses and Evaluations

The ICW systems and components were evaluated to ensure they are capable of performing their intended functions at EPU conditions. The evaluations compared the existing design parameters of the systems/components with the EPU conditions for the following design aspects:

- ICW flow and heat removal requirements,
- Design pressure/temperature of piping and components, and
- Fouling in heat exchangers cooled by service water (NRC Generic Letter 89-13).

Other evaluations of intake cooling water system and components are addressed in the following Licensing Report sections:

- Piping/component supports – LR [Section 2.2.2.2](#), Balance of Plant (BOP) Piping Components and Supports,
- Protection against dynamic effects of missiles, pipe whip, discharging fluids and flooding effects – LR [Section 2.2.1](#), Pipe Rupture Locations and Associated Dynamic Effects, LR [Section 2.5.1.1](#), Flooding, and LR [Section 2.5.1.3](#), Pipe Failures,
- Service water (ICW) instrumentation - LR [Section 2.4.1](#), Reactor Protection, Safety Features Actuation and Control Systems, and
- Safety related valve and pump testing – LR [Section 2.2.4](#), Safety Related Valves and Pumps.
- Evaluation of systems containing heat exchangers cooled by ICW is provided in the following:
 - LR [Section 2.5.4.3](#), Reactor Auxiliary Cooling Water Systems, and

- LR [Section 2.1.10](#), Steam Generator Blowdown System.

There are no ICW system components included in the environmental qualification program.

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

As discussed above, the ICW system is within the scope of License Renewal. Operation of the ICW system under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.5.4.2.2.4 Results

The following subsections evaluate the specific ICW system and component licensing, design and performance capabilities while at EPU conditions.

General Design Criteria

The evaluation of the ICW system capabilities at EPU conditions demonstrates that St. Lucie Unit 2 will continue to meet the current licensing basis with respect to the requirements of GDC-4. The system is protected from the dynamic effects of pipe break, including missiles, pipe whip, discharging fluids and flooding, as described in LR [Section 2.2.1](#), Pipe Rupture Locations and Associated Dynamic Effects, [2.5.1.1](#) Flooding, and [2.5.1.3](#), Pipe Failures.

There are no safety-related ICW components or safety-related functions shared between St. Lucie Units 1 and 2. The ICW system includes two redundant trains per unit and each train is separated from the other. The sharing of the UHS is accommodated by providing a Seismic Category I alternate source of water from the Big Mud Creek. This source is unaffected by EPU requirements. The requirements of GDC-5 continue to be met.

The evaluation of the ICW system capabilities at EPU conditions demonstrates that St. Lucie Unit 2 will continue to meet the current licensing basis with respect to the requirements of GDC-44. The ICW system provides sufficient flow during normal operation and to support the heat removal requirements of components required to mitigate the consequences of a LOCA.

No new operating modes or system lineups are required as a result of EPU.

The non-safety related turbine cooling water (TCW) heat exchangers cooled by the ICW system are being replaced for EPU to increase heat removal capacity. The replacement TCW heat exchangers will have the capability to remove the increased heat load from the TCW system. Because the heat removal capacity has increased with the new TCW heat exchangers with the

same design flow requirement, this will not have an effect on the overall hydraulic performance of the ICW system during normal and cooldown conditions.

The cooling water system for safety-related functions consists of the ICW system and the CCW system. The ICW system removes heat from the CCW heat exchangers. The CCW system serves safety-related heat loads, such as the containment fan coolers and shutdown cooling heat exchangers. The heat loads on the CCW heat exchangers are discussed in LR [Section 2.5.4.3](#), Reactor Auxiliary Cooling Water Systems. Both the CCW and the ICW have two flow loops/trains with redundant pumps, heat exchangers (for CCW), and piping arrangements. This redundancy ensures that the safety system function will be accomplished with a single failure. Both systems are operable from either the offsite power system or the onsite diesel generators. St. Lucie Unit 2 meets all the requirements of GDC-44.

Intake Cooling Water Flow and Heat Removal from Cooled Components

The ICW system supplies cooling water to the following components:

- CCW heat exchangers (safety-related),
- TCW heat exchangers (non-safety-related),
- Open Blowdown Cooling Water (OBCW) heat exchangers (non-safety-related), and
- Lubricating water to the circulating water pumps (non-safety-related).

The TCW heat exchangers, OBCW heat exchangers, and the lubricating water to the circulating water pumps are isolated automatically upon receiving SIAS.

EPU accident analyses demonstrate one ICW train provides sufficient heat removal capability from the CCW system using a 95°F design inlet temperature such that the ICW outlet temperature remains bounded by the piping analysis temperature of 130°F.

The accident analyses allowed for 10% CCW heat exchanger tube plugging.

LR [Table 2.5.4.2-1](#) shows the results of the maximum CCW/ICW temperature analysis and the LOCA containment pressure/temperature analysis.

The impact of EPU on the CCW heat exchangers is increased heat load. EPU analysis for normal operation shows the ICW system being able to cool the CCW system heat load with no change in the hydraulic performance. Analyses also demonstrated the ICW pumps supply the required flow to the CCW heat exchangers during normal operating and cooldown modes at EPU. LR [Table 2.5.4.2-2](#) shows the impact of EPU on normal operation of the ICW system.

The TCW heat exchangers are being replaced by those having a greater capacity at EPU to accommodate the increased heat load from turbine generator auxiliary components. The replacement heat exchangers maintain the same design flow condition, such that there is no effect on the hydraulic performance of the ICW system and the cooling flow requirements to the safety-related CCW heat exchangers will be achieved.

The CCW heat exchanger capacity is sufficient for EPU operation as discussed in LR [Section 2.5.4.3](#).

The design requirements of the steam generator blowdown system are unchanged at EPU and the ICW system will supply the required flow to the OBCW heat exchangers to remove the necessary heat load and maintain the ICW outlet temperature within design conditions.

Since the circulating water pumps are unchanged, the lubricating water supply requirements from the ICW do not change for EPU.

There is no change to the ICW pump head performance at EPU conditions. The ICW pumps do not require modification for EPU and will continue to operate within their design capacity. The ICW outlet temperatures remain bounded by the design temperature for EPU conditions. The ICW flow rates discharging to the circulating water discharge canal are small in comparison (ICW total flow 29,000 gpm vs. CW total flow 490,600 gpm) with circulating water discharge flow rates, such that the contribution of additional heat load is insignificant.

The system design pressure and temperature do not change and the piping and components within the ICW system are acceptable for EPU. The ability of TCW/OBCW isolation valves to close on a SIAS signal is not impacted as the system design flow, pressure, and temperature are unchanged.

NRC Generic Letter (GL) 89-13

NRC GL 89-13 requested licensees to establish a routine inspection and maintenance program to ensure that corrosion, erosion, protective coating failure, silting, and biofouling/tube plugging cannot degrade the performance of the safety-related systems supplied by service water (ICW system). In letter L-2000-215, dated November 9, 2000, FPL committed to performing routine single train inspection intervals every refueling outage for the intake well and safety-related ICW piping. The inspection and maintenance program for ICW system piping and components will continue following implementation of the EPU. Implementation of the EPU does not change maintenance practices and training procedures with respect to the ICW system. The pre-EPU 10 percent tube plugging criteria is unchanged and will still apply for EPU.

The extended power uprate does not affect the programs, procedures, and activities in place in support of implementation of the requirements of GL 89-13. The routine inspection and maintenance program from GL 89-13 will continue to ensure that the system will remain reliable and operable after the uprate.

NRC Generic Letter 96-06

NRC GL 96-06 requires certain specific actions be taken by licensees relative to cooling water systems serving containment. The ICW system piping does not enter containment; therefore, with regard to the ICW system, the requirements of Generic Letter 96-06 are not applicable to St. Lucie Unit 2.

2.5.4.2.3 Conclusion

FPL has reviewed the effects of the proposed EPU on the ICW and concludes that it has adequately accounted for the increased heat loads on system performance that would result from the proposed EPU. FPL concludes that the ICW 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, FPL has

determined that the ICW system will continue to meet its current licensing basis with respect to the requirements of GDCs -4, -5, and -44. Based on the above, FPL finds the proposed EPU acceptable with respect to the ICW.

**Table 2.5.4.2-1
EPU Accident Heat Removal**

Analysis	Heat Load (MBTU/hr)	CCW Temperature in/out of CCWHX (°F)		ICW Temperature in/out of CCWHX (°F)	
CCW/ICW System Maximum Temperature Responses ¹	151.997	155.66	118.87	95	116.60
LOCA Containment Pressure / Temperature Analysis ²	142.28	144.71	110.35	95	115.22
CCW System Design Supply Temperature			120.003		
ICW System Design Outlet Temperature					130.00 ⁴
1. The CCW/ICW system temperature response analysis maximizes the heat loads into the CCW system following a postulated LOCA by biasing containment spray flow, containment fan cooler heat removal, additional heat loads and lower heat transfer coefficients on the CCW heat exchanger to remove more heat from inside containment and transfer it to the CCW system. 2. The LOCA containment pressure/temperature analysis maximizes containment temperatures and pressures to verify containment integrity by using the minimum heat removal rate of the containment fan coolers. 3. The CCW supply temperature is being increased to 120°F from 108°F for EPU accident analyses. 4. Though the design temperature of the ICW piping from CCW heat exchanger outlet is 150°F, the piping has been analyzed to 130°F.					

Table 2.5.4.2-2
EPU Normal Conditions

	Pre-EPU Heat Load (MBTU/hr)	EPU Heat Load (MBTU/hr)
TCW heat exchangers	53.0	72.4
CCW heat exchangers	49.6	52.2
OBCW heat exchangers	69.2	69.2

2.5.4.3 Reactor Auxiliary Cooling Water Systems

2.5.4.3.1 Regulatory Evaluation

Florida Power and Light (FPL) utilizes the nomenclature component cooling water (CCW) system for St. Lucie Unit 2 in lieu of the RS-001 nomenclature reactor auxiliary cooling water system. CCW is used throughout this License Report (LR) section as well as throughout the balance of this license application. FPL's review covered the CCW system, which 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. This system includes a closed-loop CCW system for reactor system components, reactor shutdown equipment, ventilation equipment, and components of the emergency core cooling systems (ECCS). FPL'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. Emphasis was placed on the cooling water systems for safety-related components (e.g., ECCS equipment, ventilation equipment, and reactor shutdown equipment). FPL's review focused on the additional heat load that would result from the proposed EPU.

The NRC's acceptance criteria for the CCW are based on:

- General Design Criterion (GDC)-4, insofar as it requires that structures, systems and components (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,
- 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
- 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 Standard Review Plan (SRP) Section 9.2.2, as supplemented by NRC Generic Letter (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.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. Therefore, St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDCs for the CCW system are as follows:

- GDC-4 is described in UFSAR Section 3.1.4, Criterion 4 - Environmental and Missile Design Bases.

Structures, systems and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss- of- coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and approved by the Commission demonstrates that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

SSCs important to safety are designed to accommodate the effects of and to be compatible with the pressure, temperature, humidity, and radiation conditions associated with normal operation, maintenance, testing, and postulated accidents including a loss of coolant accident (LOCA), in the area in which they are located.

Non-seismic Category I piping is arranged or restrained so that failure of any non- seismic Category I piping will neither cause a nuclear accident nor prevent essential seismic Category I structures or equipment from mitigating the consequences of such an accident.

Seismic Category I piping is arranged or restrained such that in the event of rupture of a seismic Category I pipe which causes LOCA, resulting pipe movement will not result in loss of containment integrity or adequate engineered safety features systems operation.

- GDC-5 is described in the UFSAR Section 3.1.5, Criterion 5 - Sharing of Structures, Systems or Components.

SSCs important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units.

The CCW system is not shared between the two units.

- GDC-44 is described in the UFSAR Section 3.1.44, Criterion 44 - Cooling Water.

A system to transfer heat from structures, systems and components important to safety, to an ultimate heat sink shall be provided. The system safety function shall be to transfer the combined heat load of these structures, systems, and components under normal operating and accident conditions.

Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

The cooling water systems which function to remove the combined heat load from structures, systems and components important to safety under normal operating and accident conditions, are the CCW system and the intake cooling water (ICW) system.

The CCW system is a closed loop system which removes heat from the shutdown heat exchangers, containment cooling system and other essential and nonessential components as described in UFSAR Section 9.2.2. The system consists of three pumps with two heat exchangers, piping, valves and instrumentation arranged in two essential headers and one nonessential header. Two essential headers serve redundant safety related components. Only one essential header is needed to remove the heat generated under post-LOCA conditions.

The ICW system is an open loop system which removes heat from the CCW system and transfers it to the ultimate heat sink as described in UFSAR Section 9.2.1

The piping, valves, pumps and heat exchangers of the CCW system are designed and arranged so that the safety function can be performed assuming a single failure. The essential headers of the CCW system will be isolated from the nonessential header during the emergency mode of operation.

Electrical power for the operation of the CCW system may be supplied from offsite or onsite emergency power sources, with distribution arranged such that a single failure does not prevent the system from performing its safety function.

The CCW system is arranged as two redundant essential supply header systems (designated A and B) each with a pump and heat exchanger and the capability to supply the minimum safety feature requirements during plant shutdown or accident conditions. The nonessential supply header, which is connected to both essential headers during normal operation, is automatically isolated from both by valve closure on a safety injection actuation signal. During normal operation, the nonessential header supplies cooling water to the following components: sample heat exchangers, waste gas compressors, letdown heat exchanger, control element drive mechanism air coolers, reactor coolant pump motors, reactor coolant pump seals and motors, condensate recovery sample coolers, steam generator blowdown sample panel, post accident panel and the boric acid radiation monitoring.

The A and B headers serve the following components:

<u>Header A</u>	<u>Header B</u>
shutdown heat exchanger 2A	shutdown heat exchanger 2B
containment fan cooler 1A/1B	containment fan cooler 1C/1D
control room A/C 3A/3B/3C	control room A/C 3A/3B/3C
high pressure safety injection pump 2A	high pressure safety injection pump 2B
containment spray pump 2A	containment spray pump 2B
fuel pool heat exchangers 2A/2B	fuel pool heat exchangers 2A/2B
Control room A/C header 3C can be aligned to either header.	

To resolve issues relative to NRC GL 96-06, Assurance of Equipment Operability and Containment Integrity During Design Basis Accident Conditions, the CCW to and from the containment fan coolers (CFCs) was evaluated one time for the effects of water hammer loading.

FPLs response to NRC GL 96-06, which addresses overpressurization of isolated piping inside containment and boiling / two-phase flow/water hammer effects in cooling water piping to the containment recirculation fan coolers is addressed in UFSAR Section 6.2.4.1.

FPLs response to NRC GL 89-13, Service Water System Problems Affecting Safety-Related Equipment, which addresses service water fouling in heat exchangers is addressed in UFSAR Section 9.2.1.4.

Other UFSAR sections that address the design features and functions of the CCW system include:

- UFSAR Section 3.2 and UFSAR Table 3.2-1 which classifies the CCW pumps, heat exchangers, surge tank, instrumentation, and piping and valves required for performance of safety functions as seismic Class I, adequately protected for tornado wind and missiles, and flood protected,
- UFSAR Section 5.2.5 which describes the design features for detecting leakage of radioactivity into the CCW,
- UFSAR Section 6.2.1 which describes the engineered safety features (ESF) used to mitigate the consequences of a LOCA,
- UFSAR Section 6.2.2 which describes the design of the CFCs, and associated UFSAR Table 6.2-41 which analyzes the CCW system for credible single active failures, and
- UFSAR Section 6.2.4 and associated UFSAR Table 6.2-52 which describes the design features of the CCW system provided for containment isolation.

In addition to the licensing basis described in the UFSAR, the CCW system was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.3.2 of the SER identifies that components of the CCW system are within the scope of License Renewal. Programs used to manage the aging effects associated with the CCW system are discussed in SER Section 3.3.2 and Chapter 18 of the UFSAR.

2.5.4.3.2 Technical Evaluation

2.5.4.3.2.1 Introduction

The CCW system is described in UFSAR 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 as two redundant essential supply header trains (designated A and B) each with a pump and heat exchanger and the capability to supply the minimum safety feature requirements during plant shutdown or LOCA conditions. The nonessential supply header, which is connected to both essential headers during normal operation, is automatically isolated from both by valve closure on a safety injection actuation signal. Cooling water flows through the headers to the various safety- and non-safety-related components where it picks up heat from other systems and transfers that heat to the ICW system via the CCW system heat exchangers. The maximum assumed ICW inlet temperature is 95°F, which is the value used for the evaluation of safety related design features.

During normal full power operation, the CCW system is capable of providing sufficient cooling capacity to cool reactor coolant system (RCS) and auxiliary systems components with two pumps and one heat exchanger in operation, although, during normal operation, flow is established through both heat exchangers. Two pumps and two heat exchangers are used to remove the decay and sensible heat during plant shutdown. If one of the pumps or heat exchangers is not operable, safe shutdown of the plant is not affected.

The CCW loop serves as an intermediate boundary between the RCS and the ICW system, transferring heat from the RCS to the ICW system. This double barrier arrangement reduces the potential for leakage of radioactivity to the environment via the ICW system. Active CCW components which are relied upon to perform the emergency core cooling function are redundant. The design provides for detection of radioactivity and also provides for isolation means.

2.5.4.3.2.2 Description of Analyses and Evaluation

The CCW system and its components were evaluated to ensure they are capable of performing their intended functions at EPU conditions. The evaluations compared the existing design parameters of the system/components with the EPU conditions for the following design aspects:

- CCW heat exchanger performance (flow rates, duty and temperatures) at the increased EPU heat loads during normal power operation, normal cooldown, and abnormal transient and accident conditions (including GL 89-13),
- CCW system temperature limits,
- Design pressure/temperature of piping and components versus the EPU operating pressures and temperatures,
- CCW system relief valve capacities, and
- Protection of isolated piping sections from heatup effects (NRC GL 96-06).

Other related evaluations of the CCW system and components are addressed in the following LR sections:

- Piping/component supports – LR [Section 2.2.2.4](#), Balance of Plant Piping, Components and Supports,

- Protection against dynamic effects of missiles, pipe whip, discharging fluids and flooding - LR [Section 2.2.1](#), Pipe Rupture Locations and Associated Dynamic Effects; LR [Section 2.5.1.1](#), Flooding; and LR [Section 2.5.1.3](#), Pipe Failures,
- CCW instrumentation – LR [Section 2.4](#), Reactor Protection, Safety Features Actuation and Control Systems (Instrumentation and Controls - BOP),
- Environmental qualification – LR [Section 2.3.1](#), Environmental Qualification of Electrical Equipment,
- Safety related valve and pump testing and valve closure, including containment isolation requirements – LR [Section 2.2.4](#), Safety Related Valves and Pumps,
- Protection against internal missiles and turbine missiles – LR [Section 2.5.1.2.1](#), Internally Generated Missiles and [Section 2.5.1.2.2](#), Turbine Generator,
- Service water fouling in heat exchangers (NRC GL 89-13) – LR [Section 2.5.4.2](#), Station Service Water System, and
- Evaluation of systems containing heat exchangers cooled by CCW is provided in the following:
 - LR [Section 2.1.11](#), Chemical and Volume Control System,
 - LR [Section 2.2.2.6](#), Reactor Coolant Pumps and Supports,
 - LR [Section 2.5.6](#), Waste Management Systems,
 - LR [Section 2.8.4.4](#), Residual Heat Removal System,
 - LR [Section 2.8.5.6.3](#), Emergency Core Cooling System and Loss-of-Coolant Accidents,
 - LR [Section 2.5.4.1](#), Spent Fuel Pool Cooling and Cleanup System,
 - LR [Section 2.6.5](#), Containment Heat Removal,
 - LR [Section 2.1.10](#), Steam Generator Blowdown System, and
 - LR [Section 2.7](#), Habitability, Filtration, and Ventilation.
- Post-accident heat removal requirements – LR [Section 2.6.1](#), Primary Containment Functional Design, and
- 10 CFR 50 Appendix R Cooldown – LR [Section 2.8.4.4](#), Residual Heat Removal System.

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

As discussed above, the CCW system is within the scope of License Renewal. Operation of the CCW system under EPU conditions has been evaluated to determine if there any new aging effects requiring management or if there are any existing aging management programs are affected. 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. Furthermore, 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.

2.5.4.3.2.4 Results

The following subsections evaluate the specific CCW system and component licensing, design and performance capabilities while at EPU conditions:

General Design Criteria

The evaluation of the CCW system capabilities at EPU conditions demonstrates that St. Lucie Unit 2 will continue to meet the current licensing basis with respect to the requirements of GDC-4. The system is protected from the dynamic effects of pipe break as described in LR [Section 2.2.1](#), Pipe Rupture Locations and Associated Dynamic Effects and [Section 2.5.1.3](#), Pipe Failures. Safety related equipment is environmentally qualified for its worst case environments as discussed in LR [Section 2.3.1](#), Environmental Qualification. As described in LR [Section 2.5.1.3](#), Pipe Failures, the flooding analysis has considered the effects of high energy and moderate energy failures and evaluated the worst case failure in each plant building/area. The CCW system is a moderate energy system. Previous piping failure analyses with respect to the CCW system are not affected by EPU conditions since the CCW system flow rate and pressure remain unchanged at EPU with the exception of the flow to the control room air conditioning (CRAC) units which may require increased flow rates at EPU. These CRAC units will be modified prior to implementation of EPU to accommodate increased CCW supply temperatures. Any flow rate changes will be addressed as part of the design change process which will ensure the CCW system will continue to meet the current licensing basis with respect to GDC-4.

The evaluation of the CCW system capabilities at EPU conditions demonstrates that St. Lucie Unit 2 will continue to meet the current licensing basis with respect to the requirements of GDC-5. St. Lucie Units 1 and 2 do not share CCW systems or any components within the CCW systems. No new operating modes or system lineups are required as a result of the EPU that would affect the CCW system configuration. Therefore, the CCW system will continue to meet the design requirements with respect to sharing of system and components in accordance with the current licensing basis with respect to GDC-5.

The evaluation of the CCW system capabilities at EPU conditions demonstrates that St. Lucie Unit 2 will continue to meet the current licensing basis with respect to the requirements of GDC-44. The CCW system is the intermediate heat transfer system for heat removal from the reactor to the environment. The CCW system provides this capability under both normal operating and accident conditions and is capable of achieving this function considering a single failure. The implementation of EPU does not affect the capability of the system to perform this function satisfactorily as demonstrated by the system and component evaluation results described below and by the analysis results discussed in LR [Section 2.6.1](#), Primary Containment Functional Design and [Section 2.8.4.4](#), Residual Heat Removal System, using the ICW system during the postulated cooldown and accident scenarios.

Component Cooling Water Heat Removal Capability

CCW serves safety-related and non-safety related plant components including:

- CCW heat exchangers,
- Shutdown heat exchangers,
- Containment fan coolers,
- Control room air conditioners,
- High pressure safety injection pumps,
- Containment spray pumps,
- Sample heat exchangers,
- Letdown heat exchanger,
- Control element drive mechanism air coolers,
- RCP seals, motor oil coolers, motor air coolers, thermal barrier heat exchangers,
- Steam generator blowdown sampling panel,
- Waste gas compressor aftercoolers, and
- Spent fuel pool heat exchangers.

The maximum allowable CCW supply temperature is increasing from 108°F to 120°F for EPU. These cooled components are capable of removing the required EPU heat loads with the existing CCW supply flow rates with the exception of the safety-related control room air conditioning (CRAC) units. The CRAC units will be modified prior to implementation of EPU to ensure they can operate with the increased CCW supply temperatures. The EPU evaluation of systems containing these cooled components is performed in the system-related LR sections referenced above. Since none of the cooled components require more cooling flow, the existing CCW and ICW flow rates through the CCW heat exchangers are not changed by the EPU. Any changes to the cooling water requirements to the CRAC units, if required, will be addressed as part of the plant design change process.

During normal plant full power operation and normal cooldown, the CCW heat exchangers are capable of maintaining the cooling water supply temperature to individual cooled components below the following limits:

- 100°F Normal operation, and
- 120°F Normal cooldown and accident.

At normal plant EPU full power operation, the components experiencing an increased heat load are the letdown heat exchanger (+0.2 MBtu/hr) and the spent fuel pool heat exchanger (+1.5 MBtu/hr). Other heat exchangers were evaluated at their design conditions which remain bounding at EPU. The EPU evaluations concluded that the combined heat loads from the CCW cooled components are not significantly different than pre-EPU and; therefore, the above temperature limit is not challenged.

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 maximum heat loads imparted on the CCW system by the shutdown cooling heat exchangers will increase. At EPU, the plant will continue to utilize a dual train cooldown and will maintain the current administrative cooldown rate of 75°F/hr or less. For single train cooldown, in the event that ICW temperatures reach maximum values and only minimum CCW flow rates are available, the plant will procedurally control the cooldown rate to less than 75°F/hr in order to limit the CCW temperatures to ensure they do not exceed the value used in the pipe stress analysis of record. As a result of maintaining this limit with the higher reactor decay heat, the normal cooldown is lengthened as described in LR [Section 2.8.4.4](#), Residual Heat Removal System.

During LOCA conditions, the CCW system removes heat from the CFCs during the injection phase and from the CFCs and containment sump and RCS via the SDC heat exchangers during the recirculation phase. While the actual accident heat loads inside containment are higher at the EPU conditions due to increased reactor decay heat, the CCW accident heat removal capabilities used in the EPU containment analysis were conservatively modeled to maximize containment temperature and pressure. The EPU containment response analysis discussed in LR [Section 2.6.1](#) conservatively assumed emergency diesel generator (EDG) under-frequency which resulted in lower credited heat removal rates by the CFCs. The results indicate CCW heat removal rates during the injection phase are slightly higher than the analysis of record (AOR) which is due to increased containment temperatures at EPU despite the use of conservative CFC heat removal values. The EPU CCW heat removal rates during the recirculation phase are lower than the AOR due to conservative CFC heat removal values, the timing of the recirculation actuation signal, and other inputs to the analysis that form the basis of LR [Section 2.6.1](#), Primary Containment Functional Design. The EPU analyses described in LR [Section 2.6.1](#), Primary Containment Functional Design confirm that the CCW heat exchangers provide sufficient heat removal for mitigation of postulated accidents. An additional LOCA analysis was performed which conservatively maximized heat removal by the CCW system to maximize CCW temperatures at EPU. The results of this analysis show increased heat loads for both the injection and recirculation phases. The EPU analyses increased the allowable CCW supply temperature limit from 108°F to 120°F CCW. This new allowable supply temperature limit was not exceeded and successful completion of the analysis confirmed the CCW system can remove these conservative heat loads.

During 10 CFR 50 Appendix R cooldown following a plant fire, the CCW heat exchangers remove heat from the SDC system and are able to bring the plant to cold shutdown within 72 hours as described in LR [Section 2.8.4.4](#), Residual Heat Removal System.

EPU Operating Conditions versus Design Conditions of Piping and Components

The CCW flow rates remain unchanged at EPU with the exception of the flow to the CRAC units which may increase at EPU. Any flow rate changes will be addressed as part of the design change process. There is no change to the CCW pump head performance at EPU conditions. Therefore, the CCW system operating pressures are not affected by EPU conditions and the existing component design pressures are acceptable.

The maximum normal operating temperatures observed in the CCW system occur during normal cooldown when the SDC system is placed into service. After implementation of EPU, the maximum CCW temperatures will increase, but will continue to remain within allowable limits, while the time to cooldown the plant will be extended. The effect on the surge tank volume due to thermal expansion in the system is insignificant in comparison to the capacity of the surge tank.

The design temperatures of the CCW heat exchangers, pumps, surge tank, piping and valves bound the maximum CCW system normal operating temperatures at EPU operation.

Therefore, the CCW system design parameters bound all normal EPU operating conditions, thus the CCW system piping, valves, and components are acceptable for EPU operation.

The CCW analysis maximizes the heat loads into the CCW system following a postulated LOCA. This is achieved by biasing the containment heat removal systems to remove more heat from inside containment and transfer it to the CCW system. Parameters that are biased include the containment spray flow, containment fan cooler heat removal, additional heat loads, and lower heat transfer coefficients on the CCW heat exchanger.

Component Cooling Water Relief Valve Capacities

The CCW system relief valves either have no change or small changes temperatures that are bounded by the relief valve design. Since the EPU condition of below the system design temperature/pressure, no additional analysis is required to demonstrate their acceptability.

The postulated flow, pressure and temperature from a failure of the RCP thermal barrier heat exchanger does not change for EPU operation since there are no changes to the existing RCS design conditions, no changes to the CCW design conditions, and no changes are being made to the RCP thermal barrier. Therefore, the relief valves on the CCW piping at the RCP thermal barrier are unaffected by EPU conditions.

NRC Generic Letter 96-06, Assurance of Equipment Operability and Containment Integrity During Design Basis Accident Conditions

The implementation of EPU does not affect the previous corrective actions and responses to NRC GL 96-06.

NRC GL 96-06 questioned whether the higher heat loads at accident conditions could potentially cause steam bubbles, water hammer and two-phase flow due to the higher outlet temperatures from cooled components, particularly the containment fan coolers. A detailed design analysis of this concern was originally performed by FPL and accepted by the NRC. The analysis considered LOCAs and main steam line break (MSLB) events and determined that the temperatures in the piping downstream of the CFCs did not adversely affect the system flow or structural integrity of the piping. This analysis was reviewed against the EPU containment environment, CCW flow rates and heat removal from the CFCs. No changes in the CFC physical design or the CCW flow rates are made for EPU. The EPU containment environment is slightly higher in temperature than the original analysis of this event (see LR [Section 2.6.1](#) for additional discussion).

The potential for two-phase flow, void formation and water hammer were addressed in three separate calculations. One calculation confirmed that the increased containment temperature

due to EPU over the short period that the CFC is not operating does not significantly impact the heat removal from the containment. Further, the calculation concluded that there is potential for two-phase flow following a CCW restart for the design basis accident (DBA) LOCA and MSLB cases, but that it will not negatively impact system operation due to its limited location and duration. Finally, this calculation showed that the CCW pumps will have sufficient net positive suction head (NPSH) margin at restart. A second calculation determined the approximate size of voids formed and the time of bulk boiling. The calculation concluded that the limiting case for void formation was that of a DBA LOCA/loss of offsite power (LOOP) in cooler unit 1C. Data generated in this calculation was then used to evaluate the potential for water hammer in the system. This third calculation concluded that the increased EPU containment temperatures do not increase the previously calculated water hammer loads.

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. There is a decrease in containment temperature following a MSLB at the EPU conditions. Previous actions in response to GL 96-06 reviewed containment penetrations and installed thermal relief valves on CCW lines subject to over-pressurization. Since the EPU condition is below the system design temperature and pressure, no additional analysis is required to demonstrate its acceptability. Therefore, no additional lines from the CCW system that penetrate the containment are considered a potential concern; no new relief valves are required, and the existing relief valves remain acceptable at EPU conditions. See LR [Section 2.6.1](#) for additional discussion regarding post-accident containment temperatures.

NRC Generic Letter 89-13, Service Water System Problems Affecting Safety-Related Equipment

The issue in NRC GL 89-13 is related to evaluation of safety-related heat exchangers using service water (i.e., ICW) and whether they have the potential for fouling, thereby causing degradation in performance, and the mandate that there exist a permanent plant test and inspection program to accomplish and maintain this evaluation. FPL is committed to a program to perform periodic inspection, testing, and preventative maintenance of CCW heat exchangers. The conclusions relative to these 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. Subsequent to the implementation of EPU, the CCW heat exchangers will continue to be periodically inspected, tested, and maintained. The pre-EPU 10 percent tube plugging criteria is unchanged and will still apply for EPU.

2.5.4.3.3 Conclusion

FPL has reviewed the effects of the proposed EPU on the reactor auxiliary cooling water systems (i.e., CCW system) and concludes that the increased heat loads from the proposed EPU on system performance are acceptable. FPL 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, FPL has determined that the CCW system will continue to meet its current licensing basis with respect to the requirements of GDCs -4, -5, and -44. Based on the above, FPL finds the proposed EPU acceptable with respect to the CCW system.

2.5.4.4 Ultimate Heat Sink

2.5.4.4.1 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 Florida Power and Light (FPL) review focused on the impact that the proposed Extended Power Uprate (EPU) has on the decay heat removal capability of the UHS. Additionally, FPL'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:

- GDC-5, insofar as it requires that Structures, Systems or Components (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 function, and
- 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 Standard Review Plan (SRP) Section 9.2.5.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

The specific GDCs for the UHS are as follows:

- GDC-5 is described in UFSAR Section 3.1.5 Criterion 5 – Sharing of Structures, Systems or Components.

Structures, systems and components important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units.

The UHS (which performs a safety related function) supplies emergency cooling water to both St. Lucie Units 1 and 2. The canal has sufficient cross-sectional water flow area to mitigate the consequences of a loss-of-coolant accident on one unit while safely shutting down the other unit.

- GDC-44 is described in UFSAR Section 3.1.44 Criterion 44 – Cooling Water.

A system to transfer heat from structures, systems and components important to safety, to an ultimate heat sink shall be provided. The system safety function shall be to transfer the

combined heat load of these structures, systems, and components under normal operating and accident conditions.

Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

The cooling water systems which function to remove the combined heat load from structures, systems and components important to safety under normal operating and accident conditions, are the component cooling water (CCW) system and the intake cooling water (ICW) system.

St. Lucie Unit 2 utilizes two independent water sources for the UHS and shares common intake and discharge canals with St. Lucie Unit 1. The primary water source is the Atlantic Ocean, via the intake canal which is used as the source for all normal plant operational modes and accident situations. The secondary source of water is Big Mud Creek. The design of the above UHS concept complies with the regulatory positions of Regulatory Guide 1.27, Ultimate Heat Sink for Nuclear Power Plants, as discussed in UFSAR Section 9.2.7.

The UHS provides the heat dissipation capability for the reactor and essential auxiliaries through the CCW and ICW systems for both units during normal operation, shutdown, refueling, and accident conditions.

In addition to the licensing basis described in the UFSAR, the UHS was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Sections 2.3.3.5 and 2.4.2.14 of the SER identifies that components of the UHS are within the scope of License Renewal. Programs used to manage the aging effects associated with the UHS are discussed in SER Sections 3.5 and 3.5.2 and Chapter 18 of the UFSAR.

2.5.4.4.2 Technical Evaluation

2.5.4.4.2.1 Introduction

St. Lucie Units 1 and 2 share the UHS. An accident or single failure in one unit does not affect safe shutdown of the other unit. The primary water source is the Atlantic Ocean, via the intake canal which is used as the source for normal plant operational modes and accident situations. The secondary source of water is Big Mud Creek. The design of the above UHS concept complies with the regulatory positions of Regulatory Guide 1.27, Ultimate Heat Sink for Nuclear Power Plants, as discussed in Section 9.2.7 in the St. Lucie Unit 1 UFSAR. 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.

2.5.4.4.2.2 Description of Analyses and Evaluations

The UHS was evaluated to ensure it is capable of performing its intended function of supplying a reliable water supply and heat removal capacity for normal and accident conditions following EPU.

The UHS was evaluated for the circulating water discharge temperature during EPU normal power operation and initial normal cooldown, including the effect of the ICW discharge temperatures during normal power operation and cooldown.

Other evaluations related to the UHS are addressed in the following Licensing Report sections:

- Circulating water temperature rise and flow rates to the Atlantic Ocean and the State of Florida Industrial Wastewater Facility Permit limits – LR [Section 2.5.8.1](#), Circulating Water System, and
- ICW discharge temperatures, heat loads, and flow rates to the circulating water discharge to Atlantic Ocean – LR [Section 2.5.4.2](#), Station Service Water System.

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

As discussed above, the UHS is within the scope of License Renewal. Operation of the UHS under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.5.4.4.2.4 Results

The UHS continues to meet its licensing, design and performance capabilities at EPU conditions as evidenced by the evaluation results described below.

General Design Criteria

The evaluation of the UHS capabilities at EPU conditions demonstrates that St. Lucie Unit 2 will continue to meet the current licensing basis with respect to the requirements of GDC-44. The UHS is essentially an infinite heat sink (Atlantic Ocean) which contains sufficient volume to provide cooling water to both units under all normal, abnormal, and accident conditions. Therefore, the UHS continues to meet the design requirements with respect to sharing of system and components in accordance with the current licensing basis and GDC-5.

Water Supply and Heat Removal Requirements

The UHS will continue to provide the required water supply and heat sink capacity at EPU conditions. The ICW flow requirements for cooling of safety related heat exchangers are not changed by EPU.

The ICW returned to the UHS from cooled components experiences a small temperature change due to the higher heat loads from the EPU NSSS thermal power level at normal operating conditions and from the higher reactor decay heat during cooldown and accident conditions. During normal operation and normal cooldown, the ICW discharge temperatures increase slightly. During accident conditions, the ICW discharge temperatures continue to be bounded by existing analyses and the system design parameters.

The circulating water discharge flow rate to the Atlantic Ocean does not change at EPU resulting in higher discharge flow temperatures as discussed in LR [Section 2.5.8.1](#), Circulating Water System. However, the effect of the EPU ICW temperatures during normal operation, normal cooldown, and accident conditions is minimal because the total ICW flow of 29,000 gpm is mixed with a circulating water flow of approximately 490,600 gpm prior to discharge to the Atlantic Ocean. During accident conditions and plant cooldown the circulating water system may be secured.

The discharge of circulating water is governed by the State of Florida Industrial Wastewater Facility Permit. As discussed in LR [Section 2.5.8.1](#), Circulating Water System, the higher circulating water temperature during normal plant power generation has no impact on the current permit.

2.5.4.4.3 Conclusion

FPL has reviewed the information addressing the effects that the proposed EPU would have on the UHS safety function, including the validation of the design-basis UHS temperature limit based on post-licensing data. Based on the information that was provided, FPL 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 GDCs -5 and -44 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to the UHS.

2.5.4.5 Auxiliary Feedwater System

2.5.4.5.1 Regulatory Evaluation

In conjunction with a seismic Category I water source, the auxiliary feedwater (AFW) system functions as an emergency system for the removal of heat from the primary system when the main feedwater system is not available. The AFW system may also be used to provide decay heat removal necessary for withstanding or coping with a station blackout (SBO).

The Florida Power and Light (FPL) review for the proposed extended power uprate (EPU) focused on the system's ability to provide sufficient emergency feedwater flow at the expected conditions (e.g., steam generator (SG) pressure) to ensure adequate cooling with the increased decay heat. FPL'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 acceptance criteria for the AFW system are based on:

- General Design Criterion (GDC)-4, insofar as it requires that structures, systems and components (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;
- 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;
- 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;
- GDC-34, insofar as it requires that a residual heat removal (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
- 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 redundancy and isolation be provided to assure that the system safety function can be accomplished, assuming a single failure.

Specific review criteria are contained in Standard Review Plan (SRP) Section 10.4.9.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to Title 10 of the Code of Federal Regulations (10 CFR) Part 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDCs for the AFW system are as follows:

- GDC-4 is described in UFSAR Section 3.1.4 Criterion 4 – Environmental and Missile Design Bases.

Structures, systems and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss- of- coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and approved by the Commission demonstrates that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

SSCs important to safety are designed to accommodate the effects of and to be compatible with the pressure, temperature, humidity, and radiation conditions associated with normal operation, maintenance, testing, and postulated accidents in the area in which they are located.

- GDC-5 is described in UFSAR Section 3.1.5 Criterion 5 - Sharing of Structures, Systems or Components.

Structures, systems and components important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units.

Safety-related components interconnected between the two units include the condensate storage tanks (CSTs). The safety-related interconnections are not normally used by both units and employ isolation devices between them. Locked closed isolation valves are provided for the CSTs lines. The failure of equipment on one unit will not impair the ability of the counterpart on the other unit from performing its safety-related function. The interconnections provide added redundancy and operational flexibility without compromising unit and system independence.

In accordance with NRC requirements, a missile protected inter-tie is provided between the Unit 1 AFW pump suction lines and the Unit 2 CST to be used under administrative control. To add to the system's operational flexibility, the provision to supply the Unit 2 AFW pumps from the Unit 1 CST is also provided. Check valves insure against inadvertent draining of the Unit 2 CST to the Unit 1 CST, and each tank is maintained above its technical specification (TS) minimum volume limit.

In the unlikely event of loss of offsite power, both St. Lucie Units 1 and 2 have their own 100 percent capacity redundant emergency diesel generators which are available for safe shutdown.

- GDC-19 is described in UFSAR 3.1.19 Criterion 19 - Control Room.

A control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in safe condition under accident

conditions, including loss of coolant accidents. Adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent for the duration of the accident.

Equipment in appropriate locations outside the control room shall be provided (1) with a design capability for prompt hot shutdown of the reactor, including necessary instrumentations and controls to maintain the unit in a safe condition during hot shutdown, and (2) with a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

The control stations, switches, controllers and indicators necessary to operate or shut down the unit and maintain safe control of the facility are located in the control room.

The design of the control room permits safe occupancy during design basis accident conditions. The control room is isolated from the outside atmosphere during the initial period following the occurrence of an accident. The control room ventilation system recirculates control room air through HEPA and charcoal filters as discussed in UFSAR Section 9.4.1 and Section 6.4. Radiation detectors and alarms are provided. Emergency lighting is provided as discussed in UFSAR Section 9.5.3.

Alternate local controls and local instruments are available for equipment required to bring the plant to and maintain a hot standby condition. It is also possible to attain a cold shutdown condition from locations outside of the control room through the use of suitable procedures. Refer to UFSAR Section 7.4.1.

- GDC-34 is described in UFSAR Section 3.1.34 Criterion 34 - Residual Heat Removal.

A system to remove residual heat shall be provided. The system safety function shall be to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded.

Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

The transfer of fission product decay heat and other residual heat from the reactor core is accomplished by the SGs and the shutdown cooling system (SDCS) at such a rate that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded.

Residual heat removal capacity is provided with sufficient redundancies in design that in the event of a single active failure or a single limited leakage passive failure the system can still perform its function. The SG auxiliaries and the SDCS are designed to operate from either offsite or onsite electric power sources. See UFSAR Section 5.4.7 for additional information on residual heat removal.

- GDC-44 is described in UFSAR Section 3.1.44 Criterion 44 - Cooling Water.

A system to transfer heat from structures, systems and components important to safety, to an ultimate heat sink shall be provided. The system safety function shall be to transfer the combined heat load of these structures, systems, and components under normal operating and accident conditions.

Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

Although the AFW system is not specifically addressed by this GDC, the AFW system does provide for heat removal from the reactor and it ultimately transfers that heat to the environment, so that the system can remove residual heat and cool the plant to the SDCS cut-in temperature.

The AFW system is designed to maintain adequate primary-to-secondary heat transfer such that the plant can be stabilized and brought to a safe shutdown in a controlled manner.

UFSAR Section 10.4.9 documents details of the AFW system design. Additional details that define the licensing basis for the AFW system are described in:

- UFSAR Section 9.2.6 describes how the condensate storage tank is a source for feedwater for the AFW system, and
- UFSAR Chapter 15 describes how the AFW system is credited in the mitigation of transients and accident conditions.

The AFW system can remove sensible and decay heat from the reactor coolant system (RCS) during hot standby and cooldown for initiation of shutdown cooling. For events in which main feedwater flow is unavailable, (e.g., loss of main feedwater pump, loss of offsite power, and main steam line break), the AFW system is automatically initiated to provide hot standby and/or cooldown heat removal, following a specified time delay period as discussed in UFSAR Section 10.4.9.5.

TS 3/4.7.1.2 ensures operability of all AFW pumps.

TS 3/4.7.1.3 ensures operability of the CST and that it maintains minimum volume of demineralized water.

In addition to the licensing basis described in the UFSAR, the AFW system was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.4.3 of the SER identifies that components of the AFW system are within the scope of License Renewal. Programs used to manage the aging effects associated with the AFW system are discussed in SER Section 3.4 and Chapter 18 of the UFSAR.

2.5.4.5.2 Technical Evaluation

2.5.4.5.2.1 Introduction

The AFW system ensures a makeup water supply to the SG secondary side to support decay and sensible heat removal from the reactor core. The heat removal allows the operators to reduce the reactor coolant temperature to entry conditions for shutdown cooling. The AFW system normally operates to support plant startup, hot standby and shutdown evolutions.

The AFW system consists of two full capacity motor driven AFW pumps, one greater than full capacity turbine driven AFW pump, CST, and associated piping and valves. The motor-driven AFW pumps can be in normal service to support normal startup, hot-standby, and shutdown operation.

2.5.4.5.2.2 Description of Analyses and Evaluations

The AFW system and associated components were evaluated to ensure intended functions are performed at EPU conditions. The evaluations compared the existing design parameters of the systems/components with the EPU conditions in conjunction with the following design aspects:

- Design pressure and design temperature of piping and components,
- Required flow rates/pump capabilities to support plant startup and normal cooldown/shutdown,
- Required flow rates/pump capabilities to support non-LOCA accident scenarios, including Steam Generator Tube Rupture (LR [Section 2.8.5.6.2](#)), Main Steam Line Break (LR [Section 2.6.3.2](#)), and Station Blackout (LR [Section 2.3.5](#)),
- Containment isolation capabilities,
- AFW actuation system (AFAS),
- Water supplies and sources (CST), and
- Pump design and performance.

The primary impact of the EPU on the AFW system is the increased core thermal power and decay heat with the resulting higher heat removal requirements during design basis events/accidents, and cooldown modes. The AFW pump flow rates and system provide the heat removal required for response to postulated accidents and cooldown modes under EPU conditions using the existing pumps, piping and valves.

Other evaluations of the AFW system, piping and components are addressed in the following Licensing Report sections:

- Piping/component supports and water hammer effects - LR [Section 2.2.2.2](#), Balance of Plant Piping, Components and Supports,
- Steam supply to the turbine-driven AFW pump - LR [Section 2.5.5.1](#), Main Steam,

- Operation of the AFW system during postulated abnormal and accident scenarios - LR [Section 2.8.5.0](#), Accident and Transient Analysis,
- Operation of the AFW system during SBO and Appendix R fire scenarios - LR [Section 2.3.5](#), Station Blackout and LR [Section 2.5.4.1](#), Fire Protection,
- Protection against dynamic effects, including GDC-4 requirements, of missiles, pipe whip and discharging fluids - LR [Section 2.2.1](#), Pipe Rupture Locations and Associated Dynamic Effects and LR [Section 2.5.1.3](#), Pipe Failures,
- AFW instrumentation - LR [Section 2.4.1](#), Reactor Protection, Safety Features Actuation, and Control System,
- Environmental qualification of pumps and valves - LR [Section 2.3.1](#), Equipment Qualification of Electrical Equipment,
- Safety related valve and pump testing and valve closure, including containment isolation requirements - LR [Section 2.2.4](#) - Safety Related Valves and Pumps,
- Protection against turbine missiles and internal missiles - LR [Section 2.5.1.2](#), Missile Protection,
- Operation to mitigate anticipated transients - LR [Section 2.8.5.7](#), Anticipated Transients Without Scram (ATWS), and
- Operation following a small break LOCA – LR [Section 2.8.5.6.3](#), Emergency Core Cooling Systems and Loss-of-Coolant Accidents.

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

As discussed above, the AFW system is within the scope of License Renewal. Operation of the AFW system under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.5.4.5.2.4 Results

Design Pressures and Design Temperatures of Piping and Components

The design pressures of the suction, discharge, and recirculation piping in the AFW system remain adequate for EPU, because the shutoff head of the AFW pumps and the maximum static head of the CST are independent of power level, and no AFW system or physical CST modification is proposed for the implementation of the EPU.

The design temperatures of the suction, discharge, and recirculation piping in the AFW system remain adequate for EPU because the operating temperatures are bounded by the analyzed design temperatures.

Because the design pressures and temperatures of the AFW suction, discharge, and recirculation piping segments remain bounded under EPU conditions, the existing design parameters of the AFW system components (e.g., pumps, valves) are also adequate for EPU operation.

The evaluation of the AFW system capabilities at EPU conditions demonstrates that St. Lucie Unit 2 will continue to meet the current licensing basis with respect to the requirements of GDC-4, as described in LR [Sections 2.2.1](#) and [2.5.1.3](#).

Required Flow Rates/Pump Capabilities to Support Plant Startup and Normal Cooldown/Shutdown

The AFW system may be used during normal plant startup to provide a source of water inventory for the SGs in the event that condensate and feedwater are not available to support secondary water inventory. When needed for startup operations, the AFW system is required to maintain the SGs at 55 percent to 75 percent narrow range level. The required inventory for the SGs at startup will not increase at EPU. The SG pressure at startup (hot zero power) is unchanged for EPU. Therefore, flow requirements of the AFW system for startup will remain unchanged.

The AFW system is capable of providing sufficient cooling water to either or both SGs to ensure that there will be a sufficient inventory to reduce the RCS temperature to 325°F, in order to reach the point where the SDCS can be placed in service. The CST has sufficient capacity to provide the usable volume required to reduce RCS temperature to the SDCS entry conditions. The LR subsection below, entitled Water Supplies and Sources (CST) provides additional discussion of the CST volume requirements.

Required Flow Rates/Pump Capabilities to Support Non-LOCA Accident Scenarios

The evaluation of the AFW system capabilities at EPU conditions demonstrates that St. Lucie Unit 2 will continue to meet the current licensing basis with respect to the requirements of GDC-34 and GDC-44, as described in UFSAR Sections 3.1.34 and 3.1.44, respectively. The AFW system is considered one of the steam power conversion systems, which together with the SDCS, transfer the heat from the reactor core at a rate such that design limits of the fuel and the primary system coolant boundary are not exceeded. Suitable redundancy is provided in the AFW pumps, piping paths and valves to withstand a single active failure or a single passive failure. The AFW system is able to operate with either onsite or offsite power systems. The AFW system will continue to provide these same capabilities after implementation of EPU, as demonstrated by the system and component evaluation results described in this Licensing Report and by the analysis results discussed in LR [Section 2.8.5.0](#), using the AFW system to mitigate the postulated abnormal and accident scenarios, as applicable. LR [Section 2.3.5](#) demonstrates the ability of the turbine-driven AFW pump to support the decay and sensible heat removal from the RCS during a SBO event.

The evaluation of the AFW system capabilities at EPU conditions demonstrates that St. Lucie Unit 2 will continue to meet the current licensing basis with respect to the requirements of GDC-19, described in UFSAR Section 3.1.19. In the event of an emergency condition that

causes the control room to be abandoned, emergency instrumentation and controls are provided outside the control room to enable the plant operator to shutdown and maintain the plant in a safe condition. The AFW system will be operated during such a period of control room inaccessibility to maintain the plant in a safe shutdown condition. Control room design features that support safe occupancy during accident conditions at EPU are discussed in LR [Section 2.10.1](#), Occupation and Public Radiation Doses, LR [Section 2.7.1](#), Control Room Habitability System and LR [Section 2.9.2](#), Radiological Consequence Analyses Using Alternative Source Terms.

The evaluation of the AFW system capabilities at EPU conditions demonstrates that St. Lucie Unit 2 will continue to meet the current licensing basis with respect to the requirements of GDC-44, described in UFSAR Section 3.1.44. Although, the AFW system is not specifically addressed by this GDC, the AFW system does provide for heat removal from the reactor and transfer of the heat ultimately to the environment so that the system can remove residual heat over the entire range of reactor operation and cool the plant to the SDCS cut-in temperature. The AFW system provides this capability under accident conditions and is capable of achieving this function considering a single failure. The implementation of EPU does not affect the capability of the system to perform this function as demonstrated by the system and component evaluation results described in this Licensing Report and by the analysis results discussed in LR [Section 2.8.5.0](#), using the AFW system to mitigate the postulated abnormal and accident scenarios.

Containment Isolation Capabilities

Containment isolation is accomplished by the provision of isolation valves on the AFW headers outside containment. The EPU does not affect the AFW system maximum differential pressures used for determining thrust and torque values for the isolation valves. Therefore, the isolation valves remain adequate for EPU. The containment isolation requirements are unaffected by EPU and the current plant design features remain acceptable.

Auxiliary Feedwater Actuation Signal (AFAS)

The current AFAS actuation setpoint has been verified to protect the plant for EPU operation. AFAS instrumentation, analytical limits, and settings were evaluated for EPU operation. For further discussion of AFAS evaluation refer to the LR [Section 2.4.1](#).

Water Supplies and Sources (CST)

The CST analysis has demonstrated that there is sufficient inventory within the CST to provide the required back-up water supply for St. Lucie Unit 1 and enough usable water volume to meet the accident cooldown requirements of St. Lucie Unit 2.

The current TS (TS 3/4.7.1.3) requirement of a “contained volume of 307,000 gallons” bounds the calculated EPU requirement of a contained volume of 297,933 gallons. Included in this volume is the required usable water volume of 154,000 gallons to accommodate the Unit 2 decay heat removal for 10.63 hour cooldown period including the RCS at hot standby condition for 4 hours in order to reduce the reactor coolant temperature to shutdown cooling entry condition (325°F) in the event of loss of offsite power. In addition, the required usable water volume of 130,500 gallons is maintained for Unit 1 cooldown to shutdown entry conditions. Included in the EPU requirement of 297,933 gallons is an allowance for water not usable because of tank outlet

nozzle location plus submergence level above the outlet nozzle to prevent vortexing plus instrument uncertainty. The effect of the AFW pump heat on the temperature of the fluid and the potential adverse effect on the required CST inventory have been included in the EPU evaluation of required volume. Therefore, the CST contains sufficient usable volume to support AFW operation following the implementation of the EPU in accordance with the current TS Section 3/4.7.1.3 requirements.

The key CST volume parameters at pre-EPU and EPU are shown in the LR [Table 2.5.4.5-1](#).

The CSTs are safety related components interconnected between the two units. The safety related interconnection is not normally used and isolation devices are employed between the two units. Locked closed isolation valves are provided for the AFW inter-tie. The failure of equipment on one unit will not impair the ability of the counterpart on the other unit from performing its safety related function. The interconnections provide added redundancy and operational flexibility without compromising unit and system independence.

In accordance with NRC staff requirements, a missile protected inter-tie is provided between the St. Lucie Unit 1 AFW pump suction lines and the St. Lucie Unit 2 CST to be used under administrative control. Check valves prevent inadvertent draining of the St. Lucie Unit 2 CST to the St. Lucie Unit 1 CST. The minimum CST volume required by the current St. Lucie Unit 2 TS remains adequate to provide the required volume for St. Lucie Unit 1 at EPU conditions. The St. Lucie Unit 2 TS Bases will be revised to reflect the St. Lucie Unit 1 and Unit 2 EPU CST volume requirements.

Since there are no physical modifications to the AFW system required to implement the EPU, the AFW system continues to meet the current licensing basis with respect to GDC-5, as described in UFSAR Section 3.1.5.

Pump Design and Performance

The AFW pumps are capable of supplying sufficient flow to the SGs to support the AFW system flow assumptions and requirements of the non-LOCA accident scenarios at EPU operation.

The net positive suction head required for the motor and steam-driven AFW pumps are bounded by the net positive suction head available for the pumps.

Loss of Normal Feedwater Analysis

In addition to the transient analysis presented in LR [Section 2.8.5.2.3](#), Loss of Normal Feedwater Flow, analyses were performed in support of this LR section to demonstrate the ability of a degraded AFW system to maintain adequate primary-to-secondary heat transfer such that the plant can be stabilized and brought to a safe shutdown in a controlled manner.

Detailed analyses were performed using the IGOR and RETRAN codes using nominal plant conditions. A limiting single failure was assumed. For this analysis, the initiating event is a loss of main feedwater. The limiting single failure is the loss of the turbine driven AFW pump since it supplies the most AFW to the SGs of any AFW pump.

Acceptance criteria used in the analyses for these events are as follows:

- Provide sufficient capability for removal of decay heat from the reactor core,

- Prevent lifting of the pressurizer safety valves (PSVs) when considered in conjunction with the power operated relief valves (PORVs),
- Reduce the RCS temperature to entry temperature for activating the SDCS,
- Pressures in the main steam system should be less than 110 percent of design values,
- Pressures in the RCS should be less than 110 percent of design without loss of offsite power and less than 120 percent of design with loss of offsite power,
- The fuel cladding integrity should be maintained by ensuring that the minimum departure from nucleate boiling ratio (MDNBR) remains above the 95/95 DNBR limit, and
- An incident of moderate frequency should not generate a more serious plant condition without other faults occurring independently (The specific concern is pressurizer overfill which could result in loss of pressure control).

The loss of normal feedwater analyses demonstrate that the AFW system is sufficiently sized to remove the decay heat and pump heat associated as performed in support of UFSAR Section 10.4.9. For the loss of main feedwater and loss of main feedwater without offsite power events, the maximum pressurizer pressure is well below the PSV minimum opening setpoint; thus it is demonstrated that the PORVs prevent opening of the PSVs.

The pressure acceptance criterion requires that the pressures in the RCS and main steam systems must be maintained below 110 percent of their respective system design pressures, with the RCS allowable increasing to 120 percent of system design pressures concurrent with a loss of offsite power. The peak primary and secondary overpressure analyses results yield maximum values which are less than the 110 percent of the design pressures for this event. Thus, the primary and secondary system pressure limits are satisfied.

The departure from nucleate boiling (DNB) acceptance criterion requires that the MDNBR is not less than the 95/95 correlation limit. The analysis results determined the minimum DNB remained well above the safety analysis limit value. Furthermore, the EPU analyses indicate that the value of the MDNBR for EPU conditions was found to be better than the previous (pre-EPU) analysis. Thus, the DNB acceptance criterion is satisfied for EPU.

The plant condition acceptance criterion requires that the event must not generate a more serious plant condition without other faults occurring independently. In order for this criterion to be satisfied, the pressurizer must not become so full that liquid is expelled through the PSVs. The long term cooling analysis results confirm that although the PSVs open, there is no passage of water through the valves since the pressurizer does not become water solid. Thus, the plant condition restriction is satisfied for this event.

The results of the analyses relative to the use of a single motor-driven AFW pump, demonstrate that the AFW system capacity and actuation setpoint are adequate to maintain primary-to-secondary heat transfer, such that, the plant can be stabilized and brought to a safe shutdown in a controlled manner. Adequate cooling was maintained through the vaporization of the AFW and the pressurizer steam space was preserved. There was no significant heatup of the primary system. Thus, all acceptance criteria are satisfied for this event.

For the SBO event, the turbine driven AFW pump is available. At one hour into the event, operators are assumed to throttle AFW flow to prevent SG overfill. The analysis results confirm the AFW system is capable of mitigating the consequences of the event with all acceptance criterion met.

2.5.4.5.3 Conclusion

FPL has evaluated the capability of the AFW system to perform its functions under EPU conditions. FPL concludes that the review has adequately accounted for the effects of the increase in decay heat and other changes in plant conditions on the ability of the AFW system to supply adequate water to the SGs to ensure adequate cooling of the core. FPL finds that the AFW system will continue to meet its design functions following implementation of the proposed EPU. FPL further concludes that the AFW system will continue to meet its current licensing basis with respect to the requirements of GDCs -4, -5, -19, -34, and -44. Therefore, FPL finds the proposed EPU acceptable with respect to the AFW system.

Table 2.5.4.5-1
Condensate Storage Tank Volume

Parameter	Pre-EPU (gallons)	EPU (gallons)
Usable volume for cooldown for Unit 2	149,600	154,000
Usable volume for cooldown allocated to Unit 1	125,000	130,500
Unusable volume due to outlet nozzle location, vortex suppression, and instrument uncertainty	30,800	13,433
Total required volume	305,400	297,933
Technical Specification minimum total volume	307,000	307,000
Low level alarm volume	307,000	307,000

2.5.5 Balance-of-Plant Systems

2.5.5.1 Main Steam

2.5.5.1.1 Regulatory Evaluation

The main steam supply system (MSSS) transports steam from the nuclear steam supply system (NSSS) to the power conversion system and various safety-related and non-safety-related auxiliaries. The Florida Power and Light (FPL) 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:

- GDC-4, insofar as it requires that structures, systems and components (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,
- 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
- 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 Standard Review Plan (SRP) Section 10.3.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

The specific GDCs for the main steam system are as follows:

- GDC-4 is described in UFSAR Section 3.1.4 Criterion 4 – Environmental and Missile Design Bases.

Structures, systems and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and

approved by the Commission demonstrates that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

Structures, systems and components important to safety are designed to accommodate the effects of and to be compatible with the pressure, temperature, humidity, and radiation conditions associated with normal operation, maintenance, testing, and postulated accidents, including a loss-of-coolant accident (LOCA), in the area in which they are located.

Seismic Category I piping is arranged or restrained such that in the event of rupture of a seismic Category I pipe which causes LOCA, resulting pipe movement will not result in loss of containment integrity or adequate engineered safety features systems operation.

The structures inside the containment vessel are designed to sustain dynamic loads which could result from failure of major equipment and piping, such as jet thrust, jet impingement and local pressure transients, where containment integrity is needed to cope with the conditions.

Refer to UFSAR Sections 3.5, 3.6, 3.7, and 3.11 for details.

- GDC-5 is described in UFSAR Section 3.1.5 Criterion 5 - Sharing of Structures, Systems or Components.

Structures, systems and components important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units.

There are no safety-related SSCs shared between the St. Lucie Unit 1 and 2 main steam systems.

- GDC-34 is described in UFSAR Section 3.1.34 Criterion 34 - Residual Heat Removal.

A system to remove residual heat shall be provided. The system safety function shall be to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded.

The transfer of fission product decay heat and other residual heat from the reactor core is accomplished by the steam generators and the shutdown cooling system at such a rate that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded.

Residual heat removal capacity is provided with sufficient redundancies in design that in the event of a single active failure or a single limited leakage passive failure the system can still perform its function. The steam generator auxiliaries and the shutdown cooling system are designed to operate from either offsite or onsite electric power sources. See UFSAR Section 5.4.7 for additional information on residual heat removal.

UFSAR Section 10.3 documents details of the main steam system design.

The following portions of the MSSS are designated safety-related and designed to seismic Category I requirements:

- The main steam discharge piping from the steam generator up to and including the main steam isolation valves (MSIVs), and
- The main steam supply for the auxiliary feedwater pump turbine.

Technical Specification 3/4.7.1.1, Safety Valves, ensures all main steam line code safety valves are operable with lift settings as specified in Technical Specification Table 3.7-2.

Technical Specification 3/4.7.1.5, Main Steam Line Isolation Valves, ensures the operability of main steam isolation valves.

In addition to the licensing basis described in the UFSAR, the main steam system was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.4.1 of the SER identifies that components of the main steam system are within the scope of License Renewal. Programs used to manage the aging effects associated with the main steam system are discussed in SER Section 3.4.1 and Chapter 18 of the UFSAR.

2.5.5.1.2 Technical Evaluation

2.5.5.1.2.1 Introduction

The main steam system is described in UFSAR Section 10.3. The system provides heat removal from the RCS during normal, accident, and post accident conditions. During off normal conditions, the system provides emergency heat removal from the RCS using secondary heat removal capability. System components are credited for safe shutdown following station blackout events and fire events.

The main steam system is designed to produce dry saturated steam in the SGs and direct it to the high pressure (HP) turbine, as well as other steam driven components and auxiliary steam systems. The main steam system includes the steam piping, main steam safety valves (MSSVs), atmospheric dump valves (ADVs), MSIVs, main steam flow venturis, and other miscellaneous valves and piping. The main steam system also provides a flow path for steam from the SGs to the steam dump and bypass valves, which is discussed in LR [Section 2.5.5.3](#), Turbine Bypass.

The main steam system design functions are:

- Supply steam from the SGs to HP turbine,
- Supply steam to the four moisture separator reheaters (MSRs),
- Supply steam to the priming ejector,
- Supply steam to the gland sealing steam system,

- Supply steam to the steam-driven AFW pump,
- Supply steam to the auxiliary steam system,
- Provide containment isolation in the event of a LOCA,
- Provide NSSS excess heat removal capability using the ADVs and steam dump and bypass control system (SBCS),
- Provide a means of RCS decay heat removal in the event of a loss of offsite power,
- Provide overpressure protection for the SGs and MSSS, and
- Prevent uncontrolled blowdown of both SGs in the event of a steam line rupture accident.

2.5.5.1.2.2 Description of Analyses and Evaluations

The main steam system and components were evaluated to ensure they are capable of performing their intended functions at EPU conditions. The evaluations were conservatively performed for an analyzed NSSS power level of 3050 MWt. The evaluations compared the existing design parameters of the systems/components with the EPU conditions for the following design aspects:

- Design pressure/temperature of piping and components,
- Flow velocities,
- Vibration due to increased flow,
- Capacities, closure times and set pressures for the MSIVs, MSSVs, and ADVs,
- Moisture removal capability, thermal performance, vibration and erosion/corrosion of the MSRs,
- Main steam supply capacity to the turbine-driven AFW pump (LR [Section 2.5.4.5](#), Auxiliary Feedwater) and to other auxiliary loads, and
- Main steam drain system capacity.

Other evaluations of main steam system and components are addressed in the following LR sections:

- Erosion/corrosion issues – LR [Section 2.1.8](#), Flow-Accelerated Corrosion,
- Piping/component supports – LR [Section 2.2.2.2](#), Balance of Plant Piping, Components, and Supports,
- Protection against dynamic effects, including missiles, pipe whip, and discharging fluids – LR [Section 2.2.1](#), Pipe Rupture Locations and Associated Dynamic Effects and LR [Section 2.5.1.3](#), Pipe Failures,
- Environmental qualification of the MSIV actuators – LR [Section 2.3.1](#), Environmental Qualification of Electrical Equipment,
- LR [Section 2.2.4](#), Safety-Related Valves and Pumps,

- Protection against internal missiles – LR [Section 2.5.1.2.1](#), Internally Generated Missiles,
- Safety related instrumentation – LR [Section 2.4.1](#), Reactor Protection, Safety Features Actuation, and Control Systems,
- Turbine control/overspeed protection – LR [Section 2.5.1.2.2](#), Turbine Generator, and
- Appendix R cooldown – LR [Section 2.5.1.4](#), Fire Protection.

The MSRs are being replaced with new MSRs designed for EPU conditions in conjunction with the following ancillary MSR Modifications:

- Upgrade of the pneumatic MSR level controls with current generation instrumentation for improved reliability and accuracy,
- Replacement of flow orifices to accommodate increased flow rates at EPU conditions, and
- Replacement of MSR normal drain control valves to meet the EPU conditions.

The increase in pressure drop from the SG outlet to the HP turbine inlet has been evaluated for EPU conditions and has been included in establishing the main steam supply pressure at the HP turbine inlet; thus ensuring adequate steam pressure for EPU full power generation.

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

As discussed above, the main steam system is within the scope of License Renewal. Operation of the main steam system under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.5.5.1.2.4 Results

System Operating Conditions

Heat balances were developed for the current power level based on actual plant operating data and at the EPU NSSS power level of 3050 MWt. The EPU heat balances were used to determine the steam cycle parameters and the required main steam flow rate at the HP turbine throttle valve outlet pressure of 808 psia. The process parameters are used by the manufacturer as the basis for redesign of the HP turbine to achieve the EPU electrical power generation. Based on the heat balances, the main steam conditions at the SG outlet and the reheat steam conditions to/from the MSRs are listed in LR [Table 2.5.5.1-1](#).

Piping Evaluations

Design Pressure/Temperature

The main steam system design pressure and temperature of 985 psig (1000 psia) and 550°F bound the maximum EPU operating conditions. The system design pressure and temperature also bound the highest normal operating pressure of 885 psig and temperature of 532°F, which occur at no load conditions. The no load conditions are not affected by the EPU. Therefore, the existing design conditions are unchanged by the EPU.

Flow Velocities

The main steam velocities at current and EPU conditions are bounded by the industry design guidelines velocity with the exception of the following:

- Piping from the steam generator outlet to the MSIV increases to 176 fps from 157 fps and exceeds industry design guideline velocity by 9 fps, and
- Piping from the MSIV to the MSSS common header increases to 178 fps from 159 fps and exceeds industry guideline velocity by 11 fps.

The increased flow rate due to EPU will not have a significant impact on main steam system component materials because of the steam's low water content. These lines are currently monitored by the Flow Accelerated Corrosion program (See LR [Section 2.1.8](#), Flow-Accelerated Corrosion) and will continue to be monitored following EPU.

Vibration

The increase in steam flow velocity through piping and components has the potential to increase vibrations. Accordingly, during power ascension, piping will be monitored to identify line vibration anomalies. These vibration monitoring activities are discussed in LR [Section 2.12](#), Power Ascension and Testing Plan.

Component Design Evaluations

Design Pressure/Temperature

As described above under Piping Evaluations, Design Pressure/Temperature, the main steam design pressure and temperature 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

There are a total of sixteen spring-loaded MSSVs located outside the containment on the two main steam lines, upstream of the MSIVs, which discharge to the atmosphere when actuated. In the event that the SBCS valves fail to open on complete loss of turbine generator load with offsite power available, an increase in steam pressure in the SGs will occur. The SG pressure rise is terminated by opening of the MSSVs.

The loss of condenser vacuum and feedline break evaluations conservatively modeled the MSSVs and indicated that the total flow rate through the valves remains adequate for over-pressure protection.

MSSV operability setpoints are currently 1000 psia +1/-3 percent (8 valves) and 1040 psia +1/-3 percent (8 valves). The MSSV setpoints will remain unchanged for EPU. The as-found tolerances on the MSSVs in TS 3/4.7.1.1 will be changed for operational flexibility to +/- 3 percent for the MSSVs with the higher setpoint and to +2 percent/-3 percent for the MSSVs with the lower setpoint. This tolerance change has been factored into the plant's accident analyses (LR [Section 2.8.5](#)).

The evaluation results presented above confirm that the current MSSVs are acceptable at EPU without physical modification.

Atmospheric Dump Valves (ADVs)

The ADVs are located upstream of the MSIVs and adjacent to the MSSVs. During normal full power plant operation, the ADVs are closed with the controllers maintained in the manual mode. During plant startup and shutdown, the ADV controllers can be placed in auto with a desired process setpoint, and the ADVs are then automatically controlled based on measured steam line pressure. The ADVs automatically modulate open and exhaust to the atmosphere to control steam line pressure at the predetermined setpoint, which for these operations is the zero-load steam pressure which is below the setpoint of the lowest set MSSV. Since neither of these pressures change for the proposed range of NSSS design parameters, the ADV setpoint is unchanged. As the steam line pressure decreases, the ADVs modulate closed and reseal at a pressure below the opening pressure.

The primary function of the ADVs is to provide a means for decay heat removal and plant cooldown by discharging steam to the atmosphere when the condenser, the condenser circulating water pumps, or steam dump and bypass to the condenser is not available. Under such circumstances, the ADVs, in conjunction with the AFW system, permit the plant to be cooled down to the point at which the shutdown cooling system can be placed in service.

An evaluation of the installed capacity of the ADVs (275,000 lbm/hr each at 985 psia) indicates that the required plant cooldown can still be achieved for the range of EPU NSSS design parameters in the event of a loss of offsite power (LR [Section 2.8.7.2](#), Natural Circulation Cooldown).

The 10 CFR 50 Appendix R evaluation demonstrated that the ADVs are acceptable at EPU (LR [Section 2.5.1.4](#) Fire Protection).

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.

Main Steam Isolation Valves

The MSIVs are air-operated globe valves which are held open using instrument air and closed using a spring-operated actuator.

The current design pressures and temperatures for the MSIVs are 985 psig and 550°F, which match the main steam system piping design pressure and temperature. Based on these results, the current MSIV design pressures and temperatures are acceptable at EPU conditions since they are equal to the piping design pressure and design temperature.

Closing times of the MSIVs are unaffected at EPU conditions because the design of the valve is such that pressure on either side of the valve has no effect on valve closure time due to the fact that it is operated by a fail-closed spring-loaded actuator. Evaluations showed that the MSIVs will continue to close within their current maximum stroke time of 5.6 seconds under EPU conditions.

Moisture Separator Reheaters

Each of four (4) MSRs, including flow orifices, will be replaced to accommodate the increased flows, pressures and temperatures at the EPU conditions. The replacement MSRs will be designed in accordance with Heat Exchanger Institute (HEI) standards and will include new shell side relief valves.

The design of the replacement MSRs will take into account the following:

- Flow induced vibrations,
- Reheater bundle performance to meet thermal requirements of EPU at 100 percent power generation,
- Moisture removal capability of the moisture separator and internal drain system is sufficient for EPU moisture loading, and
- Erosion/corrosion concerns during EPU operation.

Turbine Stop, Control, and Reheat Stop and Intercept Valves

The HP turbine stop valves have been evaluated by the OEM as being adequate for EPU. The HP turbine control valves have been evaluated and are physically adequate for operation at EPU. The control valve opening sequence is being modified from sequential to single valve to improve the steam admission characteristics of the HP turbine. The LP turbine reheat stop and intercept valves have also been evaluated and are adequate for EPU operation. The ability of the HP turbine stop and control and the LP turbine reheat stop and intercept valves to provide overspeed protection is discussed in LR [Section 2.5.1.2](#), Missile Protection.

Auxiliary Steam Supply Flow Rates

The main steam system supplies steam to the following auxiliary loads:

- Moisture separator reheaters,
- Auxiliary feedwater pump turbine,
- Auxiliary steam system,
- Priming air ejector, and
- Turbine gland steam seal system.

The MSRs are being replaced for EPU and are designed for the uprated steam flows. The main steam system will supply the required steam flow to the MSRs at EPU.

The AFW pump turbine supply and exhaust piping were determined to be acceptable for EPU conditions. The pressure ratings of piping and valves remain bounding at EPU. The existing steam supply piping is capable of providing the required steam supply flow rate to the pump

turbine at EPU since the design brake horsepower of the AFW pump turbine bounds the brake horsepower required to supply the EPU AFW flow rate.

The main steam system's ability to supply steam to auxiliary components, including the turbine gland steam supply and the condenser air ejectors, will not be affected by the EPU. None of these steam flow requirements change appreciably due to EPU conditions. The EPU heat balances include these required auxiliary flows and confirm that sufficient main steam flow exists to ensure the high pressure turbine and moisture separator reheaters' performance meets the desired EPU power generation requirements.

Main Steam Piping Drain Capacity

The MSSS piping is provided with drains to collect water from condensing steam in the MSSS piping and direct the water to the condenser hotwells. The drains were originally designed with sufficient capacity, based on start-up conditions where hot steam is introduced into cold piping. This startup situation typically produces far more water condensation than normal operating conditions when both the incoming steam and the piping are hot. Since start-up conditions are not affected by EPU, this sizing is unaffected.

Factors that affect condensation/drainage requirements include physical characteristics of the pipe, such as size, slope, internal restrictions at valves, orifices, etc., steam temperature, insulation thickness and ambient temperature. Based on industry practices for sizing of steam drains, the expected drain flow rate is not affected by the increase in steam flow, changes in MSSS quality, or any other factors that might be affected by EPU. Due to the minor changes in steam pressure there will be some changes to the steam temperature; however, these changes are minor and do not significantly affect drain flow. Therefore, the MSSS piping drains are acceptable for EPU operation.

Other Considerations

The design of SSC's remain acceptable to protect safety related SSC's from the effects of pipe whip and jet impingement loading for EPU. Missile protection criteria is discussed in UFSAR Section 3.5. Refer to LR [Section 2.5.1.2.1](#), Internally Generated Missiles. The existing missile protection measures inside containment remain effective for EPU conditions. UFSAR Section 3.1.5 identifies the shared safety-related components between St. Lucie Units 1 and 2. The main steam system does not share any structures, systems or components and therefore complies with GDC-5.

2.5.5.1.3 Conclusion

FPL has reviewed the effects of the proposed EPU on the MSSS and concludes that the review has adequately accounted for the effects of changes in plant conditions on the design of the MSSS. FPL concludes that the MSSS will maintain its ability to transport steam to the power conversion system, provide heat sink capacity, supply steam to steam-driven safety pumps, and withstand steam hammer. FPL further concludes that the MSSS will continue to meet its current licensing basis with respect to the requirements of GDCs -4, -5 and -34. Therefore, FPL finds the proposed EPU acceptable with respect to the MSSS.

**Table 2.5.5.1-1
System Operating Conditions**

	Current Operating Condition	EPU Operating Condition
Steam Generator Outlet to Main Steam Isolation Valves		
Flow rate, lbm/hr	5,903,370	6,663,100
Pressure, psia	880.6	888.0
Temperature, °F	529.4	530.4
Main Steam Isolation Valves to MSSS Common Header		
Flow rate, lbm/hr	5,903,370	6,663,100
Pressure, psia	871.1	875.8
Temperature, °F	528.1	528.7
Main Steam Common Header		
Flow rate, lbm/hr	5,903,370	6,663,100
Pressure, psia	869.2	873.6
Temperature, °F	527.9	528.4
MSSS Common Header to HP Turbine Isolation Valves		
Flow rate, lbm/hr	5,389,440	6,149,760
Pressure, psia	861.9	866.5
Temperature, °F	526.9	527.5
MSSS Common Header to MSRs		
Flow rate, lbm/hr	254,056	254,094
Pressure, psia	861.9	866.5
Temperature, °F	526.9	527.5
Cold Reheat Piping – High Pressure Turbine Exhaust to MSR Inlet		
Flow rate, lbm/hr	2,243,052	2,540,666
Pressure, psia	209.8	232.6
Temperature, °F	385.8	394.7
Hot Reheat Piping – MSR Outlet to Low Pressure Turbine Inlet		
Flow rate, lbm/hr	2,024,638	2,271,439
Pressure, psia	202.2	228.7
Temperature, °F	509.8	515.1
Main Steam Design Pressure/Temperature		
Pressure, psig	985	985
Temperature, °F	550	550

2.5.5.2 Main Condenser

2.5.5.2.1 Regulatory Evaluation

The main condenser system 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 and control system (SBCS). The Florida Power and Light (FPL) review focused on the effects of the proposed EPU on the steam bypass capability with respect to load rejection assumptions, and on the ability of the main condenser system to withstand the blowdown effects of steam from the turbine bypass system.

The NRC's acceptance criteria for the main condenser system 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 Standard Review Plan (SRP) Section 10.4.1.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to Title 10 of the Code of Federal Regulations (10 CFR) Part 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDCs for the main condenser system are as follows:

- GDC-60 is described in UFSAR Section 3.1.60, Criterion 60 – Control of Releases of Radioactive Materials to the Environment.

The nuclear power unit design shall include means to control suitably the release of radioactive materials in gaseous and liquid effluents and to handle radioactive solid wastes produced during normal reactor operation, including anticipated operational occurrences. Sufficient holdup capacity shall be provided for retention of gaseous and liquid effluents containing radioactive materials, particularly where unfavorable site environmental conditions can be expected to impose unusual operational limitations upon the release of such effluents to the environment.

The main condenser is discussed in UFSAR Section 10.4.1.

The main condenser serves no safety function and is classified as nonseismic. The two shell, single pressure, main condenser provides a continuous heat sink for the exhaust from the two tandem-compound low pressure turbines and for miscellaneous flows, drains and vents during normal plant operation.

The main condenser also provides a heat sink for the SBCS during the initial phase of plant cooldown (after reactor shutdown).

The main condenser consists of two 50 percent capacity, divided water box, surface condensers of the single-pass type with tubes arranged perpendicular to the turbine shaft. Cooling water for the condensers is provided by the circulating water system. The condensers are of the

deaerating type and are sized to condense exhaust steam from the main turbine under full load conditions. The hot well storage is located below the bottom row of tubes in each condenser shell.

The condenser hot wells serve as a storage reservoir for deaerated condensate which supplies the condensate pumps. The storage capacity of the hot wells can provide sufficient feedwater for four minutes of operation at maximum throttle flow with some additional volume for surge protection. Condensate makeup from the condensate storage tank is admitted by gravity or by the condensate transfer pumps into the condenser.

Refer to LR [Section 2.5.3.2](#), Main Condenser Evacuation System, relative to gaseous radioactive material handling, release assumptions, and radiation monitoring.

In addition to the licensing basis described in the UFSAR, the main condenser was evaluated for License Renewal. As documented in NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003, the main condenser was determined to be outside the scope of License Renewal.

2.5.5.2.2 Technical Evaluation

2.5.5.2.2.1 Introduction

As described in UFSAR Section 10.4.1, the main condenser is of the deaerating type and is sized to condense exhaust steam from the main turbine under full load conditions. The condenser consists of two 50 percent capacity, divided waterbox, surface condensers of the single pass type with tubes arranged perpendicular to the turbine shaft. The condenser shells are connected to the low pressure turbine exhausts by belt type, rubber expansion joints.

The condenser hotwell is a storage reservoir for the deaerated condensate which supplies the condensate pumps. The hotwell supply of condensate is backed up by the condensate storage tank from which condensate may be admitted.

The condenser extracts the latent heat of vaporization from the low pressure turbine exhaust steam, the SBCS (when in operation) and miscellaneous flows, drains and vents during normal plant operation. This heat is transferred to the circulating water system. The resulting condensate is collected in the condenser hotwell before entering the condensate and feedwater system. The condensate hotwell level control system is designed to maintain sufficient level to provide the suction head for the condensate pumps. The condensate in the hotwell is deaerated.

The condenser uses circulating water for heat removal and transfer of the rejected heat to the Atlantic Ocean. The circulating water system is described in UFSAR Section 10.4.5. The evaluation of the EPU effect on the circulating water system is described in LR [Section 2.5.8.1](#), Circulating Water System.

The SBCS is discussed in UFSAR Section 10.4.4. The purpose of the SBCS is to minimize the stresses on the nuclear steam supply system induced by changes in the secondary plant steam demand. As discussed in LR [Section 2.5.5.3](#), Turbine Bypass, the SBCS requires modification for EPU operation in order to restore its steam dump capability measured as a percentage of the

new reactor thermal power level. Refer to LR [Section 2.5.5.3](#), Turbine Bypass, for additional discussion of the SBCS.

During plant operation, non-condensable gases from the main condenser are exhausted through the main condenser evacuation system (LR [Section 2.5.3.2](#), Main Condenser Evacuation System). The adequacy of the main condenser system design relative to control of the release of radioactive material from steam in the turbine to the environment is provided by demonstration of the adequacy of the main condenser to maintain structural capability during operation, the condenser evacuation system to maintain the condenser at vacuum conditions and the radiation monitoring system to monitor the effluent for release to the environment.

To support operation under EPU conditions, components internal to the main condenser will require modifications. The modifications are intended to facilitate operation at the new power level and include additional tube staking and extension of the condenser air evacuation spool pieces to improve air evacuation efficiency.

2.5.5.2.2.2 Description of Analyses and Evaluations

The main condenser will experience higher steam flows due to the increase in low pressure (LP) turbine exhaust flow at the EPU power level and higher steam flows due to the increase in the steam flow bypassed to the condenser by the SBCS at EPU. The evaluation determined the impact of the EPU conditions on condenser performance and integrity as follows:

- Determine the increased condenser duty and confirm the condenser's ability to reject heat to the circulating water system and maintain a low enough condenser backpressure for the turbine to meet its EPU megawatt output and performance requirements, without reaching the high condenser pressure turbine trip setpoint;
- Evaluate the condenser hotwell storage capacity to provide sufficient storage volume with the maximum flow rate at EPU conditions;
- Evaluate the capability of the main condenser to remove dissolved gases and air in-leakage from the condensate;
- Evaluate the effects of increased steam flow at normal EPU power operation and during steam dump to the condenser on condenser tube vibration;
- Evaluate the impact of the increased steam dump flow on condenser backpressure during steam dump conditions and confirm that the SBCS interlock on high condenser pressure is not reached;
- Evaluate the impact of the increased steam flow on the condenser connections; and
- Evaluate the impact of the increased steam flow on the plant design to control the release of radioactive effluents.

2.5.5.2.2.3 Impact on Renewed Plant Operating License Evaluations and License Renewal

As discussed above, the main condenser was determined to be outside the scope of License Renewal; therefore, with respect to the main condenser, the EPU does not impact any License Renewal evaluations.

2.5.5.2.2.4 Results

The evaluation determined that the condenser satisfactorily removes the increased EPU heat loads, condenses the required steam flows, including steam bypass flow, and maintains an acceptable vacuum using circulating water at the current normal operating flow rate. For a further discussion of condenser heat removal, refer to LR [Section 2.5.8.1](#), Circulating Water System. LR [Table 2.5.5.2-1](#) describes the key design parameters of the main condenser and compares its performance at current operating and EPU conditions.

The EPU heat balance models used a range of circulating water inlet temperatures, 65°F, 75°F, and a conservative upper limit of 90°F, to reflect seasonal ocean water temperatures. As discussed in LR [Section 2.5.8.1](#), the maximum temperature rise between the intake and discharge is calculated to be less than 30°F and remains within the limits of the State of Florida Industrial Wastewater Facility Permit. In addition, the State of Florida Industrial Wastewater Facility Permit discharge temperature limits will be maintained in accordance with the plant's discharge monitoring strategy. As seen in LR [Table 2.5.5.2-1](#), the projected condenser backpressure of 4.46" HgA, considering a 90°F circulating water inlet temperature, remains below the current low vacuum alarm setpoint of 25" HgV (4.9" HgA). Revision of this setpoint for EPU operation will be considered as part of the low pressure turbine upgrade. The current turbine trip setpoint for condenser backpressure remains acceptable for the increased flow rates at EPU conditions. However, implementation of a turbine trip setpoint on condenser backpressure that varies as a function of load will be considered as part of the turbine controls system modification.

At EPU conditions, the storage capacity of the hotwell is sufficient for four minutes of operation at maximum throttle flow. Therefore, the existing hotwell capacity is acceptable for EPU conditions.

The ability of the condenser to maintain the required deaeration of condensate flow remains acceptable at EPU conditions. Only the non-condensable gases collected in the condenser, not the air in-leakage, will increase at EPU conditions. For a further discussion of condenser deaeration refer to LR [Section 2.5.3.2](#), Main Condenser Evacuation System.

The evaluation confirmed that the condenser adequately withstands the steam blowdown effects of increased steam flow at normal EPU power operation at circulating water system temperatures up to 90°F. A main condenser tube vibration evaluation determined that the overall condenser tube support configuration is adequate for EPU operation; however, the level of tube staking will be increased to minimize the effects of vibration and ensure the reliability of the condenser tube bundle at EPU conditions.

Per LR [Section 2.5.5.3](#), Turbine Bypass, a modification to restore the capacity of the steam dump and bypass valves as a percentage of the EPU thermal power level is planned.

The condenser connections and spargers have been evaluated and will perform satisfactorily at EPU conditions. Additional tube staking and extension of spool pieces for the condenser air removal piping will be performed to facilitate operation at the new power level.

The modifications to the main condenser for EPU do not impact the ability of St. Lucie Unit 2 regarding the control of radioactive material in accordance with GDC-60, as described in LR [Section 2.5.3.2](#), Main Condenser Evacuation System. The impact of EPU on radiological effluent releases, radiation monitoring setpoints and compliance with 10 CFR 50, Appendix I, is discussed in LR [Section 2.10.1](#), Occupational and Public Radiation Doses.

2.5.5.2.3 Conclusion

FPL has reviewed the effects of the proposed EPU on the main condenser system and concludes that the review has adequately accounted for the effects of changes in plant conditions on the design of the main condenser. FPL concludes that the main condenser will continue to maintain its ability to withstand the blowdown effects of the steam from the turbine bypass system and; thereby, will continue to meet its current licensing basis with respect to the requirements of GDC-60 for controlling the release of radioactive effluents. Therefore, the proposed EPU is acceptable with respect to the main condenser system.

**Table 2.5.5.2-1
Main Condenser Performance Characteristics**

Circulating Water Inlet Temperature	Current Operation 100% Power	EPU Operating 100% Power
Condenser Duty		
75°F	6102 x 10 ⁶ BTU/hr	6788 x 10 ⁶ BTU/hr
Condenser Backpressure		
65°F	Not Available	2.26 in HgA
75°F	2.61 in HgA	2.96 in HgA
90°F	Not Available	4.46 in HgA

2.5.5.3 Turbine Bypass

2.5.5.3.1 Regulatory Evaluation

The turbine bypass system is referred to as both the steam dump and bypass system and the steam bypass control system (SBCS) in plant documents. For consistency, SBCS will be used herein. The SBCS enables the plant to take step load reductions up to the system capacity without the reactor or turbine tripping. The system is used during startup and shutdown to control steam generator (SG) pressure. FPL's review focused on the effects that extended power uprate (EPU) has on load rejection capability, analysis of postulated system piping failures, and on the consequences of inadvertent SBCS operation.

NRC's acceptance criteria for the SBCS are based on:

- GDC-4, insofar as it requires that structures, systems and components (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.
- GDC-34, insofar as it requires that a residual heat removal (RHR) system be 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 Standard Review Plan (SRP) Section 10.4.4.

St. Lucie Unit 2 Current Licensing Basis

As noted in St. Lucie Unit 2 Updated Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in St. Lucie Unit 2 UFSAR Section 3.1.

- GDC-4 is described in UFSAR Section 3.1.4 Criterion 4 – Environmental and Missile Design Bases.

Structures, systems and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss- of- coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and approved by the Commission demonstrates that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

SSCs important to safety are designed to accommodate the effects of and to be compatible with the pressure, temperature, humidity, and radiation conditions associated with normal operation,

maintenance, testing, and postulated accidents including a loss-of-coolant accident (LOCA) in the area in which they are located.

Non-Seismic Category I Piping is arranged or restrained so that failure of any non-seismic Category I piping will neither cause a nuclear accident nor prevent essential seismic Category I structures or equipment from mitigating the consequences of such an accident.

Refer to UFSAR Sections 3.5, 3.6 and 3.11 for details.

- GDC-34 is described in UFSAR Section 3.1.34 Criterion 34 – Residual Heat Removal.

A system to remove residual heat shall be provided. The system safety function shall be to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded.

Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

Residual heat removal capacity is provided with sufficient redundancies in design that in the event of a single active failure or a single limited leakage passive failure the system can still perform its function. The steam generator auxiliaries and the shutdown cooling system are designed to operate from either offsite or onsite electric power sources. See UFSAR Section 5.4.7 for additional information.

The steam dump and bypass control system, a subsystem of the distributed control system (DCS), is described in UFSAR Section 10.4.4 and is designed to provide a means of manually controlling reactor coolant temperature during plant startup and for removing nuclear steam supply system (NSSS) stored energy, decay heat, and pump energy during shutdown cooling. In addition, the system can automatically accommodate a load rejection of up to 29 percent without opening the pressurizer relief valves or the main steam safety valves or causing a reactor trip.

As stated in UFSAR Section 10.4.4.1, on a load rejection the steam dump and bypass valves are modulated in sequence to control main steam pressure to a fixed setpoint. A quick opening signal is generated as a function of the magnitude and rate of change of the load rejection determined by monitoring both the steam flow and the turbine load. The duration of the quick opening signal is proportional to the flow magnitude and rate of change. Once the signal is removed the valves revert back to the modulation control. The quick opening signal on a reactor trip is generated when both the measured reactor coolant average temperature and the main steam pressure exceed their preset threshold values.

The steam dump and bypass has no safety design bases and is classified as non-seismic. The steam dump and the bypass valves are air operated globe valves with a capacity of 24 percent and 5 percent, respectively, of the total full power steam flow.

In addition to the licensing basis described in the UFSAR, the SBCS was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems

to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.4.1 of the SER identifies that components of the SBCS are within the scope of License Renewal. Programs used to manage the aging effects associated with the SBCS are discussed in SER Section 3.4.1 and Chapter 18 of the UFSAR.

2.5.5.3.2 Technical Evaluation

2.5.5.3.2.1 Introduction

The SBCS is described in UFSAR Section 10.4.4. The SBCS consists of four steam dump valves, one turbine bypass valve, and piping from the main steam headers to the condenser. The purpose of the SBCS system is to minimize the stresses on the NSSS induced by changes in the secondary plant steam demand. The current design capacity of the dump valves and turbine bypass valve is 24 percent and 5 percent of main steam flow, respectively. In addition to limiting the reactor coolant system (RCS) temperature and pressure transients following reductions in steam loads, the SBCS aids in conducting RCS cooldowns and heatups and removes reactor decay heat following a reactor shutdown or during hot standby conditions. The design of the SBCS is based on the criteria that no single component failure or incorrect operator action can cause opening of more than one dump valve. There is a control system interlock which prevents initiation of condenser steam dump when the condenser vacuum is above a preset value (loss of vacuum).

2.5.5.3.2.2 Description of Analyses and Evaluations

The SBCS creates an artificial steam load by dumping steam from ahead of the turbine valves to the main condenser. The system (valves and piping) is currently designed to be capable of discharging 29 percent of the rated steam flow at full-load steam pressure without a reactor trip.

St. Lucie Unit 2 is equipped with 4 steam dump valves and 1 turbine bypass valve, with a total mass flow rate capacity of 3.7×10^6 lb/hr.

The SBCS was evaluated to ensure that the system is capable of performing the following functions for the range of NSSS design parameters approved for EPU:

- Provide a means of manually controlling reactor coolant temperature during plant normal heatup and cooldown, when the condenser is available,
- Remove excess heat from the NSSS during load reductions, after unit trips and anytime conditions exist which may result in high secondary system pressure, and
- Remove reactor decay heat following a reactor shutdown or during hot standby conditions.

The capacity of the SBCS (as a percentage of full-load steam flow) decreases as full-load steam pressure decreases and full-load steam flow increases. Accordingly, NSSS operation within the proposed range of design parameters for EPU will result in a reduced steam dump capability

relative to the original design. Consequently, the SBCS capacity will be increased to restore the original system design capacity as a percentage of the post EPU rated thermal power.

The upgraded SBCS capacity is bounded in the excess steam demand analyses of LR [Section 2.8.5.1](#), Increase in Heat Removal by the Secondary System. The pipe stress forcing function for the increased capacity of the SBCS is also bounded as discussed in LR [Section 2.2.2.2](#), Balance of Plant Piping, Components and Supports. Therefore, the SBCS will continue to comply with the protection against dynamic effects as discussed in GDC-4. The design of the SBCS is based on the criteria that no single component failure or incorrect operator action can cause opening of more than one dump valve. EPU has no adverse effect on this original SBCS design criteria. EPU does not adversely affect any of the existing SBCS control logic interlocks or permissives, as discussed in LR [Section 2.4.1](#), Reactor Protection Safety Features Actuation and Control Systems.

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

As discussed above, portions of the SBCS are within the scope of License Renewal. Operation of the SBCS under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.5.5.3.2.4 Results

The SBCS piping design pressure of 985 psig (1000 psia) bounds the actuation setpoint pressure of 900 psia, which is unchanged at EPU. Therefore, the design pressure of the SBCS remains bounding for EPU operation.

A modification to the SBCS is being performed such that the system will be able to pass at least 45 percent of 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).

2.5.5.3.3 Conclusion

FPL has reviewed the assessment of the effects of the proposed EPU on the SBCS. FPL concludes that the analyses have adequately accounted for the effects of changes in plant conditions on the design of the system and that the SBCS will continue to provide a means for shutting down the plant during normal operations. FPL further concludes that SBCS failures will

not adversely affect essential systems or components. Based on this, FPL concludes that the SBCS will continue to meet its current licensing basis with respect to the requirements of GDCs -4 and -34. Therefore, FPL finds the proposed EPU acceptable with respect to the SBCS.

2.5.5.4 Condensate and Feedwater

2.5.5.4.1 Regulatory Evaluation

The condensate and feedwater system (CFS) provides feedwater at the appropriate temperature, pressure, and flow rate to the steam generators (SGs). The only part of the CFS classified as safety-related is the feedwater piping from the SGs up to and including the outermost containment isolation valve. The Florida Power and Light (FPL) review focused on the effects of the proposed extended power uprate (EPU) on previous analyses and considerations with respect to the capability of the CFS to supply adequate feedwater during plant operation and shutdown, and to isolate components, subsystems, and piping in order to preserve the system's safety function. FPL's review also considered the effects of the proposed EPU on the feedwater system, including the auxiliary feedwater (AFW) system piping entering the feedwater system, 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:

- General Design Criterion (GDC)-4, insofar as it requires that structures, systems and components (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,
- 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
- 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 Standard Review Plan (SRP) Section 10.4.7.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDC for the condensate and feedwater systems are:

- GDC-4 is described in UFSAR Section 3.1.4 Criterion 4 – Environmental and Missile Design Bases.

SSCs important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss- of- coolant accidents. These

SSCs shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and approved by the Commission demonstrates that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

SSCs important to safety are designed to accommodate the effects of and to be compatible with the pressure, temperature, humidity, and radiation conditions associated with normal operation, maintenance, testing, and postulated accidents including a loss-of-coolant accident (LOCA), in the area in which they are located.

Protective walls and slabs, local missile shielding, or restraining devices are provided to protect the containment and engineered safety features systems within the containment against damage from missiles generated by equipment failures. Penetrations and piping extending outward from the containment, up to and including isolation valves are protected from damage due to pipe whipping, and are protected from damage by external missiles, where such protection is necessary to meet the design bases.

Non-seismic Category I piping is arranged or restrained so that failure of any non-seismic Category I piping will neither cause a nuclear accident nor prevent essential seismic Category I structures or equipment from mitigating the consequences of such an accident.

Seismic Category I piping is arranged or restrained such that in the event of rupture of a seismic Category I pipe which causes LOCA, resulting pipe movement will not result in loss of containment integrity or adequate engineered safety features systems operation.

The structures inside the containment vessel are designed to sustain dynamic loads which could result from failure of major equipment and piping, such as jet thrust, jet impingement and local pressure transients, where containment integrity is needed to cope with the conditions.

Refer to UFSAR Sections 3.5, 3.6 and 3.7 for details.

- GDC-5 is described in UFSAR Section 3.1.5 Criterion 5 – Sharing of Structures, Systems or Components.

Structures, systems and components important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units.

The CFS is not shared between the two units, with the exception of the condensate polisher filter demineralizer (CPFD) system. As discussed in UFSAR Section 10.3.5.5, the CPFD system can be connected to serve either St. Lucie Unit 1 or Unit 2, but not both at the same time.

- GDC-44 is described in UFSAR Section 3.1.44 Criterion 44 - Cooling Water.

A system to transfer heat from structures, systems and components important to safety, to an ultimate heat sink shall be provided. The system safety function shall be to transfer the

combined heat load of these structures, systems, and components under normal operating and accident conditions.

Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

The CFS is not specifically addressed; however, the CFS provides heat removal from the reactor coolant system (RCS) during normal power operation. The feedwater system has safety related functions, which are considered part of this GDC, by providing redundant flow paths for the AFW system flow to the SGs for heat removal from the RCS and by providing the required safety related, redundant isolation functions of main feedwater during postulated accidents.

Additional information related to the design and function of the CFS can be found in UFSAR Section 10.4.7.

The condensate, feedwater and heater drain system, shown on UFSAR Figures 10.1-2a, 2b and 10.1-3a, 3b, draws water from the condenser hotwells and feedwater heaters and pumps it to the steam generators feed nozzles.

The safety related portions of the feedwater systems have the following design bases:

- Provide feedwater to the SGs during normal, shutdown and transient operations,
- Provide automatic containment isolation in the event of a LOCA,
- Withstand pipe rupture effects as discussed in UFSAR Section 3.6,
- Withstand the adverse environmental effects of tornadoes, hurricanes and flooding as discussed in UFSAR Sections 3.3 and 3.11,
- Be protected against externally generated missiles as discussed in UFSAR Section 3.5, and
- Design to preclude hydraulic instabilities, (e.g. water hammer).

The CFS supplies full load feedwater flow plus SG blowdown flow and cycle losses at the expected SG pressures during normal plant operations. In addition, the system provides the required flow to the SGs during transient plant load changes, turbine and reactor trip.

Each feedwater line is provided with two redundant main feedwater isolation valves (MFIVs) which are designed to Quality Group B, seismic Category I requirements. These isolation valves are provided with electro hydraulic operators that enable both fast valve closure during the accident mode and slow valve closure during normal plant operations.

The design provisions for the prevention of feedwater instability (i.e., water hammer) are discussed in UFSAR Section 10.4.9.3. Transients involving loss of heat removal by the secondary system are described in UFSAR Section 15.2.

In addition to the licensing basis described in the UFSAR, the CFS was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those

systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Sections 2.3.4.2 and 2.3.4.3 of the SER identifies that components of the CFS are within the scope of License Renewal. Programs used to manage the aging effects associated with the CFS are discussed in SER Section 3.4 and Chapter 18 of the UFSAR.

2.5.5.4.2 Technical Evaluation

2.5.5.4.2.1 Introduction

The CFS is designed to supply heated condensate to the SGs for steam production. The system consists of three condensate pumps, two heater drain pumps, and two SG feedwater pumps. In addition the system consists of a gland steam condenser, steam jet air ejectors, two strings of four low pressure feedwater heaters including external drain coolers for feedwater heaters 4A/B, two strings of single high pressure heaters, main feedwater regulator valves, MFIVs, heater drain pump level control valves, and various other valves, piping, and instrumentation. EPU affects the entire CFS, but in particular the high pressure feedwater heaters, the heater drain pumps, the SG feedwater pumps, and condensate pumps; which will be replaced, and the feedwater regulator valves and low pressure feedwater heaters 4A/B, which will be modified prior to implementation of EPU.

The CFS provides feedwater at the appropriate temperature, pressure, and flow rate to the SGs. The CFS is not designed to seismic Class I standards except for the piping from the SGs to the two redundant feedwater isolation valves on each feedwater line. Details of isolation provisions are contained in UFSAR Table 6.2-52. The only part of the CFS classified as safety-related and seismic Class I is the feedwater piping from the SGs up to and including the two redundant feedwater isolation valves on each feedwater line. This portion of the CFS is located in the containment building and the steam trestle, both of which are seismic Class I structures designed to withstand tornado missiles.

Safety related components and piping within the feedwater system are used for containment isolation and feedwater isolation during accidents and transients as well as being the main feedwater flow paths to each SG during normal operation. The safety related portion of the piping is also used for AFW addition. For details on the AFW system and condensate storage tank (CST) requirements, see LR [Section 2.5.4.5](#), Auxiliary Feedwater System.

Specific CFS design functions include:

Condensate System:

- Provides condensate to the feedwater system during normal, shutdown and transient operations at the required pressure and temperature;
- Provides an increase in the power cycle efficiency during normal power generation;
- Provides sealing and cooling water to plant auxiliaries and peripheral systems during normal power generation;
- Provides for condensate polishing capability when required;

- Provides a means for chemical addition to maintain acceptable secondary chemistry; and
- Serves as a cooling medium to condense the steam from the turbine gland steam condenser (GSC) and the steam jet air ejector (SJAЕ) condensers during normal power operation.

Feedwater System:

- Provides feedwater to the SGs during normal, shutdown and transient operations at the required pressure and temperature;
- Provides an increase in the power cycle efficiency during normal power generation;
- Preheats the feedwater to a temperature such that the feedwater that enters the SGs will not cause thermal shocking to the tubes or vessel walls during normal power generation;
- Provides feedwater to the SGs at the required water quality during normal power generation;
- Provides a safety related path for AFW delivery to the SGs;
- Meets containment isolation requirements;
- Provides isolation of feedwater in the event of high energy line breaks; and
- Automatically controls the water level in the SGs during steady state and transient conditions in conjunction with the distributed control system (DCS), which monitors feedwater flow, SG water level, and SG steam flow and actuates the feedwater regulating valves.

2.5.5.4.2.2 Description of Analyses and Evaluations

The CFS and components were evaluated to assure that they are capable of performing their intended functions at EPU conditions. The evaluation considered the effects of the EPU on the following system and component design aspects:

- Design pressure and temperature on piping and valves and components versus power uprate operating pressure and temperatures,
- Flow velocities,
- MFIVs closure within the required time period at EPU hydraulic conditions of flow and pressure drop,
- Capacity and control capability of the feedwater regulating valves;
- Feedwater heater design parameters and operating characteristics including:
 - Thermal performance,
 - Shell side and tube side velocities, including steam dome velocities,
 - Shell and tube side design pressure and temperature,
 - Shell and tube pressure drops,
 - Relief valve capacities and setpoints,
 - Shell side venting capacity,

- Steam impingement and flow induced vibration, and
- Tube plugging;
- Pump and pump supporting subsystems design capabilities, including net positive suction head (NPSH), flow, head, brake horsepower, minimum flow protection, and seal water supplies, and
- Process set points for pump protection, such as pump NPSH available.

The CFS was evaluated by utilizing a hydraulic model of the system components and piping, and the EPU heat balance. Physical plant data for the installed components and piping were utilized in the hydraulic model. Physical changes to condensate and feedwater components, valves and piping that resulted from the power uprate evaluations were incorporated into the hydraulic model and verified as acceptable.

Current plant operating data were gathered and included in the heat balance and hydraulic model to reflect the present day performance of the existing components.

The EPU heat balances were used to establish the flow, temperature and heat transfer requirements.

Other evaluations of CFS and components are addressed in the following LR sections:

- Effects of increased flow and velocity on erosion and corrosion – LR [Section 2.1.8](#), Flow-Accelerated Corrosion,
- Piping component and supports – LR [Section 2.2.2.2](#), Balance of Plant Piping, Components, and Supports,
- Protection against dynamic effects, including requirements of missiles, pipe whip and discharging fluids – LR [Section 2.2.1](#), Pipe Rupture Locations and Associated Dynamic Effects, and LR [Section 2.5.1.3](#), Pipe Failures,
- MFIV testing and valve closure requirements, including containment isolation requirements, LR [Section 2.2.4](#), Safety-Related Valves and Pumps,
- LR [Section 2.3.1](#), Environmental Qualification, which addresses the qualification of the safety related MFIVs,
- Operation of the CFS, including isolation features during postulated abnormal and accident scenarios, is discussed in LR [Section 2.4.2](#), Plant Operability,
- LR [Section 2.4.1](#), Reactor Protection, Safety Features Actuation, and Controls Systems, which evaluates condensate and feedwater instrumentation,
- LR [Section 2.5.4.5](#), Auxiliary Feedwater System, which evaluates the AFW system and condensate storage tank,
- LR [Section 2.6.1](#), Primary Containment Functional Design, which addresses post-accident heat removal requirements, and
- LR [Section 2.8.5](#), Accident and Transient Analyses, which addresses operation of the CFS, including isolation features during postulated abnormal and accident scenarios.

2.5.5.4.2.3 Impact on Renewed Plant Operation License Evaluations and License Renewal Programs

As discussed above, the CFS is within the scope of License Renewal. Operation of the CFS under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.5.5.4.2.4 Results

The following subsections evaluate the specific CFS capabilities while operating at EPU conditions.

Design Criteria

The evaluation of the CFS capabilities at EPU conditions demonstrates that St. Lucie Unit 2 will continue to meet the current licensing basis with respect to GDC-4 as described in LR [Section 2.2.1](#), Pipe Rupture Locations and Associated Dynamic Effects and LR [Section 2.5.1.3](#), Pipe Failures.

GDC-5 is applicable to St. Lucie Unit 2 as it is a dual unit installation; however, the CFS is not shared between the units with the exception of the CPFCD system, which can serve either Unit 1 or Unit 2, but not both at the same time. Operation of the CFS at EPU conditions will not require any changes to the design and operation of the CPFCD. Therefore, St. Lucie Unit 2 will continue to meet the current licensing basis with respect to the requirements of GDC-5.

The evaluation of the CFS capabilities at EPU conditions demonstrates that St. Lucie Unit 2 will continue to meet the current licensing basis with respect to the requirement of GDC-44 described in UFSAR Section 3.1.44. Although the CFS are not specifically addressed in GDC-44 or in UFSAR Section 3.1.44, the feedwater system provides redundant flow paths for the AFW system flow to the SGs for heat removal from the reactor coolant system, provides an essential isolation function of feedwater flow to the SGs, and provides for containment isolation. The feedwater system provides this capability during accident conditions and is capable of achieving this function considering a single failure. The implementation of EPU does not affect the capability of the system to perform these functions as demonstrated by the system and component evaluation results described below and by the results of the analyses of postulated abnormal and accident scenarios discussed in LR [Section 2.8.5](#), Accident and Transient Analyses, and LR [Section 2.6.1](#), Primary Containment Functional Design.

System Operating Conditions – Current versus EPU Conditions

The CFS operating conditions; flow, temperature and pressure, were determined from hydraulic modeling of the piping systems and from the current operating (benchmark) and EPU heat balances. LR Table 2.5.5.4-1 compares the current CFS conditions to the EPU conditions.

Design Pressures and Temperatures – Components and Piping

The design pressures and temperatures of condensate and feedwater components and piping were evaluated at the EPU operating conditions. All piping and components were found acceptable for EPU operation.

Feedwater Heaters

Feedwater heaters 1A/B through 5A/B and external drain coolers 2A/B were evaluated for operation at the EPU conditions based upon their current design, materials, construction, and performance. All were determined to be acceptable with the exception of the high pressure 5A/B feedwater heaters. These are being replaced with new high pressure (HP) feedwater heaters designed for EPU conditions. The standards contained in Heat Exchange Institute (HEI) Standards for Feedwater Heaters along with the manufacturer's standards were used for acceptance criteria for the evaluation of the existing feedwater heaters.

Current plant operating data benchmarked the current operating heat balance. This current operating heat balance was then adjusted to predict the plant performance at EPU conditions. The replacement high pressure feedwater heaters will meet the thermal performance requirements of the EPU conditions. The EPU heat balances show the expected EPU power generation which confirms adequate performance of the existing heaters along with the addition of the new high pressure feedwater heaters.

The velocities of some feedwater heater tubes, nozzles and internal sections are above the HEI guidelines, manufacturer's guidelines or both, at EPU conditions. However, no physical changes are considered necessary to alleviate these conditions. The design and construction of the existing 1A/B through 4A/B feedwater heaters was evaluated by the vendor and found acceptable for operation at EPU conditions with specific monitoring programs in place to evaluate the potential for long term degradation. The long-term effects of the higher velocity in the tubes, nozzles and shells will be monitored.

All steam dome velocities were found to be within HEI limits and are acceptable for EPU.

The feedwater heaters' shell and tube side design pressures and temperatures are acceptable at the EPU conditions.

The feedwater heater tube side pressure drops do not exceed maximum allowable values and are acceptable for EPU operation per the vendor evaluation. The shell side pressure drop of all heaters is within HEI limits at EPU conditions with the exception of low pressure heaters 1A/B which exceed the HEI limit by 0.2 psid. However, the vendor evaluation concluded it is acceptable to operate these heaters at EPU conditions since the fluid will have sufficient energy to flow into the respective sinks (i.e. the condensers).

The sub-cooling zone end plate thickness does not meet HEI or the manufacturer's guidelines for heaters 1A/B through 3A/B. However, the vendor evaluation concluded the potential impact is

reduced thermal performance and the structural integrity of the heater is not affected. Therefore, it is acceptable to operate these heaters at the specified EPU conditions.

The existing feedwater heaters shell and tube side relief valves were evaluated. The existing relief valve capacities and setpoints are acceptable for EPU operation since the design pressures are not changing. The replacement HP feedwater heaters 5A/B will be supplied with new relief valves designed to meet the EPU conditions.

The current feedwater heaters' shell side vents can pass the required steam flow for EPU operation. However, the orifices installed in the vent lines of some feedwater heaters' venting systems will be resized to meet HEI requirements for EPU operation. The replacement HP feedwater heaters 5A/B will be supplied with new venting orifices designed to meet the EPU conditions.

Based upon the vendor's evaluation, the feedwater heaters will not be susceptible to flow induced vibration at EPU conditions.

Heat exchanger tube plugging limits were evaluated for EPU operation. Two percent of the tubes can be plugged in the future from the present condition for LP feedwater heaters 4A/B without exceeding the vendor recommended pressure differential across the pass partition plate. A modification of feedwater heater 4A/B pass partition plates will be implemented prior to operation at the EPU conditions. Ten percent of the tubes can be plugged in the future from the present condition for LP feedwater heaters 1A/B through 3A/B without exceeding the vendor recommended pressure differential across the pass partition plates.

In summary, the design and construction of the existing 1A/B through 4A/B feedwater heaters and drain coolers 2A/B is acceptable for continued operation at EPU conditions with the above modification to heaters 4A/B. An enhanced monitoring program will be implemented to develop baseline EPU erosion rates, define inspection periodicity, predict long term degradation rates, and perform maintenance as required. The flow accelerated corrosion evaluation is described in LR [Section 2.1.8](#), Flow-Accelerated Corrosion.

Flow Velocities – Piping

Flow velocities through the CFS were evaluated at the EPU power level. Velocities generally remain below the industry standard guidelines for these services although there are some pipes whose velocities exceed the guidelines. Flow velocities in the feedwater pump recirculation lines currently exceed industry guidelines; however, wear of the lines has been acceptable and flow velocities will not adversely change for EPU. Flow velocities in the condensate pump suction piping exceed industry guidelines. However, based on a physical model study of the condensate pump suction piping, no changes or modifications are required for EPU conditions. Other individual pipes are evaluated as part of the flow accelerated corrosion program as described in LR [Section 2.1.8](#), Flow-Accelerated Corrosion.

Piping vibration will be monitored per LR [Section 2.12](#), Power Ascension and Testing Plan, to confirm that piping support modifications have satisfactorily mitigated potential vibration issues. The system instrumentation has also been evaluated for flow induced vibration effects. The CFS uses flow venturis that do not contain probes extending into the flow stream. Leading edge flow meters (LEFMs) will be installed as part of EPU implementation which will enhance feedwater

flow measurement. LEFMs do not contain probes extending into the flow stream. Isokinetic sampling probes do extend into the flow stream and are used in the condensate, feedwater, and heater drain system to determine the level of various corrosion products and dissolved oxygen in the fluid streams. The probes have been evaluated by the vendor for the increased flow velocities and are acceptable for EPU operation. 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.

Feedwater Regulating Valves

The existing feedwater regulating valves are being 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. EPU is not changing the function of, or the monitoring features of, the feedwater regulating valves.

Condensate and Feedwater Pumps and Supporting Subsystems

As discussed below, the feedwater pumps, condensate pumps, and heater drain pumps and some supporting subsystems require replacement to operate successfully during EPU conditions.

The existing condensate pumps have sufficient flow and head, and can supply sufficient NPSH to the SG feedwater pumps. However, the existing pumps require replacement at the EPU conditions to improve internal hydraulic performance and increase reliability. The replacement pumps are similar to the existing pumps. The suction piping to the pumps experiences high flow velocities. However, based on a physical model study of the condensate pump suction piping, no changes or modifications are required for EPU conditions. The existing motors are adequate to provide sufficient motive force for pump operation at EPU conditions.

The condensate system recirculation flow for startup and shutdown conditions remains unchanged for EPU and will continue to supply the minimum flow required for condensate pump protection while maintaining adequate flow to the gland steam condenser and steam jet air ejectors.

The existing feedwater pumps will be replaced and will provide the operating characteristics necessary to meet the EPU hydraulic requirements for pump capacity and head. The existing motors are adequate to provide sufficient motive force for pump operation at EPU conditions.

The feedwater pump recirculation system will be modified to accommodate the increased flow rates required by the replacement feedwater pumps.

The feedwater pump low suction pressure alarm and trip setpoints are being changed to meet the requirements of the new pumps.

The replacement feedwater pumps are being purchased with new seal water subsystem designed to meet the requirements of the new pumps.

The existing heater drain pumps are inadequate to meet EPU operating conditions. Replacement pumps will be installed that provide the operating characteristics necessary to meet the EPU

hydraulic requirements for pump capacity and head. The existing motors are adequate to provide sufficient motive force for pump operation at EPU conditions.

Feedwater Isolation Valves

Feedwater isolation is required for a variety of postulated transients and accident events. The current plant design provides for feedwater isolation using redundant safety related MFIVs.

The MFIVs have been evaluated for the increased flow rates, differential pressures, and temperatures at EPU. These valves will continue to meet the existing required closure times at the EPU conditions.

Containment isolation is accomplished by the provision of redundant safety related MFIVs on the feedwater headers outside containment. The containment isolation requirements are unaffected by EPU and the current plant design features remain acceptable.

2.5.5.4.3 Conclusion

FPL has reviewed the effects of the proposed EPU on the CFS and concludes that the review has adequately accounted for the effects of changes in plant conditions on the design of the CFS. FPL concludes that the CFS will continue to maintain its ability to satisfy feedwater 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. FPL further concludes that the CFS will continue to meet its current licensing basis with respect to the requirements of GDCs -4, -5, and -44. Therefore, FPL finds the proposed EPU acceptable with respect to the CFS.

Table 2.5.5.4-1
Condensate and Feedwater System Operating Conditions

Parameter	Current Operating Condition	Extended Power Uprate Operating Condition
Condensate System		
Flow Rate, lb/hr	8,217,096 (16,531 gpm)*	9,198,441 (18,526 gpm)*
Condenser Pressure, inches Hg Abs @ Circ Water Temp., °F	2.61 @ 74.6°F	2.96 @ 75.0°F
Condensate Pump Discharge Pressure, psia	623	587
Condensate Supply Temperature, °F (FW Pump Suction)	375.7	383.4
Heater Drain System		
Heater Drain Pump Flow, lb/hr	3,687,958 (8,031 gpm)*	4,226,007 (9,289 gpm)*
Heater Drain Pump Discharge Pressure, psia	582	553
Feedwater System		
Flow Rate, lb/hr	11,905,010 (27,049 gpm)*	13,424,450 (30,693 gpm)*
Feedwater Pump Discharge Pressure, psia	1,207	1,079
Steam Generator Supply Temperature, °F	435.0	436.6
* GPM flow values are calculated using pump discharge pressure shown above along with discharge temperature taken from the heat balance calculation.		

2.5.6 Waste Management Systems

2.5.6.1 Gaseous Waste Management Systems

2.5.6.1.1 Regulatory Evaluation

The Florida Power and Light Company (FPL) St. Lucie Unit 2 review focused on the effects that the proposed EPU may have on: (1) the design criteria of the gaseous waste management systems (GWMS), (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 gaseous waste management systems are based on:

- 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,
- GDC-3 insofar as it requires that:
 - Structures, systems, and components important to safety be designed and located to minimize the probability and effect of fires,
 - Noncombustible and heat-resistant materials be used,
 - Fire detection and fighting systems be provided and designed to minimize the adverse effects of fires on structures, systems, and components important to safety;
- GDC-60 insofar as it requires that the plant design include means to control the release of radioactive effluents,
- GDC-61 insofar as it requires that systems that contain radioactivity be designed with appropriate confinement,
- 10 CFR 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 Standard Review Plan (SRP) Section 11.3.

St. Lucie Unit 2 Current Licensing Basis

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

The specific GDCs for the GWMS are as follows:

- GDC-3 is described in UFSAR Section 3.1.3 Criterion 3 - Fire Protection.

Structures, systems and components important to safety shall be designed and located to minimize, consistent with other safety requirements, the probability and effect of fires and explosions. Noncombustible and heat resistant materials shall be used wherever practical throughout the unit, particularly in locations such as the containment and control room. Fire detection and fighting systems of appropriate capacity and capability shall be provided and designed to minimize the adverse effects of fires on structures, systems and components important to safety. Fire fighting systems shall be designed to assure that their rupture or inadvertent operation does not significantly impair the safety capability of these structures, systems and components.

Noncombustible and fire resistant materials are used wherever practical throughout the facility, particularly in areas containing critical portions of the plant such as containment structure, control room and components of systems important to safety. These systems are designed and located to minimize the effects of fires or explosions on their redundant components. Facilities for the storage of combustible material are designed to minimize both the probability and the effects of a fire.

The fire protection system is designed such that a failure of any component of the system:

- a. will not cause a nuclear accident or significant release of radioactivity to the environment,
- b. will not impair the ability of redundant equipment to safely shut down and isolate the reactor or limit the release of radioactivity to the environment in the event of a LOCA.

The Fire Protection System is described in UFSAR Appendix 9.5A.

- GDC-60 is described in UFSAR Section 3.1.60, Criterion 60 - Control of Releases of Radioactive Materials to the Environment.

The nuclear power unit design shall include means to control suitably the release of radioactive materials in gaseous and liquid effluents and to handle radioactive solid wastes produced during normal reactor operation, including anticipated operational occurrences. Sufficient holdup capacity shall be provided for retention of gaseous and liquid effluents containing radioactive materials, particularly where unfavorable site environmental conditions can be expected to impose unusual operational limitations upon the release of such effluents to the environment.

The waste management system is described in UFSAR Sections 11.2, 11.3 and 11.4, and is designed to provide controlled handling and disposal of liquid, gaseous, and solid wastes. The waste management system is designed to ensure that the general public and plant personnel are protected against exposure to radioactive material to meet the intent of 10 CFR Part 20 and 10 CFR Part 50, Appendix I.

Gaseous radioactive releases from the waste management system are accomplished on a batch basis. All radioactive materials are sampled prior to release to ensure compliance with 10 CFR Part 20 and 10 CFR Part 50, Appendix I and to determine release rates. Radioactive materials

which do not meet release limits will not be discharged to the environment. The waste management system is designed with sufficient holdup capacity and flexibility for reprocessing of wastes to ensure that releases are as low as practical.

The waste management system is designed to preclude the inadvertent release of radioactive material.

All storage tanks in the GWMS are administratively controlled to prevent the addition of waste to a tank which is being discharged to the environment. Each discharge path is provided with a radiation monitor which alerts plant personnel and initiates automatic closure of an isolation valve to prevent further releases (see UFSAR Section 11.5 for details).

- GDC-61 is described in the UFSAR Section 3.1.61, Criterion 61 - Fuel Storage and Handling and Radioactive Control.

The fuel storage and handling, radioactive waste, and other systems which may contain radioactivity shall be designed to assure adequate safety under normal and postulated accident conditions. These systems shall be designed (1) with a capability to permit inspection and testing of components important to safety, (2) with suitable shielding for radiation protection (3) with appropriate containment, confinement, and filtering systems, (4) with a residual heat removal capability having reliability and testability that reflects the importance to safety of decay heat and other residual heat removal, and (5) to prevent significant reduction in fuel storage coolant inventory under accident conditions.

As discussed in UFSAR Chapter 11, the waste management system is designed to permit controlled handling and disposal of liquid, gaseous, and solid wastes which will be generated during plant operation. The principal design criterion is to ensure that plant personnel and the general public are protected against exposure to radiation from wastes in accordance with limits defined in 10 CFR 20.

Gaseous waste storage is located within the reactor auxiliary building. This area provides confinement capability in the event of an accidental release of radioactive materials, and is ventilated with discharges to the plant vent which is monitored.

The gaseous waste system processes the vent gases from equipment located in the chemical and volume control system, waste management system and fuel pool system, such that the radioactive gaseous release to the environs will be ALARA.

The waste management system is designed to provide controlled treatment and disposal and protection to the general public by ensuring that all normal releases of radioactive material meet the numerical guides for design objectives and limiting conditions for operation to meet the as-low-as is reasonably achievable criterion of 10 CFR 50, Appendix I.

Additional information concerning the GWMS is provided in UFSAR Section 11.3.

In addition to the licensing basis described in the UFSAR, the GMWS was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety

Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.3.16 of the SER identifies that components of the GWMS are within the scope of license renewal. Programs used to manage the aging effects associated with the GWMS are discussed in SER Section 3.3.16 and UFSAR Chapter 18.

2.5.6.1.2 Technical Evaluation

2.5.6.1.2.1 Introduction

The gaseous waste management system is described in UFSAR Section 11.3. Potentially radioactive gases are collected and processed according to physical and chemical properties and radioactive concentrations in accordance with station operating procedures.

The gaseous waste management system design functions are:

- Collect gas from reactor coolant degassing operations, radioactive liquid waste processing, tank purging, and tank venting via the vent gas collection header, containment vent header, and vent gas surge header,
- Hold and monitor the gas in gas surge tanks,
- Compress the gas and store it in gas decay tanks,
- Sample and analyze the gas prior to release,
- Supply nitrogen gas as a tank cover to preclude explosive gas mixtures in tanks and as a system or component purge gas, and
- Supply hydrogen to the volume control tank gas space to maintain the desired concentration of reactor coolant dissolved hydrogen to suppress the net decomposition of water in the reactor.

2.5.6.1.2.2 Description of Analyses and Evaluations

The gaseous waste management system and associated components are evaluated to ensure that they are capable of performing their intended functions at EPU conditions. The evaluation compares the design parameters of the existing GWMS and components with the EPU operating conditions.

2.5.6.1.2.3 Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

As discussed above, the GWMS is within the scope of License Renewal. Operation of the GWMS under EPU conditions has been evaluated to determine if there any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.5.6.1.2.4 Results

Implementation of the EPU does not significantly increase the amount of gaseous waste processed by the GWMS. Plant system functions do not change and assumptions related to gaseous volume inputs remain the same. Refer to LR [Section 2.9.3](#) for discussion of radiological doses and their impact.

Implementation of EPU results in an increase in the equilibrium radioactivity in the reactor coolant, which does impact the concentrations of radioactive nuclides in the GWMS. However, the design capability of the GWMS and the total volume capacity for handling gaseous radioactive waste remains unaffected by the uprate. Refer to LR [Section 2.10.1](#) for discussion of occupational and public radiation doses. Consequently, the design capability of the GWMS and the total volume capacity for handling gaseous radioactive waste remains unaffected by the uprate.

The EPU does not affect the facility design features that includes the means to maintain control over the plant radioactive gaseous effluents.

The EPU does not affect the plant design for radioactivity confinement nor does it increase the quantity of gaseous waste storage requirements.

The EPU has a small impact on the quantity of gaseous waste generated. Although implementation of the EPU impacts the inventory of radioactive nuclides in the GWMS, in accordance with the UFSAR, discharge streams remain appropriately monitored with adequate safety features incorporated to maintain releases within the requirements of 10 CFR 20. The quantity of gaseous effluent releases will be controlled as they presently are through technical specifications. EPU does not add any new sources of potentially radioactive gases.

The EPU does not affect the plant design to control the release of radioactive effluents. It does not change the system flow rates, process conditions for the collection, processing, control or monitoring of radioactive effluents.

Technical Specification 3.11.2.5, Explosive Gas Mixture specifies the limiting condition for operation of the gas decay tanks based on the concentration percentages of hydrogen and oxygen to prevent the formation of potentially explosive gas mixtures inside the in-service tanks. UFSAR Chapter 13, Section 13.7.1.5 specifies the requirements for the monitoring and surveillance system to ensure these limits are maintained. These specifications are not affected by the EPU.

Implementation of the overall requirements of 10 CFR 50, Appendix I to ensure that use of radioactive waste treatment equipment results in radioactivity discharges that are “as-low-as-is-reasonably achievable” (ALARA) are formalized in Technical Specifications 6.8.4.f, Radioactive Effluent Controls Program and 6.14, Offsite Dose Calculation Manual (ODCM). The EPU has no effect on these requirements.

2.5.6.1.3 Conclusion

FPL has reviewed the gaseous waste management system. FPL concludes that the review has adequately accounted for the effects of the increase in fission product and the amount of gaseous waste on the ability of the system to control releases of radioactive materials and preclude the possibility of an explosion if the potential for explosive mixtures exists. FPL finds that the GWMS will continue to meet its design functions following implementation of the proposed EPU. FPL further concludes that the gaseous waste system will continue to meet its current licensing basis with respect to the requirements of 10 CFR 20.1302 and 10 CFR 50, Appendix I, sections II.B, II.C, and II.D and GDC-3, GDC-60, and GDC-61. Therefore, FPL finds the proposed EPU acceptable with respect to the GWMS.

2.5.6.2 Liquid Waste Management Systems

2.5.6.2.1 Regulatory Evaluation

The Florida Power and Light Company (FPL) review for the liquid waste management system (LWMS) focused on the effects that the proposed EPU may have on previous analyses and considerations related to the LWMS 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 liquid waste management systems are based on:

- 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,
- GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents,
- GDC-61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement,
- 10 CFR 50, Appendix I, Sections II.A and II.D, which set numerical guides for dose design objectives and limiting conditions for operation to meet the as low as is reasonably achievable (ALARA) criterion.

Specific review criteria are contained in Standard Review Plan (SRP) Section 11.2.

St. Lucie Unit 2 Current Licensing Basis

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

As discussed in UFSAR Section 11.2 "Liquid Waste System", the LWMS includes design features to appropriately monitor discharge streams and safety features to preclude releases in excess of 10 CFR 20 and to maintain radioactive discharges to levels as low as is reasonably achievable (ALARA) according to the requirements of 10 CFR 50, Appendix I.

The specific GDCs for the LWMS are as follows:

- GDC-60 is described in UFSAR Section 3.1.60, Criterion 60 – Control of Releases of Radioactive Materials to the Environment.

The nuclear power unit design shall include means to control suitably the release of radioactive materials in gaseous and liquid effluents and to handle radioactive solid wastes produced during normal reactor operation, including anticipated operational occurrences. Sufficient holdup capacity shall be provided for retention of gaseous and liquid effluents containing radioactive materials, particularly where unfavorable site environmental conditions

can be expected to impose unusual operational limitations upon the release of such effluents to the environment.

The LWMS is described in UFSAR Section 11.2 and is designed to provide controlled handling and disposal of liquid wastes. The LWMS is designed to ensure that the general public and plant personnel are protected against exposure to radioactive material to meet the intent of 10 CFR 20 and 10 CFR 50, Appendix I and to preclude the inadvertent release of radioactive material.

The LWMS is designed to maintain control over radioactive materials in liquid effluents produced under normal conditions, including expected occurrences in accordance with 10 CFR 50, Appendix I, Sections II.A and II.D and does so via plant operational procedures, Technical Specifications and the Offsite Dose Calculation Manual (ODCM). The Technical Specifications and ODCM discuss the limits and conditions for controlled plant releases.

The LWMS is in conformance with 10 CFR 20 via locating operating controls, valves, panels and instrumentation in accessible areas outside shielded walls and by shielding of radioactive components in order to minimize personnel dose rate. In those cases where a given process line requires operation of several valves and instruments which are not located in non-radiation areas, the operations are conducted from shielded positions and valves are operated using extension stems through the shielded walls.

- GDC-61 is described in UFSAR Section 3.1.61, Criterion 61 – Fuel Storage and Handling and Radioactive Control.

The fuel storage and handling, radioactive waste, and other systems which may contain radioactivity shall be designed to assure adequate safety under normal and postulated accident conditions. These systems shall be designed (1) with a capability to permit inspection and testing of components important to safety, (2) with suitable shielding for radiation protection (3) with appropriate containment, confinement, and filtering systems, (4) with a residual heat removal capability having reliability and testability that reflects the importance to safety of decay heat and other residual heat removal, and (5) to prevent significant reduction in fuel storage coolant inventory under accident conditions.

The LWMS is designed to ensure adequate personnel safety under normal and postulated accident conditions by providing the following:

- Components are designed and located such that appropriate periodic inspection and testing may be performed. Filters are monitored for differential pressure and radiation level on a regular basis. Ion exchangers are monitored for radiation level on a regular basis. The flash tank is sampled for hydrogen gas stripping function. All liquid discharges to the environs are sampled for radioactivity before discharge and the discharge radiation monitors are calibrated on a regular basis to assure accuracy.
- All areas of the plant are designed with suitable shielding for radiation protection based on anticipated radiation dose rates and occupancy as discussed in UFSAR Section 12.3.2.
- Individual LWMS processing components which contain significant radioactivity are located in a separate area of the reactor auxiliary building. This area provides confinement capability in the event of an accidental release of radioactive materials and is ventilated by discharge to the plant vent which is monitored for radioactivity.

Means are provided for monitoring effluent discharge paths for radioactivity that may be released from normal operations, including anticipated operational occurrences. Radioactive waste management and monitoring are discussed in UFSAR Chapter 11. The LWMS is capable of monitoring radioactive liquid discharge from the system to ensure that activity concentrations do not exceed predetermined limits.

The LWMS is designed to permit controlled handling and disposal of liquid wastes which are generated during plant operation. The principal design criterion is to ensure that plant personnel and the general public are protected against exposure to radiation from liquid wastes in accordance with the limits defined in 10 CFR 20.1302. To meet the requirements of 10 CFR 20.1302, radiological surveys are conducted and liquid effluent released are controlled in accordance with the ODCM. Actual plant data on liquid waste effluents obtained during operation are presented in the Annual Radioactive Effluent Release Report.

The boron recovery system and the liquid waste system (integral parts of the LWMS) are designed to:

- a. Process the various potentially radioactive liquid wastes such that the radioactivity release to the environs during normal operation will be as low as is reasonably achievable. The numerical design objectives for releases during normal operation are to limit average annual liquid activity release quantity to 5 Ci and average annual activity release concentration to 2×10^{-8} $\mu\text{Ci/cc}$ excluding tritium and dissolved fission product gases;
- b. Limit the annual average tritium discharge concentration to 5×10^{-6} $\mu\text{Ci/cc}$ in accordance with the Appendix I to 10 CFR 50;
- c. Limit releases due to anticipated operational occurrences within 10 CFR 20.

In addition to the licensing bases described in the UFSAR, the LWMS was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.3.16 of the SER identifies that components of the LWMS are within the scope of License renewal. Programs used to manage the aging effects associated with the LWMS are discussed in SER Section 3.3.16 and UFSAR Chapter 18.

2.5.6.2.2 Technical Evaluation

2.5.6.2.2.1 Introduction

The LWMS is discussed in UFSAR Section 11.2 and Section 11.5.

The LWMS controls, collects, segregates, processes, stores, recycles and disposes of liquid radioactive wastes generated during normal plant operation according to physical and chemical

properties and radioactive concentrations in accordance with St. Lucie Unit 2 operating procedures. The LWMS is split into two major processing systems:

- Boron Recovery System - handles potentially high activity, high purity wastes from the reactor coolant system (RCS).
- Liquid Waste Subsystem - handles low activity, low purity wastes from various plant sources.

The boron recovery system processes reactor coolant water from the chemical and volume control system (CVCS) and any leakage, drainage and relief valve flow from the RCS and associated systems. The boron recovery system consists of the following major components:

- Reactor drain tank – receives reactor quality water influx both directly and from containment drain headers that in turn receive equipment leakage, valve leakoff and miscellaneous drainage;
- Flash tank – used for processing RCS water if reactivity is above a certain threshold or if the nitrogen blanket in the holdup tanks is lost;
- Holdup tanks – designed to accumulate liquid waste discharges until sufficient amounts are ready for processing and have adequate capacity to handle waste flow surges during normal plant operation. These tanks store the liquid wastes for a period of time to allow for natural decay of short lived radionuclides prior to further processing. Four tanks allow for redundancy in waste processing since one tank can be processed while another is in recirculation mode for thorough mixing of contents and the other two can be filling with new wastes.

The liquid waste subsystem treats aerated, chemically contaminated, low purity and low activity wastes from sources outside of containment. These liquid wastes generally consist of effluent from equipment drains and leakage, sample and laboratory sink drains, equipment decontamination, floor drains, decontamination laundry water, decontamination showers, decontamination sinks, various tank drains, sump pumps and the steam generator blowdown system (SGBD) drains.

The liquid waste subsystem segregates these wastes for batch processing and collects them in the following tanks:

- Equipment drain tank,
- Chemical drain tank, and
- Laundry drain tanks.

Equipment Drain Tank

Low activity, aerated, and potentially dirty liquid drains and building sumps discharge to the equipment drain tank (EDT) via the leakage collection and return system and the drain collection header. The tank is vented to the vent gas collection header and is equipped with local high and low level alarms. The waste liquid is normally aligned to the Unit 1 aerated waste storage tank (AWST).

Chemical Drain Tank

The chemical drain tank (CDT) receives liquid waste inputs from the sampling system, decontamination drains, chemical laboratory drains that are normally low in activity but high in impurities and from the component cooling water (CCW) surge tank vent when high activity is sensed in the CCW system.

The liquid can then be directed to either the waste concentrator, waste condensate tanks, or through the waste ion exchangers and into the waste condensate tanks. The normal flow path of chemical drain tank effluent is the same as the equipment drain tank effluent, through the waste ion exchangers into the waste condensate tanks. The tank is vented to the vent gas collection header and is provided with a local high level alarm and a low level alarm. The waste liquid is normally aligned to the Unit 1 AWST.

Laundry Drain Tank

The laundry drain tanks (LDT) receive liquid waste inputs from plant hot showers, contaminated sinks, laundry operations, and potential inputs from the steam generator blowdown system. The laundry drain tanks are vented to the vent gas collection header and are equipped with a high level alarm and a low level alarm which trips the associated pump. Laundry wastewater is pumped to the Unit 2 AWST via a laundry filter for normal storage.

After collection, the liquid waste is then processed through ion exchangers and filters for removal of low activity material, impurities and debris. Final processing, recirculation and holding are accomplished by:

- AWST – receives liquid wastes from LWMS and SGBD tanks and waste ion exchangers, and
- Waste monitor tanks (Located in Unit 1).

All liquid released at St. Lucie is from the Unit 1 waste monitoring tanks. The waste monitor tanks are the final holding point for all liquid wastes prior to their release to the discharge canal. Liquids from waste monitor tanks that meet release requirements may be discharged to the circulating water discharge. Prior to discharge, the contents of the tank to be discharged are sampled for chemical and radioactivity concentration. The activity of discharge liquid must be consistent with the discharge criteria of 10 CFR 20 and 10 CFR 50 Appendix I. The discharge flow is monitored by a flow element and process radiation monitor that will close the isolation valve on high activity.

Liquid radioactive releases from the LWMS are accomplished on a batch basis for flexibility and to accommodate faster flow rates than the average annual process rates. All storage tanks in the LWMS are administratively controlled to prevent the addition of waste to a tank which is being discharged to the environment. The LWMS is designed with sufficient holdup capacity and flexibility for reprocessing of wastes to ensure that releases are as low as is reasonably achievable.

The facility includes those means necessary to maintain control over the plant liquid radioactive effluents. Appropriate holdup capacity is provided for retention of liquid effluents, particularly where unfavorable environmental conditions can be expected to require operational limitations upon the release of radioactive effluents to the environment. In all cases, the design for

radioactivity control is based on 10 CFR 20 requirements for both normal operations and for any transient situation that might reasonably be anticipated to occur.

2.5.6.2.2.2 Description of Analyses and Evaluations

The LWMS and associated components are evaluated to ensure that they are capable of performing their intended functions at EPU conditions. The evaluation determines whether the EPU operating conditions are enveloped by the design parameters of the existing system and components.

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

As discussed above, the LWMS is within the scope of License Renewal. Operation of the LWMS under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.5.6.2.2.4 Results

Implementation of the EPU does not significantly increase the volume of liquid waste processed by the LWMS because plant system functions do not change. There are no new sources of potentially radioactive liquids, nor are any new flow paths or routes created which could allow for the contamination of drainage systems designed for uncontaminated liquids. Additionally, the EPU does not change the collection, segregation, processing, discharging or recycling of radioactive liquid wastes. Liquids leaking from process systems, liquids used during cleaning activities, liquid spills from maintenance activities, liquids generated in the labs and from resin sluicing operations will continue to enter the LWMS during all plant operating modes. No impact is expected on the system equipment, piping, or instrumentation and controls from the EPU either, since system flow rates, liquid waste inventories and process conditions remain within the original design parameters.

The EPU results in minimal increases in liquid waste generation and resulting minimal increases in discharges from the plant. This is not expected to have any impact on the LWMS because discharge streams are monitored in accordance with the Offsite Dose Calculation Manual (ODCM) with the appropriate safety features incorporated to preclude radioactive releases in excess of 10 CFR 20 limits and to maintain releases ALARA per 10 CFR 50, Appendix I. Therefore, the operation, arrangement and management of the LWMS are acceptable for EPU.

Implementation of the EPU does result in a slight increase in the equilibrium radioactivity in the reactor coolant, which impacts the concentrations of radioactive nuclides in the LWMS. However,

this slight increase in radioactivity and the small volumes of radioactive liquid generated from leakage and planned drainage operations have a minimal effect on the generation of radioactive liquid wastes. Consequently, the design capability of the LWMS and the total volume capacity required for handling liquid radioactive waste is unaffected by the uprate. The impact of EPU on the radiological waste effluents and associated doses to the public is addressed in LR

Section 2.10.1, Occupational and Public Radiation Doses.

Evaluation of the LWMS at EPU conditions shows conformance with 10 CFR 20.1302, insofar as the annual average concentrations of radioactive materials released at the boundary of the unrestricted area will not exceed specified values. This will be demonstrated by the continued compliance post-EPU with the annual dose objective of 10 CFR 50, Appendix I as discussed in LR **Section 2.10.1**. Discharge streams will remain appropriately monitored and adequate safety features remain incorporated to preclude excessive releases, in accordance with the ODCM. Since the design objectives of Appendix I have been demonstrated previously, the increased source term due to EPU operation is minimal and no changes to system design or operation result from EPU; therefore, LWMS will continue to meet the current licensing basis with respect to 10 CFR 50, Appendix I.

The EPU does not affect the capability of the LWMS to meet the requirements of GDC-60 since the EPU does not affect the ability of the LWMS to control the release of radioactive effluents. The handling, control and release of radioactive materials are in compliance with 10 CFR 50, Appendix I and is described in the ODCM. There is no increase in radioactive materials, except as described in Licensing Report **Section 2.10.1** nor is there any change in the LWMS processing that controls radioactive effluents.

The EPU does not affect the capability of the LWMS to meet the requirements of GDC-61 since the EPU does not affect the ability of the LWMS to maintain confinement of liquid effluent radioactivity under all normal and postulated accident conditions, nor does it increase the quantity of liquid requiring storage. Since system flow rates, liquid waste inventories and process conditions remain within the original design parameters, the design capacities of various holding, processing and storage tanks are sufficient at EPU conditions.

The EPU does not change the design of the LWMS and there is only a minimal increase in liquid waste. All design attributes are unchanged.

The evaluation of the LWMS at EPU conditions demonstrates conformance with the requirements of 10 CFR 50, Appendix I, Sections II.A and II.D, which set numerical guides for dose design objectives and limiting conditions for operation to meet the ALARA criterion. This is formalized in the TS 6.8.4.f, Radioactive Effluent Controls Program and TS 6.14, Offsite Dose Calculation Manual (ODCM). Refer to LR **Section 2.10.1** for details. The EPU has no effect on these requirements.

2.5.6.2.3 Conclusion

FPL has reviewed the LWMS and concludes that this review 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. FPL finds that the LWMS will continue to meet its design functions following implementation of the proposed EPU. FPL further concludes that the

LWMS will continue to meet its current licensing basis with respect to the requirements of 10 CFR 20.1302, GDCs -60, -61 and 10 CFR 50, Appendix 1, Sections II.A and II.D. Therefore, FPL finds the proposed EPU acceptable with respect to the LWMS.

2.5.6.3 Solid Waste Management Systems

2.5.6.3.1 Regulatory Evaluation

The Florida Power and Light (FPL) review of the solid waste management systems (SWMS) focused on the effects that the proposed EPU may have on previous analyses and considerations related to the design objectives in terms of expected volumes of waste to be processed and handled, the wet and dry types of waste to be processed, the activity and expected radionuclide distribution contained in the waste, equipment design capacities, and the principal parameters employed in the design of the SWMS.

The NRC's acceptance criteria for the SWMS are based on:

- 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;
- GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents;
- GDC-63, insofar as it requires that systems be provided in waste handling areas to detect conditions that may result in excessive radiation levels;
- 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 (AOOs), and postulated accidents; and
- 10 CFR 71, which states requirements for radioactive material packaging.

Specific review criteria are contained in SRP Section 11.4.

St. Lucie Unit 2 Current Licensing Basis

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 2 conform with the NRC General Design Criteria for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

The adequacy of the design relative to the GDC is discussed in UFSAR Section 3.1.

The waste management system is described in UFSAR Sections 11.2, 11.3 and 11.4, and is designed to provide controlled handling and disposal of liquid, gaseous, and solid wastes. The SWMS system design and operation are directed toward minimizing releases of radioactive materials to unrestricted areas. The equipment is designed and operated to process solid radioactive wastes which result in a form which minimizes potential harm to personnel and the environment. Handling areas are appropriately monitored and safety features are incorporated to preclude releases in excess of the limits of 10 CFR 20 and the design objectives of Appendix I to 10 CFR 50. Radioactive materials which do not meet release limits will not be discharged to the environment or shipped offsite for permanent disposal. All phases of the solidification process incorporate "As-Low-As-is-Reasonably-Achievable (ALARA)" design features and operational

procedures to ensure that personnel exposure is minimized. The waste management system is designed with sufficient holdup capacity and flexibility for reprocessing of wastes to ensure that releases are ALARA.

The specific GDCs for the SWMS are as follows:

- GDC-60 is described in UFSAR Section 3.1.60, Criterion 60 – Control of Releases of Radioactive Materials to the Environment.

The nuclear power unit design shall include means to control suitably the release of radioactive materials in gaseous and liquid effluents and to handle radioactive solid wastes produced during normal reactor operation, including anticipated operational occurrences. Sufficient holdup capacity shall be provided for retention of gaseous and liquid effluents containing radioactive materials, particularly where unfavorable site environmental conditions can be expected to impose unusual operational limitations upon the release of such effluents to the environment.

As indicated in the St. Lucie Units 1 and 2 Annual Radioactive Effluent Reports, liquid, gaseous and solid radioactive releases from the waste management system are accomplished on a batch basis. All radioactive materials are sampled prior to release to ensure compliance with 10 CFR 20 and Appendix I to 10 CFR 50.

All storage tanks in the liquid waste and gaseous waste systems are administratively controlled to prevent the addition of waste to a tank which is being discharged to the environment. Each discharge path is provided with a radiation monitor which alerts plant personnel and initiates automatic closure of isolation valves to prevent further releases in the event of noncompliance with 10 CFR 20 (see UFSAR Section 11.5 for details).

- GDC-63 is described in UFSAR Section 3.1.63, Criterion 63 – Monitoring Fuel and Waste Storage

Appropriate systems shall be provided in fuel storage and radioactive waste systems and associated handling areas (1) to detect conditions that may result in loss of residual heat removal capability and excessive radiation levels and (2) to initiate appropriate safety actions.

The storage of high level activity waste at St. Lucie Units 1 and 2 is unchanged. Low-level activity waste is stored temporarily in the drumming station in the reactor auxiliary building with local shielding provided to reduce the dose rates to the operating personnel to below 10 CFR 20 limits. Solid waste is also temporarily stored in shipping containers outdoors at locations designated by radiation protection personnel prior to final shipment. Measures are established for these locations to minimize personnel radiation dose and to preclude the spread of contamination. There are no residual or decay heat removal systems in the waste management system.

The fuel pool and waste management systems are provided with appropriate radiation indication and alarms. In addition, alarms are provided in the event of a reduction in fuel pool level.

- GDC-64 is described in UFSAR Section 3.1.64, Criterion 64 – Monitoring Radioactivity Releases

Means shall be provided for monitoring the reactor containment atmosphere, spaces containing components for recirculation of loss of coolant accident fluids, effluent discharge paths, and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences, and from postulated accidents.

Provisions are made for monitoring the containment atmosphere, the facility effluent discharge paths, the operating areas within the plant and the facility environs for radioactivity that could be released from normal operation, from anticipated transients and from an accident.

Some liquid and gaseous effluents will contain radioactive matter. The waste management system functions to remove radioactive material from these wastes by filtration, ion exchange or distillation prior to discharge, or to store the wastes until the radioactivity has decayed sufficiently to permit discharge.

As stated in the UFSAR Section 11.4, the SWMS collects, controls, processes, packages, and temporarily stores solid radioactive waste and certain liquid radioactive waste generated as a result of normal plant operations, including anticipated operational occurrences. Actual data on solid waste effluents obtained during operation are presented in the St. Lucie Units 1 and 2 Annual Radioactive Effluent Release Reports.

As stated in part in the NRC Safety Evaluation Report for St. Lucie Unit 2, the solid radwaste system capability to process the types and volumes of wastes expected during normal operation and anticipated operational occurrences is in accordance with the requirements of 10 CFR Parts 20 and 71.

In addition to the licensing bases described in the UFSAR, the SWMS was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.3.16 of the SER identifies that components of the SWMS are within the scope of License Renewal. Programs used to manage the aging effects associated with the SWMS are discussed in SER Section 3.3.16 and Chapter 18 of the UFSAR.

2.5.6.3.2 Technical Evaluation

2.5.6.3.2.1 Introduction

The SWMS is described in Section 11.4 of the UFSAR. The SWMS controls, collects, processes, packages, handles and temporarily stores solid radioactive wastes and certain liquid radioactive wastes generated as a result of normal plant operations, including anticipated operational

occurrences. The solid radioactive waste system is also designed to prepare the collected wastes for offsite shipment.

The SWMS consists of the following major components:

- Spent resin tank, and
- Portable resin dewatering and drying system.

The spent resin tank can hold the equivalent of approximately eight to ten beds of spent resin from the various plant ion exchangers, and therefore, storage capacity in excess of one year is normally available.

The SWMS prepares waste from the following sources for shipment offsite for eventual disposal:

- Spent resins from the liquid waste system ion exchangers,
- Spent resins from the chemical and volume control system ion exchangers (purification ion exchangers and deborating ion exchangers),
- Spent resins from the spent fuel pool cooling system ion exchanger,
- Filters,
- Miscellaneous solid wastes, such as contaminated clothing, plastic sheeting, tape, rags, paper, lab equipment and supplies and tools.

The SWMS processes radioactive waste in the form of ion exchanger resins and filters, compressible and non-compressible solids. Ion exchanger resins are sluiced into the spent resin tank or shipping container, and dewatered in accordance with plant procedures. Filters are moved from their vessels into shipping containers. Compressible waste is compacted by a compactor located inside the drumming station or shipped sorted, uncompacted to an offsite radioactive waste volume reduction facility for processing. The compactor is provided with HEPA filters to remove potentially radioactive airborne particulates. Non-compressible waste is packaged in boxes or bags. All of these wastes are packaged and shipped offsite in accordance with plant procedures.

Low activity waste is stored temporarily in the drumming station in the reactor auxiliary building with local shielding provided to reduce the dose rates to the operating personnel to below 10 CFR 20 limits. Solid waste is also temporarily stored in shipping containers outdoors at locations designated by radiation protection personnel prior to final shipment. Miscellaneous compressible solid waste such as contaminated clothing, plastic sheeting, and tape, accumulated as a result of radiation protection and maintenance activities, and non-compressible solid waste such as tools and contaminated equipment are stored in designated areas and then shipped offsite in accordance with plant procedures. Measures are established at these locations to minimize personnel radiation dose and to preclude the spread of contamination.

FPL maintains control over the solid radioactive waste effluents by providing adequate retention capacity, particularly where unfavorable environmental conditions can affect the release of radioactive effluents to the environment. In all cases, the design for radioactivity control is based on meeting the requirements of 10 CFR 20 for both normal and transient operations.

2.5.6.3.2.2 Description of Analyses and Evaluations

The SWMS is evaluated to ensure it is capable of performing its intended functions at EPU conditions. The evaluation determines whether the EPU operating conditions are enveloped by the design parameters of the existing system and components.

2.5.6.3.2.3 Evaluation of Impact on Renewed Plant Operating License Evaluations and License Renewal Programs

As discussed above, the SWMS is within the scope of License Renewal. Operation of the SWMS under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.5.6.3.2.4 Results

Implementation of the EPU has no significant affect on the volume of solid wastes generated by plant operations that are handled by the SWMS and no impact is expected on the system equipment, piping, or instrumentation and controls since plant system functions do not change. In addition, since no significant increase in solid waste generation is anticipated there should not be an increase in solid waste shipments from the plant.

The quantities of low-level, compressible, radioactive wastes such as paper, rags, plastics, clothing, respiratory filters, spent resins and filters are not expected to increase as a result of the EPU. The production of these wastes is not directly related to core power and drastic changes to plant and system maintenance are not anticipated due to the EPU.

The EPU results in a slight increase in the equilibrium radioactivity in the reactor coolant, which will affect the concentrations of radioactive nuclides in the liquid waste management system resins, and therefore the radioactivity level in the solid waste. However, this slight increase in solid waste radioactivity is within the design capabilities of the SWMS to handle through existing procedures. The impact of the increased activity in the waste disposal systems is detailed in LR [Section 2.10.1](#), Occupational and Public Radiation Doses. The evaluation of the SWMS at EPU conditions demonstrates compliance with 10 CFR 20.1302 since the annual average concentrations of radioactive materials released at the boundary of the unrestricted area will not exceed specified values in accordance with the St. Lucie Offsite Dose Calculation Manual. No solid waste volumes are expected to leave the site except as properly packaged and shipped by an authorized carrier to a licensed burial site in accordance with NRC, U.S. Department of Transportation, and state regulations. Plant areas continue to be monitored with adequate safety features incorporated to preclude doses to the public and operating personnel in excess of 10 CFR 20 limits and to maintain releases “As-Low-As-is-Reasonably-Achievable (ALARA)”

according to Appendix I to 10 CFR 50. This is demonstrated by the continued compliance post-EPU with the annual dose objectives of Appendix I to 10 CFR 50, as discussed in LR **Section 2.10.1**. Therefore, the management of the SWMS is acceptable for EPU.

The evaluation of the solid waste management system at EPU conditions demonstrates that St. Lucie Unit 2 will continue to meet the current licensing basis with respect to the requirements of GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents. This design capability remains unchanged by the EPU. The handling, control, and release of radioactive materials are in compliance with Appendix I to 10 CFR 50, and are described in the Offsite Dose Calculation Manual.

The evaluation of the SWMS at EPU conditions demonstrates that St. Lucie Unit 2 will continue to meet the current licensing basis with respect to the requirements of GDC-63, insofar as it requires that systems be provided in waste handling areas to detect conditions that may result in excessive radiation levels and to initiate appropriate safety actions. This design capability remains unchanged by the EPU. Radiation monitors and alarms are provided as required to warn personnel of impending excessive levels of radiation or airborne activity.

The evaluation of the SWMS at EPU conditions demonstrates that St. Lucie Unit 2 will continue to meet the current licensing basis with respect to the requirements of GDC-64, insofar as it requires that a 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. This design capability remains unchanged by the EPU. Radioactivity levels contained in the effluent discharge paths in the environs are continually monitored during normal and accident conditions by the station radiation monitoring system and by the radiation protection program.

The evaluation of the SWMS at EPU conditions demonstrates conformance with the requirements of 10 CFR 71, insofar as the radioactive material packaging accounts for the maximum dose rate allowed on the surface of the container by shielding of the package in which the container is shipped. Packaging, shielding and handling of radioactive material are not changed by EPU; thus, compliance with 10 CFR 71 is not affected.

2.5.6.3.3 Conclusion

FPL has reviewed the SWMS and has accounted for the effects of the increase in fission product in the reactor coolant system and on the ability of the SWMS to control, collect, process, package, handle, temporarily store and ship solid radioactive wastes. FPL finds that the SWMS will continue to meet its design functions following implementation of the proposed EPU. FPL further concludes that the SWMS will continue to meet its current licensing basis with respect to the requirements of 10 CFR 20.1302; GDC -60, -63 and -64; and 10 CFR 71. Therefore FPL finds the proposed EPU acceptable with respect to the SWMS.

2.5.7 Additional Considerations

2.5.7.1 Emergency Diesel Engine Fuel Oil Storage and Transfer System

2.5.7.1.1 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. Florida Power and Light's (FPL'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:

- GDC-4, insofar as it requires that Structure, Systems and Components (SSCs) important to safety be protected against dynamic effects, including missiles, pipe whip, and jet impingement forces associated with pipe breaks;
- 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
- 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.

St. Lucie Unit 2 Current Licensing Basis

As noted in UFSAR Section 3.1, the design bases of the St. Lucie Unit 2 conforms with the NRC General Design Criteria for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

The specific GDC's for the Emergency Diesel Engine Fuel Oil Storage and Transfer System are as follows:

- GDC-4 is described in UFSAR Section 3.1.4 Criterion 4 - Environmental and Missile Design Bases.

Structures, systems and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and

approved by the Commission demonstrates that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

SSCs important to safety are designed to accommodate the effects of and to be compatible with the pressure, temperature, humidity, and radiation conditions associated with normal operation, maintenance, testing, and postulated accidents, including a LOCA, in the area in which they are located.

Non-Seismic Class I Piping is arranged or restrained so that failure of any non-seismic Class I piping will neither cause a nuclear accident nor prevent essential seismic Class I structures or equipment from mitigating the consequences of such an accident.

Seismic Class I piping is arranged or restrained such that in the event of rupture of a seismic Class I pipe which causes LOCA, resulting pipe movement will not result in loss of containment integrity or adequate engineered safety features systems operation.

For those components which are required to operate under extreme conditions such as design seismic loads or containment post-LOCA environmental conditions, the manufacturers submit type test, operational or calculational data which substantiate this capability of the equipment.

Refer to UFSAR Sections 3.5, 3.6, 3.7, and 3.11 of the UFSAR for details.

- GDC-5 is described in UFSAR Section 3.1.5 Criterion 5 – Sharing of Structures, Systems or Components.

Structures, systems and components important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units.

Safety related components interconnected between the two units include the condensate storage tanks, the diesel generator fuel oil system, and the Class 1E 4.16kV switchgear (1AB and 2AB) station blackout (SBO) cross-tie. These safety-related interconnections are not normally used by both units and employ isolation devices between them. Locked closed isolation valves are provided for the auxiliary feedwater (AFW) and diesel generator fuel oil inter-ties. The SBO cross-tie has two breakers in series for isolation between the two units. The failure of equipment on one unit will not impair the ability of the counterpart on the other unit from performing its safety-related function. The interconnections provide added redundancy and operational flexibility without compromising unit and system independence.

In the unlikely event of loss of offsite power, both St. Lucie Units 1 and 2 have their own 100 percent capacity redundant diesel generator sets which are available for safe shutdown.

In the unlikely event of an SBO in one unit, i.e., total loss of AC power on- site and offsite, both units can be electrically connected, under administrative control, such that a diesel generator set from the non-blackout unit is able to provide power to the minimum loads required to maintain both units in a hot standby condition.

- GDC-17 is described in UFSAR Section 3.1.17 Criterion 17 – Electrical Power Systems.

An onsite electrical power system and an offsite electrical power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

The onsite electrical power sources, including the batteries, and the onsite electrical distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

Electrical power from the transmission network to the switchyard shall be supplied by two physically independent transmission lines (not necessarily on separate rights-of-way) designed and located so as to suitably minimize the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. Two physically independent circuits from the switchyard to the onsite electrical distribution system shall be provided. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power sources and the other offsite electrical power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a loss-of-coolant accident (LOCA) to assure that core cooling, containment integrity, and other vital safety functions are maintained.

Provisions shall be included to minimize the probability of losing electric power from any of the remaining sources as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electrical power sources.

Offsite power is transmitted to the plant switchyard by three physically independent 230 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 or of a unit generator, there is a “fast dead bus” automatic transfer to the startup transformers thus providing continuity of power.

In the event of a loss of the offsite power (LOOP) sources, two onsite emergency diesel generator (EDG) sets and redundant sets of station batteries provide the necessary ac and dc power for safe shutdown or, in the event of an accident, provide the necessary power to restrict the consequences to within acceptable limits. The onsite emergency ac and dc power systems consist of redundant and independent power sources and distribution systems such that a single failure does not prevent the systems from performing their safety function.

Refer to UFSAR Sections 8.2.1 and 8.3.2 of the UFSAR for further discussion of offsite power sources and onsite power sources respectively.

Operability and surveillance requirements for the EDGs, including the fuel oil and transfer system, are provided in Technical Specifications (TS) 3/4.8.1.1.b and 3/4.8.1.2.b. As a result of

the design requirements associated with the use of ultra low sulfur fuel oil, the EDG fuel oil storage tank and day tank levels are currently being administratively controlled above the levels required by TS.

UFSAR Section 9.5.4 describes the design of the EDG fuel oil system and states that the system is designed to provide oil storage capacity for at least seven days accident load operation of one EDG set and maintain fuel supply to at least one EDG set, assuming a single active or passive failure.

In addition to the licensing basis described in the UFSAR, the EDG engine fuel oil storage and transfer system was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003.

Section 2.3.3.4 of the SER identifies that components of the EDG engine fuel oil storage and transfer system are within the scope of License Renewal. Programs used to manage the aging effects associated with the EDG engine fuel oil storage and transfer system are discussed in SER Section 3.3.4 and Chapter 18 of the UFSAR.

2.5.7.1.2 Technical Evaluation

2.5.7.1.2.1 Introduction

The EDG engine fuel oil and transfer system is discussed in UFSAR Section 9.5.4, Diesel Generator Fuel Oil Storage and Transfer System. The design of the EDG fuel oil system provides electrical and physical separation of components to assure that the system can withstand an active or passive single failure and still provide oil storage capacity for at least seven days of continuous accident load operation (LOOP coincident with or without a LOCA) of one EDG set. Two completely redundant subsystems are provided, each consisting of the following:

- One diesel oil storage tank,
- Two day tanks,
- A transfer pump, to transfer oil from the storage tank to both of the two interconnected day tanks,
- Interconnecting piping and valves designed with locked closed valves for transferring oil between redundant systems, and
- Associated instrumentation and controls.

The EDG fuel oil storage tank and day tank levels are currently being administratively controlled in accordance with NRC Administrative Letter 98-10 in order to meet the design requirements associated with the use of ultra low sulfur fuel oil. TS 3.8.1.1 and 3.8.1.2 require that the fuel oil storage system contain at least 40,000 gallons of fuel in each storage tank. FPL has imposed administrative control which requires that a minimum of 42,500 gallons of fuel be maintained in each storage tank in order to compensate for the use of ultra low sulfur fuel oil.

Subsystem A serves EDG 2A and subsystem B serves EDG 2B. All electrical power necessary for operation of each subsystem is supplied from the associated diesel generator bus.

The pumps, tanks and other equipment in the system are designed for seismic Class I service.

2.5.7.1.2.2 Description of Analysis and Evaluations

The EDG engine fuel oil storage and transfer system and its components were evaluated to ensure they are capable of performing their intended function at EPU conditions. The evaluation is based on the system's required design functions and a comparison between the existing equipment ratings and the anticipated operating requirements at EPU conditions.

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

As discussed above, the EDG fuel oil storage and transfer system is within the scope of License Renewal. Operation of the EDG fuel oil storage and transfer system under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.5.7.1.2.4 Results

The fuel oil inventory associated with the EDGs in consideration of EPU has been evaluated. The loads on the EDG associated with a LOOP during normal operation are less than the loads on the EDG for a LOCA/LOOP scenario. Therefore the LOCA/LOOP represents the bounding scenario relative to diesel fuel oil storage requirements. The existing EDG loading analysis, as well as the existing fuel oil quantity and consumption rate analysis, was evaluated to reflect the EPU loads.

The results of the EDG loading evaluation, as well as the existing fuel oil quantity and consumption rate evaluation, indicate that the electrical load during accident conditions will continue to be within the design rating of the EDG. A time-dependent load profile was developed based on the expected power requirement and run time of each component powered by the EDG under accident conditions. The load profile was used to determine the total diesel fuel oil inventory required.

The fuel consumption rate of the EDG determines the maximum usable volume of the fuel oil storage system to run each EDG for at least 7 days on post-accident loads. The capacity of one fuel oil storage tank is required to support the operation of one EDG. No modifications to the EDGs or associated fuel oil system are required to support EPU operation. The EDG loading is further discussed in LR [Section 2.3.3](#), AC Onsite Power System.

A proposed change to TS 3.8.1.1 and TS 3.8.1.2 is provided as part of the license amendment request to capture the additional volume of ultra low sulfur fuel oil. The proposed change increases the minimum fuel storage system requirement for each diesel generator set from 40,000 gallons to 42,500 gallons.

The independence and redundancy features of the system are not impacted by EPU and continue to meet the current licensing basis with respect to the requirements of GDCs -4, -5 and -17. The design for missile protection and protection against dynamic effects associated with the postulated rupture of piping will be maintained. Refer to LR Section Numbers **2.2.1**, Pipe Rupture Locations and Associated Dynamic Effects and **2.5.1.3**, Pipe Failures.

2.5.7.1.3 Conclusion

FPL has reviewed the assessment related to the amount of required fuel oil for the EDG and concludes that the assessment has adequately accounted for the effects of the increased electrical demand on fuel oil consumption. FPL 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 their current licensing basis with respect to the requirements of GDCs -4, -5, and -17. Therefore, FPL 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)

2.5.7.2.1 Regulatory Evaluation

The light load handling system (LLHS) includes components and equipment used in handling new fuel at the receiving station and the loading of spent fuel into shipping casks. The Florida Power and Light (FPL) review covered the avoidance of criticality accidents, radioactivity releases resulting from damage to irradiated fuel, and unacceptable personnel radiation exposures. The FPL review focused on the effects of the new fuel on system performance and related analyses.

The acceptance criteria for the LLHS are based on:

- GDC-61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement and with suitable shielding for radiation protection, and
- GDC-62, insofar as it requires that criticality be prevented.

Specific review criteria are contained in Standard Review Plan (SRP) Section 9.1.4 and guidance is provided in Matrix 5 of RS-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to Title 10 of the Code of Federal Regulations (10 CFR) Part 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

- GDC-61 is described in UFSAR Section 3.1.61 Criterion 61 - Fuel Storage and Handling and Radioactive Control.

The fuel storage and handling, radioactive waste, and other systems which may contain radioactivity shall be designed to assure adequate safety under normal and postulated accident conditions. These systems shall be designed (1) with a capability to permit inspection and testing of components important to safety, (2) with suitable shielding for radiation protection (3) with appropriate containment, confinement, and filtering systems, (4) with a residual heat removal capability having reliability and testability that reflects the importance to safety or decay heat and other residual heat removal, and (5) to prevent significant reduction in fuel storage coolant inventory under accident conditions.

- GDC-62 is described in UFSAR Section 3.1.62 Criterion 62 - Prevention of Criticality in Fuel Storage and Handling.

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

The new and spent fuel storage and handling facilities are described in UFSAR Sections 9.1.1 and 9.1.2, respectively. New fuel is stored in air. Spent fuel is stored in borated water. The

spacing is sufficient to maintain a subcritical k_{eff} for the new and spent fuel assemblies when in unborated water.

New fuel is stored dry at floor elevation 48 feet with the top of the rack at elevation 62.5 feet. The new fuel storage racks consist of 80 square cavities fixed together in two 4 by 10 arrays. Provisions are made for the future storage of 16 additional fuel assemblies. New fuel in the storage racks has been analyzed for uranium enrichments up to 4.5 weight percent and with consideration of a full range of moderator (non borated water) densities from mist to full immersion.

The spent fuel storage racks are designed to: (a) allow storage of up to 1585 fuel assemblies (276 fuel assemblies in Region I with a maximum enrichment of 4.5 wt percent U-235 and 1084 assemblies in the Spent Fuel Region II racks and 225 assemblies in the Region II Cask Pit Rack) under flooded conditions; (b) maintain subcritical conditions with a k_{eff} of less than 1.0 assuming nonborated, full density water in the fuel pool; (c) maintain a fuel pool k_{eff} of less than or equal to 0.95 when flooded with water containing 520 ppm boron; (d) maintain a minimum allowable fuel spacing such that a subcritical array is ensured; and (e) preclude insertion of a fuel assembly between individual fuel storage cavities.

The fuel handling system is an integrated system of equipment, tools and procedures for refueling the reactor. The system is designed for safe handling and storage of fuel assemblies from receipt of new fuel to shipping of spent fuel.

The spent fuel handling equipment is designed to handle the spent fuel underwater from the time it leaves the reactor until it is placed in a cask for shipment from the site. Underwater transfer of spent fuel provides a transparent radiation shield, as well as a cooling medium for removal of decay heat. Boric acid is added to the water in the quantity required to ensure subcritical conditions during refueling.

In addition to the licensing basis described in the UFSAR, the fuel handling equipment was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3 of the SER identifies those systems that are within the scope of license renewal. The fuel handling equipment is not within the scope of license renewal.

2.5.7.2.2 Technical Evaluation

2.5.7.2.2.1 Introduction

UFSAR Section 9.1.4 describes the design and operation of the fuel handling equipment as an integrated system of equipment, tools and procedures for refueling the reactor and for handling and storage of fuel assemblies from receipt of new fuel to shipping or on-site storage of spent fuel. The focus of FPL's technical evaluation is on safe fuel handling and storage of new and spent fuel, which, if dropped, mishandled, or damaged, could cause releases of radioactive

materials or unacceptable personnel radiation exposure. With respect to criticality accidents, the analyses and evaluations are presented in LR [Section 2.8.6.2](#), Spent Fuel Storage.

The fuel handling system related to light load handling of new and spent fuel consists of the following components:

- Fuel Movement:
 - Refueling machine and auxiliary hoist,
 - Spent fuel handling machine,
 - Upending machine,
 - Fuel transfer tube, valve, and carriage,
 - New fuel crane, and
 - New fuel elevator.
- Tooling:
 - Gripper operating tool (CEA coupling tool),
 - Fuel handling tool (short tool for dry handling),
 - Fuel handling tool (long tool for underwater handling),
 - Surveillance capsule retrieval tool, and
 - CEA coupling tool.

2.5.7.2.2.2 Description of Analyses and Evaluations

This LR section evaluates the impact of EPU on the LLHS (related to refueling) to determine the degree of compliance with the criteria discussed in LR [Section 2.5.7.2.1](#). The evaluation determines whether changes due to EPU will affect the fuel handling equipment's ability to confine radioactive material, provide suitable shielding for radiation protection, and prevent criticality in the fuel storage and handling system.

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

As discussed above, the fuel handling equipment is not within the scope of license renewal. Operation of the fuel handling equipment under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.5.7.2.2.4 Results

The structures, systems, and components (SSCs) associated with LLHS related to refueling are not modified for EPU purposes, and St. Lucie Unit 2 will continue to use the current Westinghouse design 16x16 fuel assemblies. Fuel assembly weight will therefore remain within the load bearing capacity of the LLHS and tooling, inclusive of seismic loads. Consistent with current design, fuel assembly configuration will permit continued use of the existing fuel handling tools. The existing electrical and mechanical interlocks and procedural controls will continue to ensure adequate water depth is maintained above the spent fuel assemblies at all times to prevent excessive radiation levels at the surface of the refuel cavity and spent fuel pool. This evaluation therefore concludes that the EPU will not affect the degree of compliance with GDC-61 of the LLHS for refueling to effectively contain radioactive material and provide adequate shielding for radiation protection.

Since there are no changes to the LLHS for refueling, or to the fuel assemblies themselves, EPU does not affect the likelihood of dropping or misplacing a fuel assembly during fuel handling operations. The criticality analyses for dropped or misplaced fuel assemblies assume worst case geometry, moderation, and poisoning conditions for various scenarios. A minimum boron concentration is required to ensure adequate subcriticality for the limiting case of a fuel assembly misload. Spent fuel pool boron concentration is maintained above this minimum value by Technical Specification 3/4.9.11. The evaluation therefore concludes that the degree of compliance with GDC-62 for preventing criticality by the LLHS for refueling is not affected by the EPU.

Normal fuel assembly storage within the new or spent fuel storage racks is not within the scope of this evaluation. Criticality analyses for the fuel storage racks are discussed in LR [Section 2.8.6.1](#), New Fuel Storage, and LR [Section 2.8.6.2](#), Spent Fuel Storage.

2.5.7.2.3 Conclusion

FPL has reviewed the assessment of the effects of the new fuel and spent fuel on the ability of the LLHS to avoid criticality accidents, and concludes that the effects of the new fuel have been adequately incorporated in the analyses. FPL further concludes that the LLHS will continue to meet its current licensing basis with respect to the requirements of GDC-61 and -62 for radioactivity releases and prevention of criticality accidents. Therefore, FPL finds the proposed EPU acceptable with respect to the LLHS.

2.5.8 Additional Review Areas (Plant Systems)

2.5.8.1 Circulating Water System

2.5.8.1.1 Regulatory Evaluation

NRC Review Standard RS-001 does not explicitly call out the Standard Review Plan (SRP) or any other guidance documentation related to the capability of the circulating water system (CWS) to provide a heat sink for the main condenser under normal operating and shutdown conditions. The system serves as the primary source of water for the ultimate heat sink.

The Florida Power and Light (FPL) review focused on changes to the amount of heat absorbed by the CWS from increased heat rejection from the main condenser due to the higher EPU power level. The maximum allowable temperature rise of the water passing through the condenser is limited by restrictions in the State of Florida Industrial Wastewater Facility Permit No. FL0002208, dated January 20, 2006. FPL evaluated the impact upon CWS components to ensure that the system accomplishes its design functions after implementation of EPU. FPL evaluated the consequences of flooding resulting from a failure in this system as presented in LR

Section 2.5.1.1.3.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

The CWS is a once through cooling water design utilizing cooling water taken from the Atlantic Ocean. The cooling water is ultimately discharged back to the Atlantic Ocean upon completion of use. The CWS is classified as a non-safety and non-seismic system.

The State of Florida Industrial Wastewater Facility, Permit No. FL0002208 dated January 20, 2006, applies to both St. Lucie Units 1 and 2 and limits the discharge temperature for the plants to the Atlantic Ocean to a maximum of 113°F, and the temperature rise between the intake and discharge to 30°F. FPL has committed to operate the St. Lucie units post-uprate within the existing operating limits of the current permit.

The CWS consists of four circulating water pumps, four debris filters, the condenser intake, four continuous on-line condenser tube cleaning systems, the condenser discharge, a headwall and an ocean discharge line. The discharge canal from the seal well to the headwall is shared with St. Lucie Unit 1.

The circulating water pumps discharge into four buried pipes to the condenser. The water leaving the condenser flows from the condenser discharge water boxes through concrete tunnels and pipes to the seal well. From the seal well, the discharged condenser cooling water travels in the shared canal to a discharge headwall structure, located on the west side of the sand dune. From the discharge canal headwall, the cooling water is carried through the ocean discharge pipe to multipoint diffusers.

The four circulating water pumps are each sized to provide 25 percent of the cooling water flow for the condenser. The pumps are sized for the maximum condenser heat load and provide sufficient head to overcome system frictional losses.

In addition to the licensing bases described in the UFSAR, the CWS was evaluated for License Renewal. As documented in NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003, the CWS was determined to be outside the scope of License Renewal.

2.5.8.1.2 Technical Evaluation

2.5.8.1.2.1 Introduction

The CWS is discussed in the UFSAR Section 10.4.5. The CWS circulates water from the Atlantic Ocean through the main condensers to condense the steam exhausting from the turbines. The water is discharged back to the ocean through discharge canals. Four circulating water pumps per unit are used to circulate the water. Traveling water screens and a screen wash system remove debris from the water. This evaluation focuses on the increased heat rejection to be absorbed by the circulating water system and the resultant increased discharge temperature.

2.5.8.1.2.2 Description of Analyses and Evaluations

The CWS and its components were evaluated to ensure that they are capable of performing their intended function at EPU operating conditions. The evaluation reviewed the CWS to determine whether the existing circulating water system flow rate is capable of removing the increased steam cycle heat rejected at EPU conditions. The increased heat load to the CWS at EPU conditions raises the system operating circulating water temperature at the main condenser waterbox outlet. Heat loads during normal plant operation with different cooling water temperatures are used in the heat balance studies for the evaluation. Other evaluations related to the circulating water system, piping and components are included in the following LR sections:

- Liquid waste effluent discharge to the discharge canal – LR [Section 2.5.6.2](#), Liquid Waste Management System,
- Protection of safety-related systems, structures, and components against flooding due to a failure in the circulating water system - LR [Section 2.5.1.1.3](#), Circulating Water System (related to flooding),
- Heat removal from the main condenser – LR [Section 2.5.5.2](#), Main Condenser,
- Condenser evacuation system – LR [Section 2.5.3.2](#), Main Condenser Evacuation System,
- Intake cooling water – LR [Section 2.5.4.2](#), Station Service Water System,
- Ultimate heat sink - LR [Section 2.5.4.4](#), Ultimate Heat Sink, and
- Environmental impact of circulating water returned to the Atlantic Ocean – LAR Attachment 2, Supplemental Environmental Report.

Under EPU operation, design pressure and flow rate of the CWS will not change; however, there will be a temperature increase associated with heat load rejection to the condenser. The temperature increase will not affect the pressure retaining capability of components in the CWS. Therefore, the pressure retaining capacity of piping, valves, and other water passages in the system are unaffected by EPU. EPU does not add any new components, nor does it introduce any new functions for existing components.

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

As discussed above, the CWS was determined to be outside the scope of License Renewal; therefore, with respect to the CWS, the EPU does not impact any License Renewal evaluations.

2.5.8.1.2.4 Results

Circulating water system flow and operating pressure do not increase under EPU conditions. Circulating water system piping and components are therefore capable of performing their intended function at EPU operating conditions.

The EPU heat balance models used a range of circulating water inlet temperatures, 65°F, 75°F, and a conservative upper limit of 90°F, to reflect seasonal ocean water temperatures. The maximum temperature rise between the intake and discharge is calculated to be less than 30°F and remains within the limits of the State of Florida Industrial Wastewater Facility Permit. In addition, the State of Florida Industrial Wastewater Facility Permit discharge temperature limits will be maintained in accordance with the plants discharge monitoring strategy.

2.5.8.1.3 Conclusion

FPL has reviewed the evaluation related to the effects of the proposed EPU on the CWS. FPL concludes that the evaluation of the CWS has adequately accounted for the ability of the system to remove heat rejected from power conversion cycle at EPU conditions. The current design of the CWS provides a reliable supply of water at EPU conditions to condense the steam exhausted from the low pressure turbines. The current design of the system and its components accommodates the higher condenser duty and higher temperatures at EPU conditions. Based on this, the CWS will continue to meet its current licensing basis. Therefore, FPL finds the proposed EPU is acceptable with respect to the CWS.

2.6 Containment Review Considerations

2.6.1 Primary Containment Functional Design

2.6.1.1 Regulatory Evaluation

The containment 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.

The Florida Power and Light (FPL) review covered the pressure and temperature conditions in the containment due to a spectrum of postulated Loss-of-Coolant Accidents (LOCAs) and secondary system line-breaks.

The NRC's acceptance criteria for primary containment functional design are based on:

- 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,
- 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,
- 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,
- 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
- 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 Standard Review Plan (SRP) Section 6.2.1.1.A ([Reference 1](#)).

St. Lucie Unit 2 Current Licensing Basis

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

The specific GDCs for Primary Containment Functional Design are as follows:

- GDC-16 is described in UFSAR Section 3.1.16 Criterion 16 - Containment Design.

Reactor containment and associated systems shall be provided to establish an essentially leak tight barrier against the uncontrolled release of radioactivity to the environment and to assure that the containment design conditions important to safety are not exceeded for as long as postulated accident conditions require.

The containment system is designed to protect the public from the radiological consequences of a LOCA, based on a postulated break of reactor coolant piping up to and including a double ended break of the largest reactor coolant pipe.

The containment vessel, shield building, and the associated engineered safety features systems are designed to safely sustain all internal and external environmental conditions that may reasonably be expected to occur during the life of the plant, including both short and long term effects of a design basis accident.

Leak tightness of the containment system and short and long term performance are analyzed in UFSAR Section 6.2.

- GDC-50 is described in UFSAR Section 3.1.50 Criterion 50 - Containment Design Basis.

The reactor containment structure, including access openings, penetrations, and containment heat removal system shall be designed so that the containment structure and its internal compartments can accommodate, without exceeding the design leakage rate and, with sufficient margin, the calculated pressure and temperature conditions resulting from any loss of coolant accident. This margin shall reflect consideration of (1) the effects of potential energy sources which have not been included in the determination of the peak conditions, such as energy in steam generators and energy from metal- water and other chemical reactions that may result from degraded emergency core cooling functioning, (2) the limited experience and experimental data available for defining accident phenomena and containment responses, and (3) the conservatism of the calculational model and input parameters.

The containment structure, including access openings and penetrations, is designed to accommodate, without exceeding the design leak rate, the transient peak pressure and temperature associated with a design basis accident.

The containment structure and engineered safety features systems are evaluated for various combinations of energy release. The analysis accounts for system thermal and chemical energy, and for nuclear decay heat. The safety injection system is designed such that no single active failure could result in significant metal-water reaction. The combined cooling capacity of two containment cooling units and one containment spray train is adequate, to prevent over pressurization of the structure, and to return the containment to near atmospheric pressure.

- GDC-38 is described in UFSAR Section 3.1.38 Criterion 38 - Containment Heat Removal.

A system to remove heat from the reactor containment shall be provided. The system safety function shall be to reduce rapidly, consistent with the functioning of other associated systems, the containment pressure and temperature following any loss of coolant accident and maintain them at acceptably low levels.

Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

The containment heat removal systems described in UFSAR Section 6.2.2 consists of the containment spray system and the containment cooling system. The containment spray system consists of two trains, each containing a containment spray pump, shutdown cooling heat exchanger and spray header. The containment cooling system consists of four fan coolers. One spray pump and two containment fan coolers have the capacity to reduce containment pressure and temperature following a design basis accident and maintain them at acceptably low levels.

Both the containment spray and the containment cooling systems are provided with emergency onsite power necessary for their operation, assuming a loss of offsite power. They are provided with offsite power from the startup transformers if normal onsite power is not available. The containment spray and containment cooling systems are provided with redundant equipment so that when assuming a single failure or a failure of an emergency onsite power supply, 100 percent containment cooling capability is available.

- GDC-13 is described in UFSAR Section 3.1.13 Criterion 13 - Instrumentation and Control.

Instrumentation shall be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary, and the containment and its associated systems. Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges.

Instrumentation is provided, as required, to monitor and maintain significant process variables which can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary, and the containment and its associated systems. Controls are provided for the purpose of maintaining these variables within the limits prescribed for safe operation.

The instrumentation and control systems are described in detail in UFSAR Chapter 7.

- GDC-64 is described in UFSAR Section 3.1.64 Criterion 64 - Monitoring Radioactivity Releases.

Means shall be provided for monitoring the reactor containment atmosphere, spaces containing components for recirculation of loss of coolant accident fluids, effluent discharge paths, and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences, and from postulated accidents.

Means are provided for monitoring the reactor containment atmosphere, spaces containing components for recirculation of loss of coolant accident fluids, effluent discharge paths, and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences, and from postulated accidents.

In addition to the licensing basis described in the UFSAR, the containment was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear

Plant, Units 1 and 2, dated September 2003. Section 2.4.1 of the SER identifies that components of the containment are within the scope of License Renewal. Programs used to manage the aging effects associated with the containment are discussed in SER Section 3.5.1 and Chapter 18 of the UFSAR.

2.6.1.2 Technical Evaluation

2.6.1.2.1 LOCA Introduction

The evaluation of the design basis LOCA event relative to containment peak pressure and temperature response was completed to demonstrate the acceptability of the containment heat removal system to mitigate the consequences of a LOCA inside containment in support of EPU. This evaluation is documented in the subsections below.

The containment response analysis demonstrates the acceptability of the containment heat removal systems to mitigate the consequence of a large LOCA inside containment. The impact of LOCA mass & energy (M&E) releases on the containment vessel pressure and temperature are addressed to assure that the containment vessel pressure and temperature remain below their respective design limits. The system must also be capable of maintaining the long-term temperature response within acceptable limits at EPU conditions.

The LOCA containment response analysis considered a spectrum of cases as discussed in LR [Section 2.6.3.1](#), Mass and Energy Release Analysis for Postulated Loss of Coolant Accidents. The cases address break location, and postulated single failure (minimum and maximum engineered safety feature systems response). Only the limiting cases, which address the containment peak pressure response and limiting long-term temperature response, are presented herein.

The containment pressure / temperature calculations for the LOCA analysis are performed using the current version of the NRC approved CONTRANS computer code. The CONTRANS Topical Report ([Reference 2](#)) provides the description of the analytical techniques, governing equations and solution methods. The current version of the CONTRANS computer code incorporates the modifications and/or enhancements described in the UFSAR Section 6.2.1.1.3.

2.6.1.2.1.1 LOCA Input Parameters, Assumptions, and Acceptance Criteria

The major modeling input parameters and assumptions used in the containment evaluation model for the LOCA event are identified in this section. The assumed initial conditions and input assumptions associated with the fan coolers and containment sprays are listed in LR [Table 2.6.1-1](#). As described in LR [Section 2.8.4.4](#), Residual Heat Removal System, the primary function of the shutdown cooling heat exchanger (SDCHX) is to remove heat from containment during the recirculation phase of the LOCA event. The containment spray (CS) flow through the SDCHX transfers heat from the containment sump to the component cooling water (CCW) system.

UFSAR Section 6.2.1.1.3 presents the major input assumptions used to support the LOCA analysis. In addition to those inputs described in LR [Section 2.6.3.1](#), Mass and Energy Release Analysis for Postulated Loss of Coolant Accidents, the following are the inputs and assumptions

where differences exist between the current licensing analysis and the EPU containment response analysis.

- The analyzed reactor core thermal power is 3030 MWt (3020 MWt plus 0.3 percent measurement uncertainty) for the EPU versus currently analyzed reactor core thermal power of 2754 MWt (2700 MWt plus 2.0 percent measurement uncertainty) prior to implementation of the EPU.
- The containment initial pressure is assumed to be 15.41 psia (0.4 psig plus 0.31 psi uncertainty) for the EPU versus 14.7 psia for the current analysis.
- The containment free volume is $2.500 \times 10^6 \text{ ft}^3$ for the EPU versus $2.506 \times 10^6 \text{ ft}^3$ for the current analysis due to the application of a more conservative value for the initial volume.
- The containment heat sink areas for the EPU have been reduced by 1 percent from those assumed prior to the EPU.
- The minimum usable refueling water tank (RWT) volume is 290,300 gallons for the EPU versus 305,600 gallons assumed prior to the EPU.
- The containment spray and containment fan cooler related inputs are as listed in LR [Table 2.6.1-1](#).
- The containment fan cooler performance is based on the calculated capacities accounting for the emergency diesel generator (EDG) under frequency.

Design Basis Accident

The LOCA containment response analysis considered a spectrum of cases as discussed in LR [Section 2.6.3.1](#), Mass and Energy Release Analysis for Postulated Loss of Coolant Accidents. The cases address break location and the minimum safeguards performance used to define the limiting conditions. Only the pressure response and the long-term temperature cases which address the containment peak pressure response and limiting long-term temperature response are presented herein. The LOCA pressure and temperature response analyses were performed assuming a loss of offsite power and a worst case single failure (a loss of one EDG which causes a loss of one emergency core cooling system train and a loss of one containment cooling train, or a loss of one containment fan cooler train or a loss of one containment spray pump).

The relevant requirements to satisfy NRC acceptance criteria are as follows:

- GDC-16 and -50: In order to satisfy the requirement of GDC-16 and -50, the peak calculated containment pressure should be less than the containment design pressure of 44 psig, and
- GDC-38: In order to satisfy the requirement of GDC-38, the calculated pressure at 24 hours should be less than 50 percent of the peak calculated value (This is related to the criteria for containment leakage assumptions as affecting doses at 24 hours).

2.6.1.2.1.2 Description of LOCA Analyses and Evaluations

St. Lucie Unit 2 was licensed following the issuance of NUREG-0800 "Standard Review Plan," ([Reference 1](#)). The methodology used to perform the Primary Containment Functional Design analysis is consistent with the methodology identified in the SRP 6.2.1. The methodology

presented in the current licensing basis is also consistent with the methodology identified in the SRP 6.2.1.

LR [Section 2.6.3.1](#), Mass and Energy Release Analysis for Postulated Loss of Coolant Accidents, describes the generation of the mass and energy discharged from the reactor coolant system (RCS) into the containment. The mass and energy releases to the containment, along with other relevant data, was used to calculate the containment pressure/ temperature response using the computer code, CONTRANS, described in LR [Section 2.6.1.2.1](#).

2.6.1.2.1.3 LOCA Results

The current containment response (UFSAR Table 6.2-2) results for the containment peak pressure and vapor temperature for a LOCA event are 39.55 psig and 262.15 °F, respectively.

The containment pressure/temperature response analysis for EPU is performed with a spectrum of cases as described in LR [Section 2.6.3.1](#), M&E Release Analysis for Postulated Loss of Coolant Accidents.

The EPU containment pressure and vapor temperature profiles for the limiting double ended hot leg slot (DEHLS) break case (peak pressure case) are shown in LR [Figures 2.6.1-1](#) and [2.6.1-2](#), respectively. The results of the limiting double ended discharge leg slot (DEDLS) break case (long-term temperature response transient) are shown in LR [Figures 2.6.1-3](#) and [2.6.1-4](#). LR [Table 2.6.1-2](#) provides the containment pressure results relative to peak containment conditions as well as at 24 hours and the containment vapor and vessel temperature results relative to peak conditions. LR [Table 2.6.1-3](#) provides the acceptance limits for these parameters.

As indicated in LR [Table 2.6.1-2](#), the peak containment pressure is 43.48 psig for the limiting DEHLS case. For this case, the containment pressure at 24 hours is 6.36 psig. Therefore, the acceptance criteria for the peak pressure as well as the criteria to reach 50 percent of peak pressure at 24 hours are met.

To be consistent with the results from the analysis for the EPU, the peak calculated containment internal pressure for the design basis loss of coolant accident, P_a , in the Technical Specification 6.8.4.h, is proposed to be changed from 41.8 psig to 43.48 psig.

As indicated in LR [Table 2.6.1-2](#), the peak containment vapor temperature of 266.73 °F for the limiting DEHLS case exceeds the containment vessel design temperature of 264 °F. However, for this case, the peak containment vessel temperature is 231.64 °F, which is less than the containment vessel design temperature of 264 °F. The peak containment vapor temperature of 259.97°F for the limiting DEDLS case results in a containment vessel temperature of 238.36°F, both of which are less than the containment vessel design temperature. Therefore, the containment vessel temperature acceptance criterion is met for a LOCA event.

As illustrated above, the peak containment pressure is below the acceptance limit of 44 psig and pressure at 24 hours is below 50 percent of the calculated peak pressure. In addition, the containment vessel temperatures for the limiting DEHLS and DEDLS break cases are below the containment vessel design temperature of 264 °F. Based on the results, the applicable criteria with respect to the containment pressure have been met. The containment vessel temperature criterion is also met.

Containment pressure and temperature instrumentation ranges remain acceptable per GDC-13 requirements. The means to monitor plant environs for radioactivity that may be released from normal operations and postulated accidents remains acceptable as per GDC-64.

2.6.1.2.2 Main Steam Line Break Introduction

The main steam line break (MSLB) inside containment is characterized by the rapid blowdown of steam into containment due to a rupture in the main steam line. The location of this break is at the steam generator outlet nozzle, upstream of the main steam isolation valve (MSIV). This location results in the largest possible steam flow for a given break size. The blowdown is limited to one steam generator due to closure of the MSIV associated with each steam generator (SG). Failure of one MSIV to close would allow the steam header volume to participate in the blowdown. This failure is considered in the analysis as one of the potential single failures. In the early phase of the event, steam continues to flow to the turbine, until the reactor trips. Following the reactor trip, which occurs on containment high pressure, the turbine stop valves close. During this portion of the transient, it is conservative to feed the total main feedwater to the affected SG rather than split between both SGs.

Containment high pressure initiates the reactor trip. A main steam isolation signal (MSIS) occurs on containment high pressure or low steam generator pressure, to initiate the closure of the MSIVs and to initiate closure of the main feedwater isolation valves (MFIVs). A containment spray actuation signal (CSAS) occurs on containment high-high pressure and initiates spray following an appropriate delay for spray pumps to come up to speed and fill the spray lines. The NRC-approved SGNIII computer code ([Reference 3](#)) couples the RCS primary side (reactor core, reactor coolant loop, SG plena and tubes), SG secondary side, and containment. SGNIII simultaneously determines the time dependent containment pressure and temperature response with the M&E releases. The containment response in SGNIII is represented by the integration of the containment module from the NRC approved CONTRANS computer code ([Reference 2](#)).

The SGNIII computer code calculates the transient response of the primary coolant system, and steam generators to steam line breaks to develop M&E releases for containment design. The model consists of fluid flow and heat transfer representations in the reactor core, hot leg plena and piping, steam generators, cold leg piping and plena, and steam generator secondary side. Reverse heat transfer from the intact steam generators to the reactor coolant loop is considered. A two-lump core fuel model is used together with a point kinetics representation and non-linear moderator, Doppler, boron, and control element assembly (CEA) to account for reactivity effects. The secondary side of each steam generator is represented by a finite single node quasi-static balance of energy flux and secondary fluid thermodynamics. The steam lines to the turbine are modeled.

The most limiting single active failure for the peak pressure case has been determined to be the failure of one containment cooling train with the availability of offsite power.

2.6.1.2.2.1 MSLB Input Parameters, Assumptions, and Acceptance Criteria

The MSLB containment analysis described herein utilized revised input assumptions in support of the EPU. In addition to those inputs described in LR [Section 2.6.3.2](#), Mass and Energy

Release Analysis for Secondary System Pipe Ruptures, the following are the inputs and assumptions where differences exist between the current licensing analysis and the EPU containment response analysis.

- The analyzed reactor core thermal power is 3030 MWt (3020 MWt plus 0.3 percent measurement uncertainty) for the EPU versus currently analyzed reactor core thermal power of 2754 MWt (2700 MWt plus 2.0 percent measurement uncertainty) prior to implementation of the EPU.
- The containment initial pressure is assumed to be 15.41 psia (0.4 psig plus 0.31 psi uncertainty) for the EPU versus 14.7 psia assumed prior to the EPU.
- The containment free volume is $2.493 \times 10^6 \text{ ft}^3$ for the EPU versus $2.506 \times 10^6 \text{ ft}^3$ assumed prior to the EPU due to the addition of a more conservative value for the initial volume.
- The containment heat sink areas for the EPU are reduced by 2 percent from those assumed prior to the EPU.

Analyses have been performed to show that the containment design pressure is not exceeded even if the following single active failures are postulated: (1) loss of a containment heat removal train, (2) failure of an MFIV to close, and (3) failure of an MSIV to close.

The SGNIII core model is relatively simple and designed to provide conservative values of sensible heat for the core metal mass. It is conservative for containment MSLB analysis to maximize the rate of heat removal from the core to the steam generator. In the presence of a negative moderator temperature coefficient (MTC), this will increase the peak return to power. It is also conservative to assume no cooling of the core by safety injection. This assumption will eliminate the injection of boron through the safety injection system. As a result of these conservative assumptions, SGNIII results can over predict restart power. The EPU MSLB analysis limited the restart power to 15 percent. The 15 percent restart power is not as conservative as St. Lucie Unit 1 analysis. However, it bounds and provides significant margin (3 times the power conservatively calculated in the MSLB safety analysis), but is not as high as the value would be due to the SGNIII code and conservative assumptions that are part of the containment MSLB methodology.

The containment design pressure is 44 psig. The containment vessel design temperature is 264°F.

2.6.1.2.2.2 Description of MSLB Analyses and Evaluations

The purpose of this analysis is to determine the pressure and temperature responses for inside containment MSLB for EPU. MSLB M&E release data are generated for three single failure scenarios at 0 percent, 25 percent, 50 percent, 75 percent and full hot power (FHP) cases, as described in LR [Section 2.6.3.2](#), Mass and Energy Release Analysis for Secondary System Pipe Ruptures. The peak pressure case that produces the highest containment temperature is used for the Equipment Qualification (EQ) case. The differences between the EQ methodology and peak pressure methodology are as follows:

- The EQ case starts from the lowest initial containment pressure of 14.022 psia which delays the reactor trip,

- The EQ case utilizes the superheat model which super heats the steam as the SG tubes uncover, and
- In accordance with the Reference 4, Appendix B, Section 1.b, the EQ case utilizes re-vaporization model which allows 8 percent of the condensation that collects on the heat sink walls to evaporate.

2.6.1.2.2.3 MSLB Results

The limiting case is 0 percent power with the failure of one containment cooling train. The EPU peak pressure for that case is 42.41 psig. This is lower than the current limiting peak pressure value of 43.41 psig and below the design limit of 44 psig.

The EPU peak EQ temperature is 384.29 °F. This is slightly less than the current peak EQ temperature of 418.3 °F. The reduction in EPU temperature was due to tighter control of the SGNIII restart power as described in LR [Section 2.6.1.2.2.1](#).

As indicated in LR [Table 2.6.1-2](#), the EPU peak containment vapor temperature of 384.29 °F exceeds the containment vessel design temperature of 264 °F for a short time (approximately 2 minutes). However, for this case, the peak containment vessel temperature is 244.8 °F, which is less than the containment vessel design temperature of 264 °F. Therefore, the acceptance criterion is met.

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

As discussed above, the containment is within the scope of License Renewal. Operation of the containment under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.6.1.4 Conclusion

FPL has reviewed the containment pressure and temperature transient and concludes that the licensee has adequately accounted for the increase of mass and energy that would result from the proposed EPU. FPL further concludes that containment systems will continue to provide sufficient pressure and temperature mitigation capability to ensure that containment integrity is maintained. FPL 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 GDCs -13, -16, -38, -50, and -64 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to containment functional design.

2.6.1.5 References

1. US Nuclear Regulatory Commission Standard Review Plan, NUREG-0800, Section 6.2.1.
2. Combustion Engineering Topical Report CENPD-140-A, Description of the CONTRANS Digital Computer Code for Containment Pressure and Temperature Transient Analysis, June 1976.
3. NUREG-1462 Volume 1, Final Safety Evaluation Report Related to the Certification of the System 80+ Design Docket No. 52-002.
4. NUREG-0588, Revision 1, Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment.

Table 2.6.1-1
Containment Response Analysis Parameters

Parameter	LOCA Value	MSLB Value
Initial Containment Pressure (psia)	15.41	15.41
Initial Containment Temperature (°F)	120	120
Initial Relative Humidity (%)	45	45
Net Free Volume (ft ³)	2.500 x 10 ⁶	2.493 x 10 ⁶
Ultimate Heat Sink/Intake Cooling Water Temperature (°F)	95	NA
RWT Water Temperature (°F)	104	104
Containment Fan Coolers		
Total	4	4
Analysis Maximum	4	2
Analysis Minimum	2	0
Containment Pressure High Setpoint (psig)	5.15	5.15
Delay Time (sec)		
Without Offsite Power	24.15	NA
With Offsite Power	NA	11.15
Containment Spray Pumps		
Total	2	2
LOCA - Maximum Safeguards	2	NA
MSLB - Failed open MFIV, Failed open MSIV	NA	2
LOCA – Minimum Safeguards	1	NA
MSLB - Failure of Containment Spray Pump	NA	1
Flowrate (gpm)		
Injection Phase (per pump)	2,700	2,700
Recirculation Phase (per pump)	2,850	NA
Containment Pressure High-High Setpoint (psig)	7.05	7.05
Delay Time after the Setpoint is Reached (sec)		
Without Offsite Power	58.02 ⁽¹⁾	NA
With Offsite Power	NA	43.52
Notes: 1. The LOCA analysis assumes a 1.3 second response time to reach the Containment High-High Setpoint. Therefore, the total delay is 59.32 seconds (1.3 sec + 58.02 sec) from the initiation of the LOCA event.		

**Table 2.6.1-2
Containment Response Results for Limiting Pressure and Long-Term Temperature
Response Cases**

Case	Peak Containment Pressure @ Time	Peak Containment Vapor Temperature @ Time	Containment Pressure @ 24 hours	Peak Containment Vessel Temperature
LOCA DEHLS - (peak pressure response case)	43.48 psig @ 19.80 sec	266.73 °F @ 19.80 sec	6.36 psig	231.64 °F @ 1287 sec
LOCA DEDLS - (long-term temperature response case)	39.03 psig @ 13.31 sec	259.97 °F @ 13.31 sec	6.42 psig	238.36 °F @ 1237 sec
MSLB (peak pressure response case)	42.41 psig	NA	NA	NA
MSLB (EQ case)	NA	384.29 °F @ 48.7 sec	NA	244.8 °F @ 101 sec
LOCA-Current Analysis	39.55 psig	262.15 °F	NA	NA
MSLB-Current Analysis	43.41 psig	418.30 °F	NA	NA

**Table 2.6.1-3
Acceptance Limits**

	Design	@ 24 hours (LOCA only)
Pressure	44 psig	Less than 50% of the calculated peak pressure
Containment Vessel Temperature	264 °F	---

**Figure 2.6.1-1
Containment Pressure, LOCA DEHLS
(Peak Pressure Response Case)**

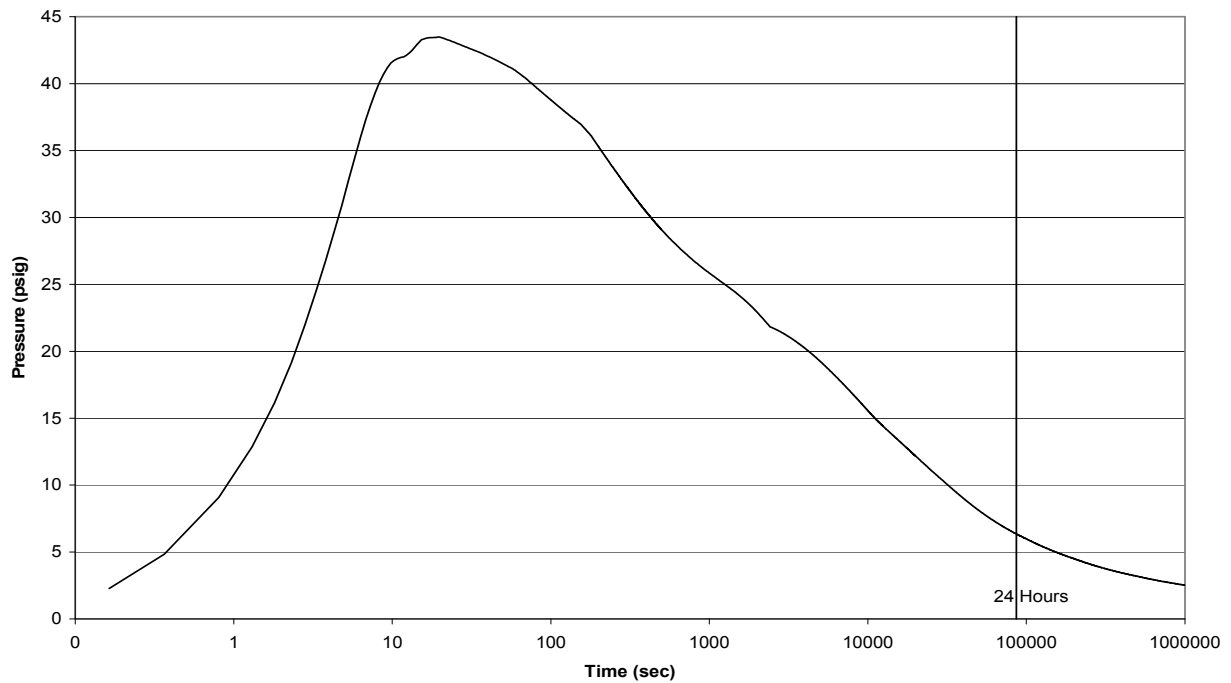


Figure 2.6.1-2
Containment Vapor Temperature, LOCA DEHLS
(Peak Pressure Response Case)

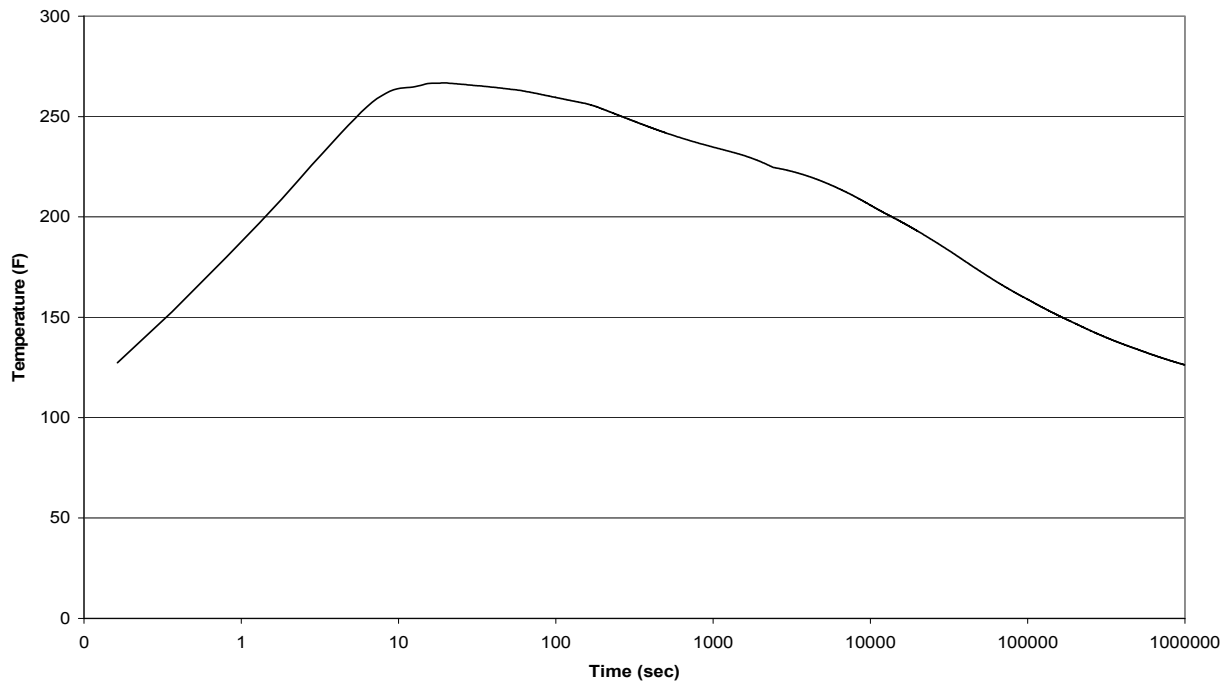


**Figure 2.6.1-3
Containment Pressure, LOCA DEDLS
(Long-Term Temperature Response Case)**

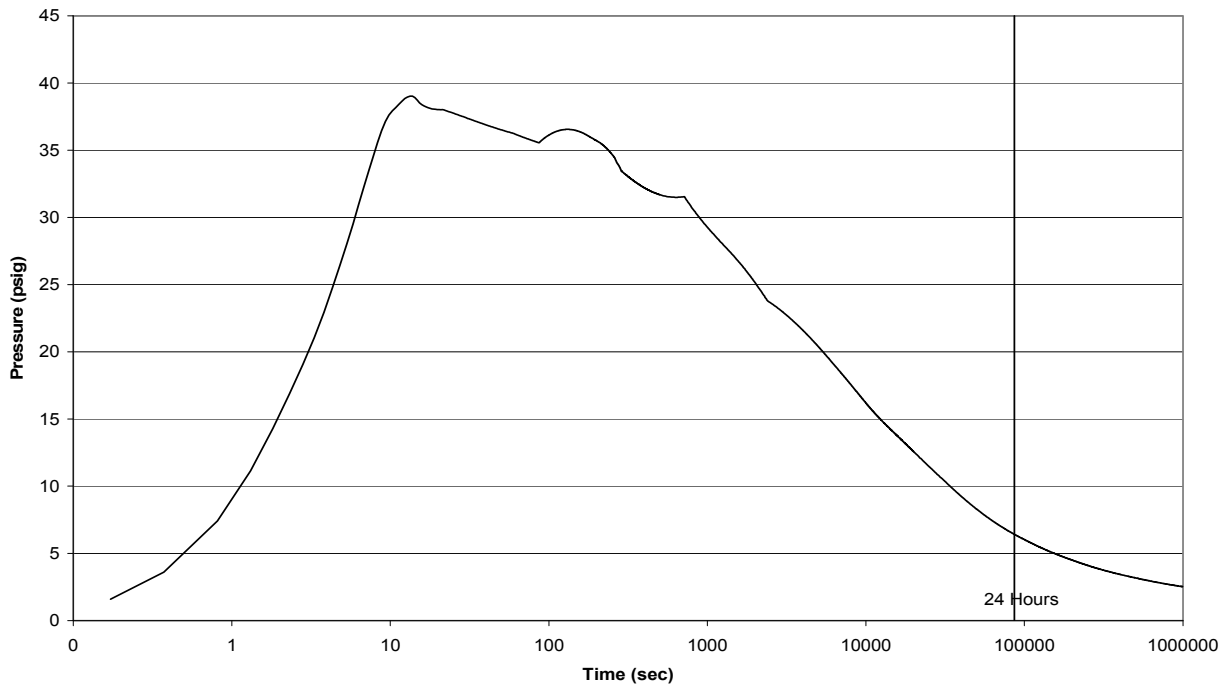


Figure 2.6.1-4
Containment Vapor Temperature, LOCA DEDLS
(Long-Term Temperature Response Case)

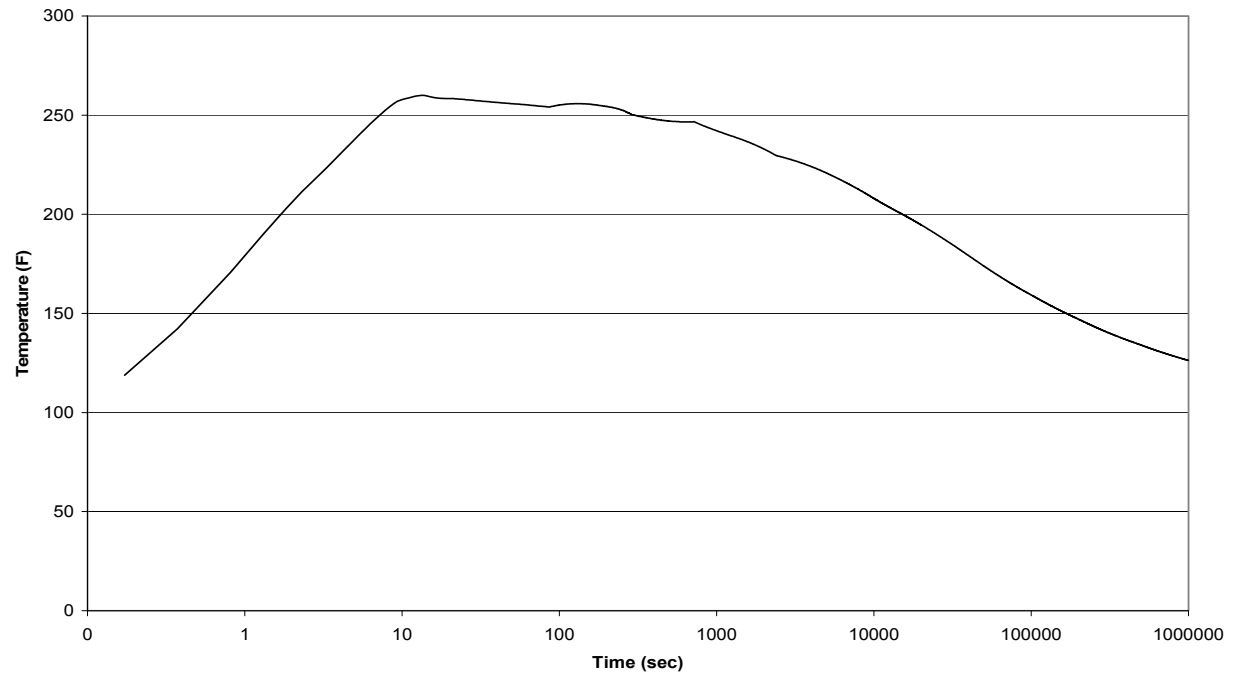


Figure 2.6.1-5
Containment Pressure, MSLB
(Peak Pressure Case)

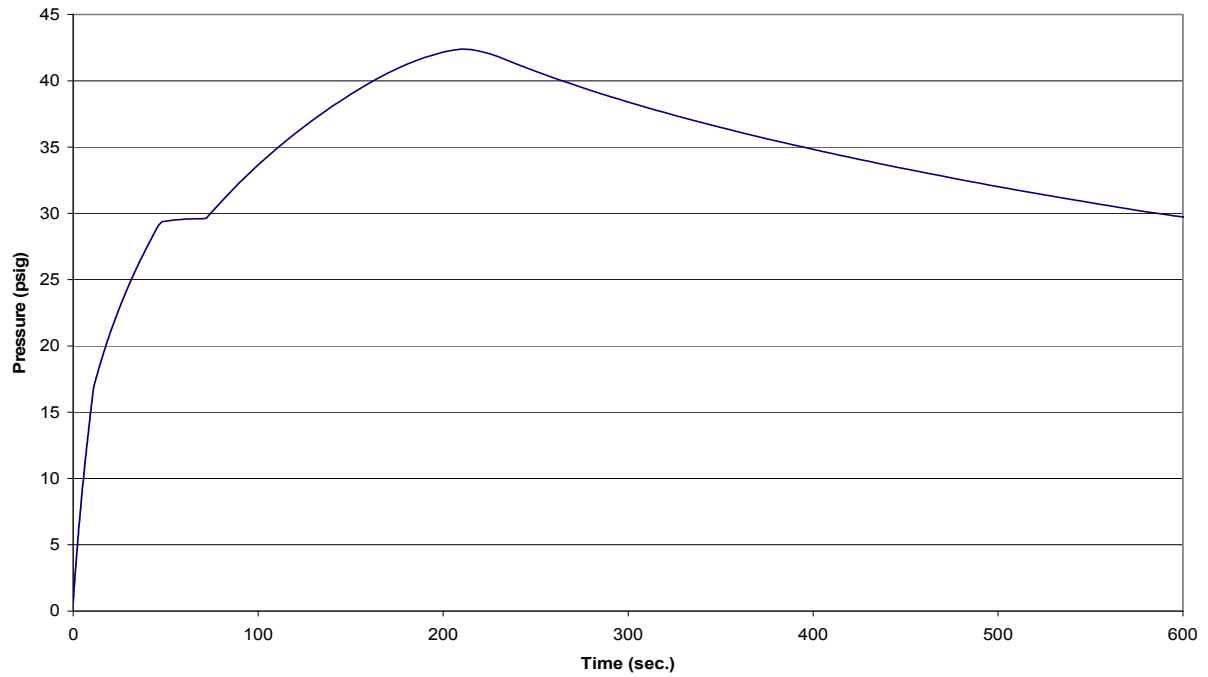
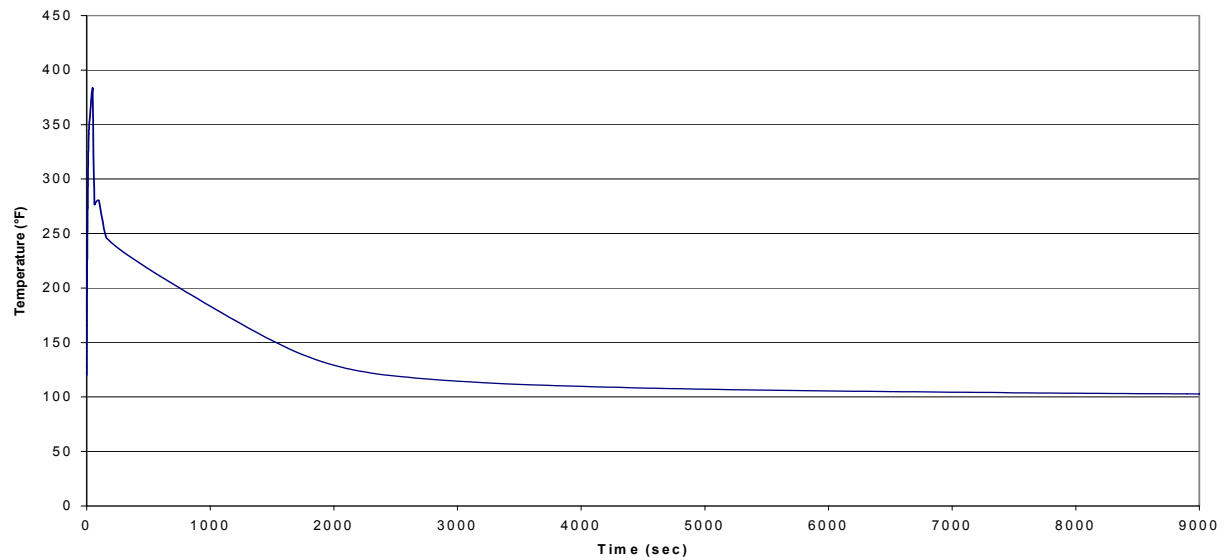


Figure 2.6.1-6
Containment Vapor Temperature, MSLB
(Environmental Qualification Case)



2.6.2 Subcompartment Analyses

2.6.2.1 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 Florida Power and Light (FPL) review for subcompartment analyses covered the determination of the design differential pressure values for containment subcompartments.

FPL's review focused on the effects of the increase in mass and energy (M&E) 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:

- 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
- 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 Standard Review Plan (SRP) Section 6.2.1.2.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Evaluation Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDC for Subcompartment Analyses are as follows:

- GDC-4 is described in UFSAR Section 3.1.4 Criterion 4 - Environmental and Missile Design Basis.

Structures, systems and components (SSCs) important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents (LOCAs). These SSCs shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and approved by the Commission demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

SSCs important to safety are designed to accommodate the effects of and to be compatible with the pressure, temperature, humidity, and radiation conditions associated with normal operation, maintenance, testing, and postulated accidents including a LOCA, in the area in which they are located.

Due to the application of leak before break (LBB) methodology to the reactor coolant system (RCS) hot and cold leg piping, the dynamic effects of a LOCA do not have to be considered. A technical evaluation (CE Owners Group Report CEN-367-A, Leak-Before-Break Evaluation of Primary Coolant Loop piping in Combustion Engineering Designed Nuclear Steam Supply Systems) was performed to demonstrate that the probability or likelihood of large breaks occurring in the primary coolant loops is sufficiently low that they need not be a design basis.

Protective walls and slabs, local missile shielding, or restraining devices are provided to protect the containment and engineered safety features systems within the containment against damage from missiles generated by equipment failures. The concrete enclosing the reactor coolant system serves as radiation shielding and an effective barrier against internally generated missiles. A missile shield is provided for control element drive mechanisms.

Penetrations and piping extending outward from the containment, up to and including isolation valves are protected from damage due to pipe whipping, and are protected from damage by external missiles, where such protection is necessary to meet the design bases.

Non-Seismic Category I Piping is arranged or restrained so that failure of any non-seismic Category I piping will neither cause a nuclear accident nor prevent essential seismic Category I structures or equipment from mitigating the consequences of such an accident.

Seismic Category I piping is arranged or restrained such that in the event of rupture of a seismic Category I pipe which causes LOCA, resulting pipe movement will not result in loss of containment integrity or adequate engineered safety features systems operation.

The structures inside the containment vessel are designed to sustain dynamic loads which could result from failure of major equipment and piping, such as jet thrust, jet impingement and local pressure transients, where containment integrity is needed to cope with the conditions.

The external concrete Shield Building protects the steel containment vessel from damage due to external missiles such as tornado propelled missiles.

Subcompartment pressurization due to the RCS hot and cold leg pipe breaks was considered in the original containment structure design. Since then, however, the NRC revised GDC-4 to eliminate the consideration of dynamic effects of a LOCA from the plant design bases. The dynamic effects of a LOCA include the effects of missiles, pipe whipping, discharging fluid (i.e., jet impingement), decompression waves within the ruptured pipe and dynamic or nonstatic pressurization in cavities, compartments, and subcompartments. The mechanical/structural loading effects or compartment pressurization from a circumferential (guillotine) or longitudinal (slot) break in the RCS hot or cold legs are no longer considered a design basis. The environmental qualification design basis for safety related equipment inside containment remains unchanged. As documented in a March 5, 1993 NRC letter to FPL, the NRC approved the St. Lucie Unit 2 LBB analysis.

Refer to UFSAR Section 3.5, 3.6, 3.7 and 3.11 for details.

- GDC-50 is described in UFSAR Section 3.1.50 Criterion 50 - Containment Design Bases.

The reactor containment structure, including access openings, penetrations, and containment heat removal system shall be designed so that the containment structure and its internal compartments can accommodate, without exceeding the design leakage rate and, with sufficient margin, the calculated pressure and temperature conditions resulting from any LOCA. This margin shall reflect consideration of (1) the effects of potential energy sources which have not been included in the determination of the peak conditions, such as energy in steam generators and energy from metal-water and other chemical reactions that may result from degraded emergency core cooling functioning, (2) the limited experience and experimental data available for defining accident phenomena and containment responses, and (3) the conservatism of the calculational model and input parameters.

The containment structure, including access openings and penetrations, is designed to accommodate, without exceeding the design leak rate, the transient peak pressure and temperature associated with a design basis accident.

The containment structure and engineered safety features systems have been evaluated for various combinations of energy release. The analysis accounts for system thermal and chemical energy, and for nuclear decay heat. The safety injection system is designed such that no single active failure could result in significant metal-water reaction. The combined cooling capacity of two containment cooling units and one containment spray train is adequate, to prevent over pressurization of the structure, and to return the containment to near atmospheric pressure. Refer to UFSAR Section 6.2.1.

Analyses of the pressure transients in the subcompartments were performed using the RELAP-4 Mod 5 computer code.

The secondary shield wall analysis is discussed in UFSAR Section 6.2.1.2.3 (b). The breaks analyzed are listed in UFSAR Table 6.2-13. For RCS breaks, flow is directed into the region between the steam generator and the primary shield wall away from the pressurizer volumes. This maximized the differential pressure across the RCS. Flow from suction and discharge leg breaks is also directed into the region between the steam generator and the secondary shield wall to find the maximum possible pressure differential across the secondary shield wall. A suction leg guillotine break at the steam generator nozzle produces the highest differential pressures for the RCS breaks.

The pressurizer area analysis is discussed in UFSAR Section 6.2.1.2.3 (c). The pressurizer area model is defined on Figure 6.2-29. For the pressurizer, a surge line guillotine break is assumed to occur at the pressurizer nozzle. In addition, breaks in the spray and relief lines are assumed in the upper pressurizer volume. The guillotine break in the surge line produces the highest differential pressures for the RCS breaks.

Additional details that define the licensing basis for the subcompartment analyses are defined in the UFSAR Section 6.2.1.

In addition to the licensing basis described in the UFSAR, the containment was evaluated for License Renewal. Operation of the containment under EPU conditions has been evaluated in LR [Section 2.6.1](#). The subcompartment analysis is not within the scope of License Renewal.

2.6.2.2 Technical Evaluation

2.6.2.2.1 Introduction

The impact of the EPU on the mass and energy (M&E) release following the postulated current licensing basis pipe breaks was evaluated and a determination was made whether the original licensing basis M&E release remained bounding.

In case that the EPU M&E release was determined to be higher than the original licensing basis M&E release, the impact of that increase on the pressure transients within the containment subcompartments (i.e., the reactor cavity, the area enclosed by the secondary shield wall, and the pressurizer cavity), was evaluated using conservative scaling techniques that reflect a comparison of the pre-EPU and EPU M&E release data.

2.6.2.2.2 Description of Analyses and Evaluations

Comparison of EPU Versus Pre-EPU M&E Release Data

As documented in UFSAR Section 6.2.1.2.1, the application of LBB criteria for large reactor coolant pipe breaks within the containment subcompartments eliminated the need to evaluate the following pipe ruptures for EPU:

- Hot Leg Guillotine Break in the Reactor Cavity,
- Discharge Leg Guillotine Break in the Reactor Cavity,
- Hot Leg Guillotine Break in the Secondary Shield Wall,
- Suction Leg Guillotine Break in the Secondary Shield Wall,
- Suction Leg Slot Break in the Secondary Shield Wall, and
- Discharge Leg Guillotine Break in the Secondary Shield Wall.

The impact of the EPU on the M&E release associated with the remaining licensing basis breaks, i.e., the pressurizer relief line break, the pressurizer spray line break and the pressurizer surge line break is documented in LR [Section 2.6.3.1](#), Mass and Energy Release Analysis for Postulated Loss of Coolant, and summarized below.

1. Pressurizer Relief Line Guillotine Break

The short term M&E release associated with a break of the pressurizer relief line is affected only by the initial pressurizer pressure, which determines the initial enthalpy of the saturated phases.

The initial pressurizer pressure utilized for the pre-EPU M&E release analysis is not impacted by the EPU. Consequently, the M&E release associated with the pressurizer relief line break is not impacted by the EPU.

2. Pressurizer Spray Line Guillotine Break

A guillotine break of the spray line will result in M&E release from both sides of the break – the pressurizer side and the cold leg side.

As discussed above for the relief line break, the M&E release from the pressurizer side of a spray line break is dependent only on the initial pressurizer pressure. Since the pressurizer pressure is unchanged, the associated M&E release is not impacted by the EPU.

The short term 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 discharge cold leg.

At the limiting EPU cold leg temperature of 543°F, the highest initial mass release rate exceeds that of the UFSAR by less than 2 percent and the highest initial energy release rate exceeds that of the UFSAR by less than 1 percent.

3. Pressurizer Surge Line Guillotine Break

A guillotine break of the pressurizer surge line will result in M&E release from both sides of the break – the pressurizer side and the hot leg side.

As discussed above for the relief line break, the M&E release from the pressurizer side of a surge line break is dependent only on the initial pressurizer pressure. Since the pressurizer pressure is unchanged, the associated M&E release is not impacted by the EPU.

The short term M&E release from the hot leg side of a pressurizer surge line break is dependent only on the core power level and initial pressure and enthalpy in the hot leg.

At the limiting EPU cold leg temperature of 543°F, the M&E release rates were conservatively estimated to increase by less than 0.8 percent in mass rate and less than 0.4 percent in energy rate of the UFSAR M&E release rates.

Impact of EPU on Containment Subcompartment Pressurization

1. Reactor Cavity

As a result of NRC approval of the application of LBB methodology and per current licensing basis, subcompartment pressurization need not be addressed for the reactor cavity area.

2. Secondary Shield Wall

As indicated in UFSAR Section 6.2.1.2.3.b, the secondary shield wall is designed to 24 psid which represents an approximately 307 percent design margin from the results of the 1400 in² suction leg guillotine break at the steam generator nozzle (5.9 psid). This break represents the bounding M&E release into the compartment for all postulated RCS pipe breaks including the main steam line double ended guillotine break within the compartment. The M&E release at the EPU conditions resulting from all other smaller postulated RCS pipe breaks including the main steam line double ended guillotine break remains bounded by the M&E release utilized for the original 1400 in² suction leg guillotine break. Therefore, the differential pressure across the

secondary shield wall structure at EPU conditions is bounded by original design basis, and the current design margin of the structure remains unchanged for EPU conditions.

3. Pressurizer Cavity

As indicated in UFSAR Section 6.2.1.2.3.c, the pressurizer cavity compartment walls are designed for a differential pressure of 14 psid for walls above El. 62 ft (Upper Pressurizer Compartment) and 24 psid for walls below EL. 62 ft (Lower Pressurizer Compartment).

- *Upper Pressurizer Compartment:*

As indicated in UFSAR Section 6.2.1.2, the double-ended pressurizer relief line, pressurizer spray line, and pressurizer surge line breaks were considered in the original plant design for the upper pressurizer subcompartment extending from elevation 62 ft to elevation 87 ft.

As indicated earlier, the EPU will not impact the M&E release rates of a pressurizer relief line break. However, the EPU pressurizer spray line break initially releases a less than 2 percent higher mass release rate and a less than 1 percent higher energy release rate while the EPU pressurizer surge line break initially releases a 0.8 percent higher mass release rate and a 0.4 percent higher energy release rate (at the lowest analyzed EPU cold leg temperature of 543°F), compared to the M&E release rates at the pre-EPU conditions.

However, relative to compartment pressurization, these minimal increases in the M&E release rates are more than compensated by the impact of the increased vent path of approximately 190 ft² due to the removal of missile shield roof of the pressurizer cavity which was not considered in the original design analyses (refer to UFSAR Section 6.2.1.2.3.c).

Thus, it is concluded that the design margin for the upper pressurizer compartment wall structure may be conservatively assumed to remain unchanged at the EPU conditions.

- *Lower Pressurizer Compartment:*

As indicated above, the pressurizer surge line break, which is the limiting break for the lower pressurizer compartment pressurization, produces a 0.8 percent higher mass release rate and a 0.4 percent higher energy release rate (at the lowest analyzed EPU cold leg temperature of 543°F), compared to the M&E release rates at the pre-EPU conditions.

It is conservative to assume that the pressure increase is proportional to the M&E release increase. Since the maximum differential pressure across the lower pressurizer compartment wall is approximately 22.5 psid as shown in UFSAR Figure 6.2-30e, then, the maximum differential pressure is conservatively estimated as approximately 22.7 psid ($= 22.5 \times 1.008$) at the EPU conditions.

It is concluded that the design margin for the lower pressurizer compartment wall structure is approximately 6 percent ($= (24 - 22.7)/22.7 \times 100$ percent) at EPU conditions.

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

As discussed above, the containment is within the scope of License Renewal. Operation of the containment under EPU conditions has been evaluated in LR [Section 2.6.1](#). The subcompartment analysis is not within the scope of License Renewal.

2.6.2.2.4 Results

Reactor Cavity: As a result of application of the LBB criteria at St. Lucie Unit 2 and per current licensing basis, subcompartment pressurization need not be addressed for the reactor cavity area.

Secondary Shield Wall: The M&E release at the EPU conditions resulting from all other smaller postulated RCS pipe breaks remains bounded by the M&E release from the original 1400 in² suction leg guillotine break at the steam generator nozzle which is eliminated as a result of application of the LBB criteria. Thus, the differential pressure across the secondary shield wall structure at the EPU conditions is bounded by the original design basis, and the current design margin of the structure remains unchanged at the EPU conditions.

Pressurizer Cavity: The expected increase in the pressure differential resulting from the minimal increases in M&E release rates following a pressurizer spray line break or a pressurizer surge line break at the EPU conditions is more than compensated by the increased vent path of approximately 190 ft² due to the removal of the missile shield roof of the pressurizer cavity. The current design margin for the upper pressurizer compartment wall structure may be conservatively assumed to remain unchanged at the EPU conditions.

The design margin for the lower pressurizer compartment wall structure is conservatively estimated as 6 percent at the EPU conditions.

2.6.2.3 Conclusion

FPL has reviewed the subcompartment analyses and the change in predicted pressurization resulting from the increased M&E release. FPL 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, FPL concludes that St. Lucie Unit 2 will continue to meet its current licensing basis with respect to the requirements of GDC-4 and GDC-50 for the proposed EPU. Therefore, FPL 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

2.6.3.1.1 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 Florida Power and Light (FPL) review covered the energy sources that are available for release to the containment and the mass and energy (M&E) release rate calculations for the initial blowdown phase of the accident.

The Nuclear Regulatory Commission's (NRC's) acceptance criteria for M&E release analyses for postulated Loss-of-Coolant Accidents (LOCAs) are based on:

- 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,
- 10 CFR Part 50, Appendix K, insofar as it identifies sources of energy during a LOCA.

Specific review criteria are contained in Standard Review Plan (SRP) ([Reference 1](#)) Section 6.2.1.3.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to Title 10 of the Code of Federal Regulations (10 CFR) Part 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

The specific GDC for the Mass and Energy Release Analysis for Postulated Loss-of-Coolant is GDC-50, which is described in UFSAR Section 3.1.50 Criterion 50, Containment Design Basis.

The containment structure and engineered safety features systems are evaluated for various combinations of energy release. The analysis accounts for system thermal and chemical energy, and for nuclear decay heat. The safety injection system is designed such that no single active failure could result in significant metal-water reaction. The combined cooling capacity of two containment cooling units and one containment spray train is adequate, to prevent over pressurization of the structure, and to return the containment to near atmospheric pressure (refer to UFSAR Section 6.2.1).

UFSAR Section 6.2.1.1.3 provides a summary of the methodology and assumptions used in calculating the LOCA mass and energy release.

LR [Section 2.6.1](#), Primary Containment Functional Design, discusses the containment LOCA response analysis. In addition, the containment functional design requirements are discussed in UFSAR Section 6.2.1.1.1.

UFSAR Section 6.2.1.3 provides the current licensing basis analysis regarding M&E releases to the containment subsequent to a LOCA. This analysis identifies the sources of energy available for release to the containment.

LR **Section 2.6.2**, Subcompartment Analyses, discusses the containment subcompartment analysis in more detail. UFSAR Section 6.2.1.1e provides a discussion regarding compartment differential pressures.

In addition to the licensing basis described in the UFSAR, the structural integrity of the containment, including subcompartments and systems within the containment, were evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems and structures determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Sections 2.3.1, 2.3.2, and 2.4.1 of the SER identifies that components of the containment structure are within the scope of License Renewal. Programs used to manage the aging effects associated with the containment structure are discussed in SER Sections 3.1, 3.2, and 3.5.1 and Chapter 18 of the UFSAR.

2.6.3.1.2 Technical Evaluation

The following sections discuss the long-term LOCA M&E releases used in the containment pressure/temperature response and short-term M&E releases for the subcompartment pressurization analysis.

2.6.3.1.2.1 Long-Term LOCA M&E Releases

2.6.3.1.2.1.1 Introduction

Consistent with the original design analyses, the M&E released into containment during these events has been calculated for the extended power uprate (EPU). This information was then used for the calculation of the transient containment pressure/temperature response which is documented in LR **Section 2.6.1**, Primary Containment Functional Design.

The methodology used in this analysis is consistent with the methodology identified in the SRP Section 6.2.1.3, UFSAR Section 6.2.1.3 and used in the original licensing basis.

The analytical simulation of the LOCA event is initiated from full core power, including measurement uncertainty, and is characterized by four distinct phases: blowdown, reflood, post-reflood and long term cooldown phase. These phases and the methodology used to analyze them are described in the following paragraphs.

The rate of energy release to the containment is biased conservatively by considering the heat transfer from the core to the reactor coolant to be always in the nucleate boiling regime. As a result, the cladding temperature has been calculated to remain below 800°F. Since the metal-water reaction rate is insignificant at low cladding temperature, the amount of cladding that

would oxidize is negligible. Therefore, the contribution to the energy release rate from the metal-water reaction is negligible and was not included in the M&E analysis.

Blowdown Phase – The LOCA causes a rapid depressurization of the reactor coolant system (RCS), which quickly falls below the shut-off head of the high pressure safety injection (HPSI) pumps. The safety injection pumps are the primary source of core cooling for the majority of the event and will start in response to a safety injection actuation signal (SIAS) on containment high pressure signal or a pressurizer pressure low signal. However, the flow from the safety injection pumps is omitted during the blowdown phase because it would not be delivered prior to the end of blowdown due to the delay associated with the diesel generator starting following a loss of offsite power concurrent with a LOCA, signal response time and pumps coming to full speed. Once RCS pressure falls below the pressure in the safety injection tanks (SIT), the SIT check valves will open and SIT water is discharged into the RCS.

The blowdown phase of the LOCA is simulated using the NRC-approved CEFLASH-4A code (Reference 2). The use of the CEFLASH-4A code to calculate M&E releases from postulated RCS pipe ruptures is discussed in UFSAR Section 6.2.1.3. Note that CEFLASH-4A is also used for the 10 CFR 50 Appendix K emergency core cooling system (ECCS) performance analysis. However, many input and nodalization changes are made for this application relative to the Appendix K model to ensure that the M&E analysis is biased conservatively. This additional conservatism is addressed via the inputs and assumptions described in the following subsections.

Reflood and Post-Reflood Phases – Following the initial blowdown, the reactor vessel (RV) is reflooded by the incoming safety injection flow, including SITs, until the core becomes quenched. Since the refill period (the interval when the RV refills to the bottom of the active core) is conservatively omitted for containment response calculations, reflood is assumed to follow the initial blowdown. The effect of the steam generators (SGs) on the M&E transferred to containment is important for cold leg breaks after blowdown because the exiting steam passes through the SGs prior to exiting the RCS to the containment. The addition of SG energy to the break flow may cause the peak containment pressure response to occur during the reflood or post-reflood phase, which is defined as the period following the core being quenched. For the hot leg break, the M&E analysis ends at the end of the blowdown phase. Since there is no viable means for the exiting break flow to pass through the SGs prior to exiting the RCS to containment for a hot leg break, the reflood and post-reflood phases are not simulated.

The reflood and post-reflood phases of the LOCA are simulated using the FLOOD3 Mod2 computer code, which is an extension of the NRC approved FLOODMOD2 code referenced in the SRP and used in supporting the analysis performed for the licensing amendment request described in Reference 3. The use of the FLOOD3 Mod2 code to calculate M&E releases from postulated RCS pipe ruptures is discussed in UFSAR Section 6.2.1.3.

Long-Term Cooldown Phase – The long-term cooldown phase of the LOCA completes the transient simulation of this event. In this phase, the analysis accounts for all residual energy in the primary and secondary systems and decay heat. This analysis is typically run until the containment temperature returns to a value near the initial value. The containment response is described in LR Section 2.6.1, Primary Containment Functional Design.

2.6.3.1.2.1.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters

The M&E release analysis is sensitive to the assumed characteristics of various plant systems, in addition to other key modeling assumptions. Where appropriate, bounding inputs are utilized and instrumentation uncertainties are included. All input parameters are chosen consistent with accepted analysis methodology to ensure generation of limiting M&E releases for use in the subsequent containment response described in LR [Section 2.6.1](#), Primary Containment Functional Design.

Blowdown M&E Releases

The critical input parameters include the RCS initial conditions, core decay heat and primary and secondary metal mass and steam generator heat release modeling. UFSAR Section 6.2.1.3.1, “Description of Blowdown Model”, presents the major input assumptions used to support the UFSAR blowdown M&E release calculations. The blowdown M&E release calculations described herein utilized revised input assumptions in support of the EPU program, listed in LR [Table 2.6.3.1-1](#).

Reflood and Post-Reflood M&E Releases

For the reflood and post-reflood M&E release analysis, heat transfer is conservatively modelled for the core, vessel walls, vessel internals, loop metal, steam generator tubes, steam generator inventory, steam generator secondary walls, and decay heat. UFSAR Section 6.2.1.3.2, “Description of Core Reflood and Post-Reflood Model”, presents the major input assumptions used to support the UFSAR reflood and post-reflood M&E release calculations. The reflood and post-reflood M&E release calculations described herein utilized revised input assumptions in support of the EPU. Except for those inputs and assumptions listed in LR [Tables 2.6.3.1-1](#) through [2.6.3.1-3](#), there are no differences between the current licensing analysis and the EPU reflood/post-reflood M&E release analysis.

Acceptance Criteria

The methodology used in this analysis is consistent with the methodology identified in the SRP and used in the current licensing basis. A large break LOCA is classified as an American Nuclear Society (ANS) Condition IV event, an infrequent fault. To satisfy the NRC acceptance criteria presented in the SRP Section 6.2.1.3, the relevant requirements are:

- 10 CFR 50, Appendix A, and
- 10 CFR 50, Appendix K, paragraph I.A.

To meet these requirements, the following must be addressed:

- Sources of energy,
- Break size and location, and
- Calculation of each phase of the accident.

2.6.3.1.2.1.3 Description of Analyses and Evaluations

Blowdown M&E Release Data

Break Size and Location

A double-ended slot break was postulated for all breaks analyzed. Previous analyses have shown that this type of break is limiting. The following break locations and sizes are considered for the blowdown M&E release analysis:

- 9.82 ft² double ended discharge leg slot (DEDLS) break,
- 9.82 ft² double ended suction leg slot (DESLS) break, and
- 19.24 ft² double ended hot leg slot (DEHLS) break.

A review of the results provided in LR [Section 2.6.1](#), Primary Containment Functional Design, LR [Table 2.6.1-2](#), indicated that the limiting peak pressure and long-term temperature response cases are the DEHLS break and DEDLS break, respectively. Consistent with these results, LR [Table 2.6.3.1-4a](#) and [Table 2.6.3.1-5](#) present the calculated M&E releases during the blowdown phase for the DEHLS and DEDLS break cases, respectively.

Reflood and Post-Reflood M&E Release Data

The limiting cold leg break case was determined to be the DEDLS with minimum safety injection flow. LR [Table 2.6.3.1-6](#) and [Table 2.6.3.1-7](#) present the calculated break flow and spillages and condensation M&E releases during the reflood/post-reflood phases for the DEDLS with minimum safety injection (SI) flow, respectively.

Sources of M&E

The sources of mass considered in the LOCA M&E release analysis are:

- RCS water,
- SIT water, and
- Safety injection pump flow.

The energy inventories considered in the LOCA M&E release analysis are:

- RCS water,
- SIT water,
- SI pump flow,
- Decay heat,
- Core-stored energy,
- RCS metal (includes steam generator tubes),
- Steam generator metal (includes transition cone, shell, wrapper, and other internals), and
- Steam generator secondary energy (includes fluid mass and steam mass).

The M&E inventories are presented at the following times, as appropriate:

- Time zero (initial conditions),
- End of blowdown (EOB), and
- End of post-reflood (EOPR).

The M&E inventories for the limiting DEHLS and DEDLS break cases are presented in LR [Table 2.6.3.1-8](#) and [2.6.3.1-9](#), respectively.

2.6.3.1.2.1.4 Long-Term LOCA Results

The M&E releases for the limiting LOCA events are presented in LR [Table 2.6.3.1-4a](#) through [2.6.3.1-7](#). For the EPU, the limiting containment peak pressure case is the DEHLS break case. The M&E from the equivalent case, i.e. DEHLS break, from the current analysis of record is presented in LR [2.6.3.1-4b](#) for comparison. The mass and energy release rates are higher for the EPU. This is because, for the EPU, the RCS (core) inlet temperature (Tcold) is higher and RCS flow rate is slightly higher than those for the current analysis. At the uprated power, this translates into a higher core outlet temperature which results in a higher enthalpy.

The results of this analysis (M&E release rates) were used in the containment integrity analysis (see LR [Section 2.6.1](#), Primary Containment Functional Design).

The consideration of the various energy sources listed in LR [Section 2.6.3.1.2.1.3](#) above, for the long-term M&E release analysis provides assurance that all available sources of energy have been included in this analysis. By addressing all available sources of energy as well as the limiting break size and location and the specific modeling of each phase of the long-term LOCA event, the review guidelines presented in SRP Section 6.2.1.3 have been satisfied.

2.6.3.1.2.2 Short-Term LOCA M&E Releases

2.6.3.1.2.2.1 Introduction

An evaluation was conducted to determine the effect of the EPU on the short-term LOCA-related M&E releases.

The short-term LOCA-related M&E releases were used as input to the subcompartment analyses (see LR [Section 2.6.2](#), Subcompartment Analyses). These analyses were performed to ensure that the walls of a subcompartment can maintain their structural integrity during the short pressure pulse (generally less than 4 seconds) accompanying a high-energy line pipe rupture within that subcompartment.

St. Lucie Unit 2 is approved for Leak-Before-Break (LBB). In accordance with the 1987 revision to GDC-4, the dynamic effects of RCS main loop piping breaks have been eliminated from consideration (see LR [Section 2.6.1](#), Leak-Before-Break).

Short-term M&E release evaluations are performed to support the pressurizer compartment. With application of Leak-Before-Break, reactor cavity pressurization is no longer a design basis for the plant (UFSAR Section 6.2.1.2.3).

The containment internal structures are designed for a pressure buildup that could occur following a postulated LOCA. If a LOCA were to occur in these relatively small volumes, the pressure would build up at a faster rate than the overall containment, thus imposing a differential pressure across the walls of the compartments.

A short-term LOCA M&E release evaluation was performed to support the pressurizer compartment. The evaluation considered the effect of the EPU on the current M&E releases. The pressurizer compartment evaluation considers breaks in the pressurizer relief line, in the pressurizer spray line and in the surge line.

LR [Section 2.6.2](#), Subcompartment Analyses, discusses the short-term subcompartment pressure and temperature response to the postulated breaks under EPU conditions.

2.6.3.1.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The short-term LOCA M&E release analysis is sensitive to the RCS fluid conditions (pressure and enthalpy). For the pipe breaks considered in the pressurizer compartment analysis, the relevant fluid conditions are those in the pressurizer, in the hot leg, and in the cold leg. The effect of the EPU on these conditions has been evaluated, relative to the conditions considered in the current analysis documented in the UFSAR, in order to determine the effect of the EPU on the short-term M&E releases. Where appropriate, bounding inputs were used and instrumentation uncertainties were included.

The following assumptions were employed to ensure that the releases were conservatively calculated for the EPU:

- Minimum RCS vessel/core inlet temperature, including uncertainty,
- Maximum RCS flow rate, including uncertainty, and
- Nominal full reactor power, including uncertainty and pump heat.

A LOCA is classified as an ANS Condition IV event – an infrequent fault. The relevant requirements to satisfy the acceptance criteria are as follows:

The NRC's SRP ([Reference 1](#)), Section 6.2.1.3, M&E Release Analysis for Postulated Loss-of-Coolant Accidents Subsection II provides guidance on NRC's expectations for what must be included in a LOCA M&E release calculation, if that calculation is to be acceptable.

2.6.3.1.2.2.3 Description of Analysis and Evaluations

The evaluation considers the effect of the EPU on the existing LOCA short-term M&E analysis, without recalculating the details of the blowdown transients.

Short-term releases are linked directly to the critical mass flux, which increases with increasing pressures and decreasing enthalpy. The short-term LOCA releases are expected to increase due to changes associated with the EPU conditions. Short-term blowdown transients are characterized by a peak M&E release rate that occurs during a sub-cooled condition. The Henry-Fauske correlation, which models this condition, is used to quantify the effect of the deviations in the RCS inlet and outlet temperature for the EPU.

The three postulated break locations are considered individually as follows.

Pressurizer Relief Nozzle Guillotine Break

For a break of the pressurizer relief line, the short-term M&E release is affected only by the initial pressurizer pressure, which determines the initial enthalpy of the saturated phases. The initial pressurizer pressure under EPU conditions is unchanged from the pressure under current conditions. The M&E release results in UFSAR Table 6.2-22 remain unchanged for EPU.

Spray Line Guillotine Break at Pressurizer Nozzle

A guillotine break of the spray line releases M&E from both sides of the break – the pressurizer side and the cold leg side.

Spray Line Break, Pressurizer Side. The M&E release from the pressurizer side of a spray line break is dependent only on the initial pressurizer pressure. Since the pressurizer pressure is unchanged for EPU, the M&E release results in UFSAR Table 6.2-23A remain unchanged for EPU.

Spray Line Break, 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 discharge cold leg.

The evaluation shows that, as the cold leg temperature decreases, both mass and energy release rates increase. At the lowest initial temperature of 543°F, the cold leg side of a spray line break initially releases 1.97 percent higher mass flux and 0.81 percent higher energy flux than it does at the conditions of the UFSAR analysis (UFSAR Table 6.2-23B).

Spray Line Break, Combined Pressurizer and Cold Leg Sides.

- An analysis of a pressurizer spray line break at the EPU conditions, with the nominal cold leg temperature (551°F), will produce a lower mass release rate (decrease of 0.5 percent) and a slightly higher energy release rate (increase of less than 0.1 percent) into the pressurizer compartment, relative to the UFSAR values.
- In the range of cold leg temperatures 543-554°F, as the temperature decreases, both mass and energy initial release rates increase. The highest initial mass release rate in this range exceeds that of the UFSAR by less than 2 percent. The highest initial energy release rate in this range exceeds that of the UFSAR by less than 1 percent.

Pressurizer Surge Line Guillotine Break at Pressurizer Nozzle

An analysis of a pressurizer surge line guillotine break at the EPU/MUR conditions will produce mass and energy release rates into the pressurizer compartment that are higher than the UFSAR values. At worst, the mass release is 0.8 percent higher and the energy release 0.4 percent higher than the current values in UFSAR Tables 6.2-21A and 6.2-21B.

2.6.3.1.2.2.4 Short-Term LOCA M&E Releases Results

In summary, the pressurizer subcompartment breaks were evaluated using RCS coolant temperatures and pressures at the EPU conditions. The results of this evaluation show small increases in the short-term M&E releases (relative to the current M&E releases documented in

the UFSAR). The impact of these increased M&E releases on the compartment response is discussed in LR [Section 2.6.2](#), Subcompartment Analysis.

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

As discussed above, the containment structure is within the scope of License Renewal. The integrity of the containment structure under EPU conditions has been evaluated to determine if there any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.6.3.1.3 Conclusion

FPL has reviewed the M&E release assessment and concludes that the assessment 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, FPL finds that the M&E release will continue to meet its current licensing basis with respect to the requirements of GDC-50 for ensuring that the analysis is conservative. Therefore, FPL finds the proposed EPU is acceptable with respect to M&E release for postulated LOCA.

2.6.3.1.4 References

1. US Nuclear Regulatory Commission NUREG-0800, Standard Review Plan, Section 6.2.1.3, "Mass and Energy Release for Postulated Loss-of-Coolant-Accidents (LOCAs)."
2. CEFLASH-4A, A FORTRAN77 Digital Computer Program for Reactor Blowdown Analysis, CENPD-133, Supplement 5-A, June 1985 and previous supplements.
3. Entergy Operations, Inc. Memorandum W3F1-99-0156, from C. M. Dugger (Waterford 3) to U.S. Regulatory Commission, "Waterford 3 SES Docket No. 50-382 License No. NPF-38 Technical Specification Change Request NPF-38-224 Containment Cooling System Reduction in Operable Containment Fan Coolers," October 18, 1999.

Table 2.6.3.1-1
System Parameters Initial Conditions

Parameters	Value
Core Thermal Power ⁽¹⁾ (MWt)	3030.0
RCS Minimum Flow Rate ⁽¹⁾ (gpm)	375,000
Core/Reactor Vessel Inlet Temperature ⁽¹⁾ (°F)	554.0
Core/ Reactor Vessel Outlet Temperature (°F)	608.56
Initial Steam Generator Steam Pressure (psia)	1000
Steam Generator Tube Plugging (%)	0
Initial Steam Generator Secondary Side Liquid Mass ⁽¹⁾ (lbm)	130,350
Assumed Containment Backpressure during Reflood (psia)	55.0
Safety Injection Tank	
Water volume (ft ³) per SIT (average) ⁽²⁾	1488.0
Gas pressure in tank (psig) (maximum)	650.0
Temperature (°F)	120
Notes: 1. Core Thermal Power, RCS Total Flow Rate, Core/Reactor Vessel Inlet Temperature, and Steam Generator Secondary Side Mass include appropriate uncertainty and/or allowance. 2. Does not include SIT line volume.	

Table 2.6.3.1-2
SI Flow Maximum Safeguards

RCS Pressure (psia)	Total Flow (gpm)
0.0	11296.0
10.4	11118.8
34.8	10670.0
56.5	10221.6
76.0	9774.0
93.4	9327.2
108.9	8881.2
122.9	8435.6
135.4	7990.8
146.8	7546.4
157.1	7102.4
166.5	6658.4
175.2	6215.2
183.2	5772.0
190.5	5328.8
197.4	4886.4
203.8	4443.6
209.8	4001.2
215.3	3558.8
220.3	3116.8
224.9	2674.8
228.9	2233.2
232.2	1792.0
233.7	1571.2
234.9	1350.8
383.3	1265.2
592.3	1150.0
773.6	1035.2
929.8	920.0
1063.1	805.2
1175.4	690.0
1268.1	575.2

Table 2.6.3.1-2 (Continued)
SI Flow Maximum Safeguards

RCS Pressure (psia)	Total Flow (gpm)
1342.1	460.0
1397.7	345.2
1434.7	230.0
1451.8	115.2
1454.8	0.0

Table 2.6.3.1-3
SI Flow Minimum Safeguards

RCS Pressure (psia)	Total Flow (gpm)
0.0	2794.0
12.4	2658.6
25.9	2497.8
38.2	2337.0
49.5	2176.2
59.9	2015.4
69.5	1854.6
78.4	1694.0
86.7	1533.4
94.3	1372.8
101.3	1212.4
107.6	1051.8
113.1	891.4
117.9	731.0
121.6	570.8
124.2	410.6
125.1	330.4
125.5	250.4
148.1	248.6
307.6	233.8
476.6	212.6
603.7	191.2
708.4	170.0
800.7	148.8
883.3	127.6
954.3	106.2
1009.7	85.0
1045.8	63.8
1062.0	42.6
1062.6	21.2
1063.1	0.0

Table 2.6.3.1-4a
EPU Blowdown M&E Releases - DEHLS Break

Time (sec)	Mass Rate (lbm/sec)	Energy Rate (BTU/sec)
0.00	0.00000E+00	0.00000E+00
0.05	1.35820E+05	8.41381E+07
0.10	1.37253E+05	8.50310E+07
0.20	1.33401E+05	8.29487E+07
0.30	1.19172E+05	7.39904E+07
0.40	1.11916E+05	6.93934E+07
0.50	1.05913E+05	6.55552E+07
0.60	1.01579E+05	6.28345E+07
0.70	9.65597E+04	5.97127E+07
0.80	9.14255E+04	5.66782E+07
0.90	8.72830E+04	5.43940E+07
1.00	8.36935E+04	5.24394E+07
1.50	7.53216E+04	4.67949E+07
2.00	7.35827E+04	4.48545E+07
2.50	6.91418E+04	4.20094E+07
3.00	6.17473E+04	3.86685E+07
3.50	5.59703E+04	3.56891E+07
4.00	5.34216E+04	3.39076E+07
5.00	4.61850E+04	2.99320E+07
6.01	3.62599E+04	2.50939E+07
7.01	2.23670E+04	1.81838E+07
8.00	1.43538E+04	1.30425E+07
9.00	9.57775E+03	9.71126E+06
10.01	4.81732E+03	5.68429E+06
11.01	3.33570E+03	4.25217E+06
11.05	3.27814E+03	4.18092E+06
11.10	3.23996E+03	4.14027E+06
11.15	3.19568E+03	4.09161E+06
11.21	3.14557E+03	4.03831E+06
11.25	3.07815E+03	3.95976E+06
11.30	3.05200E+03	3.94167E+06
11.36	2.97505E+03	3.85502E+06

Table 2.6.3.1-4a (Continued)
EPU Blowdown M&E Releases - DEHLS Break

Time (sec)	Mass Rate (lbm/sec)	Energy Rate (BTU/sec)
11.41	2.90055E+03	3.76108E+06
11.46	2.78519E+03	3.62475E+06
11.50	2.68459E+03	3.50951E+06
11.55	2.60528E+03	3.39868E+06
11.60	2.53546E+03	3.28063E+06
11.66	2.46957E+03	3.17179E+06
11.70	0.00000E+00	0.00000E+00
INTEGRAL	4.75830E+05 (lbm)	3.16987E+08 (BTU)

Table 2.6.3.1-4b
Current Blowdown M&E Releases - DEHLS Break

Time (sec)	Mass Rate (lbm/sec)	Energy Rate (BTU/sec)
0.00	0.00000E+00	0.00000E+00
0.05	1.34626E+05	8.31725E+07
0.10	1.35189E+05	8.35273E+07
0.20	1.26852E+05	7.86821E+07
0.30	1.11893E+05	6.93091E+07
0.40	1.04586E+05	6.46979E+07
0.50	9.89883E+04	6.12218E+07
0.60	9.31076E+04	5.75107E+07
0.70	8.76904E+04	5.41704E+07
0.80	8.31784E+04	5.16563E+07
0.90	7.85255E+04	4.91408E+07
1.00	7.45188E+04	4.69197E+07
1.50	6.64428E+04	4.13257E+07
2.00	6.65614E+04	4.03105E+07
2.50	6.10890E+04	3.73867E+07
3.00	5.41705E+04	3.41347E+07
3.50	4.94292E+04	3.16273E+07
4.00	4.72093E+04	3.00116E+07
5.00	4.15050E+04	2.65695E+07
6.00	3.18930E+04	2.18284E+07
7.00	1.82188E+04	1.49506E+07
8.00	1.42708E+04	1.14822E+07
9.00	9.25155E+03	8.13295E+06
10.00	5.52009E+03	5.23322E+06
11.00	2.74693E+03	3.33995E+06
12.00	3.09750E+03	3.74420E+06
12.10	3.09426E+03	3.74785E+06
12.20	0.00000E+00	0.00000E+00
INTEGRAL	4.31676E+05(lbm)	2.84699E+08(BTU)

**Table 2.6.3.1-5
Blowdown M&E Release Rates to Containment - DEDLS Break**

Time (sec)	Mass Rate (lbm/sec)	Energy Rate (BTU/sec)
0.00	0.00000E+00	0.00000E+00
0.05	7.57144E+04	4.13581E+07
0.10	1.09045E+05	5.96382E+07
0.20	1.10389E+05	6.06114E+07
0.30	1.10283E+05	6.05958E+07
0.40	1.08261E+05	5.94706E+07
0.50	1.05513E+05	5.79398E+07
0.60	1.04878E+05	5.75893E+07
0.70	1.03607E+05	5.68989E+07
0.80	1.00244E+05	5.50678E+07
0.90	1.00580E+05	5.53094E+07
1.00	9.89669E+04	5.45134E+07
1.50	8.33397E+04	4.67065E+07
2.00	6.96689E+04	3.95448E+07
2.50	5.79660E+04	3.29990E+07
3.00	5.37555E+04	3.08179E+07
3.50	5.11598E+04	2.99365E+07
4.00	4.77939E+04	2.88457E+07
5.00	3.83731E+04	2.46665E+07
6.00	3.72067E+04	2.34321E+07
7.00	3.04235E+04	2.02132E+07
8.00	2.36863E+04	1.70664E+07
9.00	1.43891E+04	1.22614E+07
9.10	1.33132E+04	1.15617E+07
9.20	1.22754E+04	1.09068E+07
9.30	1.11400E+04	1.01215E+07
9.40	1.03801E+04	9.51866E+06
9.50	9.79174E+03	8.99469E+06
9.60	9.29844E+03	8.54412E+06
9.70	8.84922E+03	8.13026E+06
9.80	8.42980E+03	7.74656E+06
9.90	8.02758E+03	7.38620E+06

Table 2.6.3.1-5 (Continued)
Blowdown M&E Release Rates to Containment - DEDLS Break

Time (sec)	Mass Rate (lbm/sec)	Energy Rate (BTU/sec)
10.00	7.64039E+03	7.04370E+06
10.10	7.27654E+03	6.72158E+06
10.20	6.93406E+03	6.41805E+06
10.30	6.60965E+03	6.13234E+06
10.40	6.31034E+03	5.86812E+06
10.50	6.03838E+03	5.62801E+06
10.60	5.77082E+03	5.38891E+06
10.70	5.88703E+03	5.51669E+06
10.80	6.23646E+03	5.75635E+06
10.90	6.55795E+03	5.93904E+06
11.00	6.98240E+03	6.14858E+06
11.20	7.68107E+03	6.41834E+06
11.40	8.34672E+03	6.62700E+06
11.60	8.85145E+03	6.67867E+06
11.80	9.32925E+03	6.71430E+06
12.00	9.89062E+03	6.65056E+06
12.20	1.05749E+04	6.66203E+06
12.40	1.09060E+04	6.51452E+06
12.60	1.08957E+04	6.24718E+06
12.80	1.07432E+04	5.86507E+06
13.00	1.06950E+04	5.52755E+06
13.20	1.06672E+04	5.16915E+06
13.40	1.06401E+04	4.83060E+06
13.60	9.60448E+03	4.10231E+06
13.80	9.29757E+03	3.70263E+06
14.00	9.31744E+03	3.47843E+06
14.20	9.20918E+03	3.24972E+06
14.40	0.00000E+00	0.00000E+00
INTEGRAL	5.08232E+05 (lbm)	3.07418E+08 (BTU)

Table 2.6.3.1-6
Reflood/Post-Reflood M&E Release Rates to Containment DEDLS Break, Minimum SI Flow

Time (sec)	Mass Rate (lbm/sec)	Energy Rate (BTU/sec)
14.40*	0.00000E+00	0.00000E+00
14.44	7.42600E+01	9.68400E+04
19.32	7.04020E+02	9.06080E+05
21.36	8.14840E+02	1.04105E+06
21.37	4.07420E+02	5.20525E+05
24.12	4.10155E+02	5.20965E+05
28.92	4.10615E+02	5.18550E+05
33.75	4.08600E+02	5.14285E+05
38.55	4.05600E+02	5.09310E+05
43.35	4.02245E+02	5.04080E+05
48.20	3.98740E+02	4.98725E+05
53.00	3.95220E+02	4.93400E+05
57.80	3.91660E+02	4.88065E+05
62.60	3.88075E+02	4.82725E+05
67.45	3.84450E+02	4.77340E+05
72.25	3.80710E+02	4.71915E+05
77.05	3.77160E+02	4.66640E+05
81.85	3.73625E+02	4.61400E+05
86.64	3.70085E+02	4.56165E+05
86.65	7.40170E+02	9.12330E+05
92.80	6.80070E+02	8.18100E+05
98.90	6.24550E+02	7.51140E+05
105.10	5.74470E+02	6.89840E+05
111.20	5.30860E+02	6.35800E+05
117.30	4.92410E+02	5.87430E+05
123.40	4.59020E+02	5.45180E+05
129.60	4.29030E+02	5.05950E+05
135.70	3.99520E+02	4.69800E+05
141.80	3.72430E+02	4.37930E+05
147.90	3.48110E+02	4.09340E+05
154.10	3.25850E+02	3.83160E+05
160.20	3.06210E+02	3.60070E+05

Table 2.6.3.1-6 (Continued)
Reflood/Post-Reflood M&E Release Rates to Containment DEDLS Break, Minimum SI Flow

Time (sec)	Mass Rate (lbm/sec)	Energy Rate (BTU/sec)
166.30	2.88470E+02	3.39210E+05
172.40	2.72420E+02	3.20330E+05
178.50	2.57870E+02	3.03230E+05
178.60	2.62098E+02	3.16732E+05
179.40	2.53420E+02	2.93654E+05
181.20	2.61024E+02	3.10790E+05
183.90	2.55736E+02	2.99073E+05
187.50	2.59263E+02	3.05926E+05
192.00	2.52652E+02	2.96539E+05
197.40	2.50312E+02	2.94943E+05
203.70	2.41460E+02	2.83614E+05
210.80	2.29526E+02	2.70470E+05
218.90	1.99263E+02	2.33890E+05
227.90	1.85181E+02	2.18332E+05
237.70	1.62202E+02	1.90445E+05
248.50	1.47428E+02	1.73626E+05
260.10	1.30078E+02	1.52795E+05
272.70	1.17065E+02	1.37838E+05
286.10 (EOPR)	0.00000E+00	0.00000E+00
* Note that the first data point is an initialization point for the reflood phase. Also, note that a 50% steam condensation by cold SIT flow is considered to start at the time when the reactor annulus is full and end at the time when the SITs are empty. No credit was taken for condensation by SI pump flow.		

Table 2.6.3.1-7
Spillage & Condensation M&E Release Rates to Containment
DEDLS Break, Minimum SI Flow

Time (sec)	Mass Rate (lbm/sec)	Energy Rate (BTU/sec)
14.40*	0.00	0.00
21.35	0.00	0.00
21.36	5669.71	483355.52
22.36	5460.44	468530.23
23.36	5269.07	454922.54
24.36	5093.02	442361.28
25.36	4930.20	430707.04
26.36	4778.92	419848.07
27.36	4637.77	409688.40
28.36	4505.59	400149.31
29.36	4381.40	391165.77
34.95	3800.65	348873.56
39.95	3396.01	319136.43
44.95	3062.30	294455.18
49.95	2779.01	273388.29
54.95	2533.32	255018.67
59.95	2316.66	238734.39
64.95	2123.04	224102.73
69.95	1948.55	210825.18
74.95	1788.80	198635.30
79.95	1642.12	187394.39
84.95	1506.55	176954.12
89.95	25.97	6655.08
94.95	25.47	6527.94
99.95	27.01	6921.43
119.90	44.65	11442.79
139.90	83.40	21374.80
159.90	129.99	33314.25
178.50	165.09	42311.70
198.50	316.86	81209.13
218.50	391.10	100234.00

Table 2.6.3.1-7 (Continued)
Spillage & Condensation M&E Release Rates to Containment
DEDLS Break, Minimum SI Flow

Time (sec)	Mass Rate (lbm/sec)	Energy Rate (BTU/sec)
238.50	426.65	109346.48
258.50	449.74	115264.40
278.50	466.08	119452.62
286.10	0.00	0.00
* Note that the first data point is an initialization point for the reflood phase.		

**Table 2.6.3.1-8
M&E Inventories for the DEHLS Break Case**

	Mass Balance	
	Initial	EOB
RCS inventory (lbm)	495,533	65,458
Change in RCS inventory (lbm)	0	-430,076
Mass added by 4 SITs (lbm)	0	-46,091
Mass added by SI pumps (lbm)	0	0
Mass lost out break to containment (lbm)	0	475,830
Mass lost out break to sump (lbm)	0	0
Error (lbm)		337
Error (%)		0.071
	Energy Balance	
	Initial	EOB
RCS coolant internal energy (Btu)	294,998,250	18,274,154
Change in RCS coolant internal energy (Btu)	0	-276,724,096
Energy added by 4 SITs (Btu)	0	4,135,007
Energy added by SI Pumps (Btu)	0	0
Heat transferred from fuel (Btu)	0	15,853,000
Heat transferred from RCS walls / internals (Btu)	0	11,614,621
Heat transferred from SG (Btu)	0	16,736,000
Energy lost out break to containment (Btu)	0	316,986,630
Energy lost out break to sump (Btu)	0	0
Error (Btu)		8,076,094
Error (%)		2.548

Table 2.6.3.1-9
M&E Inventories for the DEDLS Break, Minimum SI Flow Case

	Mass Balance		
	Initial	EOB	EOPR
RCS inventory (lbm)	495,533	22,761	57,692
Change in RCS inventory (lbm)	0	-472,772	-437,841
Mass added by 3 SITs (lbm)	0	35,500	275,950
Mass added by SI pumps (lbm)	0	0	153,544
Mass lost out break to containment (lbm)	0	508,232	667,919
Mass lost out break to sump (lbm)	0	0	165,604
Error (lbm)		40	33,812
Error (%)		0.008	4.057
	Energy Balance		
	Initial	EOB	EOPR
RCS coolant internal energy (Btu)	294,998,250	6,401,082	16,542,688
Change in RCS coolant internal energy (Btu)	0	-288,597,168	-278,455,562
Energy added by 3 SITs (Btu)	0	3,184,847	20,517,494
Energy added by SI Pumps (Btu)	0	0	10,266,943
Heat transferred from fuel (Btu)	0	15,226,000	51,128,172
Heat transferred from RCS walls / internals (Btu)	0	9,400,448	23,059,034
Heat transferred from SG (Btu)	0	-1,739,800	98,460,500
Energy lost out break to atmosphere (Btu)	0	307,418,320	458,028,950
Energy lost out break to sump (Btu)	0	0	11,937,423
Error (Btu)		7,250,343	11,921,332
Error (%)		2.358	2.537

2.6.3.2 Mass and Energy Release Analysis for Secondary System Pipe Ruptures

2.6.3.2.1 Regulatory Evaluation

The Florida Power and Light (FPL) review covered the energy sources that are available for release to the containment, the mass and energy (M&E) release rate calculations and the single-failure analyses performed for steam and feedwater line isolation provisions, which would limit the flow of steam or feedwater to the assumed pipe rupture.

The NRC's acceptance criterion for Mass and Energy release analysis for secondary system pipe ruptures is 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 the Standard Review Plan (SRP), Section 6.2.1.4 and other guidance provided in Matrix 6 of RS-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 2 are measured against the NRC General Design Criteria for Nuclear Power Plants, 10 CFR 50, Appendix A, effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1972. The adequacy of the St. Lucie Unit 2 design relative to the GDC is discussed in UFSAR Section 3.1.

The specific GDC for the Mass and Energy Release Analysis for Secondary System Pipe Ruptures are as follows:

- GDC-50 is described in UFSAR Section 3.1.50, Criterion 50 – Containment Design Basis.

The reactor containment structure, including access openings, penetrations, and containment heat removal system shall be designed so that the containment structure and its internal compartments can accommodate, without exceeding the design leakage rate and, with sufficient margin, the calculated pressure and temperature conditions resulting from any loss of coolant accident. This margin shall reflect consideration of (1) the effects of potential energy sources which have not been included in the determination of the peak conditions, such as energy in steam generators and energy from metal-water and other chemical reactions that may result from degraded emergency core cooling functioning, (2) the limited experience and experimental data available for defining accident phenomena and containment responses, and (3) the conservatism of the calculational model and input parameters.

The containment structure, including access openings and penetrations, is designed to accommodate, without exceeding the design leak rate, the transient peak pressure and temperature associated with a design basis accident.

The containment structure and engineered safety features systems are evaluated for various combinations of energy release. The analysis accounts for system thermal and chemical energy, and for nuclear decay heat. The Safety Injection System is designed such that no single active

failure could result in significant metal-water reaction. The combined cooling capacity of two containment cooling units and one containment spray train is adequate, to prevent over pressurization of the structure, and to return the containment to near atmospheric pressure (refer to UFSAR Section 6.2.1).

UFSAR Section 6.2.1.4 states that Mass and Energy release analyses for postulated secondary system breaks inside containment are performed for a spectrum of break sizes and power levels in order to assure the identification of the most severe cases for containment analysis. The spectrum of breaks was run using the SGNIII computer code at initial power levels of 102, 75, 50, 25 and 0 percent. For each power level, analyses are performed for a full double area break and at decreasing break sizes until the largest break size for which no liquid entrainment is calculated could be identified.

Mass and Energy release data for the most severe secondary system pipe rupture are given in UFSAR Tables 6.2-12F and 12G.

Since the steam generator feedwater ring is below the initial steam generator water level, feedwater break cases will result in liquid entrainment for all but the smallest break sizes. For this reason, feedwater line break cases are always less severe than steam line breaks at the same power level and a spectrum of feedwater line break cases is not required.

Additional Main Steam Line Break (MSLB) Mass and Energy release details are discussed in UFSAR Section 6.2.1.4.

In addition to the licensing basis described in the UFSAR, the mass and energy release for a main steam line break analysis was evaluated for License Renewal and determined to be outside the scope of License Renewal.

2.6.3.2.2 Technical Evaluation

2.6.3.2.2.1 Introduction

The steam line break M&E releases were generated to determine the pressure and temperature responses for MSLB events inside containment for the Extended Power Uprate (EPU). The cases that were considered in this analysis are MSLBs at various power levels ranging from hot zero power (HZIP) to hot full power (HFP). The different single failure scenarios were analyzed at each power level.

2.6.3.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters and Assumptions

The major modeling input parameters and assumptions used in the containment evaluation model for the MSLB events are identified below.

The initial conditions and input assumptions associated with the fan coolers and containment spray pumps are listed in LR [Table 2.6.1-1](#).

The current licensing basis is described in the UFSAR Section 6.2.1.1.3.

The MSLB M&E release calculations described herein utilized revised input assumptions in support of the EPU. The specific assumptions for the current MSLB analysis are listed in UFSAR Section 6.2.1.4.2. In addition to the inputs in the USFAR, a reactor coolant pump heat input of 20 MWt was assumed.

Significant differences exist between the current licensing analysis and the EPU MSLB M&E release analysis in the inputs and assumptions, as summarized below. Note that some containment parameters are also discussed below as the SGNIII code utilizes an iterative process to calculate the M&E releases and containment response for a given time step.

- The reactor thermal power is 3030 MWt (rated power of 3020 MWt with approximately 0.3 percent measurement uncertainty) for the EPU program versus 2754 MWt (102 percent of 2700 MWt) for the current analysis.
- The containment initial pressure is 15.41 psia for the EPU analysis versus 14.7 psia for the current analysis.
- The containment free volume is $2.493 \times 10^6 \text{ ft}^3$ for the EPU analysis versus $2.506 \times 10^6 \text{ ft}^3$ for the current analysis due to the addition of a more conservative uncertainty value.

Acceptance Criteria

While St. Lucie Unit 2 is not an SRP plant, the acceptance criteria for a MSLB M&E release analysis have been taken from SRP Section 6.2.1.4 (Reference 1), the relevant requirements considered are as follows:

- Sources of energy,
- Mass and energy release rate, and
- Single failure analysis.

2.6.3.2.2.3 Description of Analyses and Evaluations

The analysis was performed using the NRC approved SGNIII computer code (Reference 2) and in accordance with SRP Section 6.2.1.4 III.2 (Reference 1). The largest break that results in an all steam blowdown was analyzed. The cases analyzed are MSLBs at EPU power levels of 0 percent, 25 percent, 50 percent, 75 percent and 100.3 percent.

At each power level, three single failure scenarios were evaluated. Consistent with UFSAR Section 6.2.1.4.2, they are:

- Loss of one containment heat removal train,
- Main steam isolation valve (MSIV) fails open, and
- Main feedwater isolation valve (MFIV) fails open.

Each case was run until the affected steam generator had completed blowdown as indicated by a significant decrease in steam flow out the break. Mass and energy releases for each case were calculated. The results are used in the containment pressure and temperature response calculations (LR Section 2.6.1).

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

The mass and energy release for a main steam line break analysis is not within the scope of License Renewal. Systems and components that are credited in the analysis are evaluated as part of their system evaluation.

2.6.3.2.2.5 Results

A review of the results provided in LR [Section 2.6.1.2.1.3](#) indicated that the limiting peak pressure case is at HZP with the failure of one containment heat removal train. The limiting peak temperature case is at HFP with the failure of one MSIV to close. The M&E releases for the limiting EPU MSLB events are presented in LR [Table 2.6.3.2-1](#). LR [Figure 2.6.3.2-1](#) and [2.6.3.2-2](#) compare the M&E flow rates out the break for the current and EPU limiting cases. [Table 2.6.3.2-2](#) provides the sequence of events for the current and EPU limiting cases.

As seen in LR [Figure 2.6.3.2-1](#) and [2.6.3.2-2](#) the event analyzed for EPU lasts significantly longer than the analysis of record. This is due to the ability of the model to more accurately reflect the SG nozzle restrictors. The time difference between the current and EPU event results has no appreciable impact on maintaining containment design as discussed in LR [Section 2.6.1](#).

2.6.3.2.3 Conclusion

FPL has reviewed the mass and energy release assessment for the postulated secondary system pipe ruptures and finds that the effects on the proposed EPU have been adequately addressed. Based on this, FPL concludes that the analysis will continue to meet its current licensing basis with respect to the requirements of GDC-50 for ensuring that the analysis is conservative. Therefore, FPL finds the proposed EPU acceptable with respect to the mass and energy release for postulated secondary system pipe ruptures.

2.6.3.2.4 References

1. US Nuclear Regulatory Commission Standard Review Plan, NUREG-0800, Revision 2, Section 6.2.1.4, March 2007.
2. US Nuclear Regulatory Commission Final Safety Evaluation Report, NUREG-1462, Volume 1, August 1994.

Table 2.6.3.2-1
Blowdown M&E Release Rates to Containment for the Limiting MSLB

Time (Sec)	Peak Pressure Mass Rate (lbm/sec)	Peak Temperature Mass Rate (lbm/sec)	Peak Pressure Energy Rate (BTU/sec)	Peak Temperature Energy Rate (BTU/sec)
0.0	8029.28	7869.13	9.600E+06	9.414E+06
0.2	7772.40	7484.04	9.301E+06	8.962E+06
0.4	7599.16	7179.86	9.098E+06	8.604E+06
0.6	7459.57	6915.73	8.934E+06	8.292E+06
0.8	7338.00	6690.32	8.792E+06	8.024E+06
1.0	7227.34	6491.27	8.662E+06	7.788E+06
1.2	7123.94	6315.41	8.540E+06	7.578E+06
1.4	7025.80	6159.88	8.425E+06	7.393E+06
1.6	6931.82	6022.14	8.314E+06	7.228E+06
1.8	6841.32	5897.86	8.207E+06	7.080E+06
2.0	6753.85	5785.43	8.104E+06	6.945E+06
2.2	6669.14	5685.94	8.004E+06	6.826E+06
2.4	6586.99	5597.66	7.907E+06	6.720E+06
2.6	6507.25	5519.10	7.813E+06	6.626E+06
2.8	6430.98	5448.98	7.723E+06	6.542E+06
3.0	6357.53	5386.20	7.636E+06	6.467E+06
4.0	6020.23	5153.59	7.236E+06	6.188E+06
5.0	5735.80	5006.45	6.898E+06	6.012E+06
6.0	5495.60	5086.95	6.612E+06	6.111E+06
7.0	5292.58	5469.38	6.369E+06	6.573E+06
8.0	5121.61	5693.55	6.165E+06	6.843E+06
9.0	4972.45	5825.46	5.987E+06	7.002E+06
10.0	4858.55	5907.79	5.850E+06	7.100E+06
11.0	4773.04	5969.28	5.748E+06	7.174E+06
12.0	2294.01	5428.60	2.762E+06	6.526E+06
13.0	2264.89	4567.31	2.727E+06	5.487E+06
14.0	2233.37	3981.98	2.689E+06	4.778E+06
15.0	2199.66	3566.39	2.649E+06	4.277E+06
16.0	2163.90	3286.55	2.606E+06	3.940E+06
17.0	2126.48	3016.26	2.561E+06	3.618E+06

Table 2.6.3.2-1 (Continued)
Blowdown M&E Release Rates to Containment for the Limiting MSLB

Time (Sec)	Peak Pressure Mass Rate (lbm/sec)	Peak Temperature Mass Rate (lbm/sec)	Peak Pressure Energy Rate (BTU/sec)	Peak Temperature Energy Rate (BTU/sec)
18.0	2087.42	2699.70	2.514E+06	3.246E+06
19.0	2047.09	2636.23	2.466E+06	3.170E+06
20.0	2007.80	2578.04	2.418E+06	3.101E+06
30.0	1727.65	2207.04	2.081E+06	2.658E+06
40.0	1562.53	1969.37	1.882E+06	2.372E+06
50.0	1446.28	1786.78	1.741E+06	2.152E+06
60.0	1350.87	1605.91	1.625E+06	1.934E+06
70.0	1267.22	1375.19	1.524E+06	1.655E+06
80.0	1192.02	1068.80	1.433E+06	1.283E+06
90.0	1121.76	642.71	1.348E+06	7.667E+05
100.0	1052.14	307.82	1.263E+06	3.620E+05
125.0	904.27	2.27	1.084E+06	2.910E+03
150.0	782.52	1.73	9.361E+05	2.229E+03
200.0	458.92	1.28	5.444E+05	1.650E+03
250.0	1.57	1.01	1.942E+03	1.307E+03
300.0	1.05	0.84	1.307E+03	1.089E+03
Integral	279791	217583	3.359E+08	2.616E+08

Table 2.6.3.2-2
Sequence of Events for Limiting MSLB Inside Containment

Event	Current Analysis Peak Pressure Case (Sec)	EPU Peak Pressure Case (Sec)	Current Analysis Peak Temperature (Sec)	EPU Peak Temperature Case (Sec)
Break occurs	0.00	0.00	0.00	0.00
Main Steam Isolation Signal (MSIS) Analytical Setpoint Reached	2.15	3.13	2.15	4.68
Containment High Pressure Analytical Setpoint Reached	2.45	3.13	2.25	4.68
MFIVs Start to Close	3.30	3.13	3.30	4.68
MSIVs Start to Close	3.30	11.20*	3.30	12.60*
Containment Spray Actuation Signal (CSAS) Analytical Setpoint Reached, Containment High-High Pressure	4.50	3.60	4.40	5.40
MFIVs Closed	7.50	9.50	7.50	11.00
MSIVs Closure	8.90	11.20	8.90	12.60
Full Containment Fan Cooler Operation	13.60	13.60	13.40	15.00
Start Containment Spray Injection	29.15	NA**	29.05	NA**
Containment Peak Pressure/Temperature Occurs	42.00	211.96	34.00	48.70
Containment Sprays Full On	42.15	48.00	42.05	49.00

Table 2.6.3.2-2 (Continued)
Sequence of Events for Limiting MSLB Inside Containment

Event	Current Analysis Peak Pressure Case (Sec)	EPU Peak Pressure Case (Sec)	Current Analysis Peak Temperature (Sec)	EPU Peak Temperature Case (Sec)
End of Blowdown	57.00	229.00	46.00	108.00
*The MSIVs were conservatively modeled to step close after all of the delay times (valve travel time etc.) have timed out.				
**The containment spray flow for the EPU analysis conservatively assumes no flow until the delay time is accounted for.				

Figure 2.6.3.2-1
Mass Out the Break for the Limiting EPU and Current Cases

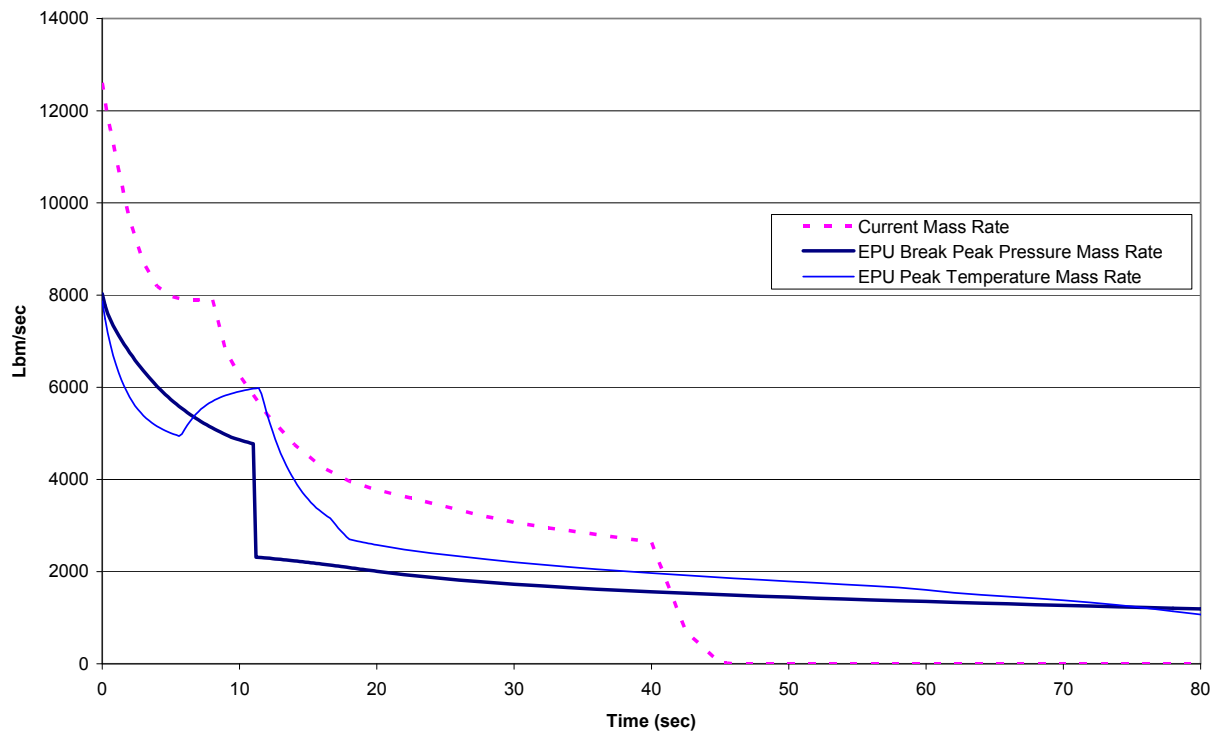
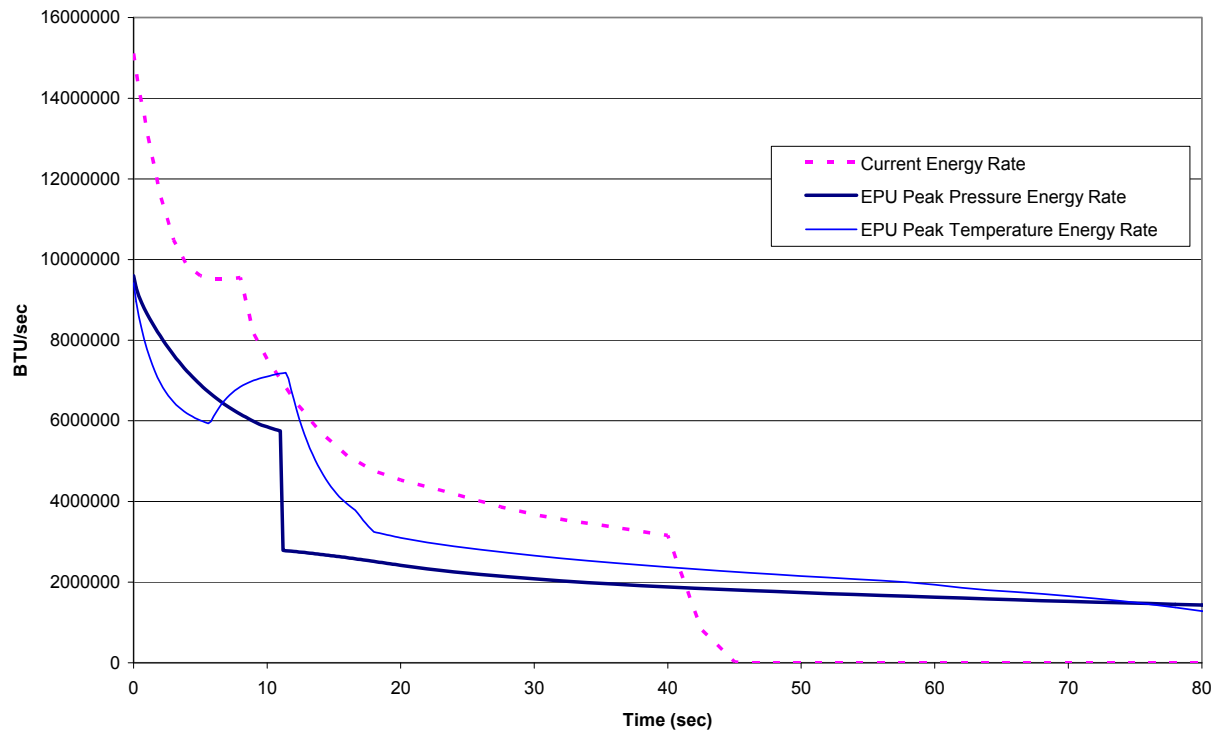


Figure 2.6.3.2-2
Energy Rate Out the Break for the Limiting EPU and Current Cases



2.6.4 Combustible Gas Control in Containment

2.6.4.1 Regulatory Evaluation

Following a loss-of-coolant accident (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 excess hydrogen is generated, it may form a combustible mixture in the containment atmosphere. The Florida Power and Light (FPL) review covered:

- The production and accumulation of combustible gases,
- The capability to prevent high concentrations of combustible gases in local areas,
- The capability to monitor combustible gas concentrations, and
- The capability to reduce combustible gas concentrations.

FPL'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

- 10 CFR 50.44, insofar as it requires that certain plants be provided with the capability for controlling combustible gas concentrations in the containment atmosphere,
- GDC-5, insofar as it requires that structures, systems and components (SSCs) important-to-safety not be shared among nuclear power plants unless it can be shown that sharing will not significantly impair their ability to perform their safety functions,
- 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,
- GDC-42, insofar as it requires that systems required by GDC-41 be designed to permit periodic inspections, and
- 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 NRC Standard Review Plan (SRP) Section 6.2.5.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

St. Lucie Unit 2 was originally licensed with two redundant hydrogen recombiners, located inside containment and a hydrogen purge system.

On September 16, 2003, the NRC amended 10 CFR 50.44, Standards for Combustible Gas Control System in Light-Water-Cooled Power Reactors, ([Reference 1](#)) to eliminate certain requirements for hydrogen recombiners and hydrogen purge systems and relaxed the requirements for hydrogen and oxygen monitoring equipment to make them commensurate with risk significance. In order for FPL to adopt the provisions of the amended rule, a license amendment request was submitted to the NRC on June 4, 2007 ([Reference 2](#)), for approval of changes to Technical Specification 3/4.6.4, Combustible Gas Control. The amendment request was prepared in accordance with the NRC-approved Technical Specification Task Force (TSTF) Traveler 447, Revision 1, Elimination of Hydrogen Recombiners and Change to Hydrogen and Oxygen Monitors. On February 22, 2008, the NRC approved the requested changes to the Technical Specifications ([Reference 3](#)).

As part of the rulemaking that revised 10 CFR 50.44, the Commission retained the following requirements relative to maintaining combustible gas control inside non-inerted containments:

1. Assurance of a mixed atmosphere inside containment;

10 CFR 50.44(b)(1) requires that the unit possess the capability to ensure a mixed atmosphere. As stated in UFSAR Section 6.2.5.1, the capability to uniformly mix the containment atmosphere and to prevent high concentration of combustible gases from forming locally are provided by forced circulation from the containment fan coolers and their associated ductwork, mixing of containment air by the containment spray system, and natural diffusion of combustible gas within the containment air as discussed in UFSAR Section 6.2.5.3.3.

2. The NRC staff, in the notice of availability for this technical specification improvement, required the licensee to make a regulatory commitment to maintain a hydrogen monitoring system capable of diagnosing beyond design-basis accidents.

10 CFR 50.44(b)(4)(ii) states that: "Equipment must be provided for monitoring hydrogen in the containment. Equipment for monitoring hydrogen must be functional, reliable, and capable of continuously measuring the concentration of hydrogen in the containment atmosphere following a significant beyond design-basis accident for accident management, including emergency planning."

As stated in the FPL letter dated June 4, 2007, ([Reference 2](#)) and the NRC's Safety Evaluation Report provided to support the License Amendment ([Reference 3](#)), FPL has committed to maintaining a hydrogen monitoring system capable of diagnosing beyond design-basis accident hydrogen concentrations. However, the components necessary to monitor hydrogen no longer need to be classified as safety-related as previously recommended by Regulatory Guide (RG) 1.97.

In addition to the licensing bases described in the UFSAR, the combustible gas control system was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of

St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Sections 2.3.2.3 and 2.3.2.5 of the SER identifies that components of the combustible gas control system are within the scope of License Renewal. Programs used to manage the aging effects associated with the combustible gas control system are discussed in SER Sections 3.2.3 and 3.2.5 and Chapter 18 of the UFSAR.

2.6.4.2 Technical Evaluation

The EPU has no impact on the fundamental mixing mechanisms identified in UFSAR Section 6.2.5.1 relative to ensuring that stratification of the containment atmosphere following a LOCA does not occur or on the capability of the hydrogen monitoring system to diagnose beyond design-basis accident hydrogen concentrations.

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

As discussed above, the combustible gas control system is within the scope of License Renewal. Operation of the combustible gas control system under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.6.4.2.2 Results

Compliance with the requirements of 10 CFR 50.44(b)(1) assures that St. Lucie Unit 2 possesses the capability to ensure a mixed atmosphere inside containment. Compliance with the requirements of 10 CFR 50.44(b)(4)(ii) assures St. Lucie Unit 2 possesses equipment for monitoring hydrogen which is functional, reliable, and capable of continuously measuring the concentration of hydrogen in the containment atmosphere following a significant beyond design-basis accident for accident management, including emergency planning.

2.6.4.3 Conclusion

FPL concludes that the hydrogen release associated with a design-basis LOCA from 10 CFR 50.44 and the associated requirements that necessitated the need for the hydrogen recombiners and the backup hydrogen purge and vent systems have been eliminated. In addition, the hydrogen monitors are no longer classified as safety-related.

St. Lucie Unit 2 will continue to meet its current licensing basis with respect to the requirements of 10 CFR 50.44. The EPU has no impact on the fundamental mixing mechanisms identified in UFSAR Section 6.2.5.1 or on the capability of the hydrogen monitoring system to diagnose

beyond design-basis accident hydrogen concentrations. Therefore, FPL finds the proposed EPU acceptable with respect to combustible gas control in containment.

2.6.4.4 References

1. Federal Register, Volume 68, Page 54123, September 16, 2003.
2. Letter L-2007-028 from Gordon L. Johnston (FPL) to NRC, "Removal of Hydrogen Recombiners and Analyzers from Technical Specifications," dated June 4, 2007.
3. Letter from Brenda L. Mozafari (NRC) to J. A. Stall (FPL), "St. Lucie Units 1 and 2 – Issuance of Amendments Regarding Removal of Hydrogen Recombiner Technical Specifications (TAC Nos. MD6096 and MD6097)," dated February 22, 2008.

2.6.5 Containment Heat Removal

2.6.5.1 Regulatory Evaluation

Fan cooler systems, spray systems, and residual heat removal (RHR) systems (referred to as shutdown cooling system at St. Lucie Unit 2) are provided to remove heat from the containment atmosphere and from the water in the containment sump.

The Florida Power and Light (FPL) review in this area focused on:

- 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
- 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 pressure and temperature following a Loss of Coolant Accident (LOCA), and maintaining them at acceptably low levels.

Specific review criteria are contained in SRP Section 6.2.2 as supplemented by Regulatory Guide 1.82, Revision 3.

St. Lucie Unit 2 Current Licensing Bases

As noted in St. Lucie Unit 2 UFSAR Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

The specific GDC for the Containment Heat Removal systems is as follows:

- GDC-38 is described in UFSAR Section 3.1.38 Criterion 38 - Containment Heat Removal.

A system to remove heat from the reactor containment shall be provided. The system safety function shall be to reduce rapidly, consistent with the functioning of other associated systems, the containment pressure and temperature following any loss of coolant accident and maintain them at acceptably low levels.

The containment heat removal systems described in UFSAR Section 6.2.2 consists of the containment spray (CS) system and the containment cooling system. The CS system consists of two trains, each containing a containment spray pump, shutdown heat exchanger and spray header. The containment cooling system consists of four fan coolers. One spray pump and two containment fan coolers have the capacity to reduce containment pressure and temperature following a design basis accident and maintain them at acceptably low levels.

UFSAR Section 6.2.2.3.1 further states that, following receipt of recirculation actuation signal, pump suction is automatically switched to the containment sump. Following an accident, the pressure inside containment exceeds the saturation pressure corresponding to sump water temperature. No credit, however, is taken for this favorable situation. As required by Regulatory

Guide 1.1 (R0), NPSH calculations are performed for the maximum assumed sump fluid temperature and the minimum containment pressure physically possible, i.e., sump water saturation pressure.

In addition to the licensing basis described in the UFSAR, the containment heat removal systems were evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Sections 2.3.2.1 and 2.3.2.2 of the SER identify that components of the containment heat removal systems are within the scope of License Renewal. Programs used to manage the aging effects associated with the containment heat removal systems are discussed in SER Sections 3.2.1 and 3.2.2 and Chapter 18 of the UFSAR.

2.6.5.2 Technical Evaluation

This section discusses the containment heat removal systems modeled in the containment integrity analysis for postulated LOCA and main steam line break (MSLB) events in support of EPU operation (see LR [Section 2.6.1](#), Primary Containment Functional Design). The mass and energy (M&E) release inside containment for both events were analyzed for the EPU operation (see LR [Section 2.6.3.1](#) Mass and Energy Analysis for Postulated LOCAs and [2.6.3.2](#), Mass and Energy Analysis for Secondary System Pipe Ruptures). The containment pressure and temperature are analyzed to confirm that the containment design basis limits are not exceeded, in accordance with GDC-38.

2.6.5.2.1 Introduction

The containment heat removal systems are described in UFSAR Chapter 6.2.2. 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 recirculation, the system is aligned to take suction from the containment sump and pass flow through the SDC heat exchangers and into the containment spray header.

The SDC system is used to reduce the temperature of the reactor coolant at a controlled rate and to maintain the proper reactor coolant temperature during refueling. The SDC system utilizes the low pressure safety injection pumps to circulate the reactor coolant through two SDC heat exchangers, returning it to the reactor coolant system (RCS) through the low pressure injection header. The SDC system is discussed in LR [Section 2.8.4.4](#), Residual Heat Removal System.

The containment cooling system consists of four containment fan cooler (CFC) units (two units loaded on each emergency diesel generator), a duct distribution system, and the associated instrumentation and controls. Each CFC unit consists of two banks of cooling coils, an axial flow fan, and a two-speed motor. Cooling water is provided to the cooling coils by the component cooling water (CCW) system. The CCW system is addressed in LR [Section 2.5.4.3](#), Reactor

Auxiliary Cooling Water. The design function of the system is to recirculate and cool the containment atmosphere following a LOCA. The normal operation of the CFCs is discussed in LR [Section 2.7.7](#), Other Ventilation – Containment.

The containment heat removal system is arranged into two independent 100 percent capacity subsystems, each of which is comprised of one containment spray train and two fan coolers. The containment heat removal system is designed such that no single failure can prevent it from performing its design function. Only one of the two independent subsystems (one CS pump and two fan coolers) is required to prevent the pressure and temperature in containment from reaching unacceptable levels following an accident. Two CS pumps without any CFCs are required to provide 100 percent heat removal capability to support the bases of Technical Specification 3.6.2.1.

The EPU increases the heat released into the containment, and thus, subsequent heat loads on the containment heat removal systems. The purpose of the containment integrity LOCA analyses is to demonstrate that the containment, containment structures, and containment cooling safeguards systems are adequate to mitigate the consequences of a hypothetical rupture of a large RCS pipe. The effect of LOCA mass and energy releases on the containment atmosphere pressure and temperature are addressed to ensure that the containment vessel pressure and temperature remain below the design limits of 44 psig at 264°F under EPU operation. The containment heat removal systems must also be capable of limiting the post-accident containment conditions such that environmental qualification acceptance limits at the EPU conditions are met.

2.6.5.2.2 Description of Analyses and Evaluations

Containment LOCA and MSLB pressure/temperature analyses were performed to demonstrate the ability of the containment spray system and the containment cooling system to limit and reduce the containment pressure and temperature following a LOCA or MSLB inside containment under EPU conditions.

LOCA cases that are considered in this analysis are the double-ended discharge leg slot (DEDLS), double-ended suction leg slot (DESLS) and double-ended hot leg slot (DEHLS) with different single failure scenarios. That is, each break location was analyzed assuming different combinations of safety injection pump and CS pump flow rates and CFCs in operation. A loss of offsite power concurrent with the LOCA event is assumed in this analysis. Coincidental with the loss of offsite power, two scenarios are considered; one where both diesel generators are available and the other where only one diesel generator is available. Additionally, a case with two CS pumps and no CFCs was evaluated to confirm 100 percent heat removal capacity. LOCA mass and energy addition to containment is discussed in LR [Section 2.6.3.1](#).

The CS system heat removal capacity is a function of refueling water tank water temperature (RWT), intake cooling water (ICW) / component cooling water (CCW) temperatures, containment spray flow, and containment spray thermal effectiveness. The minimum containment spray pump flow rates are 2700 gpm for injection mode and 2850 gpm for recirculation mode. These values were used as input for the peak containment pressure-temperature analyses. The design heat removal capacity for the CS system via the SDC heat exchanger during the recirculation mode is

87×10^6 Btu/hr (CS flow cooled from 240°F to 172°F) with an assumed CCW water temperature of 120°F.

A single CFC is designed to remove up to 61.6×10^6 Btu/hr at containment design conditions and a fan flow of 39,600 cfm at an inlet air temperature of 264°F. For the containment LOCA analysis, the 1 percent frequency tolerance of the emergency diesel generators (EDG), on which the CFCs run in accident conditions, has been taken into account and the heat removal rate adjusted accordingly. The heat removal data for the under frequency condition is taken as the minimum heat removal data for the containment analysis

MSLB mass and energy addition to containment is discussed in LR [Section 2.6.3.2](#). The analysis considered the design basis single failure scenarios, which are:

- loss of one containment cooling train,
- one main feedwater isolation valve failed open, and
- one main steam isolation valve failed open.

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

As discussed above, the containment heat removal systems are within the scope of License Renewal. Operation of the containment heat removal systems under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.6.5.2.4 Results

Containment Pressure and Temperature

The containment LOCA analysis determined that the calculated peak containment atmosphere temperature is 266.73°F and the calculated containment peak pressure is 43.48 psig, both resulting from the full double-ended hot leg slot (DEHLS) case. Therefore, the CS and containment cooling systems are adequate to keep the peak containment pressure below the design pressure under EPU conditions. Although the peak containment atmosphere temperature exceeds the containment design temperature by no more than 3°F for approximately 30 seconds, the actual surface temperature of the liner is below 264°F and is therefore considered acceptable. The two CS pumps with no CFCs case confirmed 100 percent heat removal capacity and the peak pressure and temperature are bounded by the DEHLS case. The impact of the peak containment temperature and pressure conditions on environmental qualification of equipment is evaluated in LR [Section 2.3.1](#), Environmental Qualification of Electrical Equipment.

The containment main steam line break (MSLB) analysis determined that the calculated peak containment pressure and temperature are 42.41 psig and 384.29°F respectively. The peak pressure case is from 0 percent power MSLB with the failure of one containment cooling train, and the peak temperature is from the 100.3 percent power EQ-MSLB with the failure of a MSIV to close case. The peak MSLB pressure is below the design pressure under EPU conditions, and the peak MSLB temperature is lower than its pre-EPU value and therefore, the peak MSLB pressure and temperature are acceptable under EPU conditions.

The peak containment vessel temperature during an MSLB under EPU conditions is 215.5°F for the 100.3 percent power MSLB with the failure of one MSIV to close. This is below the design limit of 264°F, and is, therefore, acceptable.

Net Positive Suction Head (NPSH)

Analyses at EPU conditions show that the available NPSH exceeds the NPSH required with adequate margin in both the injection and recirculation phases for the CS, high pressure safety injection, and low pressure safety injection pumps.

2.6.5.3 Conclusion

FPL has reviewed the containment heat removal systems assessment and concludes that it has adequately addressed the effects of the EPU. FPL finds that the systems will continue to meet their current licensing basis with respect to the requirements of GDC-38 for rapidly reducing the containment pressure and temperature following a LOCA, and maintaining them at acceptably low levels. Therefore, FPL finds the EPU acceptable with respect to containment heat removal systems.

2.6.6 Pressure Analysis for ECCS Performance Capability

2.6.6.1 Regulatory Evaluation

Following a loss-of-coolant accident (LOCA), the emergency core cooling system (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. Florida Power and Light (FPL) reviewed the 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 FPL review covered the 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 Standard Review Plan (SRP) Section 6.2.1.5.

St. Lucie Unit 2 Current Licensing

Conformance of the LOCA analysis to Criteria 1 through 4 of the ECCS acceptance criteria of 10 CFR 50.46(b) is discussed in UFSAR Sections 15.6.5.2.3 and 15.6.5.2.4. The evaluation models used to perform the ECCS performance analysis are 10 CFR 50 Appendix K evaluation models as described in the UFSAR Section 15.6.5.2.1.

NUREG-1779, Safety Evaluation Report Related of the St. Lucie Nuclear Plant, Units 1 and 2 dated September, 2003 defines the scope of license renewal. The evaluation of pressure analysis for ECCS performance capability is not within the scope of license renewal.

2.6.6.2 Technical Evaluation

2.6.6.2.1 Introduction

Appendix K to 10 CFR 50 ([Reference 1](#)) provides the required and acceptable features of ECCS evaluation models. Included is the requirement that the containment pressure assumed in the evaluation of ECCS performance not exceed a pressure calculated conservatively for that purpose.

To support the EPU, calculations of the minimum containment pressure were performed using the 1999 evaluation model (1999 EM) version of the Westinghouse LBLOCA evaluation model for Combustion Engineering (CE) designed pressurized water reactors (PWRs). The model is documented in Supplement 4 to CENPD-132 ([Reference 2](#)). The 1999 EM methodology complies with the requirements of Appendix K to 10 CFR 50 ([Reference 1](#)) and was reviewed and approved by the NRC. In this NRC-approved methodology, the CEFLASH-4A computer program was used to determine the mass and energy released to the containment during the blowdown phase of a postulated LOCA. Similarly, the NRC-approved COMPERC-II computer

program was used to determine both the mass and energy released to the containment during the reflood phase and the minimum containment pressure response to be used in the evaluation of the effectiveness of the ECCS. This methodology is unchanged from that used in the current analyses of record (AOR).

2.6.6.2.2 Input Parameters, Assumptions, and Acceptance Criteria

2.6.6.2.2.1 Input Parameters and Assumptions

Input Parameters

LR [Table 2.6.6-1](#) lists the containment initial and boundary conditions, LR [Table 2.6.6-2](#) lists the containment passive heat sink data and LR [Table 2.6.6-3](#) lists the thermal properties of passive heat sinks used in the LOCA ECCS performance analysis for EPU. The input parameters that were used in the minimum containment pressure calculation for ECCS performance analysis conservatively bound the as-operated configuration.

Assumptions

The minimum containment pressure analysis for EPU was performed concurrently with the ECCS performance analysis documented in LR [Section 2.8.5.6.3](#), Emergency Core Cooling System and Loss-Of-Coolant Accidents. As discussed above, the analysis was performed in accordance with the 1999 EM for CE designed PWRs ([Reference 2](#)) using assumptions consistent with the methodology associated with the evaluation model. There was no change in methodology assumptions made from the current AOR to the EPU analysis. In performing the EPU analysis, conservative assumptions were made concerning several aspects of the methodology and of the performance of plant equipment, which are summarized as follows:

1. **Mass and Energy Release Data** - The mass and energy released to containment for a LOCA break spectrum was calculated as a function of time concurrent with the ECCS performance analysis. For the EPU ECCS performance analysis, the quantity of containment spray and safety injection (SI) spillage that was assumed to be released to containment is based on a double-ended guillotine break in the reactor coolant pump discharge (DEG/PD) with various break sizes designed to produce the limiting peak cladding temperature (PCT). For conservatism, it was assumed that all safety injection flow delivered to the broken cold leg is lost directly to the containment to maximize its effect on steam condensation and minimize containment pressure.
2. **Steam Water Mixing** - Condensing containment steam with spilled ECCS water and containment spray was conservatively represented in the calculation of the minimum containment pressure in accordance with the 1999 EM approved methodology.
3. **Active Heat Sinks** - To minimize containment pressure, the heat removal capacity of the containment active heat sinks for the EPU, ECCS performance analysis was conservatively maximized. Both trains of containment spray pumps (two) and fan coolers (four) were assumed to be actuated in the shortest possible time following the break, and to operate at their maximum capacity assuming the minimum temperatures for both the spray water and cooling water. To minimize actuation time for these systems, offsite power was assumed to

be available. (It should be noted that offsite power was assumed not to be available for the safety injection system delivering ECCS to the reactor coolant system.

4. **Passive Heat Sinks** - The surface areas and thicknesses of all exposed containment passive heat sinks are combined into ten heat sinks and are listed in LR [Table 2.6.6-2](#). To conservatively maximize the heat transfer to these passive heat sinks, the surface areas of the individual components were assumed to be at the maximum of their uncertainty ranges, and their thermal properties (conductivity and heat capacity) were maximized. The thermal properties assumed for the analysis are shown in LR [Table 2.6.6-3](#).
5. **Heat Transfer to Passive Heat Sinks** - The condensing heat transfer coefficients between the containment atmosphere and the passive heat sinks were calculated in a conservative manner consistent with the COMPERC-II approved models and methodology.

Acceptance Criteria

As specified in 10 CFR 50.46, Appendix K, paragraph I.D.2, the containment pressure used for evaluating cooling effectiveness during reflood and spray cooling shall not exceed a pressure calculated conservatively for this purpose. The calculation shall include the effects of operation of all installed pressure-reducing systems and processes.

2.6.6.2.3 Description of Analyses and Evaluations

Calculations of the minimum containment pressure for EPU were performed using the 1999 EM described in [Reference 2](#). The analysis was performed concurrently with the ECCS performance analyses documented in LR [Section 2.8.5.6.3](#), Emergency Core Cooling System and Loss-of-Coolant Accidents.

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

EPU activities do not add any new functions for existing plant components relied upon to mitigate the effects of postulated LOCA events that would change the evaluation boundaries. As discussed above, the pressure analysis for ECCS performance was determined to be outside the scope of License Renewal, therefore, with respect to the pressure analysis, the EPU does not impact any License Renewal evaluations.

2.6.6.2.5 Results

For the most severe LOCA (in terms of PCT), for EPU, the minimum containment pressure response concurrently calculated with the ECCS performance analysis, which is used in analyzing the effectiveness of the ECCS, is shown on LR [Figure 2.6.6-1](#). The responses of containment atmosphere and containment sump temperatures for this case are shown on LR [Figures 2.6.6-2](#) and [2.6.6-3](#), respectively.

2.6.6.3 Conclusion

FPL has reviewed the assessment of the impact that the proposed EPU would have on the minimum containment pressure analysis and concludes that St. Lucie Unit 2 has adequately addressed this area of review to ensure that the requirements in 10 CFR 50.46 regarding ECCS performance will continue to be met following implementation of the proposed EPU. Therefore FPL finds the proposed EPU acceptable with respect to minimum containment pressure for ECCS performance.

2.6.6.4 References

1. Code of Federal Regulations, Title 10, Part 50, Appendix K, ECCS Evaluation Models.
2. CENPD-132, Supplement 4-P-A, Calculative Methods for the C-E Nuclear Power Large Break LOCA Evaluation Model, March 2001.

**Table 2.6.6-1
Containment Initial and Boundary Conditions**

Parameter	Value
Maximum Net Free Containment Volume	2,631,300 ft ³
Containment Initial Conditions	
Temperature	90 °F
Pressure (TS minimum – uncertainty)	13.782 psia
Relative Humidity	100%
Outside Temperature	42 °F
Containment Spray	
Number of Pumps Operating	2
Maximum Spray Flow Rate (per pump)	4,500 gpm
Spray Initiation Time After Break	0 sec
Containment Spray/RWT Temperature	51 °F
Containment Fan Coolers	
Number of Fan Coolers	4
Fan Cooler Initiation Time	0 sec
Maximum Containment Fan Cooler Capacity	
Containment Temperature (°F)	Maximum Heat Removal Capacity per Fan (Btu/sec)
0	0
60	0
120	3,230
200	15,016
280	28,192

Table 2.6.6-2
Containment Passive Heat Sink Data

Wall No.	Wall Description	Material	Thickness ⁽¹⁾ (ft)	Surface Area ft ²
1	Steel Containment Vessel--Cylinder & Dome	Paint #1 (steel)	0.00042	91,035
		Carbon Steel (CS)	0.11806	
2	Painted Concrete in Sump and Air (Side 1: Vapor)	Paint #2 (concrete)	0.00067	76,763
		Concrete	0.25000	
		Concrete	0.25000	
		Concrete	1.41902	
3	Painted Concrete in Water (Side 1: Liquid, Side 2: Ground or Insulated)	Paint #2 (concrete)	0.00067	26,414
		Concrete	0.25000	
		Concrete	0.25000	
		Concrete	2.99738	
4	Painted CS Exposed to Vapor (Side 1: Vapor, Side 2: Vapor)	Paint #1 (steel)	0.00058	197,077
		Carbon Steel (CS)	0.01848	
5	GS Coated CS (Side 1: Vapor, Side 2: Vapor or Insulated)	Galvanized Steel (GS)	0.00013	203,212
		Carbon Steel (CS)	0.00552	
6	Painted CS Exposed to Liquid (Side 1: Liquid, Side 2: Liquid)	Paint #1 (steel)	0.00058	23,473
		Carbon Steel (CS)	0.03834	
7	Painted CS in/on Concrete (Side 1: Liquid, Side 2: Concrete)	Paint #1 (steel)	0.00058	8,161
		Carbon Steel (CS)	0.05999	
		Concrete	0.25000	
		Concrete	3.75000	
8	SS Lined Concrete (Side 1: Vapor, Side 2: Concrete)	Stainless Steel (SS)	0.01558	8,715
		Concrete	0.25000	
		Concrete	6.38747	
9	SS (Side 1: Vapor or Liquid, Side 2: Insulated or Process Fluid)	Stainless Steel (SS)	0.01671	19,563
10	Painted CS (Side 1: Vapor, Side 2: Vapor, Liquid, or Concrete)	Paint #1 (steel)	0.00058	7,209
		Carbon Steel (CS)	0.09672	
		Concrete	0.25000	
		Concrete	3.75000	
1. Thickness is effective thickness as a result of combining similar thickness walls.				

Table 2.6.6-3
Thermal Properties of Passive Heat Sinks

Material	Thermal Conductivity (Btu/hr-ft-°F)	Volumetric Heat Capacity (Btu/ft³-°F)
Paint #1 (steel)	1.67	57.6
Paint #2 (concrete)	0.375	47.1
Concrete	1.0	32.4
Carbon Steel (CS)	25.90	53.57
Stainless Steel (SS)	9.8	54.0
Galvanized Steel (GS)	64.00	40.60

Figure 2.6.6-1
Minimum Containment Pressure Response for ECCS Performance Analysis

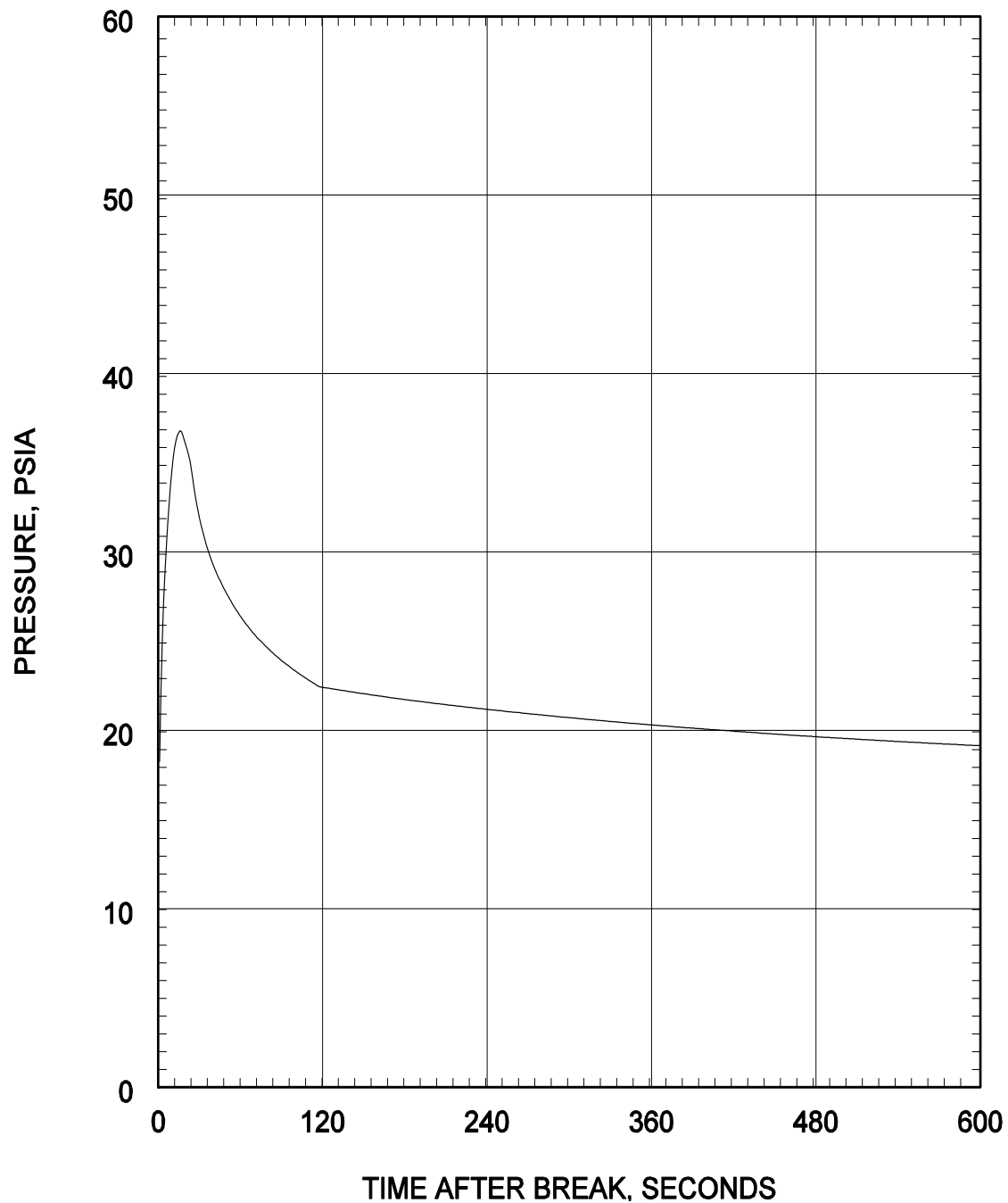


Figure 2.6.6-2
Containment Atmosphere Temperature Response for ECCS Performance Analysis

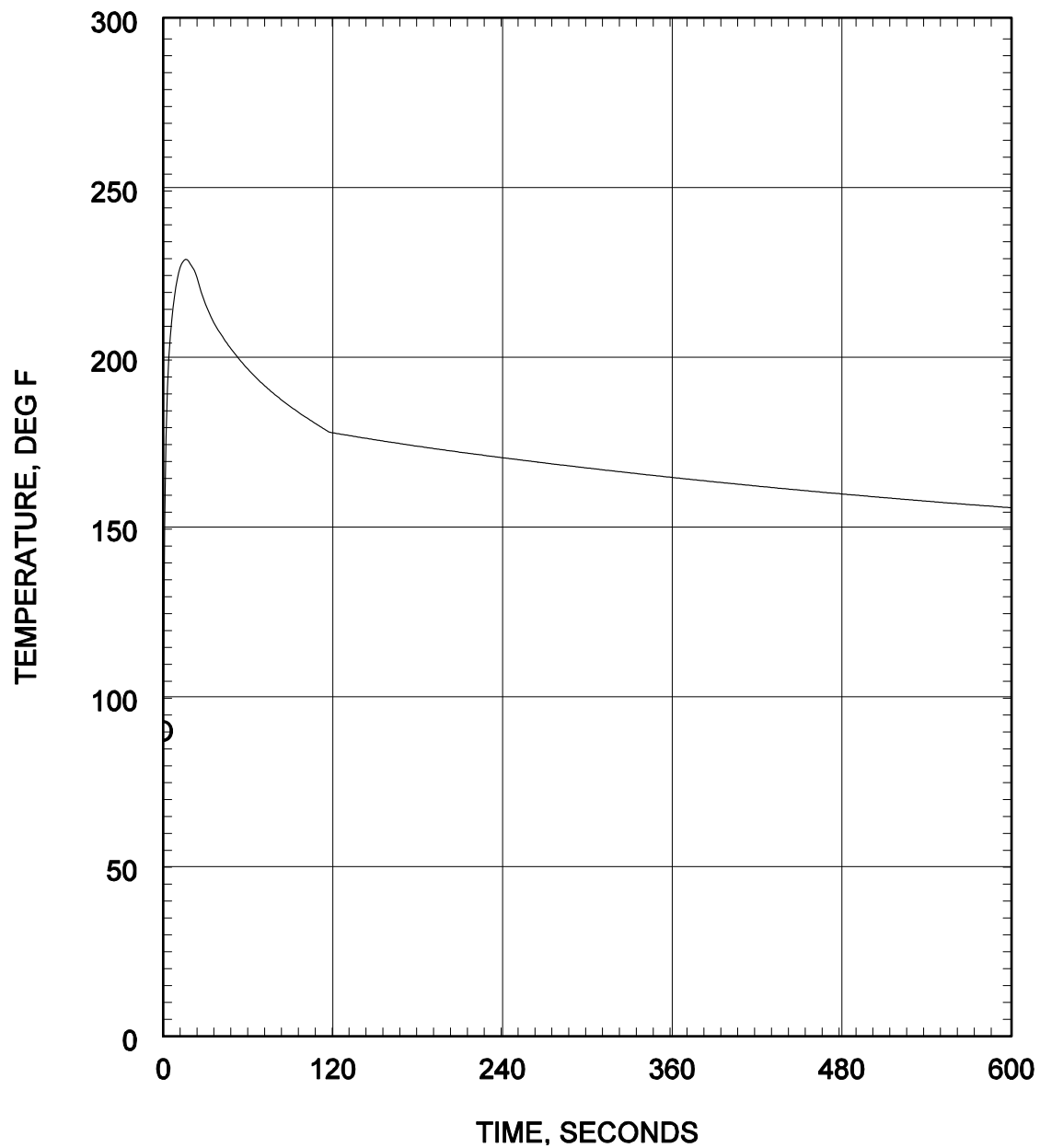
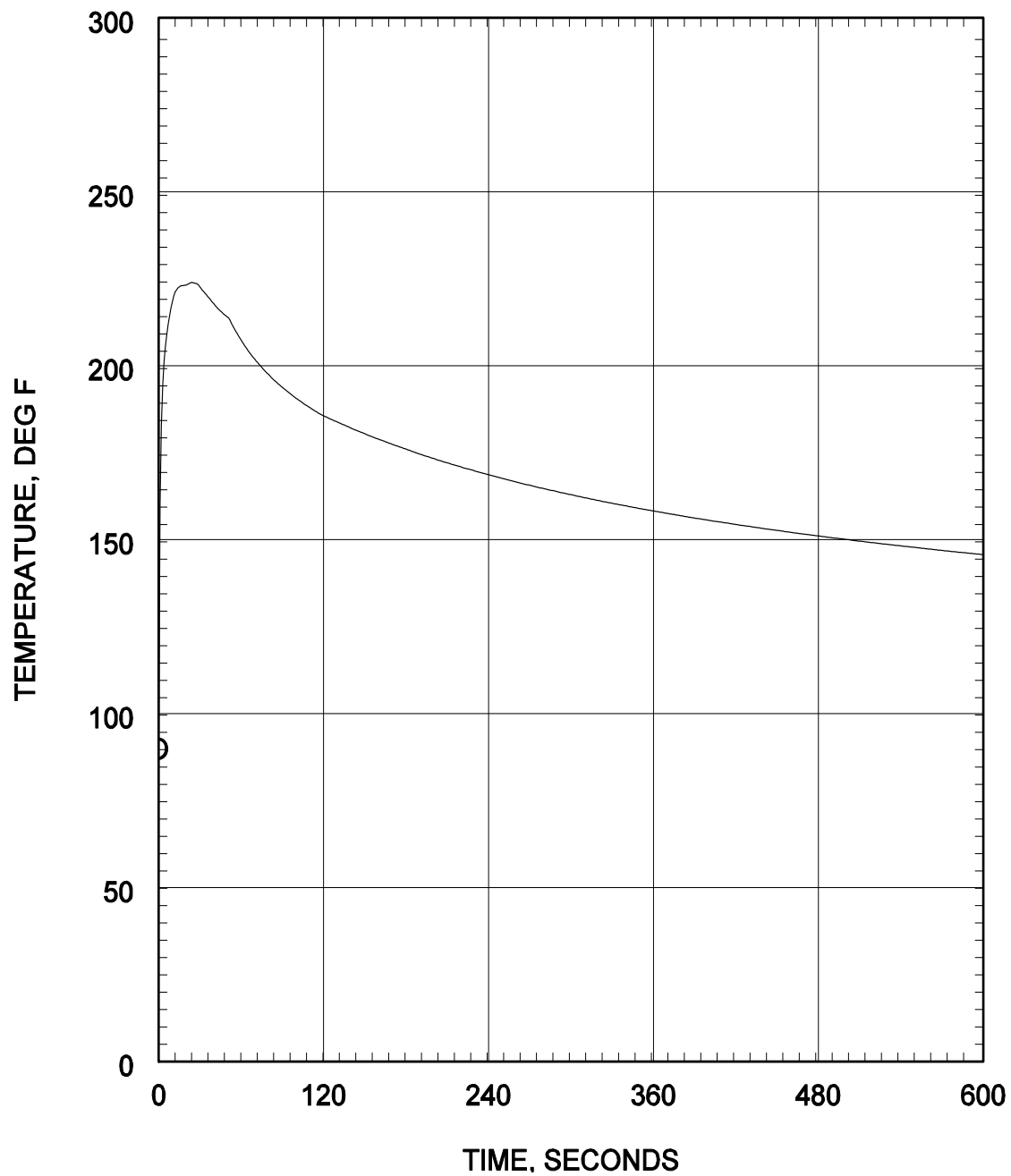


Figure 2.6.6-3
Containment Sump Temperature Response for ECCS Performance Analysis



2.7 Habitability, Filtration, and Ventilation

2.7.1 Control Room Habitability System

2.7.1.1 Regulatory Evaluation

Florida Power and Light (FPL) 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. The FPL review focused on the effects of the proposed extended power uprate (EPU) on radiation doses, toxic gas concentrations, and estimates of dispersion of airborne contamination.

The Technical Support Center (TSC), which is shared by both units, is physically located within the Unit 1 control room envelope, and has been evaluated as part of Unit 1 control room habitability.

The NRC's acceptance criteria for the control room habitability system are based on:

- General Design Criterion (GDC)-4, insofar as it requires that structures, systems and components (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
- 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.

Specific review criteria are contained in Standard Review Plan (SRP) Section 6.4 and other guidance provided in Matrix 7 of RS-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

- GDC-4 is described in UFSAR Section 3.1.4 Criterion 4 - Environmental and Missile Design Bases.

Structures, systems and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and

approved by the Commission demonstrates that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

- GDC-19 is described in UFSAR Section 3.1.19 Criterion 19 - Control Room.

A control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in safe condition under accident conditions, including loss of coolant accidents. Adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent for the duration of the accident.

Equipment in appropriate locations outside the control room shall be provided (1) with a design capability for prompt hot shutdown of the reactor, including necessary instrumentations and controls to maintain the unit in a safe condition during hot shutdown, and (2) with a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

The design of the control room permits safe occupancy during design basis accident conditions. The control room is isolated from the outside atmosphere during the initial period following the occurrence of an accident. The control room ventilation system recirculates control room air through HEPA and charcoal filters as discussed in UFSAR Section 9.4.1 and UFSAR Section 6.4. Radiation detectors and alarms are provided. Emergency lighting is provided as discussed in UFSAR Section 9.5.3.

UFSAR Section 6.4.1 identifies the following as part of the control room habitability system:

- The control room envelope includes the control room, packaged air conditioning equipment room, emergency cleanup system equipment room, emergency food and water storage areas, toilet, kitchen/dining/conference room and supervisors office;
- The control room environment is suitable for continuous occupancy during normal operation and occupancy throughout the duration (i.e., 30 days) of any one of the postulated accidents discussed in UFSAR Chapter 15 without exceeding the guidelines set forth in GDC-19 of Appendix A to 10 CFR 50;
- The control room air conditioning system is capable of either automatic actuation (on a containment isolation actuation signal or high radiation signal from outside air intakes) or manual transfer from its normal operating mode to the pressurized or isolated modes, as necessary;
- The control room envelope and the control room air conditioning systems are designed to remain functional and maintain a room temperature of $80 \pm 4^{\circ}\text{F}$ during and after a safe shutdown earthquake; and
- The habitability systems (air filtration and ventilation equipment with associated instrumentation, controls and radiation monitoring) are capable of performing their functions assuming a single active component failure coincident with a loss of offsite power.

LR **Section 2.9.2** provides a detailed discussion of the current licensing basis for the analyses that establish the radiological consequences to the operators in the control room for various events.

As stated in UFSAR Section 2.2.3, there are no analyzed chemical spills that could affect control room habitability.

Additional details that define the licensing basis for the control room habitability systems are described in UFSAR Section 9.4.1.

On September 30, 2008, the NRC approved Amendment 153 to the operating license, which adopts NRC-approved Technical Specification Task Force Standard Technical Specification Traveler TSTF-448, Control Room Habitability. This amendment established more effective and appropriate action, surveillance, and administrative requirements related to ensuring habitability of the control room envelope.

On September 29, 2008, the NRC approved Amendment 152 to the operating license, which adopts the AST as allowed in 10 CFR 50.67 and described in Regulatory Guide 1.183.

In addition to the licensing basis described in the UFSAR, the control room ventilation system was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.3.15 of the SER identifies that components of the control room ventilation system are within the scope of License Renewal. Programs used to manage the aging effects associated with the control room ventilation system are discussed in SER Section 3.3.15 and Chapter 18 of the UFSAR.

2.7.1.2 Technical Evaluation

2.7.1.2.1 Introduction

UFSAR Section 6.4 states that the control room habitability systems:

- Are provided to assure that the operators can remain in the control room and take effective actions to operate safely under normal conditions and maintain a safe condition post accident, as required by General Design Criterion 19 of Appendix A to 10 CFR 50;
- Include radiation shielding; air filtration and ventilation equipment with associated instrumentation and controls; missile protection; emergency lighting; food, water, kitchen and sanitary facilities; self contained breathing apparatus unit; fire protection equipment, and radiation monitors.

UFSAR Sections 6.4.1 and 6.4.2.1 state that the provisions for maintaining control room habitability and occupancy are based on the following:

1. A control room envelope, which includes the control room, packaged air conditioning equipment room, emergency cleanup system equipment room, emergency food and water storage areas, toilet, kitchen/dining/conference room and supervisors office, is provided;
2. The control room environment is suitable for continuous occupancy during normal operation and occupancy throughout the duration (i.e. 30 days) of any one of the postulated accidents discussed in Chapter 15 without exceeding the guidelines (5 rem total effective dose equivalent) set forth in General Design Criterion 19 of Appendix A to 10 CFR 50;
3. During emergency conditions, food, water and other supplies will be provided to the control room (as necessary) in accordance with plant procedures;
4. Respiratory protection is provided for emergency use within the control room envelope;
5. The control room air conditioning system is capable of either automatic actuation (on a containment isolation actuation signal (CIAS) from St. Lucie Units 1 or 2 or high radiation signal from outside air intakes) or manual transfer from its normal operating mode to the pressurized or isolated modes, as necessary;
6. Radiation monitors and control equipment are provided at plant locations, as necessary, to ensure the ability to meet the above design bases 2 and 5;
7. The control room envelope and the control room air conditioning systems are designed to remain functional and maintain a room temperature of $80 \pm 4^{\circ}\text{F}$ during and after a safe shutdown earthquake;
8. The habitability systems (air filtration and ventilation equipment with associated instrumentation, controls and radiation monitoring) are capable of performing their functions assuming a single active component failure coincident with a loss of offsite power.

The control room ventilation system is discussed in LR [Section 2.7.3](#), Control Room Ventilation System. The control room ventilation systems consist of the control room air conditioning system, and the control room emergency cleanup system.

2.7.1.2.2 Description of Analyses and Evaluations

The control room habitability systems were evaluated to ensure that EPU conditions during normal operation would not cause any significant changes to essential aspects of habitability, such as control room envelope integrity, equipment heat loads internal to the control room, heating and cooling capacity and the ability of the control room ventilation system to ventilate and maintain ambient temperatures required for personnel comfort and equipment operability. In addition to those aspects evaluated for normal operation, the evaluation included the essential aspects to filter airborne contaminants and maintain sufficient positive space static pressure during emergency operation.

The EPU does not introduce any toxic material hazards to the control room operators. There are no EPU modifications that would significantly increase the equipment heat loads internal to the control room in comparison to the overall load and equipment capacity. LR [Section 2.7.3](#), Control Room Ventilation System, evaluates the ability of the control room ventilation system to provide cooling to the control room envelope under EPU conditions. Where new openings are needed to support cable routing requirements for EPU modifications these penetrations will be sealed in accordance with approved site procedures. The EPU control room dose analysis is presented in LR [Section 2.9.2](#), Radiological Consequences Analyses Using Alternative Source Terms. The analyses demonstrate the effectiveness of the control room habitability systems to permit continuous occupation of the control room in compliance with the dose guidelines of GDC-19.

2.7.1.2.3 Impact on Renewed Plant Operating License Evaluations and Licensing Renewal Programs

As discussed above, the control room ventilation system is within the scope of License Renewal. Operation of the control room ventilation system under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.7.1.2.4 Results

The radiological consequences to the control room occupants are affected by the EPU. The effects on doses were evaluated and found to be within the GDC-19 guidelines. LR [Section 2.9.2](#), Radiological Consequences Analyses Using Alternative Source Terms, describes the doses to control room occupants resulting from several hypothetical accidents analyzed for the EPU. The design and operation of the control room habitability systems during normal and emergency conditions are unaffected by EPU. The EPU has no effect on the fire barrier or pressure boundary integrity of the control room envelope as new openings that are needed to support cable routing requirements for EPU modifications will be sealed in accordance with approved site procedures. The proposed EPU has no effect on the ability of the control room ventilation system to provide a controlled environment for the comfort and safety of control room personnel and to support the operability of the control room under normal and postulated accident conditions; thus, EPU has no effect on control room occupancy duration. There are no EPU modifications that would significantly increase the equipment heat loads internal to the control room in comparison to the overall load and equipment capacity and thus, they do not affect the ability of the control room ventilation system to maintain normal specified space temperatures, activate emergency filtration flow, maintain emergency filtration air flow rates, maintain space static pressure during emergency filtration air flow and meet minimum HEPA and charcoal filtration efficiencies.

2.7.1.3 Conclusion

FPL has reviewed the effects of the 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. FPL has concluded that it has adequately accounted for the increase in the post-accident source terms and radiological doses to control room occupants that would result from design basis accidents under EPU conditions. FPL further concludes that the control room habitability system will continue to provide the required protection following implementation of the proposed EPU. Based on this, FPL concludes that the control room habitability system will continue to meet its current licensing basis with respect to the requirements of GDCs -4 and -19. Therefore, the proposed EPU is acceptable with respect to the control room habitability system.

2.7.2 Engineered Safety Feature Atmosphere Cleanup

2.7.2.1 Regulatory Evaluation

The engineered safety feature (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 Florida Power and Light (FPL) review focused on the effects of the proposed extended power uprate (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:

- General Design Criterion (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;
- 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;
- 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
- 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 anticipated operational occurrences (AOOs), and postulated accidents.

Specific review criteria are contained in SRP Section 6.5.1.

St. Lucie Unit 2 Current Licensing Bases

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC GDC for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDC for the ESF atmosphere cleanup system are as follows:

- GDC-19 is described in UFSAR Section 3.1.19 Criterion 19 - Control Room.

A control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in safe condition under accident conditions, including loss of coolant accidents. Adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent for the duration of the accident.

Equipment in appropriate locations outside the control room shall be provided (1) with a design capability for prompt hot shutdown of the reactor, including necessary instrumentations and controls to maintain the unit in a safe condition during hot shutdown, and (2) with a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

The design of the control room permits safe occupancy during design basis accident conditions. The control room is isolated from the outside atmosphere during the initial period following the occurrence of an accident. The control room ventilation system recirculates control room air through HEPA and charcoal filters as discussed in UFSAR Section 9.4.1 and UFSAR Section 6.4. Radiation detectors and alarms are provided. Emergency lighting is provided as discussed in UFSAR Section 9.5.3.

- GDC-41 is described in UFSAR Section 3.1.41 Criterion 41 - Containment Atmosphere Cleanup.

Systems to control fission products, hydrogen, oxygen, and other substances which may be released into the reactor containment shall be provided as necessary to reduce, consistent with the functioning of other associated systems, the concentration and quantity of fission products released to the environment following postulated accidents, and to control the concentration of hydrogen or oxygen and other substances in the containment atmosphere following postulated accidents to assure that containment integrity is maintained.

Each system shall have suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electrical power system operation (assuming onsite power is not available) its safety function can be accomplished, assuming a single failure.

As discussed in UFSAR Section 6.5.2, the containment spray system, in conjunction with the iodine removal system, provides a function of removing fission products from a post-accident containment atmosphere. The iodine removal system removes radio-iodines from the containment atmosphere following a loss of coolant accident (LOCA) by adding controlled amounts of hydrazine to the containment spray water.

The shield building ventilation system (SBVS) consists of two full capacity redundant fan and filter systems and is designed, consistent with the functioning of other engineered safety features systems, to reduce the concentration and quantity of fission products released to the environment following a LOCA by establishing and maintaining a subatmospheric pressure within the shield building annulus to ensure that post-accident activity leakage from the containment vessel is routed through the charcoal filter system. Refer to UFSAR Section 6.2.3.

The SBVS and containment spray system/iodine removal system have suitable redundancy to assure that, for normal onsite or for offsite electrical power system failure, their safety functions can be accomplished assuming a single failure.

- GDC-61 is described in UFSAR Section 3.1.61 Criterion 61 - Fuel Storage And Handling And Radioactivity Control.

The fuel storage and handling, radioactive waste, and other systems which may contain radioactivity shall be designed to assure adequate safety under normal and postulated accident conditions. These systems shall be designed (1) with a capability to permit inspection and testing of components important to safety, (2) with suitable shielding for radiation protection (3) with appropriate containment, confinement, and filtering systems, (4) with a residual heat removal capability having reliability and testability that reflects the importance to safety of decay heat and other residual heat removal, and (5) to prevent significant reduction in fuel storage coolant inventory under accident conditions.

The fuel pool is located within the fuel handling building. The liquid waste processing equipment and the gaseous waste storage and disposal equipment are located within a separate area of the reactor auxiliary building. Both of these areas provide confinement capability in the event of an accidental release of radioactive materials, and both are ventilated with filtered discharges to the vent pipe which is monitored. The fuel handling building ventilation system (portion of system for spent fuel pool ventilation) is interconnected with the SBVS. In the event of a high radiation signal, the fuel pool area is exhausted to the plant vent via the SBVS filters.

- GDC-64 is described in UFSAR Section 3.1.64 Criterion 64 - Monitoring Radioactivity Releases.

Means shall be provided for monitoring the reactor containment atmosphere, spaces containing components for recirculation of loss of coolant accident fluids, effluent discharge paths, and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences, and from postulated accidents.

Means are provided for monitoring the reactor containment atmosphere, spaces containing components for recirculation of loss of coolant accident fluids, effluent discharge paths, and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences, and from postulated accidents.

UFSAR Section 6.5.1, Engineered Safety Feature (ESF) Filtration Systems, identifies the following ESF air filtration systems located outside containment that mitigate the consequences of a postulated design basis LOCA:

- control room emergency cleanup system,
- shield building ventilation system, and
- emergency core cooling system area ventilation system.

In addition to the licensing basis described in the UFSAR, the ESF atmosphere cleanup system was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.3.15 of the SER identifies that components of the ESF atmosphere cleanup system are within the scope of License Renewal. Programs used to manage the aging effects associated with the ESF atmosphere cleanup system are discussed in SER Section 3.3.15 and Chapter 18 of the UFSAR.

2.7.2.2 Technical Evaluation

2.7.2.2.1 Introduction

The habitability of the control room is assured by the operation of the control room air conditioning system and the control room emergency cleanup system. The systems provide a controlled environment for personnel and equipment, maintaining temperature and humidity, capturing and retaining airborne particulates and adsorbing radioactive iodine, which may be present in the control room supply air during accident conditions. The control room air conditioning system and the control room emergency cleanup system are discussed in further detail in LR [Section 2.7.1](#), Control Room Habitability and [Section 2.7.3](#), Control Room Area Ventilation System.

The containment spray system, in conjunction with the iodine removal system, and the SBVS are the ESF systems designed to control fission products that are released into the containment and reduce the concentration released to the environment following postulated accidents.

The SBVS is designed to control fission products released and to reduce the concentration and quantity of fission products released to the environment following postulated accidents. The system is designed to limit the pressure rise and to establish and maintain a slight negative pressure in the shield building annulus following a LOCA, mix the shield building air in-leakage with the air in the annulus and with any leakage from the containment and discharge it through a filter train which includes charcoal adsorbers. Also, the fuel handling building ventilation system is connected to the SBVS and maintains a slightly negative pressure in the fuel handling building upon receipt of a high radiation signal in that building. The SBVS consists of two full capacity redundant fan and filter systems located in the reactor auxiliary building which exhaust the annular space and discharge through a vent pipe to the atmosphere. On the suction side of each fan, the air is drawn subsequently through an electric heater, demister, a second electric heater, HEPA filter, charcoal adsorber and HEPA afterfilter.

The emergency core cooling system (ECCS) area ventilation system, which is a sub-set of the reactor auxiliary building ventilation system, is designed to provide post-LOCA filtration and adsorption of fission products in the exhaust air from areas of the reactor auxiliary building which contain containment isolation valves, low pressure safety injection pumps, high pressure safety injection pumps, containment spray pumps, shutdown heat exchangers, and piping which contains recirculating containment sump water following a LOCA. The system is sized to maintain a slightly negative pressure in the ECCS area with respect to the surrounding areas of the reactor auxiliary building. Under normal operation, the necessary ventilation for the ECCS area is provided by the reactor auxiliary building main ventilation supply and exhaust system. Following an accident, when several or all of the pumps are operating, the air supply to the reactor auxiliary building is realigned to include a supply flow to the pump rooms to provide the additional cooling air requirement. Simultaneously, air is directed to the ECCS exhaust fans to draw all air from the area through HEPA and charcoal filter banks before the air is discharged to the atmosphere.

The fuel handling building ventilation system provides ventilation to the spent fuel pool area. The system is designed to reduce plant personnel doses by capturing and retaining airborne particulates and to adsorb radioactive elemental iodine via bypass through the SBVS filters upon

receipt of a high radiation signal. No credit is taken for filtration during a fuel handling accident. EPU does not affect the design of the fuel handling building ventilation system and its compliance with GDC-61.

Radiation detection devices are provided in the plant to monitor normal radiation levels and to detect and annunciate any abnormal radiation condition. The radiation monitoring system consists of the following subsystems: area radiation monitoring system, airborne radiation monitoring system, and the process and effluent radiological monitoring system.

The area radiation monitoring system is designed to monitor radiation and to annunciate and warn of abnormal levels in specific areas of the plant. The shield building fan/filtration system is automatically started by a containment isolation actuation signal or a high radiation signal from the fuel handling building. Upon receipt of a high radiation signal in the fuel pool area, exhaust air from the fuel pool area is directed to the shield building filtration units and the air flow path from the annulus is isolated. A containment isolation actuation signal overrides the fuel handling building high radiation signal and initiates the depressurization of the shield building annulus.

The airborne radiation monitoring system is designed to monitor airborne particulate, gaseous and iodine activity in the plant and to annunciate in the event of any abnormal increases. Exhaust air monitors are provided to measure noble gas effluent from the ECCS areas. The containment atmosphere radiation monitors are designed to provide a continuous indication in the control room of the particulate, iodine and gaseous radioactivity levels inside the containment. Redundant radiation monitors are provided in the two control room air intakes to isolate the normal control room ventilation and activate the control room emergency system upon detection of high radiation.

The process and effluent radiological monitoring system is designed to monitor and furnish information concerning radiation levels within the plant. The system provides continuous sampling and monitoring of liquid and gaseous radioactivity levels, provides annunciation and initiates automatic closure of the appropriate waste discharge valves whenever limits for release of radioactivity are approached.

2.7.2.2.2 Description of Analyses and Evaluations

Control Room

Under EPU operation there is no significant increase in either radiation levels or contamination levels that would affect the ability of the control room air conditioning system and the control room emergency cleanup system to maintain control room dose levels and permit continuous occupation of the control room in compliance with GDC-19 (personnel dose not to exceed 5 rem total effective dose equivalent for the duration of the accident). This is addressed in LR [Section 2.7.1](#), Control Room Habitability System. The EPU control room dose analysis is presented in LR [Section 2.9.2](#), Radiological Consequences Analyses Using Alternative Source Terms, and it demonstrates the effectiveness of the control room habitability systems to permit continuous occupation of the control room in compliance with GDC-19.

Containment

EPU does not affect the ability of the containment spray system to reduce the concentration of iodine released from the containment to the environment following a postulated accident. Additional discussion of the containment spray system is provided in LR [Section 2.5.3.1](#) Fission Product Control Systems and Structures and LR [Section 2.6.5](#), Containment Heat Removal.

There are no changes to the SBVS components, air flow rates or associated controls as a result of EPU. Following a LOCA, the SBVS mixes shield building in-leakage with the air in the annulus and any post-accident activity leakage from the containment and discharges it through a filter train, which includes charcoal adsorbers, prior to release to the outdoor atmosphere. The EPU affects the post-accident containment pressure and temperature transient which in turn affects the resulting transients in the shield building annulus. The time to establish a negative pressure in the annulus decreases from 310 seconds to 282 seconds for the EPU, which is bounded by the 310 seconds assumed in the dose analyses. Contributors to the difference in the shield building annulus peak pressure and the time to establish a sub-atmospheric annulus pressure, which are included in the EPU analysis, are:

- The increased containment pressure and temperature at EPU conditions following a LOCA,
- SBVS fan performance at 1 percent emergency diesel generator under frequency,
- Change in computer modeling from WA-TEMPT (pre-EPU) to GOTHIC (EPU) used for the analysis, and
- The inclusion of the radiation heating of the air, which was considered negligible in the pre-EPU analysis presented in UFSAR Section 6.2.3.3.1.

The shield building is designed for an internal and external pressure differential of 3 psi. The EPU GOTHIC model shows that the shield building annulus pressure reaches a peak of +4.9 in. H₂O, which is an increase from the existing 3.5 in. H₂O, but remains bounded by design.

Therefore, the shield building annulus design parameters (maximum differential pressure and time to reach negative pressure) remain valid for EPU. Additionally, EPU does not affect the ability of the SBVS to reduce the concentration and quantity of fission products released from the containment to the environment following a postulated accident. The offsite and control room dose analyses, presented in LR [Section 2.9.2](#), Radiological Consequences Analyses Using Alternative Source Terms, demonstrate the effectiveness of the ESF atmospheric cleanup systems to minimize the release of radioactivity to the environment following a LOCA in compliance with GDC-41.

Additional discussion of design basis accident containment atmosphere cleanup is provided in LR [Section 2.5.3.1](#), Fission Product Control Systems and Structures.

Reactor Auxiliary Building

There are no significant changes in heat gains, equipment or airflow as a result of EPU; therefore, EPU does not affect the ability of the ECCS area ventilation system to perform its design functions. The offsite dose analyses, presented in LR [Section 2.9.2](#), Radiological Consequences Analyses Using Alternative Source Terms, demonstrate the effectiveness of the

ESF atmospheric cleanup systems to minimize the release of radioactivity to the environment following a LOCA in compliance with GDC-41.

Additional discussion of the ECCS area ventilation system is provided in LR [Section 2.7.6](#), Engineered Safety Feature Ventilation System.

Decay Heat Generation in the Charcoal Adsorbers

In UFSAR Section 6.5, charcoal filters in the SBVS, ECCS area ventilation system and the control room emergency cleanup system are identified as collection points for fission products following design basis accidents. As described below, these systems were reviewed with regard to decay heat generation and dissipation following EPU.

Shield Building Ventilation System

The existing analysis presented in UFSAR Section 6.2.3.3.1 for the SBVS charcoal filters identifies that, the amount of decay heat is small when compared to the mass and large surface area of the charcoal adsorber and filter housing. Convection and conduction to ambient atmosphere can remove this decay heat through the housing without any cooling air. However, to enhance the removal of decay heat, cooling air is allowed to pass through the inoperative filter train. UFSAR Figure 6.2-61 shows the charcoal temperature as a function of cooling air flow (no heat transfer assumed through the housing) and it is shown that with a flow rate as low as 100 cfm the temperature rise of the air at the time of maximum decay heat following a DBA would be 25°F and at the minimum design flow rate of 300 cfm the temperature rise would only be ~8°F.

The existing margin between the currently predicted heat rise at a minimum cooling flow of 300 cfm (i.e., ~8°F) and the alarm setpoint of 200°F is more than sufficient to accommodate the proposed power uprate and the change in source terms from TID-14844 to alternative source term (AST). The application of AST reduced iodine inventory and associated heat load in the charcoal filters to less than that predicted to have been accumulated in the TID-14844 design basis analysis. Although the power uprate will increase the source term, the resulting iodine inventory and associated heat load in the charcoal filters will still remain below the design basis TID-14844 values. The heat contribution to the charcoal media due gamma heating resulting from the particulate inventory accumulated in the HEPA filters is not significant since the associated gamma heating rate in the charcoal is less than that generated by the iodine in the charcoal during the first 30 days following the DBA when the decay heat rate is the highest.

ECCS Area Ventilation System

The ECCS area ventilation system charcoal filters are not impacted only by EPU as neither the quantity of iodine nor the chemical form of the iodine is dependent on whether an AST or TID source term is utilized. The UFSAR Table 6.5-1 Regulatory Position 3k evaluation indicates that the ECCS area ventilation system did not require separate provisions for filter cooling as the maximum charcoal temperature rise with no flow through the filters was small as was the iodine loading. The maximum temperature in the charcoal in this analysis was found to be well below the ignition temperature or the iodine de-adsorption temperature. EPU would not change this conclusion.

Control Room Emergency Cleanup System

For the control room filters, there are several factors that are considered in making an assessment of the control room ventilation system charcoal absorber loading relative to that of the SBVS. Following a LOCA, the airborne fission products that eventually reach the control room charcoal filters originate from two sources: filtered effluent releases from the SBVS and unfiltered containment bypass leakage. The net source from these two pathways is less than that which is used to calculate the SBVS inventory. When this is combined with atmospheric dilution the concentration of fission products that can potentially reach the control room outside air intakes and penetrate the control room envelope as unfiltered inleakage is greatly reduced resulting in significantly lower iodine inventories per gram of charcoal on the control room filter. The UFSAR Table 6.5-1 Regulatory Position 3k evaluation indicates that the iodine decay heating rate is small in the control room charcoal filters. With the maximum decay heat rate and the adsorbers thermally isolated, the maximum temperature rise in the charcoal is approximately 1°F. This temperature rise added to the control room temperature of 81°F results in an adsorber temperature well below the ignition temperature. EPU would not change this conclusion. Lastly, the application of AST reduced iodine inventory and associated heat load in the charcoal filters to less than that predicted to have been accumulated in the TID-14844 design basis analysis. Although the proposed power uprate will increase the source term, the resulting iodine inventory and associated heat load in the charcoal filters will still remain below the design basis TID-14844 values. Thus it is expected that both the maximum temperature rise and the iodine loading will be much smaller when compared to that of the SBVS filters addressing both the impact of the AST and EPU.

For the control room filters, there are several factors that are considered in making an assessment of the control room ventilation system charcoal absorber loading. Following a LOCA, the airborne fission products that eventually reach the control room charcoal filters originate from two sources: filtered effluent releases from the SBVS and unfiltered containment bypass leakage. The net source from these two pathways is less than that which is used to calculate the SBVS inventory. When these sources are combined with atmospheric dilution the concentration of fission products that can potentially reach the control room outside air intakes and penetrate the control room envelope as unfiltered inleakage is greatly reduced resulting in significantly lower iodine inventories per gram of charcoal on the control room filter. The UFSAR Table 6.5-1 Regulatory Position 3k evaluation indicates that the iodine decay heating rate post-LOCA is small in the control room charcoal filters and thus required no provisions for cooling in the design. With the maximum decay heat rate and no flow passing through the filters, the maximum temperature in the charcoal was well below both the ignition temperature and the iodine de-adsorption temperature. EPU would not change this conclusion. Lastly, the application of AST reduces the iodine inventory and associated heat load in the charcoal filters to less than that predicted for the TID-14844 design basis analysis. Although the proposed increase due to EPU will increase the source term, the resulting iodine inventory and associated heat load in the charcoal filters will remain below the design basis TID-14844 values.

Radiation Monitoring

The ability of the radiation monitoring systems to perform their function in compliance with GDC-64 is not affected by the EPU. Refer to LR [Section 2.10.1](#), Occupational and Public Radiation Doses, for additional discussion.

2.7.2.2.3 Impact on Renewed Plant Operating License Evaluations and Licensing Renewal Programs

As discussed above, the ESF atmosphere cleanup system is within the scope of License Renewal. Operation of the ESF atmosphere cleanup system under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.7.2.2.4 Results

The proposed EPU has no effect on the ability of ESF atmosphere cleanup systems to control the release of radioactivity to the environment in compliance with GDCs -19, -41, -61 and -64. The offsite and control room dose analyses presented in LR [Section 2.9.2](#), Radiological Consequences Analyses Using Alternative Source Terms, demonstrate the effectiveness of the ESF atmosphere cleanup systems to minimize the release of radioactivity to the environment following a LOCA.

2.7.2.3 Conclusion

FPL has reviewed the effects of the proposed EPU on the ESF atmosphere cleanup systems. FPL has concluded that it has adequately accounted for the increase of fission products and changes in expected environmental conditions that would result from the proposed EPU, and 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, FPL concludes that the ESF atmosphere cleanup systems will continue to meet its current licensing basis with respect to the requirements of GDCs -19, -41, -61, and -64. Therefore, FPL finds the proposed EPU is acceptable with respect to the ESF atmosphere cleanup systems.

2.7.3 Control Room Ventilation System

2.7.3.1 Regulatory Evaluation

The function of the control room ventilation system (CRVS) 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, anticipated operational occurrence (AOO), and design basis accident (DBA) conditions. The Florida Power and Light (FPL) review of the CRVS focused on the effects that the proposed extended power uprate (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 CRVS.

The NRC's acceptance criteria for the CRVS are based on:

- General Design Criterion (GDC)-4, insofar as it requires that structures, systems and components (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,
- 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
- 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 Standard Review Plan (SRP) Section 9.4.1.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

- GDC-4 is described in UFSAR Section 3.1.4 Criterion 4 - Environmental and Missile Design Bases.

Structures, systems and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss- of- coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and

approved by the Commission demonstrates that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

Refer to UFSAR Sections 3.5, 3.6, 3.7, and 3.11 for details.

- GDC-19 is described in UFSAR Section 3.1.19 Criterion 19 - Control Room.

A control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in safe condition under accident conditions, including loss of coolant accidents. Adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent for the duration of the accident.

Equipment in appropriate locations outside the control room shall be provided (1) with a design capability for prompt hot shutdown of the reactor, including necessary instrumentations and controls to maintain the unit in a safe condition during hot shutdown, and (2) with a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

- GDC-60 is described in UFSAR Section 3.1.60 Criterion 60 - Control of Releases of Radioactive Materials to the Environment.

The nuclear power unit design shall include means to control suitably the release of radioactive materials in gaseous and liquid effluents and to handle radioactive solid wastes produced during normal reactor operation, including anticipated operational occurrences. Sufficient holdup capacity shall be provided for retention of gaseous and liquid effluents containing radioactive materials, particularly where unfavorable site environmental conditions can be expected to impose unusual operational limitations upon the release of such effluents to the environment.

UFSAR Section 9.4.1 identifies the following as part of the CRVS:

- The control room air conditioning system, and
- The control room emergency cleanup system.

Operation of the CRVS under postulated accident conditions does not contribute to the generation of radioactive materials. As described in UFSAR Section 9.4.1, upon receipt of a containment isolation signal, or in the event of high radioactivity in the CRVS outside air intakes, the CRVS will be automatically aligned to operate in a filtered recirculation mode until operators align the system to operate in a pressurized mode, using filtered outside air as make-up.

Additional details that define the licensing basis for the CRVS are described in the following UFSAR Sections:

- 6.4 Habitability Systems,
- 7.4.1 Systems Required for Safe Shutdown,
- 9.5.3 Lighting Systems,
- 12.3.3 Ventilation,

- 15.6.3 Steam Generator Tube Rupture (SGTR), and
- 15.6.5 Loss of Coolant Accidents.

Technical Specification 3/4.7.7, Control Room Emergency Air Cleanup System, ensures that the ambient air temperature does not exceed the allowable temperature for continuous duty rating for the equipment and instrumentation cooled by the system and the control room will remain habitable for operations personnel during and following all credible accident conditions.

On September 29, 2008, the NRC approved Amendment 152 to the operating license, which adopts the AST as allowed in 10 CFR 50.67 and described in Regulatory Guide (RG) 1.183.

On September 30, 2008, the NRC approved Amendment 153 to the operating license, which adopts NRC-approved Technical Specification Task Force Standard Technical Specification Traveler TSTF-448, Control Room Habitability. This amendment establishes more effective and appropriate action, surveillance, and administrative requirements related to ensuring habitability of the control room envelope.

In addition to the licensing basis described in the UFSAR, the CRVS was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.3.15 of the SER identifies that components of the CRVS are within the scope of License Renewal. Programs used to manage the aging effects associated with the CRVS are discussed in SER Section 3.3.15 and Chapter 18 of the UFSAR.

2.7.3.2 Technical Evaluation

2.7.3.2.1 Introduction

The control room air conditioning system and control room emergency cleanup system are designed to:

- Control the environment in the control room envelope, for the comfort of the control room personnel and to assure the operability of control components;
- Assure that no single active failure coincident with a loss of offsite power can result in loss of functional performance;
- Provide means to limit the introduction of airborne radioactivity, smoke, toxic gases or steam to the control room envelope;
- Provide air cleaning for the control room envelope atmosphere so that airborne radiological dose, experienced by control personnel following a design basis accident does not exceed limits; and
- Assure that makeup air brought in during an event that has resulted in control room isolation does not bypass the air cleaning process before it mixes with the control room envelope air.

During normal operation, the control room air conditioning system draws air from its associated control room, passes the air through air conditioning units, and returns the air to the control room. In addition, outside makeup air is supplied to ensure that a positive pressure is maintained in the control room. During emergency conditions, the control room emergency cleanup system is started, the outside air is isolated, and the control room air is recirculated. A portion of the recirculated control room air is passed through high-efficiency particulate air (HEPA) filters and charcoal adsorbers located in the control room emergency cleanup system. The system is operated post-loss of coolant accident (LOCA) to maintain a positive control room pressure. Makeup in the positive pressure mode is filtered using the charcoal filters.

2.7.3.2.2 Description of Analyses and Evaluations

The control room air conditioning system and control room emergency cleanup system are two of the systems required to assure control room habitability. They were evaluated to assure they are capable of performing their intended functions at EPU conditions as follows:

- At EPU conditions there is no significant increase in either radiation levels or contamination levels that would affect the ability of the system to maintain control room dose levels and permit continuous occupation of the control room in compliance with GDC-19 (personnel dose not to exceed 5 rem total effective dose equivalent for the duration of the accident). This is addressed in LR [Section 2.7.1](#), Control Room Habitability System.
- Under EPU conditions the temperatures of the areas surrounding the control room do not significantly change.
- Under EPU conditions there is no significant increase in equipment heat loads internal to the control room.
- The capability of the system to humidify/dehumidify the control room to assure equipment operability and maintain operator comfort in compliance with GDC-4 is not affected by EPU.
- At EPU conditions, the temperatures of the areas surrounding the control room do not significantly change. The existing digital electro-hydraulic (DEH) computer is an older computer. It is being replaced with a more modern DEH computer that generates less heat and will provide a reduction in the control room equipment heat load. The installation of the Cameron Leading Edge Flow Meter CheckPlus™ system computer will not significantly increase the heat load in the control room. 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. Therefore during normal, abnormal and emergency conditions the system will provide sufficient control of room temperatures to maintain equipment temperatures within design limits and maintain operator comfort in compliance with GDC-4.
- Implementation of EPU does not impose any new threat to the control room from toxic gas, or smoke.
- Component cooling water provides the cooling medium for the control room ventilation systems. Currently the ventilation equipment capability is evaluated based on a maximum cooling water temperature of 108°F. As a result of EPU the maximum temperature of the cooling water will be raised to 120°F. The modification process implementing this change will

address the control room cooling equipment operation at the elevated component cooling water temperature, and to ensure the systems are capable of maintaining control room temperature and humidity within design limits to ensure the systems provide a controlled environment for personnel and equipment for EPU operation in compliance with GDC-4.

Compliance with GDC-60 with regards to the means to control the release of radioactive effluents is addressed in LR [Section 2.5.6.1](#), Gaseous Waste Management Systems, LR [Section 2.5.6.2](#), Liquid Waste Management Systems, and LR [Section 2.5.6.3](#), Solid Waste Management Systems.

Based on the above, the control room air conditioning system and control room emergency cleanup system will provide an environment in the control room that limits the introduction of airborne activity and allows for continuous occupancy under normal and post accident conditions. For the evaluation of radiation protection of control room occupants see LR [Section 2.7.1](#), Control Room Habitability System and [Section 2.9.2](#), Radiological Consequences Analyses Using Alternative Source Terms.

2.7.3.2.3 Impact on Renewed Plant Operating License Evaluations and Licensing Renewal Programs

As discussed above, the CRVS is within the scope of License Renewal. Operation of the CRVS under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.7.3.2.4 Results

The proposed EPU has no effect on the ability of the CRVS to provide a controlled environment for the comfort and safety of control room personnel and to support the operability of control room under normal and postulated conditions. An increase in the maximum cooling water temperature supplied to the control room cooling equipment will be addressed by the modification process to ensure the ventilation systems will maintain design conditions at the elevated component cooling water temperature under EPU operation. EPU has negligible effect on internal heat gain in the control room and therefore EPU does not affect the ability of the ventilation system to maintain normal specified space temperatures. Likewise the system limits the introduction of airborne activity and allows for continuous occupancy under normal and post accident conditions at EPU conditions. The ability of the system to activate emergency filtration flow, maintain emergency filtration air flow rates, maintain space static pressure during emergency filtration air flow and meet minimum HEPA and charcoal filtration efficiencies is not affected by EPU. The ability of the CRVS to limit the radiation dose to personnel within the control room is addressed in LR [Section 2.7.1](#), Control Room Habitability System, and

Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms. LR **Section 2.5.6.1**, Gaseous Waste Management Systems, **Section 2.5.6.2**, Liquid Waste Management Systems, and **Section 2.5.6.3**, Solid Waste Management Systems, also confirm compliance with GDC-60.

2.7.3.3 Conclusion

FPL has assessed the effects of the EPU on the ability of the CRVS to provide a controlled environment for the comfort and safety of control room personnel and to support the operability of control room components. FPL concludes that the assessment has adequately accounted for the increase of toxic and radioactive gases that would result from a DBA under the conditions of the EPU, and associated changes to parameters affecting environmental conditions for control room personnel and equipment. Accordingly, FPL concludes that the system will continue to provide an acceptable control room environment for safe operation of the plant following implementation of the proposed EPU. FPL also concludes that the system will continue to suitably control the release of gaseous radioactive effluents to the environment. Based on this, the control room air ventilation system will continue to meet its current licensing basis with respect to the requirements of GDCs -4, -19, and -60. Therefore, the proposed EPU is acceptable with respect to the control room air ventilation system.

2.7.4 Spent Fuel Pool Area Ventilation System

2.7.4.1 Regulatory Evaluation

The spent fuel pool area ventilation system is referred to as the fuel handling building ventilation system. The function of the fuel handling building ventilation system is to maintain ventilation in the spent fuel pool equipment areas, permit personnel access, and control airborne radioactivity in the area during normal operation, anticipated operational occurrences (AOO), and following postulated fuel handling accidents. The Florida Power and Light (FPL) review focused on the effects of the proposed extended power uprate (EPU) on the functional performance of the system.

The NRC's acceptance criteria for the fuel handling building ventilation system are based on:

- General Design Criteria (GDC)-60, insofar as it requires that the plant design include means to control the release of radioactive effluents, and
- GDC-61, insofar as it requires that systems which contain radioactivity be designed with appropriate confinement and containment.

Specific review criteria are contained in Standard Review Plan (SRP) Section 9.4.2.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conform with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

- GDC-60 is described in UFSAR Section 3.1.60, Criterion 60 - Control of Releases of Radioactive Materials to the Environment.

The nuclear power unit design shall include means to control suitably the release of radioactive materials in gaseous and liquid effluents and to handle radioactive solid wastes produced during normal reactor operation, including anticipated operational occurrences. Sufficient holdup capacity shall be provided for retention of gaseous and liquid effluents containing radioactive materials, particularly where unfavorable site environmental conditions can be expected to impose unusual operational limitations upon the release of such effluents to the environment.

- GDC-61 is described in UFSAR Section 3.1.61, Criterion 61 - Fuel Storage and Handling and Radioactivity Control.

The fuel storage and handling, radioactive waste, and other systems which may contain radioactivity shall be designed to assure adequate safety under normal and postulated accident conditions. These systems shall be designed (1) with a capability to permit inspection and testing of components important to safety, (2) with suitable shielding for radiation protection (3) with appropriate containment, confinement, and filtering systems, (4) with a residual heat removal capability having reliability and testability that reflects the

importance to safety or decay heat and other residual heat removal, and (5) to prevent significant reduction in fuel storage coolant inventory under accident conditions.

The fuel pool is located within the fuel handling building which provides confinement capability in the event of an accidental release of radioactive materials, and during normal operation is ventilated with discharges to the fuel handling building vent stack, which is monitored.

The fuel pool is designed to withstand the postulated tornado driven missiles and seismic event without loss of the pool water.

UFSAR Section 9.4.2 describes the fuel handling building ventilation system. The system is designed to reduce plant personnel doses by preventing the accumulation of airborne radioactivity in the fuel handling building due to diffusion of fission products from the spent fuel pool. The fuel pool area air is exhausted through air inlets around the periphery of the fuel pool. During normal operation, air is discharged to the atmosphere through a prefilter, HEPA filter bank, and out the fuel handling building vent stack. In the event of a high radiation signal, the fuel handling building ventilation system is realigned to direct exhaust flow through the shield building ventilation system (SBVS) filters and out the plant vent.

In addition to the licensing basis described in the UFSAR, the fuel handling building ventilation system was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.3.15 of the SER identifies that the fuel handling building ventilation system is within the scope of License Renewal. Programs used to manage the aging effects associated with the control room ventilation system are discussed in SER Section 3.3.15 and Chapter 18 of the UFSAR.

2.7.4.2 Technical Evaluation

2.7.4.2.1 Introduction

Ventilation to the spent fuel pool area is provided by the fuel handling building ventilation system. The fuel handling building ventilation system is described in UFSAR Section 9.4.2 and is addressed in UFSAR Section 15.7.4.1.2.

The fuel handling building ventilation system is designed to reduce plant personnel doses by preventing the accumulation of airborne radioactivity. The system HEPA and charcoal filters are designed to capture and retain airborne particulates and to adsorb radioactive elemental iodine, which may be present in the fuel handling building atmosphere due to diffusion of fission products from the spent fuel pool. The system is also designed to ventilate the spent fuel pool cooling equipment contained within the fuel handling building.

The system consists of two separate supply systems and two separate exhaust systems, one system for the fuel pool area and another system for the cooling equipment area. Each supply system consists of a hooded wall intake, an air handling unit with filters, a fan section, and a duct distribution system. The fuel pool area air is exhausted through air inlets around the periphery of

the pool. Air is discharged to the atmosphere through a prefilter, HEPA filter bank, and out the fuel handling building vent stack. Air exhausted from the equipment area is passed through a prefilter and HEPA filter bank before being discharged to the atmosphere through the fuel handling building vent stack. System exhaust effluent flow and radiation passing out the fuel handling building vent stack are monitored.

The fuel pool exhaust ductwork, the supply and exhaust motorized isolation dampers, and the ductwork of the fuel pool exhaust line to the SBVS are safety related, while the remaining supply and exhaust ductwork of the fuel handling building ventilation system is non-safety related. However, no credit is taken in the fuel handling building ventilation system for filtration of the airborne gaseous effluent releases during a fuel handling accident in the fuel handling building. The spent fuel pool ventilation portion of the system is interconnected with the SBVS. In the event of a high radiation signal, the fuel pool area is exhausted to the plant vent via the SBVS charcoal and HEPA filters.

2.7.4.2.2 Description of Analyses and Evaluations

The fuel handling building ventilation system was evaluated to ensure it is capable of performing its intended functions during normal plant operation at EPU conditions. The decay heat loads in the spent fuel pool increase due to the EPU conditions. EPU decay heat loads and spent fuel pool water temperatures have been evaluated to ensure that the fuel pool cooling system is capable of maintaining the pool temperature within the current design temperature of 150°F under normal EPU and refueling modes. This evaluation is addressed in LR [Section 2.5.4.1](#), Spent Fuel Pool Cooling and Cleanup System. Other heat sources in the spent fuel pool areas are from electrical equipment, mechanical equipment and ambient outside conditions and will not increase due to EPU. Since the design temperature of the spent fuel pool does not increase and there are no increases from other heat sources, there will be no increase in the fuel handling building's design ambient temperature following implementation of EPU. The fuel handling building ventilation system air distribution, exhaust airflow rates and patterns, and filtration do not change with EPU. Therefore the ability of the system to reduce plant personnel doses due to potential airborne activity resulting from diffusion of fission products from the spent fuel pool water is not impacted by EPU.

The radiological evaluations of fuel handling accidents are addressed in LR [Section 2.9.2](#). The evaluation in this section shows that the radiological consequences of a fuel handling accident occurring in the fuel handling building under EPU conditions are still within the applicable dose guidelines.

The design of the fuel handling building ventilation system does not change as a result of the implementation of EPU. Airborne radioactivity released from the spent fuel in the pool will continue to be collected by the system and discharged to the atmosphere via the monitored fuel handling building vent stack. The evaluation in LR [Section 2.10.1](#), Occupational and Public Radiation Doses, shows that offsite doses from normal effluent releases will not increase significantly under EPU conditions.

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

The fuel handling building ventilation system is within the scope of License Renewal as identified in the License Renewal Safety Evaluation Report, NUREG-1779, Section 2.3.3.15, Ventilation. EPU activities do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries. There are no changes associated with operation of the fuel handling building ventilation system at EPU conditions and the EPU does not add any new or previously unevaluated materials to the system. System component internal and external environments remain within the parameters previously evaluated. Thus, no new aging effects requiring management are identified.

2.7.4.2.4 Results

The air temperature in the spent fuel pool area is affected by heat released from the spent fuel pool. Although the decay heat in the spent fuel is greater at EPU conditions, the spent fuel pool water temperature during normal and abnormal EPU operation does not exceed the current limits. Therefore, the fuel handling building ventilation system will maintain the required air temperature conditions for personnel and equipment during EPU operation. Refer to LR [Section 2.5.4.1](#), Spent Fuel Pool Cooling and Cleanup System.

The design of the fuel handling building ventilation system does not change following the implementation of the EPU. During normal operation airborne radioactivity released from the spent fuel pool will continue to be collected, filtered, and exhausted by the fuel handling building ventilation system to the atmosphere via the monitored fuel handling building vent stack. During emergency operation (upon receipt of a high radiation signal from the fuel pool area), the fail closed isolation dampers located at fuel pool area ventilation penetrations automatically close, the normal ventilation systems are de-energized and the SBVS is actuated. The SBVS evacuates the air from the fuel pool area and provides charcoal and HEPA filtration. The SBVS evacuation of the fuel pool air area ensures a negative pressure in that area to preclude unfiltered leakage of radioactivity to the environment. The redundant isolation dampers on the supply and exhaust building penetrations ensure that no set of circumstances could cause air to be evacuated from the fuel pool area other than through the SBVS.

The handling, control, and release of radioactive materials are in compliance with 10 CFR 50, Appendix I, as described in the offsite dose calculation manual. Similarly, the radiological consequences of a fuel handling accident occurring in the fuel handling building under EPU conditions are still within the applicable dose guidelines.

2.7.4.3 Conclusion

FPL has reviewed the effects of the proposed EPU on the fuel handling building ventilation system. FPL has concluded that it has adequately accounted for the effects of the proposed EPU on the fuel handling building ventilation 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, FPL concludes that the fuel handling building ventilation system will

continue to meet its current licensing basis with respect to the requirements of GDCs -60 and -61. Furthermore, the radiological consequences of a fuel handling accident have been evaluated and found to be within acceptable guidelines. Therefore, the proposed EPU is acceptable with respect to the fuel handling building ventilation system.

2.7.5 Auxiliary and Radwaste Area and Turbine Areas Ventilation Systems

2.7.5.1 Regulatory Evaluation

The auxiliary and radwaste areas are located within areas of the reactor auxiliary building (RAB) served by the RAB ventilation systems. The turbine building is an open structure that has no ventilation systems, except for the turbine switchgear room and chemical storage area. These turbine building ventilation systems provide no credited safety functions. The function of the RAB ventilation systems is to maintain ventilation in the auxiliary and radwaste equipment areas, permit personnel access and control the concentration of airborne radioactive material during normal operation, during anticipated operational occurrences, and after postulated accidents. The Florida Power and Light (FPL) review focused on the effects of the extended power uprate (EPU) on the functional performance of the safety-related portions of these systems.

The NRC's acceptance criteria for the auxiliary and radwaste ventilation system and turbine area ventilation system 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 Standard Review Plan (SRP) Sections 9.4.3 and 9.4.4.

St. Lucie Unit 2 Current Licensing Bases

As noted in Updated final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDCs for the auxiliary and radwaste area and turbine areas ventilations systems are as follows:

- GDC-60 is described in UFSAR Section 3.1.60 Criterion 60 - Control of Releases of Radioactive Materials to the Environment.

The nuclear power unit design shall include means to control suitably the release of radioactive materials in gaseous and liquid effluents and to handle radioactive solid wastes produced during normal reactor operation, including anticipated operational occurrences. Sufficient holdup capacity shall be provided for retention of gaseous and liquid effluents containing radioactive materials, particularly where unfavorable site environmental conditions can be expected to impose unusual operational limitations upon the release of such effluents to the environment.

The ventilation systems serving the RAB are as follows:

- RAB main ventilation system,
- RAB electrical equipment and battery room ventilation system,
- RAB miscellaneous ventilation systems, and
- ECCS area ventilation system.

Details that define the licensing basis for the reactor auxiliary building ventilation systems are described in UFSAR Section 9.4.3. Details that define the licensing basis for the turbine building ventilation system are described in UFSAR Section 9.4.4. UFSAR Section 11.3 provides additional information relative to these ventilation systems.

In addition to the licensing bases described in the UFSAR, the auxiliary building, radwaste area and turbine areas ventilation systems were evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.3.15 of the SER identifies that components of the auxiliary building, radwaste area and turbine areas ventilation systems are within the scope of License Renewal. Programs used to manage the aging effects associated with the auxiliary building, radwaste area and turbine areas ventilation systems are discussed in SER Section 3.3.15 and Chapter 18 of the UFSAR.

2.7.5.2 Technical Evaluation

2.7.5.2.1 Introduction

Reactor Auxiliary Building Ventilation Systems

The RAB ventilation systems are designed to perform the following functions:

- Provide ventilation to permit proper functioning of equipment during normal operation,
- Provide air flow from areas of low potential radioactivity to areas of higher potential radioactivity,
- Provide an air supply for cooling of safety related equipment assuming a single active failure coincident with a loss of offsite power,
- Withstand safe shutdown earthquake loads without loss of capability of cooling safety related equipment required for a safe shutdown,
- Prevent the accumulation of a combustible concentration of hydrogen in the battery rooms during normal and accident conditions,
- Assure that the ventilation system operation during normal, AOO and postulated accidents does not cause an offsite release of gaseous radioactivity from the plant to exceed limits allowed by 10 CFR 50, Appendix I, and
- Assure that occupational radiation exposure, resulting from airborne contaminants that may be present from the ECCS area and Radwaste processing equipment and piping, is maintained within 10 CFR 20 guidelines.

The RAB ventilation systems consist of the following:

- RAB main ventilation system,

- RAB electrical equipment and battery room ventilation system, and
- RAB miscellaneous ventilation systems.

The RAB main ventilation system supplies air to the ECCS pump rooms, shutdown cooling heat exchanger rooms, penetration areas and nonessential areas of the RAB. The system consists of a redundant air supply system and a redundant air exhaust air system. The supply air passes through wall louvers, roughing filters, two 100 percent capacity centrifugal fans and associated duct distribution systems. The air supply is designed to seismic Category 1 requirements and is automatically connected to the emergency diesel generator sets under loss of normal power. The air exhaust system includes a 100 percent capacity bank of prefilters and HEPA filters, two 100 percent capacity exhaust fans and associated duct exhaust systems. Exhaust air is discharged through the plant vent stack. The exhaust system serves no safety function. Ventilation flow is designed to limit the temperature to a maximum ambient temperature of 104°F within the equipment areas with an outside air temperature of 93°F. Under accident conditions, the air supply to the nonessential sections of the RAB is redirected to the ECCS pump rooms to provide additional cooling and these engineered safety features pump rooms are exhausted by the emergency core cooling systems (ECCS) area ventilation system (additional details are provided in LR [Section 2.7.6](#)).

RAB electrical equipment and battery room ventilation system provides ventilation to the electrical equipment rooms and battery rooms. The system consists of a louvered intake, filters, two redundant supply fans, a duct distribution system, and exhaust fans. Ventilation flow rates are designed to maintain the temperature in the electrical battery rooms less than 104°F assuming an outside air temperature of 93°F. Upon loss of offsite power, the system is automatically connected to the emergency diesel generator sets. Each battery room ventilation rate has been sized to avoid buildup of hydrogen.

The RAB miscellaneous ventilation systems provide ventilation to various areas of the RAB. Radiological cold and hot locker room personnel areas are provided with local air conditioning units and exhaust fans. Air from locker room personnel areas that is clean is exhausted directly to the atmosphere. Air which may contain radioactivity is passed through a prefilter and HEPA filter before being vented. The laboratory supply and storage room, first aid room and health physics office are serviced by a packaged heat pump. The packaged unit provides ventilation, filtration, cooling during the summer and heating during the winter. The health physics station, counting room, instrument calibration and repair shop, and radiochemistry lab are serviced by a packaged air conditioning unit. A portion of the air is exhausted through laboratory hoods in the radiochemistry lab with the balance being recirculated. The elevator machine room and tank room are ventilated and exhausted by wall propeller fans. Makeup air is provided by outside air intake hoods. The control element drive mechanism control system equipment enclosure located in the cable spreading room is air conditioned by two independent 100 percent capacity split systems. These units also provide cooling air to the emergency response data acquisition and display systems (ERDADS) enclosure under normal operating conditions. Two standby through-the-wall units are provided as backup to maintain temperature in the ERDADS enclosure in the case of a loss of normal cooling.

Radwaste Area Ventilation

The radwaste area is located inside the RAB and is serviced by the RAB main ventilation system.

Turbine Area Ventilation

The turbine building is an open structure with no mechanical ventilation system for the equipment areas except for the switchgear room and chemical storage areas which are enclosed.

Equipment in open areas is ventilated by natural ventilation. The turbine building switchgear room ventilation system includes two filtered supply air ventilation units, ductwork, and a relief air system to maintain room temperature below 104°F with an outside design temperature of 93°F. Pressure relief dampers are provided to maintain slight positive pressure to maintain a dust free environment for switchgear equipment operation. The chemical storage ventilation system draws outside air through a motorized filtered intake louver and supply fan and relieves air through a wall mounted fixed open discharge louver. The room is maintained at a slightly positive pressure. Because the chemical storage area is not impacted by the EPU, its ventilation is not discussed further. The turbine building ventilation is not required to mitigate the consequences of a design basis accident or provide safe shutdown of the reactor, therefore it is not designed to safety or seismic requirements.

2.7.5.2.2 Description of Analyses and Evaluations

The RAB ventilation systems and the turbine building ventilation system were evaluated to ensure that at EPU conditions, there are no significant changes to any system operation including maintaining acceptable cooling conditions within the RAB and turbine building, maintaining acceptable hydrogen concentration levels in the battery rooms, maintaining space pressurization and ensuring the systems ability to filter and remove airborne contaminants during normal and emergency conditions.

EPU does not change the ability of the RAB ventilation systems to move air from areas of low potential radioactivity to areas of higher potential radioactivity and filter the air from rooms within the RAB that may contain radioactivity. After filtration, the air is released to the atmosphere via the plant vent stack which is monitored for radiation. EPU does not alter the supply or exhaust air flow paths, air flow rates, filtration, or ability to isolate any portion of the RAB ventilation systems. EPU does not result in additional equipment or heat loads being added to areas served by the RAB ventilation systems during normal operation. No additional batteries were added. EPU does not change the requirements for maintaining hydrogen concentrations in the RAB below allowable limits. Refer to LR [Section 2.10.1](#), Occupational & Public Radiation Doses, for additional information and discussion of compliance with GDC-60.

Refer to LR [Section 2.7.6](#), Engineered Safety Features Ventilation System, for additional information regarding ventilation to the ECCS area during accident conditions.

The general areas of the turbine building are an open structure design; therefore mechanical ventilation is not required. The turbine switchgear room ventilation system will be affected by the additional heat given off as a result of planned EPU modifications. EPU will increase currents for selected existing motors supplied from 6.9 and 4.16 kV switchgear (connected horsepower rating does not change). EPU will also increase the total connected nameplate rating of the motors supplied by the 480V load centers. These increases amount to less than 1 percent of the existing

total nameplate motor ratings supplied by the switchgear and load centers in the turbine switchgear room. The existing ventilation system can accommodate this small increase.

2.7.5.2.3 Impact on Renewed Plant Operating License Evaluations and Licensing Renewal Programs

As discussed above, the auxiliary building, radwaste area and turbine area ventilation systems are within the scope of License Renewal. Operation of the auxiliary building, radwaste area and turbine areas ventilation systems under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.7.5.2.4 Results

EPU will not affect the ability of the RAB ventilation systems or the turbine area ventilation system to perform their respective design functions. EPU will not diminish the capability of the RAB ventilation systems or the turbine area ventilation system to meet the requirements of GDC-60.

2.7.5.3 Conclusion

FPL has reviewed the effects of the proposed EPU on the RAB ventilation systems and turbine switchgear room ventilation system. FPL has concluded that it 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 and control the concentration of airborne radioactive material in these areas, and control release of gaseous radioactive effluents to the environment. Based on this, FPL concludes that the RAB ventilation systems and turbine switchgear room ventilation system will continue to meet their current licensing basis with respect to the requirements of GDC-60. Therefore, the EPU is acceptable with respect to the RAB ventilation systems and turbine switchgear room ventilation system.

2.7.6 Engineered Safety Feature Ventilation System

2.7.6.1 Regulatory Evaluation

The function of the engineered safety feature (ESF) ventilation system is to provide a suitable and controlled environment for ESF components following certain anticipated transients and design basis accidents (DBA). St. Lucie Unit 2 does not have a singular ESF ventilation system; there are several ventilation systems that perform this function. The Florida Power and Light (FPL) review focused on the effects of the proposed extended power uprate (EPU) on the functional performance of the safety-related portions of these systems.

FPL's review also covered:

- the ability of the ESF equipment in the areas being serviced by the ventilation system to function under degraded ESF ventilation system performance;
- the capability of the ventilation systems 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
- the capability of the ventilation systems to control airborne particulate material (dust) accumulation.

The NRC's acceptance criteria for the ESF ventilation systems are based on:

- General Design Criterion (GDC)-4, insofar as it requires that structures, systems and components (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;
- GDC-17, insofar as it requires onsite and offsite electric power systems be provided to permit functioning of SSCs important to safety; and
- 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.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDCs for the ESF Ventilation System are as follows:

- GDC-4 is described in UFSAR Section 3.1.4 Criterion 4 - Environmental and Missile Design Bases.

Structures, systems and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal

operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and approved by the Commission demonstrates that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

SSCs important to safety are designed to accommodate the effects of and to be compatible with the pressure, temperature, humidity, and radiation conditions associated with normal operation, maintenance, testing, and postulated accidents including a loss of coolant accident (LOCA), in the area in which they are located.

Refer to UFSAR Sections 3.5, 3.6, 3.7, and 3.11 for details on missile protection, pipe rupture and jet impingement protection, seismic design criteria and environmental qualification, respectively.

- GDC-17 is described in UFSAR Section 3.1.17 Criterion 17 - Electrical Power Systems.

An onsite electrical power system and an offsite electrical power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

The onsite electrical power sources, including the batteries, and the onsite electrical distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure.

Electrical power from the transmission network to the switchyard shall be supplied by physically independent transmission lines (not necessarily on separate rights-of-way) designed and located so as to suitably minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite electrical power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a loss of coolant accident to assure that core cooling, containment integrity, and other vital safety functions are maintained.

Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electrical power supplies.

Refer to UFSAR Sections 8.2 and 8.3 for further discussion of offsite power sources and onsite power sources respectively.

- GDC-60 is described in UFSAR Section 3.1.60 Criterion 60 - Control of Releases of Radioactive Materials to the Environment.

The nuclear power unit design shall include means to control suitably the release of radioactive materials in gaseous and liquid effluents and to handle radioactive solid wastes produced during normal reactor operation, including anticipated operational occurrences. Sufficient holdup capacity shall be provided for retention of gaseous and liquid effluents containing radioactive materials, particularly where unfavorable site environmental conditions can be expected to impose unusual operational limitations upon the release of such effluents to the environment.

UFSAR Section 9.4 provides design and licensing basis information on ventilation systems associated with ESF structures, systems and components.

In addition to the evaluations described in the UFSAR, the ESF ventilation system was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.3.15 of the SER identifies that components of the ESF ventilation system are within the scope of License Renewal. Programs used to manage the aging effects associated with the ESF ventilation system are discussed in SER Section 3.3.15 and Chapter 18 of the UFSAR.

2.7.6.2 Technical Evaluation

2.7.6.2.1 Introduction

The ESF ventilation systems function to maintain temperatures within specified limits in areas containing safety-related equipment. Normal ventilation exhausts from potentially contaminated areas are filtered and the discharge is monitored for radiation. Included in the scope of the ESF ventilation systems are the following subsystems:

- Emergency core cooling system (ECCS) area ventilation (described in UFSAR Section 9.4.3.1 and 9.4.3.2.4),
- Diesel generator building ventilation (described in UFSAR Section 9.4.5),
- Intake structure ventilation system (described in UFSAR Section 9.4.6), and
- Component cooling area ventilation system (described in UFSAR Section 9.4.7).

Other Ventilation Systems are discussed in the following LR Sections:

- LR [Section 2.7.1](#), Control Room Habitability System,
- LR [Section 2.7.2](#), Engineered Safety Features Atmosphere Cleanup,

- LR [Section 2.7.3](#), Control Room Ventilation System,
- LR [Section 2.7.4](#), Spent Fuel Pool Areas Ventilation System,
- LR [Section 2.7.5](#), Auxiliary and Radwaste Area and Turbine Area Ventilation Systems, and
- LR [Section 2.7.7](#), Other Ventilation Systems (Containment).

The auxiliary feedwater pumps and associated components are located in the steam trestle area, which is an open structure that is not provided with a ventilation system.

ECCS Area Ventilation System

The ECCS area ventilation system is designed to provide post-LOCA filtration and adsorption of fission products in the exhaust air from areas of the reactor auxiliary building (RAB) which contain the following equipment: containment isolation valves, low pressure safety injection (SI) pumps, high pressure SI pumps, containment spray (CS) pumps, shutdown cooling heat exchangers, and piping which contains recirculating containment sump water following a LOCA. Redundant safety related components, such as the SI pumps, shutdown cooling heat exchangers, or CS pumps require ventilation for proper operation. Both trains of ECCS equipment are located within a single ventilation system envelope that is served by two trains of ventilation. Each ventilation train is capable of providing the necessary air flow to support operation of two trains of ECCS. Each of the redundant ventilation components and its controls is powered from a separate emergency bus.

The ECCS pump compartments are maintained at or below 104°F by normal ventilation system operation (RAB main ventilation system). During such periods, the ECCS pumps are not required to operate, except for shutdown cooling. The ventilation system is designed to maintain pump room temperature below 104°F with the ECCS pumps and associated electrical equipment operating at full design capacity under LOCA conditions or pump testing periods.

During normal operation, the RAB main ventilation supply and exhaust system provides the necessary ventilation of the ECCS pump rooms. Refer to LR [Section 2.7.5](#) Auxiliary and Radwaste Area and Turbine Areas Ventilation Systems for the evaluation of the RAB main ventilation system. Under accident conditions when several or all of the pumps are operating, some of the air supply to the nonessential section of the RAB is directed to the pump rooms to provide the additional cooling air requirement. Simultaneously, the exhaust fans are energized and dampers in the exhaust ductwork are positioned to allow the fans to draw all exhaust air from the area through the HEPA and charcoal filter banks before discharge to the atmosphere. Two ECCS area ventilation system exhaust monitors measure the airborne effluent from the ECCS area. The system is sized to maintain a slightly negative pressure in the ECCS area with respect to surrounding areas of the RAB.

Diesel Generator Building Ventilation System

The diesel generator building ventilation system is designed to provide ambient conditions suitable for occupancy when the emergency generators are not in operation. The system maintains the diesel generator rooms at or below 104°F during normal operation when the emergency diesel generators (EDGs) are not in operation. When the EDGs are in operation, the

fans serving the engine cooling system radiators provide ventilation air flow through the building to maintain temperature at or below 104°F during emergency conditions.

Intake Structure Ventilation System

The intake structure ventilation system is designed to provide adequate ventilation air to assure reliable operation of the intake cooling water (ICW) system pumps and auxiliary equipment, and to maintain temperature at or below 120°F during normal operation and under accident conditions.

Component Cooling Area Ventilation System

The component cooling area ventilation system is designed to provide ventilation to assure a controlled thermal environment in the component cooling area. For personnel comfort during normal operation, exhaust fans and exhaust ductwork are provided in the component cooling area. Air is drawn in through the intake openings, warmed by the area's heat gain and is exhausted through exhaust ductwork by the exhaust fans.

During normal or accident conditions, the mechanical exhaust fans are not required to operate. Ventilation to the component cooling area is based on natural ventilation. Cool air is drawn through the intake openings and warmed by the area's heat gain from the equipment. Because of a stack effect, the hot air rises and is exhausted through the openings in the roof. Natural ventilation is sufficient to maintain design temperatures below 104°F during normal operations and below 120°F under accident conditions; therefore, the component cooling area ventilation system is nonsafety and nonseismic.

2.7.6.2.2 Description of Analyses and Evaluations

Changes in heat loads which affect the ventilation subsystems in areas served by the ESF ventilation systems were evaluated to ensure that the ventilation subsystems are capable of performing their intended functions and performance under EPU conditions. The ESF ventilation systems were also reviewed for impacts as a result of EPU on the ability of the systems to prevent accumulation of flammable or explosive gas or to control airborne particulate material accumulation.

Other evaluations related to the ESF ventilation systems are addressed in the following Licensing Report sections:

- Protection against dynamic effects, including GDC - 4 requirements, of missiles, pipe whip and discharging fluids - LR [Section 2.2.1](#), Pipe Rupture Locations and Associated Dynamic Effects and LR [Section 2.5.1.3](#), Pipe Failures;
- Electrical equipment qualification - LR [Section 2.3.1](#), Environmental Qualification of Electrical Equipment;
- Onsite and offsite electric power systems, including GDC - 17 requirements – LR [Section 2.3.2](#), Offsite Power System and LR [Section 2.3.3](#), AC Onsite Power System;
- Protection against turbine missiles and internal missiles is discussed in LR [Section 2.5.1.2](#), Missile Protection; and

- Potential radioactive releases to the environment - LR [Section 2.10.1](#), Occupational and Public Radiation Doses.

2.7.6.2.3 Impact on Renewed Plant Operating License Evaluations and Licensing Renewal Programs

As discussed above, the ECCS area and the intake structure ventilation systems are within the scope of License Renewal. Operation of these ventilation systems under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.7.6.2.4 Results

EPU does not change the requirements for filtering the air from ECCS areas within the RAB that may contain of fission products. After filtration by HEPA and charcoal filters, two ECCS ventilation system exhaust monitors measure the airborne effluent from the ECCS area prior to discharge to the atmosphere. Refer to LR [Section 2.10.1](#) Occupational and Public Radiation Doses for additional information and discussion of compliance with GDC-60.

EPU does not alter the supply or exhaust air flow paths, air flow rates, filtration, or ability to isolate any portion of the ECCS. Refer to LR [Section 2.7.5](#) Auxiliary and Radwaste Area and Turbine Areas Ventilation Systems for additional information regarding the RAB ventilation system function of the ECCS areas during normal operation. There are no changes in the operation of the ECCS system or RAB structure which could affect pressurization of the ECCS areas as a result of EPU. No additional equipment heat gains were added by EPU to areas served by the ECCS area ventilation system. Any increases in piping or transmission heat gains at EPU are within the capability of the existing system. There is no change to seismic classification to SSCs within the RAB.

The EDG design capacity is not increased after implementation of the EPU (Refer to LR [Section 2.3.3](#), AC Onsite Power System). Therefore, the ventilation system's ability to provide the required temperature conditions for personnel and equipment is not impacted for EPU.

The heat loads in the intake structure are from intake cooling water pump motors, transmission through walls and roof, lights, people and ambient outside conditions. None of these heat load increase as a result of EPU. The ICW system piping temperature remains at a maximum of 95°F, well below the intake structure maximum design air temperature of 120°F. There are no additional heat loads added to the intake structure enclosure as a result of EPU. Refer to LR [Section 2.5.4.2](#) for additional information regarding evaluation of ICW pump operation at EPU. There are no revisions to the intake structure ventilation system by EPU. Therefore, the ventilation system's capability to provide appropriate ventilation to ensure acceptable

temperature conditions for equipment operation during normal and emergency conditions is not impacted by EPU.

The heat loads in the component cooling area are from component cooling water (CCW) pump motors, piping, transmission through walls and roof, lights, people and ambient outside conditions. EPU will result in an increase in heat gain from the CCW and ICW piping and heat exchangers, however; the increase remains within the capability of the component cooling area ventilation system to maintain design temperatures during accident conditions. The space temperature during normal operation will increase approximately 1°F, however no credit was taken in the analysis for the operation of the ventilation fans which are available as needed during normal operation. There are no other additional heat loads added to the component cooling area enclosure that result from EPU. Refer to LR [Section 2.5.4.3](#) for additional information regarding evaluation of the CCW system operation at EPU conditions. There are no revisions to the component cooling area ventilation system by EPU. Therefore, the component cooling area ventilation system's capability to provide appropriate ventilation to ensure acceptable temperature conditions for equipment operation during normal and emergency conditions is not impacted by EPU.

The evaluation of the plant equipment changes for the proposed EPU did not identify any need to modify the ESF ventilation systems. There are no equipment changes as a result of EPU that could create a new potentially unmonitored radioactive release path. Thus, St. Lucie Unit 2 will continue to meet its current licensing basis with respect to GDC-60. The effects of potential releases to the environment, evaluated in LR [Section 2.10.1](#), remain within current limits following the EPU.

The evaluation of the ESF ventilation systems demonstrates that no changes are required to the system. Therefore, the design capability of the system to maintain an acceptable building environment related to control of airborne particulate material accumulation is not impacted.

2.7.6.3 Conclusion

FPL has reviewed the effects of the proposed EPU on the ESF ventilation systems. FPL has concluded that it has adequately accounted for the effects of the proposed EPU on the ability of the ESF ventilation systems to provide a suitable and controlled environment for ESF components. FPL further concludes that the ESF ventilation systems will continue to provide an acceptable environment for the ESF components following implementation of the proposed EPU. FPL also concludes that the ESF ventilation systems will continue to suitably limit the release of gaseous radioactive effluents to the environment following implementation of the proposed EPU. Based on this, the ESF ventilation systems will continue to meet their current licensing basis with respect to the requirements of GDCs -4, -17 and -60. Therefore, the EPU is acceptable with respect to the ESF ventilation systems.

2.7.7 Other Ventilation Systems (Containment)

2.7.7.1 Regulatory Evaluation

The functions of the containment cooling systems are to provide heat removal from the containment atmosphere, to remove radioactive materials from the containment atmosphere, and to provide containment pressure control under normal and accident conditions. The Florida Power and Light (FPL) review of the containment ventilation system focused on the effects that the proposed extended power uprate (EPU) will have on the functional performance of system.

The acceptance criteria for the containment ventilation system are based on:

- General Design Condition (GDC)-4, insofar as it requires that safety-related structures, systems, and components (SSCs) be designed to accommodate the effects of and be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents;
- GDC-38, insofar as it requires that the containment heat removal system(s) function to rapidly reduce the containment pressure and temperature following any loss of coolant accident (LOCA) and maintain them at acceptably low levels;
- 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; and
- GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDC for the containment ventilation systems are as follows:

- GDC-4 is described in UFSAR Section 3.1.4 Criterion 4 - Environmental and Missile Design Bases.

Structures, systems and components important to safety are designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss- of- coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and approved by the Commission demonstrates that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

Refer to UFSAR Sections 3.5, 3.6, 3.7, and 3.11 for details.

- GDC-38 is described in UFSAR Section 3.1.38 Criterion 38 - Containment Heat Removal.

A system to remove heat from the reactor containment shall be provided. The system safety function shall be to reduce rapidly, consistent with the functioning of other associated systems, the containment pressure and temperature following any loss of coolant accident and maintain them at acceptably low levels.

Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

The containment heat removal systems described in UFSAR Section 6.2.2 consists of the containment spray (CS) system and the containment cooling system. The CS system consists of two trains, each containing a CS pump, shutdown cooling heat exchanger and spray header. The containment cooling system consists of four fan coolers. One CS pump and two containment fan coolers have the capacity to reduce containment pressure and temperature following a design basis accident and maintain them at acceptably low levels.

Both the CS and the containment cooling systems are provided with emergency onsite power necessary for their operation, assuming a loss of offsite power. The systems are provided with redundant equipment so that when assuming a single failure or a failure of an emergency onsite power supply, 100 percent containment cooling capability is available.

- GDC-41 is described in UFSAR Section 3.1.41 Criterion 41 - Containment Atmosphere Cleanup.

Systems to control fission products, hydrogen, oxygen, and other substances which may be released into the reactor containment shall be provided as necessary to reduce, consistent with the functioning of other associated systems, the concentration and quantity of fission products released to the environment following postulated accidents, and to control the concentration of hydrogen or oxygen and other substances in the containment atmosphere following postulated accidents to assure that containment integrity is maintained.

Each system shall have suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electrical power system operation (assuming onsite power is not available) its safety function can be accomplished, assuming a single failure.

- GDC-60 is described in UFSAR Section 3.1.60 Criterion 60 - Control of Releases of Radioactive Materials to the Environment.

The nuclear power unit design shall include means to control suitably the release of radioactive materials in gaseous and liquid effluents and to handle radioactive solid wastes produced during normal reactor operation, including anticipated operational occurrences. Sufficient holdup capacity shall be provided for retention of gaseous and liquid effluents

containing radioactive materials, particularly where unfavorable site environmental conditions can be expected to impose unusual operational limitations upon the release of such effluents to the environment.

UFSAR Section 9.4.8 identifies the following ventilation systems located inside and/or serving the containment vessel:

- containment purge system,
- containment vacuum relief,
- containment fan coolers,
- reactor support cooling system,
- control element drive mechanism (CEDM) cooling system,
- reactor cavity cooling system, and
- continuous containment/hydrogen purge system.

The containment purge system discussed, in UFSAR Section 9.4.8.1, is designed to reduce the level of radioactive contamination in the containment atmosphere below the limits of 10 CFR 20 so as to permit personnel access to the containment during shutdown and refueling.

The containment vacuum relief system, discussed in UFSAR Section 6.2.1.1.3, provides protection of the containment vessel against excessive external pressure by two independent vacuum relief lines each sized to prevent the differential pressure between the containment and the shield building atmosphere from exceeding the design value of 0.70 psi.

The containment fan coolers, discussed in UFSAR Section 6.2.2, are designed to operate during normal plant operation and following a LOCA or a main steam line break (MSLB) inside containment. The outlets of the fan coolers are connected to a ductwork system which transports cooled air to various regions of the containment atmosphere.

The reactor support cooling system (in conjunction with the reactor cavity cooling system), discussed in UFSAR Section 9.4.8.4, is designed to limit the temperature of the lubrication plates between the reactor and support leg to 300°F, restrict thermal growth of the supporting steel work for the reactor vessel to 3/16 inches by limiting surface temperature to 140°F and limit the temperature at steel-concrete interfaces to 150°F.

The CEDM cooling system, discussed in UFSAR Section 9.4.8.5.1, is designed to ventilate the CEDM magnetic jack coils and thus maintain them at a temperature below 350°F.

The reactor cavity cooling system, discussed in UFSAR Section 9.4.8.6.1, is designed to ventilate the annular space between the reactor vessel and the concrete primary shield wall to limit the concrete surface temperature to a maximum of 150°F to minimize the possibility of concrete dehydration.

The continuous containment purge/hydrogen purge system, discussed in UFSAR Section 9.4.8.8, is designed to:

- Provide a sufficiently low concentration of radionuclides in the containment atmosphere in order to allow required access time for plant operators during inspection and maintenance operations,
- Provide a means of relieving containment pressure buildup as a result of instrument air leakage and/or containment atmosphere temperature fluctuations, and
- Provide the capability of ensuring that the containment source term contribution to the annual average offsite doses is maintained as low as is reasonably achievable, and provide a hydrogen removal capability.

Technical Specification 3/4.6.1, Primary Containment, Section 3.6.1.7, states that the 48-inch containment purge supply and exhaust isolation valves are required to be closed during plant operation since these valves have not been demonstrated capable of closing during a loss of coolant accident or steam line break accident.

In addition to the licensing basis described in the UFSAR, the containment cooling system was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.3.15 of the SER identifies that components of the containment cooling system are within the scope of License Renewal. Programs used to manage the aging effects associated with the containment cooling system are discussed in SER Section 3.3.15 and Chapter 18 of the UFSAR.

2.7.7.2 Technical Evaluation

2.7.7.2.1 Introduction

The following ventilation systems as described above are evaluated for EPU:

- Containment purge system,
- Containment vacuum relief system,
- Containment fan coolers,
- Reactor support cooling system,
- CEDM cooling system,
- Reactor cavity cooling system, and
- Continuous containment purge/hydrogen purge system.

2.7.7.2.2 Description of Analyses and Evaluations

The containment purge system is evaluated to verify that EPU does not change any parameters in containment that would affect the performance of the containment purge system which is designed to reduce the level of radioactive contamination in the containment atmosphere below the limits of 10 CFR 20 so as to permit personnel access to the containment during shutdown and refueling.

The containment vacuum relief system is evaluated to ensure that the bounding design parameters (operation of the CS system, containment fan cooler operation, containment winter operating temperature, refueling water tank (RWT) water temperature and shield building annulus initial temperature and pressure) for the operation of the system remain unchanged at EPU.

The changes in heat loads for cooling subsystems in the containment were evaluated to ensure that the containment fan cooler, reactor support, CEDM, and the reactor cavity cooling systems are capable of performing their intended functions under normal EPU modes.

The continuous containment purge/hydrogen purge system is evaluated to verify that EPU does not change any parameters in containment that would affect the performance of the continuous containment purge/hydrogen purge system which is designed to:

- Provide a sufficiently low concentration of radionuclides in the containment atmosphere in order to allow required access time for plant operators during inspection and maintenance operations,
- Provide a means of relieving containment pressure buildup as a result of instrument air leakage and/or containment atmosphere temperature fluctuations,
- Provide the capability of ensuring that the containment source term contribution to the annual average offsite doses is maintained as low as is reasonably achievable, and
- Provide a hydrogen removal capability.

Other evaluations related to the containment ventilation systems are addressed in the following Licensing Report sections:

- Electrical equipment qualification - LR [Section 2.3.1](#), Environmental Qualification of Electrical Equipment;
- Radiological consequences analysis – LR [Section 2.9.2](#), Radiological Consequences Analyses Using Alternative Source Terms;
- Normal operation radiation effluents – LR [Section 2.10.1](#), Occupational and Public Radiation Doses;
- Combustible gas control in containment - LR [Section 2.6.4](#), Combustible Gas Control; and
- Containment post accident heat removal – LR [Section 2.6.5](#), Containment Heat Removal.

2.7.7.2.3 Impact on Renewed Plant Operating License Evaluations and Licensing Renewal Programs

As discussed above, the containment cooling system is within the scope of License Renewal. Operation of the containment cooling system under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.7.7.2.4 Results

Containment Purge System

As indicated in LR [Section 2.10.1](#), Occupational and Public Radiation Doses, EPU may result in an increase in the inventory of airborne radionuclides in the containment atmosphere by approximately 12.2 percent, the percentage of the power uprate. However, radiological offsite doses will continue to be within regulatory limits due to continued implementation of actions described in the plant offsite dose calculation manual to maintain doses as low as is reasonably achievable.

EPU does not affect the present containment purge system configuration, components, air flow rates, isolation signals or associated controls. Therefore, the containment purge system will continue to perform its design function following EPU in compliance with GDC-60.

Refer to LR [Section 2.2.4](#), Safety Related Valves and Pumps, for the evaluation of the impact of EPU on the containment purge valves' ability to perform containment isolation in the event of a LOCA.

Containment Vacuum Relief

The design basis event for the vacuum relief system is the accidental initiation of the CS system (both pumps) while all four fan coolers are in operation and the containment is at its winter operating temperature of 90°F and 20 percent relative humidity. The CS pumps are assumed to reach full runout flow instantaneously, the initial humidity is assumed to be 20 percent and one vacuum relief subsystem is assumed to fail to operate. The CS water supplied from the RWT and the component cooling water (CCW) system, which is the heat sink for the fan coolers, are both conservatively assumed to be at their low wintertime operating temperatures.

The conditions described above consider the worst case vacuum condition, (containment winter air temperature of 90°F at a conservatively low relative humidity of 20 percent, and conservatively low CS and CCW system temperatures that would occur when all four containment fan coolers are in operation and both CS pumps actuate instantaneously reaching full runout flow. Following EPU, there are no changes that would cause a reduction of temperature in the CS and CCW system, increase in flow rates or a reduction in operating

pressure of the CS pumps. Therefore the conditions at EPU are bounded by the previously analyzed condition.

The ability of the vacuum relief valves to perform a containment isolation function to remain closed against the maximum differential pressure in the event of a LOCA at EPU conditions is addressed in LR [Section 2.2.4](#).

EPU does not affect the containment vacuum relief system configuration, components, air flow rates, isolation signals or associated controls. Therefore, the containment vacuum relief system will continue to perform its design function following EPU.

Containment Cooling System

EPU results in increased heat gains from the primary heat sources in containment. The containment normal operating bulk air temperature will increase slightly at EPU conditions; however, the increase will not exceed the maximum normal operating bulk temperature limit of 120°F. The post-EPU containment ambient temperatures were calculated based on the maximum percentage increase in heat release from piping and equipment, which is proportional to the temperature difference between the fluid temperature inside piping or equipment and the ambient temperature (approximately a 1 percent increase based on the EPU reactor coolant system (RCS) piping temperature). The containment air temperature for EPU increased 1.6°F, resulting in a post-EPU containment temperature of approximately 109°F, which is approximately 11°F below the bounding temperature of 120°F. There are no physical modifications or changes to the fan cooler units and related components. Therefore, the containment temperature will be maintained below 120°F at EPU conditions.

Refer to LR [Section 2.6.5](#), Containment Heat Removal, for the evaluation of the impact of EPU on the containment cooling system's ability to perform its design function following a LOCA and its compliance with GDC-38.

Reactor Support Cooling System

The reactor support cooling system provides cooling to areas heated by the reactor vessel and RCS piping. The EPU results in an approximate 1 percent increase in the heat load from the reactor vessel and RCS piping. Considering the margin between the predicted post-EPU operating temperature and the containment design condition, this increase in heat release is bounded by the design conditions.

EPU does not affect the reactor support cooling system configuration, components, air flow rates, or associated controls. Therefore, the reactor support cooling system will continue to perform its design function following EPU in compliance with GDC-4.

Control Element Drive Mechanism (CEDM) Cooling System

EPU results in increased heat gains from the primary heat sources in containment, however the evaluation of the CEDM cooling system concluded that the CEDM heat load used in the pre-EPU analysis will remain valid for the EPU. This evaluation included the following bounding design parameters that were used in the existing computational fluid dynamics analysis report (thermal analysis) and determined that they were bounding or changed negligibly for EPU:

- Temperature under the reactor vessel head insulation,

- Containment normal operating temperature,
- Thermal siphoning heat load,
- CEDM coil electrical heat load,
- CEDM cooling shroud inlet air velocity and air flow rate,
- Average normal operating reactor coolant outlet temperature, and
- Normal operating reactor coolant inlet (cold leg) temperature, which increases by only 1°F (from the temperature used in the existing computational fluid dynamics analysis) from 550°F to 551°F.

EPU does not affect the CEDM cooling system's configuration, components, air flow rates, associated controls, or the design temperature of the containment ambient air. Therefore, the CEDM cooling system will continue to perform its design function following EPU in compliance with GDC-4.

Reactor Cavity Cooling System

The heat release from the reactor vessel was shown to increase by approximately 1 percent. Therefore, the EPU heat load to this system from only the heat sources (reactor vessel and neutron heating in the shield wall) would increase by approximately 1 percent. EPU does not affect the reactor cavity cooling system configuration, components, air flow rates, or associated controls. The total reactor cavity cooling system cooling load requirement is met for EPU with the temperature of the air leaving the cavity below the design condition of 120°F. Therefore, the reactor cavity cooling system will continue to perform its design function following EPU in compliance with GDC-4.

Hydrogen Control System

There are no EPU changes or planned modifications to the continuous containment purge/hydrogen purge system, components, air flow rates, isolation signals or associated controls that would impact the system's ability to reduce the concentration of airborne radionuclides in the containment during normal operation. Operation of the system (with the exception of containment isolation) is manually from the control room.

The impact of the EPU on the differential pressure used to determine required torque values for closing the air-operated containment isolation valves in this system is addressed in LR

Section 2.2.4.

2.7.7.3 Conclusion

FPL has reviewed the effects of the proposed EPU on the containment ventilation systems. FPL has concluded that it has adequately accounted for the effects of the proposed EPU on the ability of these systems to provide a suitable and controlled environment for containment components served by these systems. In addition, FPL concludes containment ventilation systems designed to control fission products released to the environment continued to meet these requirements. FPL further concludes that, following implementation of the proposed EPU, the containment ventilation systems will continue to assure a suitable environment for the served containment

components. Based on this, the containment ventilation systems will continue to meet the requirements of GDCs -4, -38, -41, and -60. Therefore, the proposed EPU is acceptable with respect to the containment ventilation systems.

2.8 Reactor Systems

2.8.1 Fuel System Design

2.8.1.1 Regulatory Evaluation

The fuel system consists of arrays of fuel rods, burnable poison rods, spacer grids and springs, end plates, and reactivity control rods. Florida Power and Light (FPL) reviewed the fuel system to ensure that:

- The fuel system is not damaged as a result of normal operation and anticipated operational occurrences (AOO),
- Fuel system damage is never so severe as to prevent control rod insertion when it is required,
- The number of fuel rod failures is not underestimated for postulated accidents, and
- Coolability is always maintained.

The FPL 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:

- 10 CFR 50.46, insofar as it establishes standards for the calculation of emergency core cooling system (ECCS) performance and acceptance criteria for that calculated performance,
- 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 AOOs,
- 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
- 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 loss-of-coolant accident (LOCA).

Specific review criteria are contained in Standard Review Plan (SRP) Section 4.2 and other guidance is provided in Matrix 8 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971, and subsequently amended July 7, 1971, and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

The specific GDCs for the fuel system design are as follows:

- GDC-10 is described in UFSAR Section 3.1.10 Criterion 10 – Reactor Design.

The reactor core and associated coolant, control and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

Plant conditions have been categorized in accordance with their anticipated frequency of occurrence and risk to the public, and design requirements are given for each of the categories. The categories covered by this criterion are:

- Normal operation, and
- Anticipated operational occurrence.

The design requirement for normal operation condition is that margin shall be provided between any plant parameter and the value of that parameter which would require either automatic or manual protective action; it is met by providing an adequate control system (refer to UFSAR Section 7.7). The design requirement for an AOO is that such faults shall be accommodated with, at most, a shutdown of the reactor, with the plant capable of returning to operation after corrective action; it is met by providing a reactor protective system (refer to UFSAR Section 7.2).

SAFDLs are stated in UFSAR Section 4.4. Minimum margins to SAFDLs are prescribed in the technical specifications (limiting conditions for operation) which support UFSAR Chapters 4 and 15. The plant is designed such that operation within limiting conditions for operation, with safety system settings not less conservative than limiting safety system settings prescribed in the technical specifications, assures that SAFDLs will not be violated as a result of AOOs. During non-accident conditions, operation of the plant within limiting conditions for operation ensures that SAFDLs are not approached within the minimum margins. Operator action, aided by the control systems and monitored by plant instrumentation, maintains the plant within limiting conditions for operation during non-accident conditions.

- GDC-27 is described in UFSAR Section 3.1.27 Criterion 27 – Combined Reactivity Control Systems Capability.

The reactivity control systems shall be designed to have a combined capability, in conjunction with poison addition by the emergency core cooling system, of reliably controlling reactivity changes to assure that under postulated accident conditions and with appropriate margin for stuck rods the capability to cool the core is maintained.

The reactivity control systems that provide the means for making and holding the core subcritical under postulated accident conditions are discussed in UFSAR Sections 9.3 and 4.3. Combined use of control element assemblies (CEAs) and chemical shim control by the chemical and volume control system (CVCS) provides the shutdown margin required for plant cooldown and long-term xenon decay, assuming the highest worth CEA is stuck out of the core.

During an accident, the safety injection system (SIS) functions to inject concentrated boric acid into the reactor coolant system (RCS) for short term and long term cooling and for reactivity control. Details of the system are given in UFSAR Section 6.3.

The SIS, in conjunction with the combined capabilities of the reactivity control systems, is available to maintain short and long term cooling of the core even in the event a CEA of highest worth is stuck out of the core. Upon receipt of a safety injection actuation signal, the SIS functions to inject borated water from the refueling water tank into the RCS.

- GDC-35 is described in UFSAR Section 3.1.35 Criterion 35 – Emergency Core Cooling.

A system to provide abundant emergency core cooling shall be provided. The system safety function shall be to transfer heat from the reactor core following any loss of reactor coolant at a rate such that:

1. Fuel and clad damage that could interfere with continued effective core cooling is prevented, and
2. Clad metal-water reaction is limited to negligible amounts.

Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electrical power system operation (assuming offsite power is not available) and for offsite electrical power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

The SIS provides cooling water at a rate sufficient (1) to assure that the zirconium-water reaction is limited to a negligible rate of less than one percent and (2) to assure that the fuel remains in a coolable geometry. Therefore, compliance with the intent of the acceptance criteria for ECCS for light water power reactors of 10 CFR 50, paragraph 50.46(b), is satisfied.

The SIS design includes adequate provisions to ensure that the required safety functions are provided with a single active failure relying on either onsite or offsite electrical power supply (see UFSAR Section 6.3).

UFSAR Section 6.3.3 establishes standards for the calculation of ECCS performance and acceptance criteria and states that the SIS provides coolant to the core in adequate quantity to comply with the requirements of 10 CFR Part 50.46.

UFSAR Section 4.2 describes fuel system design. It addresses mechanical design of the reactor core components and their physical arrangement. A summary of the core mechanical design is presented in UFSAR Table 4.2-10.

UFSAR Section 4.4 presents the thermal and hydraulic analysis of the reactor core, analytical methods utilized, and experimental work for supporting the analytical techniques. The prime objective of the thermal and hydraulic design of the reactor is the assurance that the fuel and supporting structures can meet normal steady state and transient performance requirements without exceeding the design bases. A summary of the significant thermal and hydraulic parameters is presented in UFSAR Table 4.4-1.

Technical Specification (TS) 6.9.1.11, Core Operating Limits Report (COLR), requires that core operating limits be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR. Furthermore, this TS requires that the

analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, as described in TS 6.9.1.11.

NUREG-1779, Safety Evaluation Report Related of the St. Lucie Nuclear Plant, Units 1 and 2 dated July 7, 2003 defines the scope of license renewal. The adequacy of the fuel assembly mechanical design, core design, and thermal hydraulic safety analyses are evaluated once per fuel cycle and therefore are not included in the scope of license renewal.

2.8.1.2 Technical Evaluation

The following sections address the fuel system design features, the mechanical compatibility and performance, the seismic/LOCA evaluations, and the fuel rod performance analyses and evaluations that were performed in support of the EPU program. The fuel rod performance section covers a number of different areas, including the fuel rod internal pressure, departure from nucleate boiling (DNB) propagation, cladding stress, cladding strain, etc. which were examined to ensure that the EPU could be supported for the existing 16x16 CE HID-1L fuel design.

2.8.1.2.1 Fuel System Design Features

The licensing basis for the fuel system design is contained in UFSAR Chapter 4.0. For the EPU, the fuel design will remain the 16x16 CE HID-1L fuel assembly design (high impact design). The key features of the 16x16 CE HID-1L fuel assembly are as follows:

- 0.382 inch outside diameter fuel rods,
- 136.7 inch pellet stack length,
- Gadolinia burnable absorber fuel rods,
- ZIRLO® fuel rod cladding,
- HID-1L Zircaloy-4/OPTIN mid spacer grids,
- Inconel top spacer grid,
- Zircaloy-4 guide thimbles,
- Bottom Inconel GUARDIAN™ grid for debris protection,
- Low-cobalt removable top nozzle, and
- Low-cobalt bottom nozzle.

The 16x16 CE HID-1L fuel rod is currently licensed to a peak pin burnup of 60,000 MWD/MTU by the NRC ([Reference 8](#)).

2.8.1.2.2 Mechanical Compatibility and Performance

The effects of the EPU on the fuel mechanical design and specifically on the fuel mechanical compatibility and performance are limited to an increase in the operating temperature and a slight increase on spacer grid and fuel assembly uplift forces, which have been considered in the

supporting calculations. Since the fuel mechanical design is not being changed for the EPU application, there are no transition core effects. With respect to the mechanical design of the fuel, analyses and evaluations were performed to confirm that the fuel design is structurally and mechanically acceptable for the EPU. The fuel mechanical design analyses and evaluations considered the effects of higher temperatures and uplift forces 1) on fuel rod stress, strain, fatigue, and collapse; 2) on fuel assembly stresses during seismic/LOCA events; and 3) on fuel assembly dimensional changes. All of the applicable design criteria continue to be satisfied. The fuel assembly holddown margin was evaluated and conservatively assumed fuel assembly growth and increased temperatures associated with the EPU conditions. The effects of the EPU on the seismic/LOCA performance of the fuel mechanical design were evaluated to confirm that all of the acceptance criteria and regulatory requirements are met, as noted in the following section. Finally, since there is no change to the fuel design and the RCS mechanical design flow rate does not change, there will be no adverse impact on the fuel rod clad fretting wear. Therefore, with respect to the fuel mechanical compatibility and performance, it is confirmed that the fuel design is structurally and mechanically acceptable for the EPU.

2.8.1.2.3 Seismic/LOCA

The fuel assembly is capable of withstanding the loads resulting from the mechanical excitations occurring during the seismic and/or LOCA events while ensuring that 1) fuel rod fragmentation does not occur, 2) a coolable core geometry is maintained and 3) control rod insertability is maintained. Based on a review of the current licensing basis analyses, it was determined that the existing core plate motions and vertical impact loads on the nozzles used in the seismic/LOCA analyses are unaffected by the EPU project. Since the fuel design does not change, the effects of the EPU on the fuel mechanical design are limited to changes in the uprate parameters (see LR [Section 1.1](#), Nuclear Steam Supply System Parameters), including the uprated power condition and the associated increase in the operating temperatures. These changes have been accounted for in the fuel rod stress analysis, which show that the acceptance criteria continue to be satisfied, and the conclusions of the UFSAR remain valid.

2.8.1.2.4 Fuel Rod Performance

2.8.1.2.4.1 Introduction

Fuel rod design evaluations for the 16x16 CE HID-1L gadolinia and UO₂ fuel designs for the analyzed reactor core thermal power level of 3030 MWt, were performed using NRC-approved models and design criteria methods ([References 1 through 6](#) and [Reference 8](#)) to demonstrate that fuel rod design criteria are satisfied.

The fuel rod design criteria given below are verified by evaluating the predicted performance of the limiting fuel rod, defined as the rod which gives the minimum margin to the design limit. In general, no single rod is limiting with respect to the design criteria. Generic evaluations have identified which rods are most likely to be limiting for each criterion, and exhaustive screening of fuel rod power histories to determine the limiting rod is typically not required.

The NRC-approved FATES3B model ([References 1 through 10](#)) for in-reactor behavior is used to calculate the fuel rod performance over its irradiation history. FATES3B iteratively calculates the

interrelated effects of temperature, pressure, cladding elastic and plastic behavior, fission gas release, and fuel densification and swelling as a function of time and linear power.

2.8.1.2.4.2 Input Parameters, Assumptions, and Acceptance Criteria

The fuel rod design analysis is performed on a cycle-specific basis. The reference analysis presented here is based on the bounding high-temperature nuclear design cases representing four cycles at EPU conditions (three transition cycles and one equilibrium cycle) developed for the nuclear design (see LR [Section 2.8.2](#), Nuclear Design). Both the reference analysis and the cycle-specific analysis consider compliance for all fuel designs in the core. Since the different fuel configurations were explicitly evaluated, there is no impact due to having fuel with gadolinia and UO₂ composite fuel rods. The mechanical fuel rod design evaluation for each region incorporates all appropriate design features of the region, including any changes to the fuel rod or pellet geometry from that of previous fuel regions.

The design bases for the 16x16 CE HID-1L fuel assembly with ZIRLO® cladding is discussed in CENPD-404-P-A ([Reference 8](#)). The fuel rod design evaluations for the 16x16 HID-1L fuel at the EPU conditions were performed using NRC-approved models and design criteria methods as described in [References 1](#) through [6](#), and [Reference 8](#) to demonstrate that all of the fuel rod design criteria are satisfied.

The fuel rod design criteria given below are verified by evaluating the predicted performance of the limiting fuel rod, defined as the rod that has the minimum margin to the design limit. The changes in the operating conditions, and specifically, the operating temperatures associated with the EPU condition were considered in the fuel rod design analysis as reported in this section. This includes the effects of gadolinia rods.

The criteria pertinent to the fuel rod design include the following:

A. Maximum Rod Internal Pressure

The fuel rod internal hot gas pressure shall not exceed the critical maximum pressure determined to cause an outward cladding creep rate that is in excess of the fuel radial growth rate anywhere locally along the entire active fuel length of the fuel rod.

B. Fuel Rod DNB Propagation

The radiological dose consequences of DNB failures shall remain within the specified limits.

C. Clad Stress

1. During normal operation and AOO events, the primary tensile stress in the cladding and end-cap welds must not exceed 2/3 of the minimum unirradiated yield strength of the material at the applicable temperature. During emergency condition events, the primary

tensile stress limit is the yield strength and during faulted condition seismic and LOCA (mechanical excitation only) conditions, the stress limit is the lesser of 0.7 Su or 2.4 Sm.

2. During normal operation, AOO and emergency condition events, the primary compressive stress in the cladding and the end-cap welds must not exceed the minimum unirradiated yield strength of the material at the applicable temperature. During faulted condition seismic and LOCA (mechanical excitation only) conditions, the stress limit is the lesser of 0.7 Su or 2.4 Sm.

D. Clad Strain

The design limit for the fuel rod clad strain is the total plastic tensile creep strain due to uniform cladding creep and uniform cylindrical fuel pellet expansion due to swelling and thermal expansion is less than 1 percent from the unirradiated condition, and that the total tensile strain due to uniform cylindrical pellet thermal expansion during a transient is less than 1 percent from the pre-transient value.

E. Clad Oxidation and Hydrating

The design criteria related to clad corrosion for ZIRLO® cladding require (Reference 8) that the maximum predicted best estimate oxide thickness remains below 100 microns for all locations of the fuel. Also for ZIRLO® clad fuel (Reference 8), the modified fuel duty index (mFDI) of each ZIRLO® clad fuel pin will be restricted to 110 percent of the baseline mFDI of 600, while a fraction of the fuel pins in a limited number of assemblies (8) will have mFDI restricted to 120 percent of the baseline mFDI of 600.

F. Fuel Temperature

The fuel rod centerline temperature shall not exceed the fuel melt temperature, accounting for degradation due to burnup and addition of burnable absorbers.

G. Clad Fatigue

For the number and type of transients which occur during normal operation, the end-of-life (EOL) cumulative fatigue damage factor in the cladding and in the end-cap welds must be less than 0.8.

H. Cladding Creep Collapse

The time required for the radial buckling of the cladding in any fuel or gadolinia absorber rod must exceed the reactor operating time necessary for the appropriate batch to accumulate its design average discharge burnup. This criterion must be satisfied for continuous reactor operation at any reasonable power level and during any normal operation, AOO or emergency condition event. It will be considered satisfied if it can be demonstrated that axial gaps longer than 0.125 inches will not occur between the fuel pellets and the plenum spring radial support capacity is sufficient to prevent cladding collapse under all design conditions.

I. Shoulder Gap

The axial length between the end fittings must be sufficient to accommodate differential thermal expansion and irradiation-induced differential growth between the fuel rods and the guide tubes, such that it can be shown with 95 percent confidence that no interference exists.

2.8.1.2.4.3 Description of Analyses and Evaluations

A. Maximum Rod Internal Pressure

Maximum internal gas pressure depends on fuel rod temperatures, fission gas release, and void volume. The critical pressure limit depends on fuel swelling rate and clad tensile creep during normal operation. An evaluation demonstrated that predicted maximum rod internal pressures will not exceed the critical pressure limit at any time in life for anticipated operation and anticipated operational occurrences.

B. Fuel Rod DNB Propagation

Calculation of DNB propagation depends on rod internal gas pressure, high-temperature creep, and high-temperature rupture stress (burst stress). An evaluation demonstrated that no DNB propagation will occur with the maximum rod internal pressures predicted for St. Lucie Unit 2. If conditions change, the changes will be evaluated as part of the reload safety evaluation process to verify the lack of DNB propagation or to demonstrate that with DNB propagation the radiological dose consequences of DNB failures will remain within the specified limits

C. Clad Stress

The above fuel rod stress criteria have been evaluated for the fuel design containing ZIRLO® cladding and were found to be satisfied for EPU conditions. This evaluation considered differential cladding pressures and the higher cladding temperatures associated with EPU and accounted for cladding thinning due to oxidation.

D. Clad Strain

The above fuel rod strain criteria have been evaluated for the fuel design containing ZIRLO® and were found to be satisfied for EPU conditions. This evaluation considered differential cladding pressures and cladding temperatures associated with EPU, cladding creep, and pellet swelling.

E. Clad Oxidation and Hydriding

An analyzed reactor core thermal power level of 3030 MWt and ZIRLO® clad fuel, cycle-specific fuel rod corrosion evaluations will be performed. Evaluations of waterside corrosion of ZIRLO® clad fuel as anticipated for operation in the uprated core show acceptable performance. The maximum predicted best estimate oxide thickness was below the 100 micron limit, and the maximum predicted mFDI was below the requirements associated with the baseline mFDI of 600

F. Fuel Temperature

An evaluation demonstrated that maximum predicted fuel centerline temperatures will not exceed the fuel melt temperature limit at any time in life for anticipated operation.

G. Clad Fatigue

The above fuel rod fatigue damage factor criterion has been evaluated for fuel design containing ZIRLO® cladding and was found to be satisfied for EPU conditions. This evaluation considered differential cladding pressures and cladding temperatures associated with EPU, cladding creep, and pellet swelling.

H. Cladding Creep Collapse

The above fuel rod cladding collapse criterion has been evaluated for the fuel design containing ZIRLO® cladding and was found to be satisfied for EPU conditions. This evaluation considered differential cladding pressures and cladding temperatures associated with EPU, and cladding creep; and accounted for cladding thinning due to oxidation.

I. Shoulder Gap

The above design criterion is evaluated using the irradiation-induced and thermal growth characteristics of the fuel rod cladding and the guide thimbles. The EPU conditions increase the shoulder gap margin relative to the current operating conditions since the slight increase in the uplift forces on the spacer grids associated with the EPU increases the guide thimble growth slightly, thus increasing the shoulder gap.

2.8.1.2.4.4 Fuel Rod Performance - Results

Fuel performance evaluations have been completed for EPU transition and equilibrium cycles to demonstrate that the design criteria can be satisfied for all fuel rod types in the core under the planned EPU operating conditions. Any additional changes from the plant operating conditions currently evaluated for the mechanical design of a fuel region will be addressed for all affected fuel regions as part of the reload safety evaluation process when the plant changes are to be implemented.

As expected, the increase in power will have an impact on the fuel rod design margin. The rod internal pressure (RIP) criteria, including “no gap reopening” and DNB propagation, clad corrosion, clad stress, clad strain, clad fatigue, and fuel temperature criteria all continue to show acceptable results with power increase. These criteria will be verified for each reload cycle.

Continued compliance with fuel rod design criteria for the 16x16 CE HID-1L fuel will be confirmed for each reload cycle design. In summary, all of the fuel rod design criteria have been evaluated for the 16x16 CE HID-1L fuel assembly design at the EPU conditions. Based on these evaluations, it is concluded that all fuel rod design criteria can be satisfied for the EPU condition.

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

As discussed above, the fuel system design was determined to be outside the scope of License Renewal; therefore, with respect to the fuel system design, the EPU does not impact any License Renewal evaluations.

2.8.1.3 Conclusion

FPL has reviewed the analyses related to the effects of the proposed EPU on the fuel system design of the fuel assemblies, control systems, and reactor core. FPL concludes that the analyses have adequately accounted for the effects of the proposed EPU on the fuel system and demonstrated that:

- The fuel system will not be damaged as a result of normal operation and AOOs,
- The fuel system damage will never be so severe as to prevent control rod insertion when it is required,
- The number of fuel rod failures will not be underestimated for postulated accidents, and
- Coolability will always be maintained

Based on this, FPL 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 FPL finds the proposed EPU acceptable with respect to the fuel system design.

2.8.1.4 References

1. CENPD-139-P-A, Fuel Evaluation Model, July 1974.
2. CEN-161(B)-P-A, Improvements to Fuel Evaluation Model, August 1989.
3. CEN-161(B)-P, Supplement 1-P-A, Improvements to Fuel Evaluation Model, January 1992.
4. CENPD-275-P, Revision 1-P-A, C-E Methodology for Core Designs Containing Gadolinia-Urania Burnable Absorbers, May 1988.
5. CEN-372-P-A, Fuel Rod Maximum Allowable Gas Pressure, May 1990.
6. CENPD-275-P, Revision 1-P, Supplement 1-P-A C-E Methodology for PWR Core Designs Containing Gadolinia-Urania Burnable Absorbers, April 1999.
7. Letter from B. T. Moroney (NRC) to J. A. Stall (FP&L), St. Lucie Plant, Unit 2 – Issuance of Amendment Regarding Change in Reload Methodology and Increase in Steam Generator Tube Plugging Limit (TAC No. MC1566), January 31, 2005.

8. CENPD-404-P-A, Revision 0, Implementation of ZIRLO™ Cladding Material in CE Nuclear Power Fuel Assembly Designs, November 2001.
9. CEN-386-P-A, Verification of the Acceptability of a 1-Pin Burnup Limit of 60 MWD/kgU for Combustion Engineering 16x16 PWR Fuel, ABB Combustion Engineering, Inc., August 1992.
10. CENPD-384-P, Report on the Continued Applicability of 60 MWD/kgU for ABB Combustion Engineering PWR Fuel, ABB Combustion Engineering, Inc., September 1995.

2.8.2 Nuclear Design

2.8.2.1 Regulatory Evaluation

Florida Power and Light (FPL) 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 reactor coolant pressure boundary (RCPB) or impair the capability to cool the core. The FPL review covered core power distribution, reactivity coefficients, reactivity control requirements and control provisions, control rod patterns and reactivity worths, criticality, burnup, and vessel irradiation. Note that FPL utilizes the “control element assembly” (CEA) nomenclature whereas NRC Review Standard (RS)-001 uses “control rod.” It is FPL’s intention to use CEA where applicable throughout this LR section.

The NRC’s acceptance criteria are based on:

- 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 operating occurrences (AOO);
- 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;
- 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;
- 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;
- 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;
- 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;
- 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;
- 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 emergency core cooling system (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

- 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.

Specific review criteria are contained in Standard Review Plan (SRP) Section 4.3 and other guidance provided in Matrix 8 of (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

The specific GDCs for the nuclear design are as follows:

- GDC-10 is described in UFSAR Section 3.1.10 Criterion 10 – Reactor Design.

The reactor core and associated coolant, control and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

SAFDLs are stated in UFSAR Section 4.3. Minimum margins to SAFDLs are prescribed in the technical specifications (TS) (limiting conditions for operations(LCO)) which support UFSAR Chapters 4 and 15.

- GDC-11 is described in UFSAR Section 3.1.11 Criterion 11 – Reactor Inherent Protection.

The reactor core and associated coolant systems shall be designed so that in the power operating range the net effect of the prompt inherent nuclear feedback characteristics tends to compensate for a rapid increase in reactivity.

In the power operating range, the combined response of the fuel temperature coefficient, the moderator temperature coefficient, the moderator void coefficient, and the moderator pressure coefficient to an increase in reactor power in the power operation range is a decrease in reactivity, i.e., the inherent nuclear feedback characteristics are not positive. The reactivity coefficients are discussed in detail in UFSAR Section 4.3.

- GDC-12 is described in UFSAR Section 3.1.12 Criterion 12 – Suppression of Reactor Power Oscillations.

The reactor core and associated coolant, control, and protection systems shall be designed to assure that power oscillations which can result in conditions exceeding specified acceptable fuel design limits are not possible or can be reliably and readily detected and suppressed.

Power level oscillations will not occur. The effect of the negative power coefficient of reactivity, together with the coolant temperature program maintained by CEAs and soluble boron, provide fundamental mode stability. Power level is monitored continuously by neutron flux detectors (refer to UFSAR Chapter 7) and by reactor coolant temperature difference measuring devices.

Power distribution oscillations are detected by neutron flux detectors. Axial mode oscillations are suppressed by means of CEAs. Radial oscillations are expected to be convergent. It is a design objective that azimuthal xenon oscillations be convergent. Monitoring and protective requirements are discussed in UFSAR Chapter 4

- GDC-13 is described in UFSAR Section 3.1.13 Criterion 13 – Instrumentation and Control.

Instrumentation shall be provided to monitor variables and systems over their anticipated ranges for normal operation, for anticipated operational occurrences, and for accident conditions as appropriate to assure adequate safety, including those variables and systems that can affect the fission process, the integrity of the reactor core, the reactor coolant pressure boundary, and the containment and its associated systems. Appropriate controls shall be provided to maintain these variables and systems within prescribed operating ranges.

Instrumentation is provided, as required, to monitor and maintain significant process variables which can affect the fission process, the integrity of the reactor core, the RCPB, and the containment and its associated systems. Controls are provided for the purpose of maintaining these variables within the limits prescribed for safe operation.

The principal variables and systems monitored include neutron flux level (reactor power); reactor coolant temperature, flow, and pressure; pressurizer liquid level; steam generator level and pressure; and containment pressure and temperature.

The following is provided to monitor and maintain control over the fission process during both transient and steady state periods over the lifetime of the core:

- a. Twelve independent channels of nuclear instrumentation, which constitute the primary monitor of the fission process, four wide range channels; four safety channels; two control channels and two startup channels,
- b. Two independent CEA position indicating systems,
- c. A method of determining soluble poison concentration by sampling and analysis of reactor coolant water,
- d. Manual control of reactor power by means of CEAs, and
- e. Manual regulation of coolant boron concentrations.

Incore instrumentation provides information on core power distribution and for calibration of excore flux detectors.

Instrumentation measures temperatures, pressures, flows, and levels in the main steam system and auxiliary systems and is used to maintain these variables within prescribed limits.

The reactor protective system (RPS) is designed to monitor the reactor operating conditions and to effect reliable and rapid reactor trip if any one or a combination of conditions deviate from a preselected operating range.

The containment pressure, temperature, and radiation instrumentation is designed to function during normal operation and the postulated accidents.

The instrumentation and control systems are described in detail in UFSAR Chapter 7

- GDC-20 is described in UFSAR Section 3.1.20 Criterion 20 – Protection System Functions.

The protection system shall be designed (1) to initiate automatically the operation of appropriate systems including the reactivity control systems, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and to initiate the operation of systems and components important to safety.

The RPS monitors reactor operating conditions and automatically initiates a reactor trip when the monitored variable or combination of variables exceeds a prescribed operating range. The reactor trip setpoints are selected to ensure that anticipated operational occurrences do not cause specified acceptable fuel design limits to be violated. Specific reactor trips are described in UFSAR Section 7.2.

The engineered safety features actuation system (ESFAS) monitors potential accident conditions and automatically initiates engineered safety features and their supporting systems when the monitored variables reach prescribed setpoints. The parameters which automatically actuate engineered safety features are described in UFSAR Section 7.3. Manual actuation is provided to the operator.

- GDC-25 is described in UFSAR Section 3.1.25 Criterion 25 – Protection System Requirements for Reactivity Control Malfunctions.

The protection system shall be designed to assure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of control rods.

Reactor shutdown with CEAs is accomplished completely independent of the control functions since the trip breakers interrupt power to the CEA drive mechanisms regardless of existing control signals. The design is such that the system can withstand accidental withdrawal of controlling groups without exceeding acceptable fuel design limits. Analysis of possible reactivity control malfunctions is given in UFSAR Section 15.4. The RPS will prevent SAFDLs from being exceeded for any AOO.

- GDC-26 is described in UFSAR Section 3.1.26 Criterion 26 – Reactivity Control System Redundancy and Capability.

Two independent reactivity control systems of different design principles shall be provided. One of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margin for malfunctions such as stuck rods, specified acceptable fuel design

limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure acceptable fuel design limits are not exceeded. One of the systems shall be capable of holding the reactor core subcritical under cold conditions.

Two independent reactivity control systems of different design principles are provided. The first system, using CEAS, includes a positive means (gravity) for inserting CEAs and is capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including specified anticipated operational occurrences, specified acceptable fuel design limits are not exceeded. The CEAs can also be mechanically driven into the core. The appropriate margin for stuck rods is provided by assuming in the analyses of anticipated operational occurrences that the highest worth CEA does not fall into the core.

The second system, the chemical and volume control system (CVCS), using neutron absorbing soluble boron, is capable of reliably compensating for the rate of reactivity changes resulting from planned normal power changes (including xenon burnout) such that acceptable fuel design limits are not exceeded. This system is capable of holding the reactor subcritical under cold conditions. For a further description, see UFSAR Section 9.3.4.

Either system is capable of making the core subcritical from a hot operating condition.

For further discussion, see UFSAR Sections 7.4 and 7.7.

- GDC-27 is described in UFSAR Section 3.1.27 Criterion 27 – Combined Reactivity Control Systems Capability.

The reactivity control systems shall be designed to have a combined capability, in conjunction with poison addition by the emergency core cooling system, of reliably controlling reactivity changes to assure that under postulated accident conditions and with appropriate margin for stuck rods the capability to cool the core is maintained.

The reactivity control systems that provide the means for making and holding the core subcritical under postulated accident conditions are discussed in UFSAR Sections 9.3 and 4.3. Combined use of CEAs and chemical shim control by the CVCS provides the shutdown margin required for plant cooldown and long-term xenon decay, assuming the highest worth CEA is stuck out of the core.

During an accident, the safety injection system (SIS) functions to inject concentrated boric acid into the reactor coolant system (RCS) for short term and long term cooling and for reactivity control. Details of the system are given in UFSAR Section 6.3.

The SIS, in conjunction with the combined capabilities of the reactivity control systems is available to maintain short and long term cooling of the core even in the event a CEA of highest worth is stuck out of the core. Upon receipt of a safety injection actuation signal, the SIS functions to inject borated water from the refueling water tank into the RCS.

- GDC-28 is described in UFSAR Section 3.1.28 Criterion 28 – Reactivity Limits.

The reactivity control systems shall be designed with appropriate limits on the potential amount and rate of reactivity increase to assure that the effects of postulated reactivity accidents can neither (1) result in damage to the RCPB greater than limited local yielding nor

(2) sufficiently disturb the core, its support structures, or other reactor pressure vessel internals to impair significantly the capability to cool the core. These postulated reactivity accidents shall include consideration of rod ejection (unless prevented by positive means), rod dropout, steam line rupture, changes in reactor coolant temperature and pressure, and cold water addition.

The bases for CEA design include ensuring that the reactivity worth of any one CEA is not greater than a preselected maximum value. The CEAs are divided into two sets: a shutdown set and a regulating set. These sets are further subdivided into groups as necessary. Administrative procedures and control interlocks ensure that the amount and rate of reactivity increase is limited to predetermined values. The regulating groups are withdrawn only after the shutdown groups are fully withdrawn. The regulating groups are programmed to move in sequence and within limits which prevent the rate of reactivity addition and the worth of individual CEAs from exceeding limiting values (see UFSAR Sections 4.3 and 7.7).

The RCPB (UFSAR Chapter 5) and the reactor internals (UFSAR Chapter 4) are designed to appropriate codes and accommodate the static and dynamic loads associated with an inadvertent, sudden release of energy, such as that resulting from a CEA ejection or a steam line break, without rupture and with limited deformation which will not impair the capability of cooling the core.

UFSAR Section 4.3 describes the design bases and functional requirements used in the nuclear design of the fuel and reactivity control system.

As stated in UFSAR Section 4.3.2.2.3 SAFDL require that the core power distribution does not result in either fuel centerline melting or a departure from nucleate boiling ratio (DNBR) less than the limiting value. Assurance that SAFDL's are not exceeded is obtained through the RPS and the TS which enforce LCO. LCOs are evaluated such that the initial conditions assumed in the analysis of AOOs and postulated accidents are conservative with respect to allowed reactor conditions. The nuclear design limits on power distributions are, therefore, intimately related to the LCO.

The reload safety evaluation process provides evaluation and analysis to confirm that the fuel design, core design, and safety analyses are acceptable for the proposed operating cycle. The reload design methodology includes the evaluation of the reload core key safety parameters which comprise the nuclear design-dependent input to the UFSAR safety evaluation for each fuel cycle.

NUREG-1779, Safety Evaluation Report Related of the St. Lucie Nuclear Plant, Units 1 and 2 dated September 3, 2003, defines the scope of license renewal. The adequacy of 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 are evaluated once per fuel cycle and therefore are not included in the scope of license renewal. Design aspects of systems and components are addressed in other licensing report sections. Specific transient analysis is not within the scope of License Renewal.

2.8.2.2 Technical Evaluation

2.8.2.2.1 Introduction

The licensing basis for the reload core nuclear design is defined in UFSAR Section 4.3. The purpose of the extended power uprate (EPU) core analysis is to determine a range of neutronic parameter values for the key safety parameters to be used in the EPU analysis, with intent to bound future EPU cycles. The core analysis also provided the basis for any changes to the limits in the core operating limits report (COLR). This process allows future EPU core reload analysis to utilize the verification methodology described in [Reference 1](#). The primary physics codes used for these analyses are described in [References 2](#) and [3](#).

2.8.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters

The EPU core will continue to utilize the current CE 16X16 fuel assembly design. The key nuclear features of this design are:

- 0.382 inch outside diameter fuel rods,
- Solid axial blanket pellets (6 inches at top and bottom),
- 136.7 inch pellet stack length,
- ZIRLO[®] fuel rod clad, and
- Radial enrichment zoning.

The specific values of core safety parameters (e.g., power distributions, peaking factors, rod worths, and reactivity parameters) are loading pattern dependent. The variations in loading pattern dependent safety parameters for the EPU cycle are expected to be similar to the cycle-to-cycle variations for past reload cycles.

Limits for radial peaking factor (F_R^T) are reduced to offset the impact of EPU on core thermal hydraulics and fuel rod performance. The nuclear design will be constrained to comply with this (and any other) limits required as a result of the EPU.

No changes to the nuclear design philosophy or methods are necessary because of the transition to EPU. The reload design methodology described in [Reference 1](#) includes the evaluation of the reload core key safety parameters which comprise the nuclear design-dependent input to the UFSAR safety evaluation for each reload cycle. These key safety parameters will be evaluated for each reload cycle. If one or more of the parameters fall outside the bounds assumed in the reference safety analysis, the affected transients will be re-evaluated/re-analyzed using standard methods and the results documented in the reload evaluation for that cycle.

LR [Table 2.8.2-2](#) provides the key safety parameter ranges compared to the current limits.

2.8.2.2.3 Description of Analyses and Evaluations

The effects of transitioning to EPU conditions on the nuclear design bases and methodologies are evaluated in this section.

Core designs were developed for several typical EPU reload cycles to model the transition to equilibrium EPU conditions based on a nominal projected energy requirement of 515 EFPD (See LR [Table 2.8.2-1](#)). One core design with an atypically long cycle length was also developed to examine the impact of cycle length and feed batch size variations. Note that these core designs are not intended to represent limiting designs, but were instead developed with the intent to determine limiting parameters for safety analysis to allow enough margin between expected EPU parameter values and the corresponding safety analysis limits for flexibility in designing actual EPU reload cores. Cycle specific calculations will confirm that the actual values are within the safety analysis limits. The values for the EPU cycles were compared to values for recent reload cycles to evaluate the continued adequacy of margins between typical safety parameter values and the corresponding limits.

The nuclear design analysis for the EPU cores employed standard analytical models and methods ([References 1, 2 and 3](#)) that have previously been demonstrated to accurately describe the neutronic behavior of the reactor cores.

The effect of extended burnup on nuclear design parameters has been previously discussed in detail in [Reference 4](#). That discussion is valid for the discharge burnups that are anticipated for the EPU cycles. The burnup limit remains unchanged for EPU.

CEA patterns have been considered in the calculation of the shutdown margin and control rod worths reported in LR [Table 2.8.2-2](#).

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

As discussed above, the nuclear design was determined to be outside the scope of License Renewal; therefore, with respect to the nuclear design, the EPU does not impact any License Renewal evaluations.

2.8.2.2.5 Results

As shown in LR [Table 2.8.2-2](#), the margin to key safety parameter limits is not significantly reduced by the EPU implementation. The key safety parameters evaluated for St. Lucie Unit 2 as it transitions to EPU show little change relative to the current design. The variations in these parameters are similar to the normal cycle-to-cycle variations that occur as fuel loading patterns are changed each cycle. Changes to the core power distributions and peaking factors are also within the normal cycle-to-cycle variations expected in core loading patterns. As shown in LR [Table 2.8.2-1](#), the discharge burnups and assembly requirements have increased, relative to the current design, due to the increase in core power. These will vary cycle-to-cycle based on actual energy requirements. The normal methods of feed enrichment variation and insertion of fresh burnable absorbers will be employed to control peaking factors. Compliance with the TS/COLR peaking factors can be assured using these standard nuclear design techniques.

In summary, EPU implementation will not require changes to the current UFSAR nuclear design bases or methodology. That methodology requires checking a number of key core parameters for EPU cycles as it does for the current cycle.

2.8.2.3 Conclusion

FPL has reviewed the analyses related to the effect of the proposed EPU on the nuclear design of the fuel assemblies, control systems, and reactor core. FPL concludes that the analyses have 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, FPL concludes that the nuclear design of the fuel assemblies, control systems, and reactor core will continue to meet their current licensing basis with respect to the applicable requirements of GDCs -10, -11, -12, -13, -20, -25, -26, -27, and -28. Therefore, FPL finds the proposed EPU acceptable with respect to the nuclear design.

2.8.2.4 References

1. Davidson, S. L. (Ed.), et al., Westinghouse Reload Safety Evaluation Methodology, WCAP-9273-NP-A, July 1985.
2. Nguyen, T. Q., et al., Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores, WCAP-11596-P-A, June 1988.
3. Liu, Y. S., et al., ANC: A Westinghouse Advanced Nodal Computer Code, WCAP-10965-P-A, September, 1986.
4. CEN-386-P-A, Verification of the Acceptability of a 1-Pin Burnup Limit of 60 MWD/kgU for Combustion Engineering 16x16 PWR Fuel, ABB Combustion Engineering, Inc., August 1992.

**Table 2.8.2-1
Core Characteristics of the EPU Scoping Cycles**

Cycle	Power Rating (MWth)	Nominal Cycle Length (EFPD)	Number of Feed Assemblies (Note 1)	Radial Power Peaking FH	3D Peaking Factor FQ	Maximum MTC @ HZP (pcm/°F)	Peak Rod Burnup (MWD/MTU) (Note 2)
N Pre-uprate	2,700	482	72	1.549	1.922	1.6	54,767
N+1	3,020	515	96	1.500	1.860	2.7	58,548
N+2	3,020	515	92	1.486	1.829	2.7	56,368
N+3	3,020	515	92	1.509	1.830	2.6	57,312
Alt N+3	3,020	580	112	1.457	1.795	3.0	57,089

Notes:

1. All feed assemblies utilize the CE 16X16 standard fuel assembly design, with radial zoning.
2. Peak rod burnup is listed for the nominal cycle length, excluding 1,000 MWD/MTU coastdown.

Table 2.8.2-2
Range of Key Safety Parameters

Safety Parameter	Current Design Values	EPU Analysis Values
Reactor Core Power (MWt)	2,700	3,020
Core Average Coolant Temperature HFP ⁽¹⁾ (°F)	573.3	578.5
Nominal Coolant System Pressure (psia)	2,250	2,250
Least Negative MTC ⁽²⁾ (pcm/°F)	$\leq + 5.0$ (Power < 70%) ≤ 0.0 (Power $\geq$ 70%)	$\leq + 5.0$ (Power < 70%) ≤ 0.0 (Power $\geq$ 70%)
Most Negative TS Surveillance MTC (pcm/°F)	-32.0	-32.0
Most Positive MDC ⁽³⁾ ($\Delta K/g/cm^3$)	0.43	0.43
Doppler Temperature Coefficient (pcm/°F)	-2.90 to -0.91	-2.90 to -0.91
Doppler Only Power Coefficient (pcm/%Power)	(See below)	(See below)
Least Negative, HZP ⁽⁴⁾ to HFP	-8.50 to -5.00	-8.50 to -5.00
Most Negative, HZP to HFP	-19.40 to -12.6	-19.40 to -12.6
Beta-Effective	0.0044 to 0.0070	0.0044 to 0.0070
Normal Operation F_R (with uncertainties)	1.802	1.696
Required Shutdown Margin (% $\Delta\rho$)	3.60	3.60
Normal Operation FQ	2.72	2.42

Table 2.8.2-2 (continued)
Range of Key Safety Parameters

Safety Parameter	Current Design Values		EPU Analysis Values	
	Fraction of Rod Insertion	Rod Worth (%k)	Fraction of Rod Insertion	Rod Worth (%k)
Trip Reactivity versus Rod Position ⁽⁵⁾	0.00	0.0000	0.00	0.0000
	0.05	-0.0005	0.05	-0.0057
	0.10	-0.0022	0.10	-0.0281
	0.15	-0.0043	0.15	-0.0588
	0.20	-0.0076	0.20	-0.0884
	0.25	-0.0151	0.25	-0.1217
	0.30	-0.0200	0.30	-0.1529
	0.35	-0.0275	0.35	-0.1862
	0.40	-0.0400	0.40	-0.2267
	0.45	-0.0594	0.45	-0.2766
	0.50	-0.0907	0.50	-0.3385
	0.55	-0.1426	0.55	-0.4186
	0.60	-0.2279	0.60	-0.5231
	0.65	-0.3672	0.65	-0.6651
	0.70	-0.5870	0.70	-0.8632
	0.75	-0.9223	0.75	-1.1419
	0.80	-1.4645	0.80	-1.5532
	0.85	-2.3425	0.85	-2.1975
	0.90	-3.5948	0.90	-3.2375
	0.95	-4.7698	0.95	-4.6051
	1.00	-5.4000	1.00	-5.2000

Table 2.8.2-2 (continued)
Range of Key Safety Parameters

Safety Parameter	Current Design Values		EPU Analysis Values	
	BOC ⁽⁶⁾	EOC ⁽⁷⁾	BOC	EOC
Maximum Ejected Rod Worth (% $\Delta\rho$)	0.60 (HZIP) 0.25 (HFP)	0.60 (HZIP) 0.25 (HFP)	0.60 (HZIP) 0.25 (HFP)	0.60 (HZIP) 0.25 (HFP)
Maximum Ejected Rod $F_Q(Z)$	15.0 (HZIP) 5.25 (HFP)	26.25 (HZIP) 5.25 (HFP)	15.0 (HZIP) 5.25 (HFP)	26.25 (HZIP) 5.25 (HFP)
Maximum Burnup at Ejected Rod Hot Spot (MWD/MTU)	31,034 (HZIP) 31,034 (HFP)	48,276 (HZIP) 48,276 (HFP)	31,034 (HZIP) 31,034 (HFP)	48,276 (HZIP) 48,276 (HFP)
Least Negative ITC ⁽⁸⁾ (pcm/deg-F)	+5.0 (HZIP) 0.0 (HFP)	-5.0 (HZIP) -20.0 (HFP)	+5.0 (HZIP) 0.0 (HFP)	-5.0 (HZIP) -20.0 (HFP)
Notes: 1. Hot full power 2. Moderator temperature coefficient 3. Moderator density coefficient 4. Hot zero power 5. The current values are based on a pre-trip axial shape index (ASI) of +0.60, which is not actually permitted at high powers. The EPU values are based on a pre-trip ASI of +0.23, which is the bottom-peaked limit at full power with uncertainties included. The EPU values are still a bound to expected EPU cycles. 6. Beginning of cycle 7. End of cycle 8. Isothermal temperature coefficient				

2.8.3 Thermal and Hydraulic Design

2.8.3.1 Regulatory Evaluation

Florida Power and Light (FPL) reviewed the thermal and hydraulic design of the core and the reactor coolant system (RCS) to confirm that the design:

- Has been accomplished using acceptable analytical methods,
- Is equivalent to or a justified extrapolation from proven designs,
- Provides acceptable margins of safety from conditions which would lead to fuel damage during normal reactor operation and anticipated operational occurrences (AOOs), and
- Is not susceptible to thermal hydraulic instability.

The review also covered hydraulic loads on the core and RCS components during normal operation and design basis accident (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:

- 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 AOOs; and
- 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.

Specific review criteria are contained in Standard Review Plan (SRP) Section 4.4 and other guidance provided in Matrix 8 of RS-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

The specific GDCs for the thermal and hydraulic design are as follows:

- GDC-10 is described in UFSAR Section 3.1.10 Criterion 10 – Reactor Design.

The reactor core and associated coolant, control and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

SAFDLs are stated in UFSAR Section 4.3. Minimum margins to specified acceptable fuel design limits are prescribed in the technical specifications (limiting conditions for operations) which support UFSAR Chapters 4 and 15.

- GDC-12 is described in UFSAR Section 3.1.12 Criterion 12 – Suppression of Reactor Power Oscillations.

The reactor core and associated coolant, control, and protection systems shall be designed to assure that power oscillations which can result in conditions exceeding specified acceptable fuel design limits are not possible or can be reliably and readily detected and suppressed.

Power level oscillations will not occur. The effect of the negative power coefficient of reactivity, together with the coolant temperature program maintained by control element assemblies (CEAs) and soluble boron, provide fundamental mode stability. Power level is monitored continuously by neutron flux detectors and by reactor coolant temperature difference measuring devices.

Power distribution oscillations are detected by neutron flux detectors. Axial mode oscillations are suppressed by means of CEAs. Radial oscillations are expected to be convergent. It is a design objective that azimuthal xenon oscillations be convergent. Monitoring and protective requirements are discussed in UFSAR Chapter 4.

UFSAR Section 4.4 presents the steady-state thermal and hydraulic analysis of the reactor core, the analytical methods, and the experimental work done to support the analytical techniques. Discussions of the analyses of anticipated operational occurrences and accidents are presented in UFSAR Chapter 15. The prime objective of the thermal and hydraulic design of the reactor is to ensure that the core can meet steady-state and transient performance requirements without violating the design bases.

NUREG-1779, Safety Evaluation Report Related of the St. Lucie Nuclear Plant, Units 1 and 2 dated September 3, 2003 defines the scope of license renewal. The adequacy of the thermal and hydraulic design of the core and the RCS during normal operation and anticipated operational transients are evaluated once per fuel cycle and therefore are not included in the scope of license renewal.

2.8.3.2 Technical Evaluation

2.8.3.2.1 Background

This section describes the thermal-hydraulic (T-H) analysis performed to support operation with a core consisting of 16x16 standard fuel assemblies at EPU conditions.

The current licensing basis for T-H design includes the prevention of departure from nucleate boiling (DNB) on the limiting fuel rod with a 95% probability at a 95% confidence level and criteria to ensure fuel cladding integrity. This is documented in UFSAR Section 4.4. The EPU analysis is based on the same licensing basis incorporating the increased core power. Since the EPU is not implementing a fuel transition, there will be no T-H stability issues typically associated with a transition core.

2.8.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

For the purposes of the EPU analysis, bounding fuel-related safety and design parameters have been chosen. These bounding parameters have been used in the safety and design analyses discussed in this section and in other relevant sections of this report, such as the 2.8.5 series of LRs.

LR [Table 2.8.3-1](#), Thermal-Hydraulic Design Parameters Comparison, lists the T-H parameters for the current design at 2700 MWt as well as for the EPU design at 3030 MWt. The limiting direction for these parameters is shown in LR [Table 2.8.3-2](#), Limiting Parameter Direction for DNB.

2.8.3.2.2.1 Design Basis and Methodology

The T-H departure from nucleate boiling ratio (DNBR) analysis of the 16x16 standard fuel in St. Lucie Unit 2 is based on the revised thermal design procedure (RTDP) ([Reference 3](#)) and the ABB-NV DNB correlation ([Reference 4](#)) using the VIPRE-W subchannel analysis code ([Reference 1](#)). See LR [Section 2.8.5.0](#), Accident and Transient Analyses, for a description of VIPRE-W and a reference for the NRC approval of this code. The standard thermal design procedure (STDP) methodology is used when RTDP is not applicable. The analyses demonstrate that the 95/95 design basis is met for the core while operating at the maximum analyzed core power of 3030 MWt.

2.8.3.2.2.1.1 Subchannel Analysis Code

The Westinghouse version of the VIPRE-01 (VIPRE-W) code is used for DNBR calculations. The use of VIPRE-W for the EPU analyses is in full compliance with the conditions specified in the NRC Safety Evaluation Report (SER) in WCAP-14565 ([Reference 1](#)). See LR Appendix A for code applicability.

2.8.3.2.2.2 DNB Methodology

With the RTDP methodology, uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters, computer codes, and DNB correlation predictions are considered statistically to obtain the overall DNB uncertainty factors. Based on the DNB uncertainty factors, RTDP design limit DNBR values are determined such that there is a 95% probability at a 95% confidence level that DNB will not occur on the most limiting fuel rod during normal operation, operational transients, or transient conditions arising from AOOs.

The uncertainties included in the overall DNB uncertainty factor are:

- Nuclear enthalpy rise hot channel factor ($F_{\Delta H}^N$ or F_r),
- Enthalpy rise engineering hot channel factor ($F_{\Delta H}^E$),
- Uncertainties in the VIPRE-01 and transient codes,
- Vessel coolant flow,
- Effective core flow fraction,

- Core thermal power,
- Coolant temperature,
- System pressure,
- Rod pitch, and
- Rod outer diameter.

LR [Table 2.8.3-3](#), Peaking Factor Uncertainties, provides a listing and description of the peaking factor uncertainties. Only the random portion of each plant operating parameter uncertainty is included in the statistical combination for RTDP. Any adverse instrumentation bias is treated either as a direct DNBR penalty or a direct analysis input. Instrument uncertainties in core thermal power, RCS flow, pressure and temperature used for the EPU analyses are listed in LR [Table 2.8.3-4](#), RTDP Uncertainties.

In addition to the above considerations for uncertainties, DNBR margin was retained by performing the safety analyses to DNBR limits higher than the design limit DNBR values. Sufficient DNBR margin was conservatively maintained in the safety analysis DNBR limits to offset the rod bow, and potential future DNBR penalties and to provide flexibility in design and operation of the plant. LR [Table 2.8.3-5](#), RTDP DNBR Margin Summary, provides the DNBR margin and penalties applicable at EPU conditions.

STDP is used for those analyses where RTDP is not applicable. The DNBR limit for STDP is the appropriate DNB correlation limit increased by sufficient margin to offset the applicable DNBR penalties.

2.8.3.2.2.2.1 DNB Correlation and Limits

The ABB-NV DNB correlation is used for the EPU analyses. NRC acceptance of a 95/95 correlation limit DNB ratio (DNBR) of 1.13 for the 16x16 standard fuel assemblies is documented in [Reference 3](#). For the EPU analysis, the RTDP design limit DNBR values are 1.30, 1.29 and 1.32 for small thimble, large thimble and matrix (typical) cells, respectively. After accounting for the plant-specific margin, the Safety Analysis Limit (SAL) DNBR is set to 1.42 and 1.39 for the matrix and thimble cells, respectively. For events where STDP is used, the ABB-NV correlation DNBR limit is 1.13.

2.8.3.2.2.2.2 Acceptance Criteria

The reactor core is designed to meet the following limiting thermal and hydraulic criteria:

- There is at least a 95% probability that DNB will not occur on the limiting fuel rods during MODES 1 and 2, operational transients, or any conditions of moderate frequency at a 95% confidence level;
- No fuel melting during any anticipated normal operating condition, operational transients, or any conditions of moderate frequency; and
- Mode of operation under normal operation and AOOs will not lead to thermo-hydrodynamic instabilities.

The ratio of the heat flux causing DNB at a particular core location, as predicted by a DNB correlation, to the actual heat flux at the same core location is the DNBR. Analytical assurance that DNB will not occur is provided by showing the calculated DNBR to be higher than the 95/95 limit DNBR for all conditions of normal operation and operational transients. The design limit DNBR is calculated by using the RTDP methodology, which, for all operating conditions, assures compliance with the DNBR criteria above.

For use in the DNB safety analyses, the design limit DNBR is conservatively increased to provide DNB margin to offset the effect of rod bow and any other DNB penalties that may occur, and to provide flexibility in design and operation of the plant. This increase in the design limit DNBR to account for various penalties and operational issues is the plant-specific margin retained between the design limit DNBR and the Safety Analysis Limit (SAL) DNBR.

2.8.3.2.3 Description of Analyses and Evaluations

To support the operation at EPU conditions, DNBR reanalysis was required to define new core limits and axial offset limits to confirm compliance with accident analyses criteria. With the SAL DNBR set, the core limits, axial offset limits ([Reference 2](#)), and dropped rod limits are generated. Based on these limits, the maximum design F_r that can be supported is 1.696. This limit incorporates applicable uncertainties, including a measurement uncertainty of $\pm^{a,c}$ percent and is adjusted for the power level using the following equation ([Reference 5](#)):

$$F_r = 1.696 \cdot [1 + 0.4 (1 - P)]$$

where P is the fraction of full power.

The accident DNB analyses to support the EPU are addressed below.

2.8.3.2.3.1 Loss of Flow

This section supplements the methodology discussed in LR [Section 2.8.5.3.1](#), Loss of Forced Reactor Coolant Flow.

The loss of flow DNBR analysis was performed using RTDP and the ABB-NV correlation for both complete loss of flow (CLOF) and partial loss of flow (PLOF) events. The minimum DNBRs calculated for both CLOF and PLOF were greater than the safety analysis DNBR limit, thereby demonstrating compliance to the design criterion for this event.

2.8.3.2.3.2 Locked Rotor

This section supplements the methodology discussed in LR [Section 2.8.5.3.2](#), Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break.

The locked rotor DNBR analysis was performed using RTDP methodology and the ABB-NV correlation. The locked rotor accident is classified as a postulated accident. To calculate the radiation release as a consequence of this accident, DNB calculations were performed to calculate the number of rods that would experience DNB and be conservatively assumed to fail.

The analysis confirmed that no fuel rods were predicted to be in DNB, thereby demonstrating compliance to the design criterion for this event.

The locked rotor peak clad temperature (PCT) analysis was performed using STDP methodology. The acceptance criterion for this analysis is that the PCT is less than 2700°F for the ZIRLO™ fuel. The analysis confirms that the acceptance criterion is met.

2.8.3.2.3.3 CEA Drop/Misoperation

This section supplements the methodology discussed in LR [Section 2.8.5.4.3](#), Control Rod Misoperation.

The NRC-approved Westinghouse analysis methods for negative flux rate trip plants in [Reference 6](#) were used for analyzing the CEA drop event. The CEA drop event analysis defines the maximum allowable F_r limit as a function of given rod worth for the SAL DNBR. The maximum post-drop F_r determines the maximum allowable F_r limit, therefore confirming that the DNB acceptance criterion is met for this event. The maximum linear heat rate for the CEA drop event is also confirmed to be lower than the fuel centerline melt limit, therefore confirming that the peak fuel centerline melt temperature criterion is met for this event.

The maximum allowable limit for CEA misalignment was calculated using RTDP methodology and the ABB-NV correlation. This is the value of F_r at normal operating conditions that gives a minimum DNBR equal to the RTDP SAL DNBR limit. The applicability of this limit is confirmed every cycle.

2.8.3.2.3.4 Steamline Break Accident

This section supplements the methodology discussed in LR [Section 2.8.5.1.2](#), Steam System Piping Failures Inside and Outside Containment.

The NRC-approved Westinghouse analysis methods in [Reference 7](#) were used for analyzing the steam line break (SLB) accident. The DNB analyses of the steam line break events were performed at EPU conditions. Cases were analyzed for both hot zero power (HZP) and hot full power (HFP) conditions. For each of these cases, the appropriate methodology was applied.

For the HFP cases, the RTDP methodology and the ABB-NV correlation were used. The HFP cases analyzed included failure of fast bus transfer (FFBT) and loss of offsite power (LOOP). The DNB analysis for FFBT showed that the minimum DNBR values were above the SAL DNBR, confirming that the acceptance criterion is met. The analysis for LOOP was performed using the loss of flow or locked rotor DNB methodology. The analysis showed that there were no rods in DNB, thereby demonstrating compliance to the design criterion for this event.

For the HZP cases, the STDP methodology and W-3 correlation were used. The W-3 correlation limit for this transient is []. The DNBR limit is the correlation limit increased to account for any DNB penalties applicable at these conditions. The analysis showed that the minimum DNBR was greater than the DNBR limit, thereby demonstrating that the DNBR design basis was met.

2.8.3.2.3.5 Uncontrolled Control Element Assembly Withdrawal from Subcritical

The analysis for the uncontrolled CEA withdrawal from subcritical is based on the STDP methodology since the event was initiated from HZP conditions. Additional information is contained in LR [Section 2.8.5.4.1](#), Uncontrolled Rod Assembly Withdrawal from a Subcritical or Low Power Startup Condition.

The DNB analysis of the rod withdrawal from subcritical accident was performed at EPU conditions. This transient results in a power excursion and a bottom-skewed power shape due to the withdrawal of the rod bank. A conservative accident-specific power shape was applied. STDP methodology and the ABB-NV correlation were used. The ABB-NV correlation limit for this transient is 1.0 . The DNBR limit is the correlation limit increased to account for any DNB penalties applicable at these conditions. The analysis showed that the minimum DNBR was greater than the DNBR limit, thereby demonstrating that the DNBR design basis was met.

2.8.3.2.3.6 Bypass Flow

Two different bypass flow rates are usually used in the thermal-hydraulic design analysis. The thermal design bypass flow (TDBF) is the conservatively high core bypass flow used with the thermal design flow (TDF) in power capability analyses that use standard (non-statistical) methods, and is also used to calculate fuel assembly pressure drops. The best estimate bypass flow (BEBF) is the core bypass flow that would be expected using nominal values for dimensions and operating parameters that affect bypass flow without applying uncertainty factors. For conservatism, the TDBF was used for all analyses using both STDP and RTDP design procedures. The BEBF was used to calculate fuel assembly lift forces.

2.8.3.2.3.7 Effects of Fuel Rod Bow on DNBR

Rod bow can occur between mid-grids, reducing the spacing between adjacent fuel rods and reducing the margin to DNB. Rod bow must be accounted for in the DNBR safety analyses. The rod bow penalty for the 16x16 standard fuel is 1.0% DNBR and is unchanged for EPU.

2.8.3.2.3.8 Fuel Temperatures

Fuel temperature and associated rod internal pressure calculations are discussed in LR [Section 2.8.1.2.4](#), Fuel Rod Performance.

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

As discussed above, the T-H design was determined to be outside the scope of License Renewal, therefore, with respect to the T-H design, the EPU does not impact any License Renewal evaluations.

2.8.3.3 Conclusion

FPL has reviewed the analyses related to the effects of the proposed EPU on the St. Lucie Unit 2 thermal and hydraulic design of the core and the RCS. FPL concludes that the analyses have adequately accounted for the effects of the proposed EPU on the thermal and hydraulic design and demonstrated that the design:

- Has been accomplished using acceptable analytical methods,
- Is equivalent to proven designs,
- Provides acceptable margins of safety from conditions that would lead to fuel damage during normal reactor operation and AOOs, and
- Is not susceptible to thermal-hydraulic instability.

FPL further concludes that it has adequately accounted for the effects of the proposed EPU on the hydraulic loads on the core and RCS components. Based on this, FPL concludes that the thermal and hydraulic design will continue to meet the requirements of GDCs -10 and -12 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to thermal and hydraulic design.

2.8.3.4 References

1. WCAP-14565-P-A, VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, October 1999.
2. WCAP-8745-P-A, "Design Bases for the Thermal Overpower T and Thermal Overtemperature T Trip Functions", September 1986.
3. WCAP-11397-P-A, Revised Thermal Design Procedure, April 1989.
4. WCAP-14565-P-A, Addendum 1, Addendum 1 to WCAP-14565-P-A, Qualification of ABB Critical Heat Flux Correlations with VIPRE-01 Code, June 2002.
5. WCAP-7308-L-P-A, Evaluation of Nuclear Hot Channel Factor Uncertainties, June 1988.
6. WCAP-10297-P-A, Dropped Rod Methodology for Negative Flux Rate Trip Plants, June 1983.
7. WCAP-9226-P-A Rev. 1, Reactor Core Response to Excessive Secondary Steam Releases, February 1998.

Table 2.8.3-1
Thermal-Hydraulic Design Parameters Comparison

Thermal-Hydraulic Design Parameters	Current Value	EPU Value
Reactor Core Heat Output, MWt	2700	3030 ⁽¹⁾
Reactor Core Heat Output, 10 ⁶ BTU/Hr	9213	10339 ⁽¹⁾
Heat Generated in Fuel, %	97.5	97.5
Core Pressure, Nominal, psia	2250	2250
Pressurizer Pressure, Nominal, psia	2225	2225
Radial Power Distribution ⁽²⁾	1.802[1+0.4(1-P)]	1.696[1+0.4(1-P)]
HFP Nominal Coolant Conditions		
Vessel Thermal Design Flow Rate (including bypass)		
10 ⁶ lb _m /hr	126.10	140.76
GPM	335,000	375,000
Core Flow Rate (excluding Bypass, ⁽⁵⁾ based on TDF)		
10 ⁶ lb _m /hr	121.43	135.56
GPM	322,605	361,125
Core Flow Area, ft ²	54.82	54.82
Core Inlet Mass Velocity (based on TDF), 10 ⁶ lb _m /hr-ft ²	2.22	2.47
Nominal Vessel/Core Inlet Temperature, °F	549.0	551.0
Vessel Average Temperature, °F	576.5	578.5
Core Average Temperature, °F	578.7	580.7
Vessel Outlet Temperature, °F	604.1	606.0
Core Outlet Temperature, °F	606.0	608.0
Average Temperature Rise in Vessel, °F	55.1	55.0
Average Temperature Rise in Core, °F	57.0	57.0
Heat Transfer		
Active Heat Transfer Surface Area, ft ²	58,168	58,168
Average Heat Flux, BTU/hr-ft ² ⁽⁶⁾	154,426	173,330 ⁽¹⁾
Average Linear Power, kW/ft	4.637	5.209
Peak Linear Power for Normal Operation, kW/ft	13.0 ⁽³⁾	12.5 ^(1,4)
Peak Linear Power for Prevention of Centerline Melt, kW/ft	22.0	22.0
Pressure Drop Across Core, psi	13.3	18.8

Table 2.8.3-1 (Continued)
Thermal-Hydraulic Design Parameters Comparison

Thermal-Hydraulic Design Parameters	Current Value	EPU Value
Notes: 1. The proposed power level of 3030 MWt (including 0.3% power measurement uncertainty) has been used for all thermal-hydraulic design analyses. 2. $P = \frac{\text{Thermal Power}}{\text{Rated Thermal Power}}$ 3. Based on maximum F_Q of 2.809. 4. Based on maximum F_Q of 2.4. 5. Design bypass flow of 3.7% was used for current and uprate conditions. 6. Average Heat Flux does not account for 2.5% energy deposited in the coolant.		

Table 2.8.3-2
Limiting Parameter Direction for DNB

Parameter	Limiting Direction for DNB
F _r , nuclear enthalpy rise hot-channel factor	maximum
Heat generated in fuel (%)	maximum
Reactor core heat output (MWt)	maximum
Average heat flux (BTU/hr-ft ²)	maximum
Nominal vessel/core inlet temperature (°F)	maximum
Core pressure (psia)	minimum
Pressurizer pressure (psia)	minimum
Thermal design flow for non-RTDP analyses (gpm)	minimum
Minimum measured flow for RTDP analyses (gpm)	minimum

**Table 2.8.3-3
Peaking Factor Uncertainties**

$F_r = F_r^N \times F_{\Delta H}^E$		
where:	F_r	Nuclear Enthalpy Rise Hot Channel Factor – The ratio of the relative power of the hot rod, which is one of the rods in the hot channel, to the average rod power. The normal operation value of this is given in the plant Core Operating Limit Report (COLR).
	$F_{\Delta H}^E$	Engineering Enthalpy Rise Hot Channel Factor – The nominal enthalpy rise in an isolated hot channel can be calculated by dividing the nominal power into this channel by the core average inlet flow per channel. The engineering enthalpy rise hot channel factor accounts for the effects of flow conditions and fabrication tolerances. It can be written symbolically as:
$F_{\Delta H}^E = f (F_{\Delta H,1}^E, F_{\Delta H,2}^E, F_{\Delta H \text{ inlet maldist}}^E, F_{\Delta H \text{ redistrib}}^E, F_{\Delta H \text{ mixing}}^E)$		
where:	$F_{\Delta H,1}^E$	accounts for rod-to-rod variations in fuel enrichment and weight
	$F_{\Delta H,2}^E$	accounts for variations in fuel rod outer diameter, rod pitch, and bowing
	$F_{\Delta H \text{ inlet maldist}}^E$	accounts for the non-uniform flow distribution at the core inlet
	$F_{\Delta H \text{ redistrib}}^E$	accounts for flow redistribution between adjacent channels due to the different thermal-hydraulic conditions between channels
	$F_{\Delta H \text{ mixing}}^E$	accounts for thermal diffusion energy exchange between adjacent channels caused by both natural turbulence and forced turbulence due to the mixing vane grids
The value of these factors and the way in which they are combined depends upon the design methodology used, that is, STDP or RTDP. Note that no actual combined effect value is calculated for $F_{\Delta H}^E$. These factors are accounted for by using the VIPRE-01 code.		

**Table 2.8.3-4
RTDP Uncertainties**

Parameter	Uncertainty
Power	$\pm^{a,c}$
Reactor Coolant System Flow	$\pm^{a,c}$
Pressure	$\pm^{a,c}$
Inlet Temperature	$\pm^{a,c}$

**Table 2.8.3-5
RTDP DNBR Margin Summary**

Subchannel	Typical (Matrix)	Small Thimble	Large Thimble
DNB Correlation	ABB-NV	ABB-NV	ABB-NV
DNBR Correlation Limit	1.13	1.13	1.13
DNBR Design Limit	1.32	1.30	1.29
DNBR SAL	$\square^{a,c}$	$\square^{a,c}$	$\square^{a,c}$
DNBR Retained Margin ⁽¹⁾	$\square^{a,c}$	$\square^{a,c}$	$\square^{a,c}$
Rod Bow DNBR Penalty	$\square^{a,c}$	$\square^{a,c}$	$\square^{a,c}$
Available DNBR Margin ⁽²⁾	$\square^{a,c}$	$\square^{a,c}$	$\square^{a,c}$
Notes: 1. DNBR margin is the margin that exists between the SAL and the design limit DNBRs. 2. This table does not account for minimum DNBR values that are greater than the safety analysis limit.			

2.8.4 Emergency Systems

2.8.4.1 Functional Design of Control Rod Drive System

2.8.4.1.1 Regulatory Evaluation

St. Lucie Unit 2 refers to the control rod drive mechanism as the control element drive mechanism (CEDM). In addition the control rod drive system is referred to as the control element drive system (CEDS). The Florida Power and Light (FPL) review covered the functional performance of the CEDS to confirm that the system can effect a safe shutdown, respond within acceptable limits during anticipated operational occurrences (AOO), and prevent or mitigate the consequences of postulated accidents. The review also covered the CEDS cooling system to ensure that it will continue to meet its design requirements.

The NRC's acceptance criteria are based on:

- General Design Criteria (GDC)-4, insofar as it requires structures, systems, and components (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;
- GDC-23, insofar as it requires that the protection system be designed to fail into a safe state;
- GDC-25, insofar as it requires that the protection system be designed to ensure that specified acceptable fuel design limits (SAFDLS) are not exceeded for any single malfunction of the reactivity control systems;
- 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;
- 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 emergency core cooling system (ECCS), of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to ensure the capability to cool the core is maintained;
- GDC-28, insofar as it requires that the reactivity control systems be designed to ensure that the effects of postulated reactivity accidents can neither result in damage to the reactor coolant pressure boundary (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
- GDC-29, insofar as it requires that the protection and reactivity control systems be designed to ensure an extremely high probability of accomplishing their safety functions in event of anticipated operational occurrences.

Specific review criteria are contained in the SRP, Section 4.6.

St. Lucie Unit 2 Current Licensing Basis

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976.

St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria (GDC) as discussed in UFSAR Section 3.1.

The specific GDCs for the CEDS are as follows:

- GDC-4, Environmental and Missile Design Bases, is described in UFSAR Section 3.1.4.

Structures, systems and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and approved by the Commission demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

SSCs important to safety are designed to accommodate the effects of and to be compatible with the pressure, temperature, humidity, and radiation conditions associated with normal operation, maintenance, testing, and postulated accidents including a loss of coolant accident (LOCA), in the area in which they are located.

Protective walls and slabs, local missile shielding, or restraining devices are provided to protect the containment and engineered safety features systems within the containment against damage from missiles generated by equipment failures. The concrete enclosing the reactor coolant system (RCS) serves as radiation shielding and an effective barrier against internally generated missiles. A missile shield is provided for control element drive mechanisms. Penetrations and piping extending outward from the containment, up to and including isolation valves are protected from damage due to pipe whipping, and are protected from damage by external missiles, where such protection is necessary to meet the design bases.

- GDC-23, Protection System Failure Modes, is described in UFSAR Section 3.1.23.

The protection system shall be designed to fail into a safe state or into a state demonstrated to be acceptable on some other defined basis if conditions such as disconnection of the system, loss of energy (e.g., electric power, instrument air) or postulated adverse environments (e.g., extreme heat or cold, fire, pressure, steam, water, and radiation) are experienced.

Protective system trip channels are designed to fail into a safe state or into a state established as acceptable in the event of loss of power supply or disconnection of the system. A loss of power to the CEDM holding coils results in gravity insertion of the full length control element assemblies (CEAs) into the core. Redundancy, channel independence, and separation incorporated in the

protective system design minimize the possibility of the loss of a protection function under adverse environmental conditions. Refer to UFSAR Sections 7.2 and 7.3.

- GDC-25, Protections System Requirements for Reactivity Control Malfunctions, is described in UFSAR Section 3.1.25.

The protection system shall be designed to assure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of control rods.

Reactor shutdown with CEAs is accomplished completely independent of the control functions since the trip breakers interrupt power to the full-length CEDM regardless of existing control signals. The design is such that the system can withstand accidental withdrawal of controlling groups without exceeding SAFDLs. Analysis of possible reactivity control malfunctions is given in UFSAR Section 15.4. The reactor protection system will prevent SAFDLs from being exceeded for any anticipated transients.

- GDC-26, Reactivity Control System Redundancy and Capability, is described in UFSAR Section 3.1.26.

Two independent reactivity control systems of different design principles shall be provided. One of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margin for malfunctions such as stuck rods, specified acceptable fuel design limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure acceptable fuel design limits are not exceeded. One of the systems shall be capable of holding the reactor core subcritical under cold conditions.

Two independent reactivity control systems of different design principles are provided. The first system, using CEAs, includes a positive means (gravity) for inserting CEAs and is capable of controlling reactivity changes to assure that under conditions of normal operation, including AOO, SAFDLs are not exceeded. The CEAs can be mechanically driven into the core. The appropriate margin for stuck CEA is provided by assuming in the analyses that the highest worth CEA does not fall into the core.

The second system, using neutron absorbing soluble boron, is capable of compensating for the rate of reactivity changes resulting from planned normal power changes, (including xenon burnout), such that SAFDLs are not exceeded. This system is capable of holding the reactor subcritical under cold conditions.

Either system is capable of making the core subcritical from a hot operating condition and holding it subcritical under cold conditions (refer to UFSAR Sections 7.4, 7.7, and 9.3.).

- GDC-27, Combined Reactivity Control System Capability is described in UFSAR Section 3.1.27.

The reactivity control systems shall be designed to have a combined capability, in conjunction with poison addition by the emergency core cooling system, of reliably controlling reactivity

changes to assure that under postulated accident conditions and with appropriate margin for stuck rods the capability to cool the core is maintained.

The reactivity control systems provide the means for making and holding the core subcritical under postulated accident conditions, as discussed in UFSAR Sections 9.3 and 4.3. Combined use of CEAs and chemical shim control by the chemical and volume control system provides the shutdown margin required for plant cooldown and long-term xenon decay, assuming the highest worth CEA is stuck out of the core.

- GDC-28, Reactivity Limits is described in UFSAR section 3.1.28.

The reactivity control systems shall be designed with appropriate limits on the potential amount and rate of reactivity increase to assure that the effects of postulated reactivity accidents can neither (1) result in damage to the reactor coolant pressure boundary greater than limited local yielding nor (2) sufficiently disturb the core, its support structures or other reactor pressure vessel internals to impair significantly the capability to cool the core. These postulated reactivity accidents shall include consideration of rod ejection (unless prevented by positive means) rod dropout, steam line rupture, changes in reactor coolant temperature and pressure, and cold water addition.

The bases for CEA design and control program for positioning in the core include ensuring that the reactivity worth of any one CEA is not greater than a pre-selected maximum value. The CEAs are divided into two sets: a shutdown set and a regulating set, and is further subdivided into groups as necessary. Administrative procedures and interlocks ensure that the amount and rate of reactivity increase is limited to predetermined values. The regulating groups are withdrawn only after the shutdown groups are fully withdrawn. The regulating groups are programmed to move in sequence and within limits which prevent the rate of reactivity addition and the worth of individual CEAs from exceeding limiting values as discussed in UFSAR Sections 4.3 and 7.7.

- GDC-29, Protection Against Anticipated Operational Occurrences is described in UFSAR Section 3.1.29.

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.

Plant conditions designated as Condition I and Condition II in ANSI-N 18.2 have been carefully considered in the design of the reactor protective system and the reactivity control systems. Consideration of redundancy, independence and testability in the design, coupled with careful component selection, overall system testing, and adherence to detailed quality assurance, assure an extremely high probability that safety functions are accomplished in the event of AOOs. For additional discussion, see the responses for GDC-10, -13, -15 and -20.

Other UFSAR and Technical Specification sections that address the design features and functions of the CEDS include:

- UFSAR Section 3.9.4 provides an overall design description of the CEDM, including the magnetic-jack and pulse counting and reed switch position transmitter (RSPT);

- UFSAR Sections 4.2.1.4, 4.2.2.4, 4.2.2.5, and 4.2.3.4 provide a general description and performance evaluation of the mechanical and nuclear design of the CEAs and CEDMs;
- UFSAR Section 4.5.1 provides a description of the materials used in the CEDM;
- UFSAR Section 4.6 provides functional design details for the CEDM;
- UFSAR Section 7.2 describes the reactor protection system interface with the control rod drive system;
- UFSAR Sections 7.5.1.4 and 7.5.2.4 describe the operation and design requirements of the RSPT based rod position indication systems;
- UFSAR Sections 7.7.1.1.1 and 7.7.1.2.1 describe the design and operation of the CEDS, including the control system interlocks;
- UFSAR Section 9.4.8.5 describes the design and design requirements of the CEDM cooling system;
- UFSAR Sections 15.4.1, 15.4.2 and 15.4.3 describe the transient and accident analyses associated with the malfunctions of the CEDS;
- St. Lucie Unit 2 Core Operating Limits Report (COLR) describes operating requirements pertaining to CEA misalignment and CEA insertion limits; and
- Technical Specification 3/4.1.3 and associated bases which describe the operability requirements for the control rods and control rod position indication system.

The CEDMs are designed to function during and after all normal plant transients of temperature and pressure. The CEA trip time for 90 percent insertion is 3.1 seconds maximum where trip time is defined as the interval between the opening of the CEDM coil power circuit breakers and the time the CEA has reached 90 percent of fully inserted position.

The CEDM is designed to function normally during and after being subjected to the operating basis earthquake loads. The CEDM allows for tripping and drive-in of the CEA during and after a safe shutdown earthquake.

The CEDM pressure housings are part of the RCPB, and they are designed to meet stress requirements consistent with those of the vessel. The pressure housings are capable of withstanding, throughout the design life, all normal operating loads, which include the steady-state and transient operating conditions specified for the vessel.

The CEDM cooling system is designed to ventilate the CEDM magnetic jack coils, and thus, maintain them at a temperature below 350°F.

The CEDM cooling system consists of redundant cooling fans and a cooling coil enclosed in a Mounting. A negative pressure is maintained inside the CEDM cooling shroud. Air enters the cooling shroud at the ambient containment air temperature, is distributed by an orifice plate to the CEDM chimneys, and leaves at approximately 155°F. The CEDM Cooling System is in service during normal plant operation.

In addition to the licensing bases described in the UFSAR, the CEDS was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical

systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.1.3 of the SER identifies that components of the CEDS are within the scope of License Renewal. Programs used to manage the aging effects associated with the CEDS are discussed in SER Section 3.1.3 and Chapter 18 of the UFSAR.

2.8.4.1.2 Technical Evaluation - Control Element Drive System

2.8.4.1.2.1 Introduction

The impact of EPU on the CEDS results from the temperature effects associated with increasing the total Nuclear Steam Supply System (NSSS) thermal power level from 2714 megawatts thermal (MWt) to 3034 MWt with an associated increase in the best-estimate RCS average temperature from 571.7°F to 577.3°F. The total NSSS thermal power level includes the 14 MWt contribution in thermal power from the reactor coolant pump net heat input and is conservative relative to the 2700 MWt (pre-EPU) and 3020 MWt (EPU) reactor core power levels. The increase in RCS average temperature is expected to increase the best-estimate vessel head and CEDM temperature from 595.0°F to 603.6°F. The vessel head and 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 CEDS, operating coil stacks, power supplies, or the solid state electronic control cabinets. Changes such as recalibration, rescaling, and setpoint changes to the NSSS Control Systems are required to facilitate the changes in operating conditions associated with operation at EPU. These changes are discussed in LR [Section 2.4.1](#), Reactor Protection, Safety Features Actuation, and Control Systems.

2.8.4.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

There is no fuel design change required to support the EPU operating condition. The fuel column is the same length and begins at the same elevation, and the upper end fitting is unchanged. Additionally, the fuel assembly interface with the CEA remains unchanged.

The CEDS must demonstrate that the CEDS can effect a safe shutdown, respond within acceptable limits during AOOs, and prevent or mitigate the consequences of postulated accidents under EPU conditions.

2.8.4.1.2.3 Description of the Analyses and Evaluations

The effects to the CEDS associated with increasing reactor core power from 2700 MWt to 3034 MWt are:

- 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; and

- Increased heat load to the CEDM cooling system resulting from the higher head temperatures. The impact to the CEDM cooling system is evaluated in LR [Section 2.8.4.1.3](#) below.

Analyses and evaluations of the impact of EPU on the structural integrity of the CEDS during normal, transient, and accident conditions were performed using the EPU conditions listed in LR [Section 1.1](#), Nuclear Steam Supply System Parameters, LR [Table 1.1-1](#). These analyses and evaluations are discussed in LR [Section 2.2.2.4](#), Control Rod Drive Mechanisms. The impact of EPU NSSS transients is discussed in LR [Section 2.2.6](#), NSSS Design Transients. The results of the analyses and evaluations determined the structural integrity of the CEDS remained within acceptable limits at EPU conditions.

The evaluation of the effects to the CEDS associated with EPU demonstrates that the CEDS can affect a safe shutdown, respond within acceptable limits during AOOs, and prevent or mitigate the consequences of postulated accidents.

2.8.4.1.3 Technical Evaluation - Control Element Drive Mechanism Cooling System

2.8.4.1.3.1 Introduction

CEDMs use electro-magnetic coils to position the CEA within the reactor core. The insulation and potting materials used in the construction of the coils are subject to thermal aging. In order to reduce the thermal aging, CEDM cooling systems were designed to remove heat supplied by conduction and convection from the reactor head and reactor coolant. The design basis CEDM heat load is 30,500 BTU/HR per CEDM, which results in a total design basis heat load of 2,775,500 BTU/HR for the 91 CEDMs installed at St. Lucie Unit 2. The computational fluid dynamics (CFD) analysis included an additional heat load of ten percent of this total design basis heat load to account for any downstream heat load transferred from nozzles and insulation. The value for CEDM heat load that was originally used in the CFD analysis (design basis CEDM heat load plus ten percent) is not impacted by EPU. Moreover, as a result of the EPU, there are no physical changes required to the CEDM cooling system.

The CEDM cooling system was recently modified as a part of the replacement reactor vessel closure head project. Modification of the CEDM cooling system resulted in the original ductwork design being modified from a three inlet manifold type design to a two inlet direct duct design. The original shroud assembly, which had eighteen rectangular outlets, was replaced with one that had two large outlets which allowed for the direct attachment to the two North and South duct assemblies. It should be noted that the two outlets for the modified shroud assembly are significantly larger than the eighteen rectangular outlets for the original shroud assembly. As part of the shroud replacement, the shroud plenum plate was also replaced. Modification of the CEDM cooling system did not require replacement of the original fans and coolers. Other modifications to the CEDM cooling system included the installation of an easy disconnect ductwork assembly and replacement of the original 64 bolt connection with a 32 bolt connection associated with attachment of the North and South ductwork to the reactor cavity wall. Additionally, in order to resolve fit up issues (associated with attachment of the North and South ductwork to the shroud) that were encountered during the original installation of the modified CEDM cooling system, modifications to the North and South duct assemblies were completed

during a more recent refueling outage. Use of these modified duct assemblies did not impact the results of the CFD analysis.

This system is discussed in UFSAR Section 9.4.8.5, CEDM Cooling System.

2.8.4.1.3.2 Input Parameters, Assumptions, and Acceptance Criteria

The CEDM cooling system is designed to maintain air flow sufficient to ensure the CEDM magnetic jack coils are maintained at a temperature below 350°F. Furthermore, the system is designed to maintain a cooling shroud exit temperature of approximately 155°F with a cooling shroud inlet temperature at the ambient containment air temperature.

As a result of the EPU, the vessel head temperature increases to 603.6°F. This post-EPU temperature is bounded by an assumption used in the CFD analysis that the reactor pressure vessel (RPV) surface temperature, which is applied at the base of the nozzles and the inside surface of the insulation, is fixed at 650°F°. This assumed value is unaffected by the EPU. The following other parameters are unaffected by the EPU:

- Maximum value for containment ambient temperature of 120°F,
- Total design basis CEDM cooling system heat load of 30,500 BTU/HR per CEDM, and
- Minimum flow of 700 scfm per CEDM.

2.8.4.1.3.3 Description of Analyses and Evaluations

A CFD analysis was performed as part of the modification to the CEDM cooling system to verify that the modified system provided sufficient cooling to ensure that the CEDM magnetic jack coils were maintained at a temperature below 350°F. This analysis concluded that a maximum CEDM coil centerline temperature of 328.9°F for the modified design was located at the innermost CEDM, which corresponded to the location with the lowest flow rate, and that this maximum temperature is 21.1°F below the allowable limit of 350°F.

The CFD analysis used as its input parameters a total CEDM cooling system heat load of 3,053,050 BTU/HR (110 percent x 91 CEDMs x 30,500 BTU/HR per CEDM), an inlet (containment) air temperature of 120°F and assumed that the heat load of other components (insulation and nozzles) is a function of a fixed RPV surface temperature of 650°F applied at the base of the nozzles and the inside surface of the insulation. Since none of these parameters change as a result of the EPU, the CFD analysis results are not impacted by the EPU.

UFSAR Section 4.6.2 discusses a potential source of common mode failure associated with a loss of air cooling to the CEDM coils. This UFSAR section discusses a test that was performed to determine the maximum CEDM temperature under conditions that simulated loss of air cooling. The mechanism was tested at a reactor coolant loop temperature of 600°F. The hot leg temperature under EPU conditions is 603.6°F. Although reactor operating fluid temperature increases 3.6°F, the test remains valid for EPU conditions based upon the following:

- Convective cooling was prevented and radiant heat loss was minimized during the test. These conditions are conservative compared with actual plant conditions during a potential

loss of CEDM cooling where convective cooling and normal radiant heat loss would exist;
and

- The temperature increase at the CEDM coils due to EPU would be negligible based upon their location above the reactor head. Any temperature increase would be seen at a lower elevation of the CEDM closer to the top of the reactor head (i.e., the temperature increase attenuates along the length of the CEDM toward the coil location).

An evaluation of the impact of the EPU on the structural integrity of the CEDM cooling ductwork and associated support hardware was performed and it was determined that the results of the calculations previously performed associated with the CEDM cooling system modification are not affected by the EPU.

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

As discussed above, the CEDS is within the scope of License Renewal. Operation of the CEDS under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.8.4.1.3.5 Results

EPU has minimal impact upon the temperature in the vicinity of the RSPT. The design temperature of the RSPT and its sub-components are well in excess of the temperature that the RSPT will experience during EPU operation. The RSPT and associated sub-components are not safety related.

FPL has reviewed the functional design of the CEDS and the CEDM cooling system for the effects of EPU. Accident and Transient Analyses described in LR [Section 2.4.2](#), Plant Operability, and LR [Section 2.8.5.0](#), Accident and Transient Analyses, have demonstrated that at EPU conditions the CEDS 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.

The impact of the EPU on the structural integrity of the CEDMs is discussed in LR [Section 2.2.2.4](#), Control Rod Drive Mechanism. The impact of EPU NSSS Transients is discussed in LR [Section 2.2.6](#), NSSS Design Transients. No modifications have been made to the hardware, logic or operation of the system that affect the system's current ability to fail into a safe state.

The impact of EPU on the CEDM cooling system was evaluated and it was determined that this system will be capable of maintaining the CEDM magnetic jack coils below 350°F at the EPU conditions. Also, the results of the CFD analysis are not impacted by the EPU.

The increased containment heat load on the CEDM cooling system has been evaluated as part of the containment cooling system as discussed in LR [Section 2.7.7](#), Other Ventilation Systems (Containment), and determined to be acceptable.

2.8.4.1.4 Conclusion

FPL has reviewed the analyses related to the effects of the proposed EPU on the functional design of the CEDS and the CEDM cooling system. FPL concludes that the evaluation has adequately accounted for the effects of the proposed EPU on the systems 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. FPL further concludes that the evaluation has demonstrated that there is sufficient cooling to ensure the system's design bases will continue to be followed upon implementation of the proposed EPU. Based on this, FPL concludes that the CEDS and the CEDM cooling system will continue to meet the St. Lucie Unit 2 current licensing basis with respect to the requirements of GDC-4, -23, -25, -26, -27, -28, and -29 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to the functional design of the CEDS.

2.8.4.2 Overpressure Protection During Power Operation

2.8.4.2.1 Regulatory Evaluation

Overpressure protection for the reactor coolant pressure boundary (RCPB) during power operation is provided by relief and safety valves and the reactor protection system (RPS). The Florida Power and Light (FPL) review covered pressurizer relief and safety valves and the piping from these valves to the quench tank and reactor coolant system (RCS) relief and safety valves.

The Nuclear Regulatory Commissions' (NRC's) acceptance criteria are based on:

- General Design Criterion (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 anticipated operational occurrences (AOOs); and
- 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 Standard Review Plan (SRP) Section 5.2.2 and other guidance provided in Matrix 8 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in the Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDCs for overpressure protection during power operation:

- GDC-15 is described in UFSAR Section 3.1.15 Criterion 15 - Reactor Coolant System Design.

The reactor coolant system and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.

The design criteria and bases for the RCPB are described in the response to GDC-14.

The operating conditions for normal steady state and transient plant operations are established conservatively. Normal operating limits are selected so that an adequate margin exists between operating and design limits. The plant control systems are designed to ensure that plant variables are maintained well within the established operating limits. The plant transient response characteristics and pressure and temperature distributions during normal operations are considered in the design as well as the accuracy and response of the instruments and controls. These design techniques ensure that a satisfactory margin is maintained between the plant's normal operating conditions, including design transients, and the design limits for the RCPB.

The plant control systems function to minimize deviations from normal operating limits in the event of most anticipated operational occurrences. Where control systems response would be inadequate or fail upon demand, the RPS and the engineered safety features actuation system (ESFAS) function to mitigate the consequences of such events.

The RPS and ESFAS function to mitigate the consequences of accidents such that the design limits for the RCPB are not exceeded.

- GDC-31 is described in UFSAR Section 3.1.31 Criterion 31 - Fracture Prevention of Reactor Coolant Pressure Boundary

The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions: (1) the boundary behaves in a non-brittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing, and postulated accident conditions and the uncertainties in determining: (1) material properties, (2) the effects of irradiation on material properties, (3) residual, steady-state and transient stresses, and (4) size of flaws.

UFSAR Section 5.1 states that overpressure protection for the reactor coolant pressure boundary is provided by three spring-loaded ASME Code pressurizer safety valves (PSVs) connected to the top of the pressurizer. Two power operated relief valves (PORVs) are provided to minimize the opening of the PSVs. The PSVs and PORVs discharge to the quench tank where the steam is released under water to be condensed and cooled.

Overpressure protection for the secondary side of the steam generators is provided by 16 spring-loaded ASME Code safety valves located in the main steam system upstream of the steam line isolation valves.

UFSAR Appendix 5.2A presents the design bases for sizing the overpressurization protection system.

Reference 1 documents NRC acceptance of the relief and safety valve test program designed to qualify the operability of prototypical valves and to demonstrate that their operation would not invalidate the integrity of the associated equipment and piping. NRC review of NUREG-0737 items including relief and safety valve testing is discussed in UFSAR Appendix 1.9A.

Technical Specification (TS) 3/4.4.3, Reactor Coolant System - Operating, ensures the pressurizer code safety valves are operable with the lift settings as specified. TS 3/4.7.1.1, Turbine Cycle - Safety Valves, ensures the main steam line code safety valves are operable with the lift settings as specified in Table 3.7-2.

In addition to the licensing basis described in the UFSAR, the RCPB was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.1 of the SER identifies that the components of the RCPB are

within the scope of License Renewal. Programs used to manage the aging effects associated with the RCPB are discussed in SER Section 3.1.1 and Chapter 18 of the UFSAR.

2.8.4.2.2 Technical Evaluation

2.8.4.2.2.1 Introduction

The limiting AOO with respect to primary and secondary system overpressurization is the loss of condenser vacuum (LOCV) event. Details of the LOCV analysis are given in LR [Section 2.8.5.2.1](#), Loss of External Load, Turbine Trip, and Loss of Condenser Vacuum. The LOCV analysis documented in LR [Section 2.8.5.2.1](#) demonstrates that the primary and secondary pressures limits are met.

The limiting postulated accident with respect to primary and secondary system overpressurization is the feedwater line break event. See LR [Section 2.8.5.2.4](#), Feedwater System Pipe Breaks Inside and Outside Containment, for details of the feedwater line break analysis.

This section briefly summarizes the analyses documented in LR [Sections 2.8.5.2.1](#) and [2.8.5.2.4](#). A comparison of the current and EPU results for each of these events is provided in the respective LR sections.

The technical evaluation of the piping from the safety valves to the pressurizer relief tank (PRT) is included in LR [Section 2.5.2](#), Pressurizer Relief Tank.

Note that overpressure protection during low temperature operation is discussed in LR [Section 2.8.4.3](#), Overpressure Protection During Low Temperature Operation.

2.8.4.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

For AOOs, primary and secondary pressures must remain below 110 percent of their respective design pressures at all times during the transient. Demonstrating that the primary and secondary pressure limits are met satisfy the requirements of GDC-15.

For postulated accidents, primary pressure must remain below 120 percent of the design pressure and secondary pressure must remain below 110 percent of the design pressure at all times during the transient. Demonstrating that the primary and secondary pressure limits are met satisfy the requirements of GDC-31.

2.8.4.2.2.3 Description of Analyses and Evaluation

The LOCV analysis documented in LR [Section 2.8.5.2.1](#) demonstrates that the primary pressure limit is met at the PSVs setpoint with the proposed +/- 3 percent tolerance value. Specifically, the maximum pressure in the primary system is 2669.1 psia vs. a limit of 2750 psia (110 percent of design pressure). Additionally, the LOCV analysis demonstrates that the secondary pressure limit is met at the MSSVs setpoint with a +/- 3 percent tolerance on Bank 1, a +/- 3 percent tolerance on Bank 2, and a 3 percent accumulation on both banks. The maximum pressure in the secondary system is 1093.97 psia vs. a limit of 1100 psia (110 percent of design pressure).

For feedwater line break event analysis discussed in LR [Section 2.8.5.2.4](#), the peak primary system pressure is 2704.2 psia at the PSVs setpoint with the proposed +/-3 percent tolerance, compared to a limit of 3000 psia (120 percent of design pressure). For the feedwater line break event the peak secondary pressure is met at the MSSVs setpoint with a +/-3 percent tolerance on Bank 1, a +2/-3 percent tolerance on Bank 2, and a 3 percent accumulation on both banks. The maximum pressure in the secondary system is 1094.2 psia vs. a limit of 1100 psia (110 percent of design pressure).

2.8.4.2.2.4 Impact on Renewed Plant Operating License Evaluations and License Renewal

As discussed above, the RCPB components are within the scope of License Renewal. Operation of the RCPB components under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.8.4.2.2.5 Results

The analyses described in LR [Section 2.8.5.2.1](#), Loss of External Load, Turbine Trip, and Loss of Condenser Vacuum, and LR [Section 2.8.5.2.4](#), Feedwater System Pipe Breaks Inside and Outside Containment, demonstrate that the applicable pressure limits continue to be met at EPU conditions. No changes are needed to the primary or secondary relief or safety valves in order to meet the applicable pressure limits. The EPU analyses supports +/-3% tolerance on Bank 1 MSSVs and +2/-3% tolerance on Bank 2 MSSVs.

2.8.4.2.3 Conclusion

FPL has reviewed the analyses related to the effects of the proposed EPU on the overpressure protection capability of the plant during power operation. FPL concludes that the analyses have:

- Adequately accounted for the effects of the proposed EPU on pressurization events and overpressure protection features, and
- Demonstrated that the plant will continue to have sufficient pressure relief capacity to ensure that pressure limits are not exceeded.

Based on this, FPL 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, FPL finds the proposed EPU acceptable with respect to overpressure protection during power operation.

2.8.4.2.4 References

1. Letter, from J.A. Norris (NRC) to C.O. Woody (FPL), NUREG-0737 Item II.D.1 Performance Testing of Relief and Safety Valves, dated May 11, 1989.

2.8.4.3 Overpressure Protection During Low Temperature Operation

2.8.4.3.1 Regulatory Evaluation

Overpressure protection for the reactor coolant pressure boundary (RCPB) during low temperature operation of the plant is provided by pressure-relieving systems that function during the low temperature operation.

The Florida Power and Light (FPL) review covered relief valves with piping to the quench tank, the charging system and the high-pressure safety injection (HPSI) system. For St. Lucie Unit 2, the pressurizer power operated relief valves and the relief valves of the shutdown cooling system (referred to as the residual heat removal system in RS-001) are credited for providing low temperature overpressure protection (LTOP).

The NRC's acceptance criteria are based on:

- General Design Criterion (GDC)-15, insofar as it requires that the reactor coolant system (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 anticipated operational occurrences (AOOs), and
- GDC-31, insofar as it requires that the RCPB be designed with sufficient margin to assure that it behaves in a non-brittle manner and the probability of rapidly propagating fracture is minimized.

Specific review criteria are contained in Standard Review Plan (SRP) Section 5.2.2.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria for Nuclear Power Plants as specified in Appendix A to Title 10 of the Code of Federal Regulations (10 CFR) Part 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDCs applicable to the overpressure protection during low temperature operation are:

- GDC-15 is described in UFSAR Section 3.1.15 Criterion 15 – Reactor Coolant System Design.

The reactor coolant system and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operations including anticipated operational occurrences.

The operating conditions for normal steady state and transient plant operations are established conservatively. Normal operating limits are selected so that an adequate margin exists between operating and design limits. The plant control systems are designed to ensure that plant variables are maintained well within the established operating limits. The plant transient response characteristics and pressure and temperature distributions during normal operations are

considered in the design as well as the accuracy and response of the instruments and controls. These design techniques ensure that a satisfactory margin is maintained between the plant's normal operating conditions, including design transients, and the design limits for the reactor coolant pressure boundary.

- GDC-31 is described in UFSAR Section 3.1.31 Criterion 31 – Fracture Prevention of Reactor Coolant Pressure Boundary.

The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions: (1) the boundary behaves in a nonbrittle manner, and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing and postulated accident conditions and the uncertainties in determining: (1) material properties, (2) the effects of irradiation on material properties, (3) residual, steady-state and transient stresses, and (4) size of flaws.

RCPB components are designed and constructed in accordance with ASME Code Section III, and comply with the test and inspection requirements of this code. These test and inspection requirements assure that flaw sizes are limited so that the probability of failure by rapid propagation is extremely remote. Particular emphasis is placed on the quality control applied to the reactor vessel, on which tests and inspections exceeding ASME Code requirements are performed. The tests and inspections performed on the reactor vessel are summarized in UFSAR Sections 5.2 and 5.3.

Carbon and low-alloy steel materials that form part of the pressure boundary are tested for fracture toughness to the acceptance criteria and requirements of 10 CFR 50, Appendix G (see UFSAR Section 5.2).

LTOP of the RCS prevents exceeding the reactor vessel heatup and cool down pressure-temperature (P-T) operating limits presented in the technical specification (TS) during periods of low temperature operation. The P-T limits, described in UFSAR Section 5.3.2, are designed to protect the reactor vessel from potential brittle fracture.

Overpressure protection of the RCS during low temperature conditions is provided by power operated relief valves (PORVs) connected to the pressurizer steam space and when the shutdown cooling system (SDCS) is in operation also by the SDCS relief valves (SDCRV). During hot standby and power operations, the PORVs open at a high pressure setpoint of 2370 psia. When the RCS is at low temperatures, the operator realigns the PORV setpoints to a low pressure value of 490 psia for low temperature overpressure protection. The protection provided by the PORVs precludes any overpressure transient from exceeding the pressure-temperature (P-T) operating limits.

Technical Specification 3/4.4.9.3 provides requirements for use of the PORVs for LTOP of the RCS. Unless the RCS is depressurized and vented by at least 3.58 square inches, at least one of the following overpressure protection systems shall be OPERABLE:

- a. Two PORVs with a lift setting of less than or equal to 490 psia and with their associated block valves open. These valves may only be used to satisfy low temperature

overpressure protection (LTOP) when the RCS cold leg temperature is greater than the temperature listed in TS Table 3.4-4;

- b. Two SDCRVs with a lift setting of less than or equal to 350 psia; and
- c. One PORV with a lift setting of less than or equal to 490 psia and with its associated block valve open in conjunction with the use of one SDCRV with a lift setting of less than or equal to 350 psia. This combination may only be used to satisfy LTOP when the RCS cold leg temperature is greater than the temperature listed in TS Table 3.4-4.

The low temperature overpressure protection provided by the relief valves is required during heatup and cooldown and during extended periods of cold shutdown. The PORV setpoint of 490 psia is incorporated in the LTOP mode since each PORV is designed to accommodate the most limiting transients as described in UFSAR Section 5.2.6.2.1. Per the technical specifications, the PORVs are used for LTOP during heatup when any RCS cold leg temperature is in the range from 80-246°F and during cooldown when any RCS cold leg temperature is 224°F and below to 132°F. For temperatures below 132 °F during cooldown, the shutdown cooling system relief valves provide LTOP protection.

In addition to administrative controls and procedures, a low temperature alarm is provided to alert the operator to align the LTOP system. To maintain RCS overpressure protection, the relief valves are aligned at all temperatures below the P-T curve limits corresponding to the pressurizer safety valve setpoint. At temperatures above the temperature limit which corresponds to the pressurizer safety valve setpoint, the “normal” PORV setpoint of 2370 psia is selected. Backup overpressure protection is provided by the pressurizer safety valves as described in UFSAR Section 5.4.13.

During heatup, RCS pressure is maintained below the PORV pressure setpoints until after the PORVs are re-set to the “normal” high setpoint. The PORVs can be re-set to the normal setpoint when cold leg temperature increases above the maximum temperature for LTOP during heatup defined in the technical specifications.

During cooldown, RCS pressure is decreased to below the PORV low pressure setpoint before cooling the plant to below the maximum temperature for LTOP during cooldown, defined in the Technical Specifications. Once temperature is lowered, the PORV control switch is aligned in the LTOP mode. The LTOP mode applies for all temperatures within the maximum LTOP temperature range. The PORVs will remain in the LTOP mode until the RCS is opened during refueling. The LTOP system is designed to be aligned during all heatup and cooldown operations.

P-T limits are applicable to a finite time period and are based upon an irradiation damage prediction for the end of the period. The LTOP analysis documents the selection of LTOP controls (i.e.: PORV setpoints and acceptable heatup and cool down rates over respective applicable temperature ranges) and is periodically revised when revisions to the P-T operating limits are required to account for changes in the adjusted reference temperature of the reactor vessel materials and to allow plant operation beyond the existing applicability limits.

In addition to the licensing bases described in the UFSAR, LTOP capability was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3 of the SER identifies that components associated with LTOP are within the scope of License Renewal. Programs used to manage the aging effects associated with LTOP are discussed in SER Section 3.1.2 and Chapter 18 of the UFSAR.

2.8.4.3.2 Technical Evaluation

2.8.4.3.2.1 Introduction

The maximum transient pressures for the most limiting LTOP transients were evaluated for both mass addition transients and energy addition transients. The peak transient pressures from the analyses were then compared to the RCS P-T limits to determine updated LTOP requirements. The LTOP system analysis for the EPU also examines the applicability of the current PORV and SDCRV setpoints and current TS limits for LTOP enable temperature, minimum temperature for PORV use for LTOP protection, and maximum cooldown rates with respect to the P-T limits. Discussion of P-T limits can be found in LR [Section 2.1.2](#), Pressure-Temperature Limits and Upper-Shelf Energy. LR [Section 2.1.2](#) documents that the existing P-T limits are projected to remain valid for approximately 47 EFY.

2.8.4.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

TS Table 3.4-4 describes the current LTOP applicable RCS temperature range and the minimum cold leg temperature for PORV use for LTOP during both heat up and cool down scenarios. The SDCRV relief setpoint is 350 psia. The PORV relief setpoint is 470 psia for low temperature overpressure protection.

For the evaluation of the adequacy of the TS minimum vent area the pressurizer is water solid at atmospheric pressure and saturation temperature. The pressurizer remains water solid at this temperature (212°F) throughout this transient. For the evaluation of the TS minimum vent area, the vent area is assumed to be located on the top of the pressurizer.

The acceptance criterion for this analysis is that the P-T limits will not be violated for the limiting mass and energy addition overpressure events analyzed.

2.8.4.3.2.3 Description of Analysis

The LTOP system is designed to prevent violation of the RCS brittle fracture P-T limits in case of an overpressure event within the LTOP temperature range. The reactor coolant pump (RCP) start overpressure event is one of two design basis events for the LTOP. The RCP start from a condition in which the steam generator liquid inventory is hotter than the RCS coolant inventory is referred to as the Energy Addition event. The other design basis events are the Mass Addition

transients, which are based on the inadvertent start of select combinations of safety injection pumps and charging pumps in the LTOP temperature range. The design basis Mass Addition transients are based on the operability requirements for the PORV, the charging pumps, and the HPSI pumps. Each energy addition or mass addition event is analyzed at the most limiting initial plant temperature and pressure and the worst case alignment of system components permitted by the Technical Specification.

The EPU project does not change the LTOP transients bases but updates inputs for EPU operating conditions. Generally, the EPU results in an increase in peak transient pressure for each Mass Addition and the Energy Addition events due to the EPU increase in core decay heat.

The LTOP mass addition transients are identified based on the current operability requirements for the SDCS, the PORVs, charging pumps, and HPSI pumps. These requirements are unchanged for EPU. Either a single PORV or single SDCRV provides LTOP overpressure protection.

The LTOP energy addition transients analyze cases with either a single PORV or single SDCRV providing LTOP overpressure protection during a RCS pressure transient caused by an RCP start with an initial steam generator-to-reactor vessel temperature differential of 40°F during RCS water-solid, low temperature conditions.

In the LTOP analysis, peak transient pressures determined for a spectrum of cases at EPU conditions in the Energy Addition analysis and the Mass Addition analysis are compared to the RCS P-T limits. The results of this comparison are used to determine the EPU LTOP requirements, which are compared to the current TS to determine whether the existing limits are applicable to the EPU.

Per TS Section 3/4.4.9.3, in Mode 6, if the RCS is not vented with a vent greater than 3.58 square inches, the LTOP system is required to be operable. This remains valid for the EPU. The PORV orifice area is 3.58 square inches. For any configuration where the PORV is shown to provide sufficient overpressure protection the TS minimum vent area also provides sufficient overpressure protection.

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

As discussed above, the overpressure mitigation system (OMS) is within the scope of License Renewal. Operation of the OMS under EPU conditions has been evaluated to determine if there are any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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

2.8.4.3.2.5 Results

An analysis of the current TS LTOP requirements was performed on the EPU mass addition and energy addition transients and compared to the P-T limits. The results of the analysis show that the current TS PORV setpoint (490 psia), the current TS SDCRV setpoint (350 psia), LTOP enable temperatures, minimum cold leg temperatures for PORV use, and allowable cooldown rates provide adequate margin from the P-T limits for the limiting LTOP transients.

The LTOP enable temperature limits are conservative. The TS minimum vent area of 3.58 square inches for not requiring LTOP protection by the PORVs or SDC relief valves is adequate for the period ending at 47 EFPY.

2.8.4.3.3 Conclusion

FPL has reviewed the effects of the proposed EPU on the overpressure protection capability of the plant during low temperature operation and concludes that the review 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-temperature limits are not exceeded. Based on this review, FPL concludes that the low temperature overpressure protection features will continue to meet its current licensing basis with respect to the requirements of GDC-15 and GDC-31 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to overpressure protection during low temperature operation.

2.8.4.4 Residual Heat Removal System

2.8.4.4.1 Regulatory Evaluation

The residual heat removal (RHR) system, referred to as the shutdown cooling system (SDC) at St. Lucie Unit 2, is used to cool down the reactor coolant system (RCS) following shutdown. The RHR system is a low-pressure system that takes over the shutdown cooling function when the RCS temperature is reduced to SDC entry conditions. The Florida Power and Light (FPL) review covered the effect of the proposed EPU on the functional capability of the SDC system to cool the RCS following shutdown and provide decay heat removal.

The NRC's acceptance criteria are based on:

- GDC-4, insofar as it requires that structures, systems, and components important-to-safety be protected against dynamic effects,
- GDC-5, insofar as it requires that important-to-safety structures, systems, and components 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
- GDC-34, which specifies requirements for a residual heat removal system.

Specific review criteria are contained in Standard Review Plan (SRP), Section 5.4.7 and other guidance provided in Matrix 8 of RS-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to Title 10 of the Code of Federal Regulations (10 CFR) Part 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

The specific GDCs for the residual heat removal system are as follows:

- GDC-4 is described in UFSAR Section 3.1.4 Criterion 4 – Environmental and Missile Design Bases.

Structures, systems and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss- of- coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and approved by the Commission demonstrates that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

Structures, systems and components important to safety are designed to accommodate the effects of and to be compatible with the pressure, temperature, humidity, and radiation conditions associated with normal operation, maintenance, testing, and postulated accidents including a loss-of-coolant accident (LOCA) in the area in which they are located.

Protective walls and slabs, local missile shielding, or restraining devices are provided to protect the containment and engineered safety features systems within the containment against damage from missiles generated by equipment failures. The concrete enclosing the reactor coolant system serves as radiation shielding and an effective barrier against internally generated missiles. A missile shield is provided for control element drive mechanisms. Penetrations and piping extending outward from the containment, up to and including isolation valves are protected from damage due to pipe whipping, and are protected from damage by external missiles, where such protection is necessary to meet the design bases.

Non-Seismic Category I Piping is arranged or restrained so that failure of any non-seismic Category I piping will neither cause a nuclear accident nor prevent essential seismic Category I structures or equipment from mitigating the consequences of such an accident.

Seismic Category I piping is arranged or restrained such that in the event of rupture of a seismic Category I pipe which causes LOCA, resulting pipe movement will not result in loss of containment integrity or adequate engineered safety features systems operation.

Refer to UFSAR Sections 3.5, 3.6, 3.7, and 3.11 for details on missile protection, pipe rupture and jet impingement protection, seismic design criteria and environmental qualification, respectively.

- GDC-5 is described in UFSAR Section 3.1.5 Criterion 5 – Sharing of Structures, Systems or Components.

Structures, systems and components important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units.

SDC system components are not shared between the two St. Lucie units.

- GDC-34 is described in UFSAR Section 3.1.34 Criterion 34 – Residual Heat Removal.

A system to remove residual heat shall be provided. The system safety function shall be to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded.

Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

The transfer of fission product decay heat and other residual heat from the reactor core is accomplished by the steam generators and the shutdown cooling system at such a rate that

specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded.

Residual heat removal capacity is provided with sufficient redundancies in design that in the event of a single active failure or a single limited leakage passive failure the system can still perform its function. The steam generator auxiliaries and the shutdown cooling system are designed to operate from either offsite or onsite electric power sources. See UFSAR Section 5.4.7 for additional information on residual heat removal.

The SDC system is used to reduce the temperature of the reactor coolant at a controlled rate for refueling. The SDC system utilizes the low pressure safety injection pumps to circulate the reactor coolant through two shutdown heat exchangers, returning it to the reactor coolant system through the low pressure injection header.

The functional design bases associated with SDC are presented in UFSAR Section 5.4.7.1.2.

The SDC system is used in conjunction with the main steam and main or auxiliary feedwater to reduce the temperature of the reactor coolant system (RCS) in post shutdown periods from normal operating temperature to the refueling temperature. The initial phase of the cooldown is accomplished by heat rejection from the steam generators to the condenser or atmosphere. For a normal cooldown the reactor coolant hot leg temperature is reduced to 325°F and the pressurizer pressure is reduced to 276 psia. Then, the SDC can be put into operation to reduce the reactor coolant temperature to the refueling temperature of 140°F, or less, and to maintain this temperature during refueling.

Once the RCS has been adequately cooled down and depressurized, SDC is aligned and the cooldown proceeds by rejecting heat to the SDC heat exchangers.

The shutdown cooling throttle valves are adjusted as necessary to maintain the RCS cooldown rate at 75°F/hr. or less. The total SDC flow is maintained greater than or equal to 3000 gpm through one or both shutdown cooling trains when required by Technical Specifications. At other times, SDC flow is maintained as required to meet the heat removal requirements. The SDC bypass flow control valves are manually controlled by the operator.

The SDC is described in UFSAR Section 5.4.7.

Generic Letter (GL) 88-17, Loss of Decay Heat Removal, was issued to address concerns related to the loss of decay heat removal capability during non-power operations based on several industry incidents. The GL required the implementation of expeditious actions as well as programmed plant enhancements to address this issue. Refer to UFSAR Section 5.1.4 and LR [Section 2.8.7.1](#), Loss of Decay Heat Removal at Mid-Loop Operation, for detailed information pertaining to the FPL response to GL 88-17 requirements.

The operability of the shutdown cooling system is governed by Technical Specifications 3.4.1.3, 3.4.1.4.1, 3.4.1.4.2, 3.9.8.1 and 3.9.8.2.

In addition to the licensing bases described in the UFSAR, the SDC system was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which

components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.2 of the SER identifies that components of the SDC system are within the scope of License Renewal. Programs used to manage the aging effects associated with the SDC system are discussed in SER Section 3.2 and Chapter 18 of the UFSAR.

2.8.4.4.2 Technical Evaluation

2.8.4.4.2.1 Introduction

The SDC system is described in UFSAR Section 5.4.7. The system is designed to remove residual and sensible heat from the core and reduce the temperature of the RCS during the second phase of plant cool down. During the first phase of cool down, the temperature of the RCS is reduced by transferring heat from the RCS to the steam and power conversion system.

2.8.4.4.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The analysis assumes:

- The SDC heat exchanger data assumes design fouling factors and design tube plugging of 10-percent,
- For normal cooldown SDC is initiated 3.5 hours after reactor shutdown,
- Initial component cooling water system (CCW) supply temperature of 120°F, and
- ANS 1979 decay heat values.

To meet 10 CFR 50 Appendix R cold shutdown criteria, the SDC system, in conjunction with the natural circulation of the RCS, must be able to achieve cold shutdown within 72 hrs. Additionally, the system is needed to support cooling the RCS in accordance with TS Action requirements without violating the administrative maximum cooldown rate of 75°F per hour.

2.8.4.4.2.3 Description of Analysis and Evaluations

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 the RCS during normal and accident conditions. The removal of core decay heat for accident conditions is addressed in LR [Section 2.6.5](#), Containment Heat Removal. The increased heat loads will be transferred to the CCW and ultimately to the service water system (SWS) referred to as the intake cooling water system (ICW) at St. Lucie Unit 2. Evaluation of the EPU impact on the performance of the SDC system in conjunction with the CCW and ICW with the increased heat loads is addressed in this section, LR [Section 2.5.4.3](#), Reactor Auxiliary Cooling Water Systems, and LR [Section 2.5.4.2](#), Station Service Water System. The natural circulation portion of the cooldown is addressed in LR [Section 2.8.7.2](#), Natural Circulation Cooldown and 10 CFR 50, Appendix R is addressed in LR [Section 2.5.1.4](#), Fire Protection.

The EPU affects the plant cooldown time(s) due to the increase in core power. The plant cooldown calculation was performed at the current power rating and at the EPU rating. The RCS heat capacity and the other CCW heat loads were explicitly considered in this analysis. The analysis was performed to demonstrate that the SDC system design basis functional requirements and performance criteria for plant cooldown under the EPU conditions remain valid. The two-train system alignment was considered to address the design capability discussed in the UFSAR. A cooldown analysis was performed to support the worst-case scenario for the 10 CFR 50, Appendix R safe shutdown analysis. Also, an analysis was performed to demonstrate that the SDC system will continue to support current technical specification action times at EPU conditions. The plant cooldown durations described in this LR Section start from hot standby conditions (Mode 3) at SDC entry temperature and end at either cold shutdown (Mode 5) at 200°F or refueling (Mode 6) at 140°F conditions as applicable.

Analyses were performed to demonstrate continued support of technical specifications action times with respect to achieving cold shutdown (Mode 5) within the most limiting action time of 20 hours at EPU conditions.

2.8.4.4.2.4 Impact on Renewal Plant Operating License, Evaluations and License Renewal

As discussed above, the SDC system is within the scope of License Renewal. Operation of the SDC system under EPU conditions has been evaluated to determine if there any new aging effects requiring management or if any existing aging management programs are affected. 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. Furthermore, 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.

2.8.4.4.2.5 Results

Continued compliance with the SDC system cooldown performance requirements was demonstrated at the EPU conditions with no plant changes. The EPU cooldown analyses results are as follows:

- The normal plant cooldown duration to 200°F, cold shutdown (Mode 5) with both trains of SDC and CCW equipment in operation will increase by approximately 0.1 hours. The normal plant cooldown duration to 140°F for refueling (Mode 6) will increase by 12 hours with both trains of SDC in operation. At the beginning of the cooldown, decay heat differences for Pre-EPU and Post-EPU are minimal compared to the capability of the SDC system but as the cooldown progresses the decay heat difference for Pre-EPU and Post-EPU conditions is more significant compared to the capability of the SDC system at the lower temperature difference. Therefore, the time it takes to reach Mode 5 increased by 0.1 hours where as the time it takes to reach Mode 6 increased by 12 hours. Since there are no design criteria for normal plant cooldown times, these increases in the calculated durations, based on design

conditions, are acceptable. These results are achieved without violating the administrative limit on maximum cooldown rate of 75°F per hour.

- For the Appendix R/safe shutdown cooldown scenario, the worst case cooldown scenario assumes a loss-of-offsite power, one steam generator, one atmospheric dump valve and one train of SDC equipment in operation. At EPU conditions, the plant reaches SDC system entry (325°F and 276 psia without exceeding the maximum cooldown rate of 75°F per hour) in 36 hours. One train of SDC equipment is then placed in operation and 200°F is achieved in approximately 10 additional hours. Therefore, continued compliance with the Appendix R cold shutdown (Mode 5) requirement within the 72-hour time was demonstrated at EPU conditions.
- Post-EPU performance of the SDC system will continue to support the technical specification action times with respect to achieving cold shutdown (Mode 5 $\leq$ 200°F) within 20 hours. Performance is demonstrated with two trains of SDC and CCW equipment in operation and with one SDC and CCW train in operation assuming SDC system initiation at a conservative duration following shutdown.

The EPU does not impact the design temperature and pressure of the SDC system piping and associated components. Evaluations described in LR [Section 2.2.2.1](#), Nuclear Steam Supply System Piping, Components and Supports, LR [Section 2.2.2.2](#), Balance of Plant Piping Components and Supports, and LR [Section 2.5.1.3](#), Pipe Failures, show the response of the SDC system piping to the EPU environmental and dynamics efforts remain acceptable relative to meeting the current licensing basis with respect to GDC-4.

The EPU has no effect on the ability of the SDC system to remove residual heat at reduced reactor coolant system inventory, and therefore, St. Lucie Unit 2 will continue to meet the current licensing basis requirements with respect to NRC GL 88-17. Additional discussion of NRC GL 88-17 is provided in LR [Section 2.8.7.1](#), Loss of Decay Heat Removal at Mid-loop Operation.

2.8.4.4.3 Conclusion

FPL has reviewed the effects of the proposed EPU on the SDC system. FPL concludes that the review has adequately accounted for the effects of the proposed EPU on the system and demonstrated that the SDC system will maintain its ability to cool the RCS following shutdown and provide decay heat removal. Based on this, FPL concludes that the SDC system will continue to meet its current licensing basis with respect to the requirements of GDCs -4, -5, and -34 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to the SDC system.

2.8.5 Accident and Transient Analyses

2.8.5.0 Accident and Transient Analyses

This section summarizes the non-loss-of-coolant-accident (non-LOCA) transient analyses and evaluations performed in support of the extended power uprate (EPU).

2.8.5.0.1 Fuel Design Mechanical Features

The effects of fuel design mechanical features on the non-LOCA transient analyses are accounted for in fuel-related input assumptions, such as fuel and cladding dimensions, cladding material, fuel temperatures, and core bypass flow. Additional information regarding the fuel related inputs are provided in LR [Section 2.8.3](#), Thermal and Hydraulic Design.

2.8.5.0.2 Peaking Factors, Kinetics Parameters

The power distribution is characterized by an enthalpy hot channel factor (radial peaking factor, F_r) of either 1.60 (Revised Thermal Design Procedure (RTDP) ([Reference 1](#))) or 1.696 (non-RTDP.) Also a peak linear heat rate of 12.5 kW/ft is applied for the 16x16 Combustion Engineering (CE) High Impact Design (HID)-IL fuel design with ZIRLO™ cladding. F_r is important for transients that are departure from nucleate boiling (DNB) limited (note that LR [Table 2.8.5.0-2](#) identifies those events analyzed for DNB concerns as well as the DNB methodology used: (RTDP or non-RTDP)). Since F_r increases with decreasing power level (due to rod insertion), transients that may be DNB limited are assumed to begin with an F_r consistent with the value defined in the technical specifications (TS) for the nominal power level. Peak linear heat rate is important for transients that will be overpower limited. The peak linear heat rate will increase with decreasing power level such that the full power hot-spot heat flux is not exceeded. Consequently, all non-LOCA transients for the EPU that will be overpower limited assume an initial hot full power peak linear heat rate of 12.5 kW/ft. The analyses of events that are sensitive to minimum shutdown margin (SDM) are analyzed with a SDM of 3,600 pcm (T_{avg} greater than 200 °F), which is consistent with the current core operating limits report (COLR) limits. Additional information regarding the above described inputs is provided in LR [Sections 2.8.2](#), Nuclear Design, and [2.8.3](#), Thermal and Hydraulic Design.

2.8.5.0.3 EPU Features

The key EPU features considered in the non-LOCA transient analyses are as follows:

1. A nuclear steam supply system (NSSS) power of 3050 MWt which includes uncertainty and a reactor coolant pump (RCP) heat input of 20 MWt;
2. A nominal, full power reactor coolant vessel inlet temperature (T_{in}) window of 535.0°F to 551.0°F;
3. A reactor coolant system (RCS) thermal design flow (TDF) of 375,000 gpm (187,500 gpm per loop);

4. A design core bypass flow of 3.7%;
5. The CE 16x16 Standard Fuel product;
6. The AREVA Model 86/19 TI steam generators (SGs) with a maximum steam generator tube plugging (SGTP) of 10%;
7. Radial peaking factor changed from 1.7 to 1.6 (full power) to gain analysis margin; and
8. Control Element Assembly (CEA) drop time changed to 3.25 sec for 90% insertion.

For accidents that are DNB limited, the allowances on power, temperature, and pressure are determined on a statistical basis and included in the design limit departure from nucleate boiling ratio (DNBR), as described in WCAP-11397 (Reference 1). This procedure is known as the RTDP.

The standard thermal design procedure (STDP) is used for accidents that are not DNB limited, or in which the RTDP is not employed, the initial conditions are obtained by applying the maximum steady state errors. The following steady state errors are considered:

- Core power: calorimetric error is a function of analyzed power level (LR Figure 2.8.5.0-1),
- Average RCS temperature: $\pm 3.0^{\circ}\text{F}$ temperature measurement error, and
- Pressurizer pressure: ± 45 psi steady state fluctuations and pressure measurement error.

LR Table 2.8.5.0-2 summarizes initial conditions and computer codes used in the accident analyses and shows which accidents employ RTDP.

2.8.5.0.4 Other Major Assumptions

LR Table 2.8.5.0-1 lists the rated thermal power (RTP) (core) for the EPU. It also presents the NSSS thermal power output that includes the thermal power generated by the RCPs. The values of the initial conditions used for each transient analyzed are given in LR Table 2.8.5.0-2, which support the proposed licensed core power of 3020 MWt associated with EPU. LR Table 2.8.5.0-3 presents a comparison of the current and EPU nominal pertinent plant parameters used in the non-LOCA safety analyses.

1. The pressurizer safety valves (PSVs) are modeled assuming a $\pm 3\%$ setpoint tolerance.
2. The main steam safety valves (MSSVs) are modeled with different opening pressures for the two banks. The first bank of valves is modeled using a 3% tolerance and a 3% accumulation. A maximum tolerance of 2% (+2%), a minimum tolerance of 3% (-3%) and 3% accumulation are modeled for the second bank of MSSVs.
3. The fission product contribution to decay heat assumed in the non-LOCA analyses bounds the American Nuclear Society (ANS)-5.1-1979 residual decay heat model, increased by two standard deviations for conservatism.

2.8.5.0.5 Thermal Margin/Low Pressure Reactor Trip Setpoints

The current thermal margin/low pressure (TM/LP) reactor trip function ensures that the DNB design basis is satisfied for St. Lucie Unit 2. It also precludes hot leg boiling to ensure that power can be calculated as a function of T_{inlet} and ΔT . The TM/LP reactor trip is a function of the RCS temperature, the pressurizer pressure, the core power as measured by the excore detector or the ΔT and the axial power shape as defined by the bottom detector signal minus the top detector signal divided by the total power (axial shape index (ASI)). The TM/LP reactor trip is valid from the TM/LP floor (low pressurizer pressure trip) to the high pressurizer pressure trip (safety analysis values). The TM/LP is also limited by the locus of conditions defined by:

- The MSSVs, which will limit an increase in the RCS temperature; and
- The variable high power reactor trip function (safety analysis value), which limits the overpower condition.

The TM/LP is based on all of the RCPs being in operation and accounts for changes in the axial power shape via the A_1 function, which adjusts the setpoint for variations in the axial power shape.

The current TM/LP reactor trip function in the TS is presented below.

$$P_{var} \text{ (trip)} = 1400 * Q_{DNB} + 17.85 * T_{in} - 9410$$

$$\text{Where: } A_1 * QR_1 = Q_{DNB}$$

Where the QR_1 and A_1 functions are defined in the TS

The QR_1 function is a linear function which adjusts the TM/LP setpoint to account for the effects of an increase in the F_r at lower power levels. As noted above, the A_1 function adjusts the setpoint for variations in the axial power shapes.

The current TM/LP reactor trip setpoint described above was confirmed to be valid for the EPU. The confirmation of the TM/LP reactor trip setpoint was based on the approach presented in WCAP-8745-P-A (Reference 2). The approach presented in WCAP-8745 ensures that the Overtemperature ΔT (OTDT) reactor trip setpoint, which is similar in functionality to the TM/LP reactor trip function (Reference 11), protects the core thermal limits, which include the DNB core thermal limits and the hot leg boiling limits. The TM/LP setpoint with an A_1 function of 1.0 (that is, corresponding to an axial power shape with an ASI of 15%) was demonstrated to bound a conservative set of core thermal limits, based on a limiting reference axial power shape for an ASI of 15%. These core limits are applicable to St. Lucie Unit 2 fuel and are based on a rated core power of 3030 MWt (including uncertainty), an RCS minimum measured flowrate (MMF) of 390,000 gpm and a design F_r of 1.60. The core thermal limits present a locus of conditions where the DNB design basis is satisfied and hot leg boiling is precluded and consider variations in the RCS inlet temperature with power and pressure. The relationship of the TM/LP setpoint with an A_1 of "1.0" (minimum value) corresponding to an ASI of 15% to the reference core thermal limits is illustrated in LR Figure 2.8.5.0-2. The locus of conditions for the TM/LP is obtained as a function of the inlet temperature and the pressurizer pressure. The area of permissible operation (power, temperature, and pressure) is bounded by the combination of the following:

- Variable high power reactor trip which is 112% of rated thermal power, the TM/LP analysis conservatively assumes a maximum of 125% of rated thermal power;
- High pressurizer pressure reactor trip is evaluated at 2415 psia;
- TM/LP floor setpoint is evaluated at 1855 psia for a normal environment; and
- The MSSVs assuming a pressure corresponding to 110% of design pressure (1100 psia).

It should be noted that the TM/LP “protection lines” in LR [Figure 2.8.5.0-2](#) are drawn to include the uncertainties as defined by the approved Extended Statistical Combination of Uncertainties (ESCU) methodology ([Reference 13](#)). The uncertainties include processing uncertainties, system parameter uncertainties, ASI uncertainties and critical heat flux correlation uncertainties. These uncertainties, as defined by the ESCU penalty factors, have been incorporated into the TM/LP “protection lines.” Under nominal conditions, a reactor trip on the TM/LP reactor trip function would occur well within the area bounded by these lines. The figure shows that the safety analysis limit DNBR is bounded by the TM/LP protection lines, the variable high power protection lines including uncertainties, and the main steam safety valve lines.

In addition to confirming that the TM/LP reactor trip function protects the core thermal limits, it is necessary to ensure that the current A_1 function is adequately adjusting the TM/LP reactor trip setpoint for skewed axial power shapes. The approach for confirming the A_1 function is similar to the approach performed for the OTDT $f(\Delta I)$ function, as discussed in WCAP-8745-P-A ([Reference 2](#)). That is, a DNB analysis is performed on a large number of highly skewed axial power shapes, as generated via the relaxed axial offset control (RAOC) methodology ([Reference 9](#)). A conservative penalty of T_{in} versus ASI is generated based on this DNB analysis. This curve is used to adjust the core thermal limits for various ASI values. The resulting relationship is compared to the TM/LP A_1 function. The result is that for skewed axial power shapes, the TM/LP A_1 function continues to conservatively protect the locus of conditions corresponding to the safety analysis DNBR limit.

The TM/LP reactor trip function is directly credited in the safety analysis models, which includes the dynamic effects associated with fluid transport, instrumentation response time, protection system delays and delays associated with the time for the control rods to drop. The analysis of the Updated Final Safety Analysis Report (UFSAR) Chapter 15 non-LOCA events, such as CEA Withdrawal at Power and RCS Depressurization, ensure that the TM/LP function adequately protects against the onset of DNB. Inclusion of the trip function in the safety analyses, including the dynamic effects, is necessary because the evaluation of the TM/LP protective function against the core thermal limits is performed as a “steady state” calculation. The UFSAR Chapter 15 non-LOCA safety analyses demonstrate that under transient conditions, the TM/LP reactor trip function with uncertainties provides protection such that the DNB design basis is satisfied and hot leg boiling is precluded.

Based on the above, the current TM/LP reactor trip function has been confirmed to provide the necessary protection to ensure that the DNB design basis is satisfied and to ensure that vessel exit boiling is precluded, thereby ensuring that power can be calculated as a function of T_{inlet} and ΔT .

2.8.5.0.6 Reactor Protection System and Engineered Safety Features Evaluation Functions Assumed in Analyses

Limiting trip setpoints assumed in accident analyses and the time delays assumed for each trip function are given in LR [Table 2.8.5.0-4](#). The total delay to trip is defined as the time delay from the time that the trip conditions are reached until the time the rods are released. There are various instrumentation delays associated with each trip function including delays in signal actuation, in opening of the trip breakers, and in the release of the rods. A reactor trip signal acts to open trip breakers that remove power to the control rod drive mechanism (CRDM). The loss of power to the mechanism coils cause the release of the CEAs, which then fall by gravity into the core.

The difference between the limiting trip point assumed for the analysis and the nominal trip point represents an allowance for instrumentation channel error and setpoint error. Nominal trip setpoints are specified in the plant technical specifications. Additionally, protection system channels are calibrated and instrument response times are determined periodically in accordance with the plant technical specifications. No changes to the trip setpoints or delay times were required from the current analysis basis to support the EPU.

2.8.5.0.7 CEA Reactivity Characteristics

The negative reactivity insertion following a reactor trip is a function of the position versus time of the CEAs and the variation in rod worth as a function of rod position. The CEA position versus time assumed in accident analyses is shown in LR [Figure 2.8.5.0-3](#). Following a 0.74 second breaker opening delay, a CEA insertion time of 2.81 seconds, for a total drop time of 3.55 seconds, is assumed in the safety analyses unless otherwise noted in the discussion of a specific event. The insertion times are specified in the plant technical specifications.

LR [Figure 2.8.5.0-4](#) shows the fraction of total negative reactivity insertion versus normalized rod position for a core that the axial distribution is skewed to the lower region of the core. The total negative reactivity insertion assumes that the most reactive CEA is stuck in the fully withdrawn position. This curve is used to compute the negative reactivity insertion versus time following a reactor trip which is input to the point kinetics core model used in the transient analyses. The bottom skewed power distribution itself is not an input into the point kinetics core model. Incorporating a skewed flux distribution which would exist infrequently in the normalized CEA worth versus normalized CEA position ensures that there is inherent conservatism in the use of LR [Figure 2.8.5.0-4](#) as input to the analysis.

A total negative reactivity insertion of 5.2 percent following reactor trip is assumed in the transient analyses except where specifically noted otherwise. This assumption is conservative with respect to the calculated trip reactivity worth available. LR [Figure 2.8.5.0-3](#) shows the normalized CEA drop time characteristics. The safety analyses assume a drop time of 2.81 seconds. LR [Figures 2.8.5.0-3](#) and [2.8.5.0-4](#) are used to define a conservative trip reactivity versus time relationship in those transient analyses for which a point kinetics core model is used.

In the CEA ejection and CEA withdrawal from a subcritical or low power condition analyses, LR [Sections 2.8.5.4.6](#) and [2.8.5.4.1](#), respectively, which use the TWINKLE code ([Reference 6](#)), a one-dimensional axial core model is employed where the negative reactivity insertion resulting

from the reactor trip is calculated directly by the reactor kinetics code and is not separable from the other reactivity feedback effects. Note that the trip reactivity is verified to ensure that it does not exceed the technical specification limits.

2.8.5.0.8 Reactivity Coefficients

The transient response of the reactor system is dependent on reactivity feedback effects, and in particular the moderator temperature coefficient (MTC) and the Doppler power coefficient. The values used in the analysis of each event are given in LR [Table 2.8.5.0-2](#).

In the analysis of the non-LOCA events, either the maximum reactivity feedback values or the minimum reactivity feedback values are assumed for conservatism. LR [Figure 2.8.5.0-5](#) shows the upper and lower bound Doppler power coefficients as a function of power, used in the accident analysis. LR [Figure 2.8.5.0-6](#) shows the maximum MTC as a function of power level. The justification for use of maximum versus minimum reactivity feedback coefficient values is treated on an event-by-event basis. In some cases conservative combinations of parameters are used for a given transient to bound the effects of core life, although these may represent unrealistic combinations.

2.8.5.0.9 Computer Codes Utilized

Summaries of the principal computer codes used in the transient analyses are given below. The codes used in the analyses of each non-LOCA transient have been listed in LR [Table 2.8.5.0-2](#).

FACTRAN

The FACTRAN program calculates the transient temperature distribution in a cross section of a metal clad uranium dioxide (UO₂) fuel rod and the transient heat flux at the surface of the cladding using it as input to the nuclear power and the time dependent coolant parameters (pressure, flow, temperature, and density). The code uses a fuel model which exhibits the following features simultaneously:

- A sufficiently large number of radial space increments to handle fast transients, such as rod ejection accidents;
- Material properties, which are functions of temperature and a sophisticated fuel-to-cladding gap heat transfer calculation; and
- The necessary calculations to handle post DNB transients: film boiling heat transfer correlations, Zircaloy-water reaction, and partial melting of the fuel.

The FACTRAN licensing topical report, WCAP-7908-A ([Reference 3](#)), was approved by the Nuclear Regulatory Commission (NRC) via a Safety Evaluation Report (SER) from C. E. Rossi (NRC) to E. P. Rahe (Westinghouse), dated September 30, 1986. The FACTRAN SER identifies seven conditions of acceptance, which are summarized and discussed in LR Appendix A. FACTRAN is used to perform the current analyses of record for St. Lucie Unit 2.

RETRAN

RETRAN is used for studies of transient response of a pressurized water reactor (PWR) system to specified perturbations in process parameters. This code simulates a multi-loop system which includes the reactor vessel, hot- and cold-leg piping, RCPs, SGs (tube and shell sides), steam lines, and the pressurizer. The pressurizer heaters, spray, relief valves, and safety valves are also modeled. RETRAN includes a point neutron kinetics model and reactivity effects of the moderator, fuel, boron, and control rods. The secondary side of the steam generator uses a detailed nodalization for the thermal transients. The reactor protection system (RPS) modeled with RETRAN includes reactor trips on variable high power, TM/LP, low RCS flow, high pressurizer pressure, low pressurizer pressure (TM/LP floor), low steam generator pressure, and low steam generator water level. Control systems are also simulated including rod control and pressurizer pressure control. Parts of the safety injection system (SIS), including the safety injection tanks, may also be modeled. RETRAN approximates the transient value of DNBR based on input from the core thermal limits.

The RETRAN licensing topical report, WCAP-14882-P-A ([Reference 5](#)), was approved by the NRC via a SER from F. Akstulewicz (NRC) to H. Sepp (Westinghouse), dated February 11, 1999. The RETRAN SER identifies three conditions of acceptance, which are summarized and discussed in LR Appendix A. RETRAN is further discussed in [Reference 4](#). RETRAN is used to perform the current analyses of record for St. Lucie Unit 2 with the exception of the Steam Generator Tube Rupture (SGTR) event (LR [Section 2.8.5.6.2](#)), although RETRAN is used for the EPU SGTR analysis.

TWINKLE

The TWINKLE program is a multi-dimensional spatial neutron kinetics code that is patterned after steady state codes presently used for reactor core design. The code uses an implicit finite-difference method to solve the two-group transient neutron diffusion equations in one, two, and three dimensions. The code uses six delayed neutron groups and contains a detailed multi-region fuel-cladding-coolant heat transfer model for calculating point-wise Doppler and moderator feedback effects. The code handles up to 8000 spatial points and performs its own steady state initialization. Aside from basic cross-section data and thermal-hydraulic parameters, the code accepts as input basic driving functions such as inlet temperature, pressure, flow, boron concentration, control rod motion, and other functions. Various edits are provided; e.g., channel-wise power, axial offset, enthalpy, volumetric surge, point-wise power, and fuel temperatures.

The TWINKLE code is used to predict the kinetic behavior of a reactor for transients that cause a major perturbation in the spatial neutron flux distribution.

The TWINKLE licensing topical report, WCAP-7979-P-A ([Reference 6](#)), was approved by the U.S. Atomic Energy Commission (AEC) via a SER from D. B. Vassallo (AEC) to R. Salvatori (Westinghouse), dated July 29, 1974. The TWINKLE SER does not identify any conditions, restrictions, or limitations that need to be addressed for application to St. Lucie Unit 2. TWINKLE is used to perform the current analyses of record for St. Lucie Unit 2.

Advanced Nodal Code (ANC)

ANC is an advanced nodal code capable of two-dimensional (2-D) and three-dimensional (3-D) neutronics calculations. ANC is the reference model for certain safety analysis calculations, power distributions, peaking factors, critical boron concentrations, control rod worths, reactivity coefficients, etc. In addition, 3-D ANC validates 1-D and 2-D results and provides information about radial (x-y) peaking factors as a function of axial position. It can calculate discrete pin powers from nodal information as well.

The ANC licensing topical report, WCAP-10965-P-A ([Reference 10](#)), was approved by the NRC via a SER from C. Berlinger (NRC) to E. P. Rahe (Westinghouse), dated June 23, 1986. The ANC SER does not identify any conditions, restrictions, or limitations that need to be addressed for application to St. Lucie Unit 2. ANC is used to perform the current analyses of record for St. Lucie Unit 2. The ANC qualification report is documented in WCAP-11596-P-A ([Reference 14](#)).

VIPRE-W

VIPRE-W predicts the 3-D velocity, pressure, and thermal energy fields and fuel rod temperatures for single- and two-phase flow. It solves the finite difference equations for mass, energy, and momentum conservation for an interconnected array of channels, assuming an incompressible, thermally expandable homogeneous flow. The equations are solved with no time step or channel size restrictions for stability. Although the formulation is homogeneous, non-mechanistic models are included for subcooled boiling and vapor/liquid slip in two-phase flow.

Like most other core thermal-hydraulic codes, the VIPRE-W modeling structure is based on a subchannel analysis. The core or section of symmetry is defined as an array of parallel flow channels with lateral connections between adjacent channels. A channel may represent a true subchannel within a rod array, a closed tube, or a larger flow area representing several subchannels or rod bundles. The shape and size of the channels and their interconnections are essentially arbitrary. The user has a great deal of flexibility for modeling reactor cores or any other fluid flow geometry.

The VIPRE licensing topical report, WCAP-14565-P-A ([Reference 7](#)), was approved by the NRC via a SER from T. H. Essig (NRC) to H. Sepp (Westinghouse), dated January 19, 1999. The VIPRE-W SER identifies four conditions of acceptance, which are summarized and discussed in LR Appendix A. The VIPRE-W code includes the ABB-NV critical heat flux correlation ([Reference 7](#)). VIPRE-W is used to perform the current analyses of record for St. Lucie Unit 2.

2.8.5.0.10 Classification of Events

Each of the non-LOCA events listed in LR [Table 2.8.5.0-5](#) is presented in Chapter 15, Accident Analysis, of the UFSAR. Each non-LOCA event is categorized with respect to its potential consequences. For St. Lucie Unit 2, the events fall into two principal classifications: Anticipated Operational Occurrences (AOOs) and Postulated Accidents (PAs). Where applicable, the RPS and/or Engineered Safety Features (ESFs) were assumed to fulfill their function as needed to

mitigate the consequences of a given event. The classification for St. Lucie Unit 2 is described below.

- Anticipated Operational Occurrences include those events which: (1) do not induce fuel failures, (2) do not lead to a breach of barriers and fission product release, (3) may not require operation of any engineered safety features, and (4) do not lead to significant radiation exposures offsite.

Postulated Accidents include those events which: (1) may induce fuel failures, (2) may lead to a breach of barriers and fission product release, (3) may require operation of engineering safety features, and (4) may result in offsite radiation exposures in excess of normal operational limits.

Reference 5 lists each event and its associated classification.

2.8.5.0.11 Events Evaluated or Analyzed

Each of the UFSAR Chapter 15 transients listed in LR **Table 2.8.5.0-5** were analyzed or evaluated in support of the EPU using cycle-independent input parameters based on the approved Westinghouse WCAP-9272 reload evaluation methodology (**Reference 12**). The key input parameters for each reload core design uses values that are conservatively bounded by those in the EPU reference safety analyses. For each reload core, the values of the key input parameters are examined to determine whether a transient analysis is required or not. If all key input parameters are conservatively bounded, the reference safety analysis remains valid for the reload core. If a reload parameter is not bounded, further analysis or evaluation is required for the reload core. The transient analyses and evaluations performed for the EPU demonstrate that all applicable safety analysis acceptance criteria are satisfied.

The non-LOCA safety analyses did not identify the need to add any new system components to achieve accident mitigation. Because the non-LOCA safety analyses did not require the addition of new components, or require existing components to function in a way not previously evaluated, the license renewal evaluation bases are not changed. The results of the non-LOCA safety analyses show that the components credited for the accident analyses will be exposed to the same internal and external environments as previously evaluated.

As there is no change to the components, component materials of construction, and internal or external operating environments required to mitigate the non-LOCA accidents, no new aging effects requiring management have been identified. Accordingly, there is no impact on the plant license renewal as a result of the EPU non-LOCA analyses.

Limits and results for each of the UFSAR Chapter 15 events analyzed are presented in LR **Table 2.8.5.0-5**.

2.8.5.0.12 Analysis Methodology

The transient-specific analysis methodologies that were applied have been reviewed and approved by the NRC via topical reports and/or through the review and approval of plant-specific safety analysis reports. Specifically, the non-LOCA safety analysis methods utilized in support of the EPU were previously approved by the NRC as part of the 30% steam generator tube

plugging and WCAP-9272 (Reference 11) reload methodology change program. LR Table 2.8.5.0-2 identifies the UFSAR Chapter 15 non-LOCA safety analyses and the computer codes utilized in their analysis. Consistent with the current non-LOCA safety analyses only safety grade systems are credited as part of the transient. Note that control grade systems may be credited should their use make the transient more limiting with respect to the acceptance criteria. Note that the current methodology (Reference 11) was used to analyze the steam generator tube rupture event; however, the thermal-hydraulic response computer code utilized was changed. In the current methodology (Reference 11), the thermal-hydraulic response of this event was analyzed with the CESEC computer code. As part of the EPU, this event was analyzed with the RETRAN computer code (References 4 and 5) to make it consistent with the remainder of the current UFSAR Chapter 15 safety analyses. Although the computer code used in the analysis of this event was migrated, the methodologies outlined and approved in Reference 11 were maintained. Details of the SGTR analysis are provided in LR Section 2.8.5.6.2, Steam Generator Tube Rupture. Compliance for the EPU safety analyses with the limitations, restrictions, and conditions presented in the RETRAN SER (Reference 5) are discussed in LR Appendix A, Section A.7.

2.8.5.0.13 Operator Actions

The UFSAR Chapter 15 non-LOCA transient safety analyses analyzed or evaluated in support of the EPU did not credit operator action to benefit the transients.

2.8.5.0.14 Key Safety Analysis Input Changes

The key non-LOCA transient safety analysis input changes made in support of the EPU are identified in LR Table 2.8.5.0-3.

2.8.5.0.15 References

1. WCAP-11397-P-A (Proprietary) and WCAP-11397-A (Non-Proprietary), Revised Thermal Design Procedure, April 1989.
2. WCAP-8745-P-A, Design Bases for the Thermal Overpower ΔT and Thermal Overtemperature ΔT Trip functions, September 1986.
3. WCAP-7908-A, FACTRAN - A FORTRAN IV Code for Thermal Transients in a UO₂ Fuel Rod, December 1989.
4. EPRI NP-1850-CCMA, RETRAN-02 - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems.
5. WCAP-14882-P-A (Proprietary) and WCAP-15234-A (Non-Proprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, April 1999.

6. WCAP-7979-P-A (Proprietary) and WCAP-8028-A (Non-Proprietary), TWINKLE - A Multi-Dimensional Neutron Kinetics Computer Code, January 1975.
7. WCAP-14565-P-A, Addendum 1, Addendum 1 to WCAP-14565-P-A Qualification of ABB Critical Heat Flux Correlations with VIPRE-01 Code, June 2002.
8. Not used.
9. WCAP-10216-P-A, Relaxation of Constant Axial Offset Control; - FQ Surveillance Technical Specification, February 1994.
10. WCAP-10965-P-A, ANC - A Westinghouse Advanced Nodal Computer Code, September 1986.
11. NRC Letter to J. A. Stall (FPL) from B. T. Moroney (NRC), St. Lucie Plant, Unit No. 2 - Issuance of Amendment Regarding Change in Reload Methodology and Increase in Steam Generator Tube Plugging Limit (TAC No. MC1566), January 2005 (ADAMS Accession No. ML050120363)
12. WCAP-9272-P-A, Westinghouse Reload Safety Evaluation Methodology, July 1985.
13. CEN-348(B)-P-A, Extended Statistical Combination of Uncertainties, January 1988.
14. WCAP-11596-P-A, Qualification of the Phoenix-P/ANC Nuclear Design System for Pressurized Water Reactor Cores, June 1988.

Table 2.8.5.0-1
EPU Nuclear Steam Supply System Power Ratings

Rated Reactor Core Thermal Power Output, MWt	3020
NSSS Rated Thermal Power, MWt	3034.2
Thermal Power Generated by the Reactor Coolant Pumps, MWt	
Nominal (total, 4 pumps in operation)	14.2
Maximum (total, 4 pumps in operation)	20

Table 2.8.5.0-2
Summary of Initial Conditions and Computer Codes

	Event	Computer Codes Used	Moderator Density Coefficient ($\Delta k/gm/cc$)	Moderator Temperature Coefficient ($pcm/^{\circ}F$)	Doppler Power Coefficient	DNB Correlation	Revised Thermal Design Procedure	Initial Core Thermal Power (MWt)
Increase in Heat Removal by the Secondary System								
	Decrease in Feedwater Temperature	RETRAN	0.43	See Figure 2.8.5.0-6	Upper Curve of Figure 2.8.5.0-5	ABB-NV	Yes	3020
	Increase in Feedwater Flow Rate	RETRAN	0.43	See Figure 2.8.5.0-6	Upper Curve of Figure 2.8.5.0-5	ABB-NV	Yes	3020
	Excessive Increase in Main Steam Flow	RETRAN	N/A	See Figure 2.8.5.0-6	Upper Curve of Figure 2.8.5.0-5	ABB-NV	Yes	3020
	Inadvertent Opening of an SG Relief or Safety Valve	RETRAN	N/A	See Figure 2.8.5.0-6	Upper Curve of Figure 2.8.5.0-5	ABB-NV	Yes	3020
	Pre-Trip Steamline Break with Failure of the Fast Bus Transfer (FFBT)	RETRAN, VIPRE, ANC	0.0 to 0.43	See Figure 2.8.5.0-6	Upper Curve of Figure 2.8.5.0-5	ABB-NV	Yes	3020
	Pre-Trip Steamline Break Coincident with Loss of Offsite Power (LOOP)	RETRAN, VIPRE, ANC	0.30	See Figure 2.8.5.0-6	Upper Curve of Figure 2.8.5.0-5	ABB-NV	Yes	3020
	Post-Trip Steamline Break	RETRAN, VIPRE, ANC	See Figure 2.8.5.0-7	-4.5	See Figure 2.8.5.0-8	ABB-NV	No	0 (subcritical)

Table 2.8.5.0-2 (Continued)
Summary of Initial Conditions and Computer Codes

	Event	Computer Codes Used	Moderator Density Coefficient ($\Delta k/gm/cc$)	Moderator Temperature Coefficient (pcm/ $^{\circ}F$)	Doppler Power Coefficient	DNB Correlation	Revised Thermal Design Procedure	Initial Core Thermal Power (MWt)
Decrease in Heat Removal by the Secondary System								
	Loss of Condenser Vacuum – Overpressure Case	RETRAN	N/A	See Figure 2.8.5.0-6	Upper Curve of Figure 2.8.5.0-5	N/A	No	3030
	Loss of Condenser Vacuum – DNB Case	RETRAN, VIPRE	N/A	See Figure 2.8.5.0-6	Upper Curve of Figure 2.8.5.0-5	ABB-NV	Yes	3020
	Loss of Non-Emergency AC to the Station Auxiliaries	Bounded by LOCV and Loss of Flow	N/A	N/A	N/A	N/A	N/A	N/A
	Loss of Normal Feedwater Flow	Bounded by LOCV and Loss of Flow	N/A	N/A	N/A	N/A	N/A	N/A
	Feedwater System Pipe Rupture – RCS Overpressure Case	RETRAN	N/A	See Figure 2.8.5.0-6	Upper Curve of Figure 2.8.5.0-5	N/A	No	3030
	Feedwater System Pipe Rupture – MSS Overpressure Case	RETRAN	N/A	See Figure 2.8.5.0-6	Upper Curve of Figure 2.8.5.0-5	N/A	No	3030
	Asymmetric Steam Generator Transient	RETRAN	0.43	See Figure 2.8.5.0-6	Upper Curve of Figure 2.8.5.0-5	ABB-NV	Yes	3020

Table 2.8.5.0-2 (Continued)
Summary of Initial Conditions and Computer Codes

	Event	Reactor Coolant Pump Heat (MWt)	Reactor Vessel Flow Rate (gpm)	Vessel T-avg (°F)	Pressurizer Pressure (psia)	Pressurizer Water Level (%)	Feedwater Temp. (°F)	SG Tube Plugging Level (%)
Increase in Heat Removal by the Secondary System								
	Decrease in Feedwater Temperature	14.2	390,000	578.5	2225	63.0	441.0	0.0
	Increase in Feedwater Flow Rate	14.2	390,000	578.5	2225	63.0	441.0	0.0
	Excessive Increase in Main Steam Flow	14.2	390,000	578.5	2225	63.0	441.0	0.0
	Inadvertent Opening of a SG relief or Safety Valve	14.2	390,000	578.5	2225	63.0	441.0	0.0
	Pre-Trip Steamline Break with FFBT	14.2	390,000	578.5	2225	63.0	441.0	0.0
	Pre-Trip Steamline Break Coincident with LOOP	14.2	390,000	578.5	2225	63.0	441.0	0.0
	Post-Trip Steamline Break	14.2	375,000	532.0	2225	33.1	70.0	0.0

Table 2.8.5.0-2 (Continued)
Summary of Initial Conditions and Computer Codes

	Event	Reactor Coolant Pump Heat (MWt)	Reactor Vessel Flow Rate (gpm)	Vessel T-avg (°F)	Pressurizer Pressure (psia)	Pressurizer Water Level (%)	Feedwater Temp. (°F)	SG Tube Plugging Level (%)
Decrease in Heat Removal by the Secondary System								
	Loss of Condenser Vacuum – Overpressure Case	14.2	375,000	560.0	2180	66.0	441.0	10
	Loss of Condenser Vacuum – DNB Case	14.2	390,000	578.5	2225	66.0	441.0	10
	Loss of Non-Emergency AC to the Station Auxiliaries	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Loss of Normal Feedwater Flow	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Feedwater System Pipe Rupture – RCS Overpressure Case	14.2	375,000	560.0	2180	66.0	441.0	10
	Feedwater System Pipe Rupture – MSS Overpressure	14.2	375,000	581.5	2180	66.0	441.0	0.0
	Asymmetric Steam Generator Transient	14.2	390,000	578.5	2225	66.0	441.0	0 or 10

Table 2.8.5.0-2
Summary of Initial Conditions and Computer Codes

	Event	Computer Codes Used	Moderator Density Coefficient ($\Delta k/gm/cc$)	Moderator Temperature Coefficient (pcm/ $^{\circ}F$)	Doppler Power Coefficient	DNB Correlation	Revised Thermal Design Procedure	Initial Core Thermal Power (MWt)
Decrease in RCS Flow Rate								
	Partial/Complete Loss of Forced Flow	RETRAN, VIPRE	N/A	See Figure 2.8.5.0-6	Lower Curve of Figure 2.8.5.0-5	ABB-NV	Yes	3020
	Reactor Coolant Pump Seized Rotor/Shaft Break – DNB Case	RETRAN, VIPRE	N/A	See Figure 2.8.5.0-6	Lower Curve of Figure 2.8.5.0-5	ABB-NV	Yes	3020
	Reactor Coolant Pump Seized Rotor/Shaft Break – Overpressure/PCT Case	RETRAN	N/A	See Figure 2.8.5.0-6	Lower Curve of Figure 2.8.5.0-5	N/A	No	3030

Table 2.8.5.0-2 (Continued)
Summary of Initial Conditions and Computer Codes

Event	Computer Codes Used	Moderator Density Coefficient ($\Delta k/gm/cc$)	Moderator Temperature Coefficient (pcm/ $^{\circ}F$)	Doppler Power Coefficient	DNB Correlation	Revised Thermal Design Procedure	Initial Core Thermal Power (MWt)
Reactivity and Power Distribution Anomalies							
Uncontrolled CEA Bank Withdrawal from Subcritical	TWINKLE, FACTRAN, VIPRE	N/A	5.0	900 pcm	ABB-NV	No	0.0 (subcritical)
Uncontrolled CEA Bank Withdrawal at Power	RETRAN	0.0 to 0.43	See Figure 2.8.5.0-6	Upper & Lower Curve of Figure 2.8.5.0-5	ABB-NV	Yes – DNBR No – RCS Peak Pressure	3020
CEA Misoperation (Dropped Rod)	RETRAN, VIPRE, ANC	N/A	0.0 to 35.0	Lower Curve of Figure 2.8.5.0-5	ABB-NV	Yes	3020
Startup of an Inactive Loop at an Incorrect Temperature	Precluded by Technical Specifications	N/A	N/A	N/A	N/A	N/A	N/A
Chemical and Volume Control System (CVCS) Malfunction That Results in a Decrease In The Boron Concentration in the Reactor Coolant	ABORTV1	N/A	N/A	N/A	N/A	N/A	N/A
CEA Ejection	TWINKLE, FACTRAN	N/A	See Note 1	900 pcm	N/A	No	0.0 & 3030

Table 2.8.5.0-2
Summary of Initial Conditions and Computer Codes

	Event	Reactor Coolant Pump Heat (MWt)	Reactor Vessel Flow Rate (gpm)	Vessel T-avg (°F)	Pressurizer Pressure (psia)	Pressurizer Water Level (%)	Feedwater Temp. (°F)	SG Tube Plugging Level (%)
Decrease in RCS Flow Rate								
	Partial/Complete Loss of Forced Flow	14.2	390,000	578.5	2225	63.0	441.0	10
	Reactor Coolant Pump Seized Rotor/Shaft Break – DNB Case	14.2	390,000	578.5	2225	63.0	441.0	10
	Reactor Coolant Pump Seized Rotor/Shaft Break – Overpressure/PCT Case	14.2	375,000	581.5	2395	66.0	441.0	10
Reactivity and Power Distribution Anomalies								
	Uncontrolled CEA Bank Withdrawal from Subcritical	N/A	375,000	532.0	2180	N/A	N/A	N/A
	Uncontrolled CEA Bank Withdrawal at Power	14.2	390,000	578.5	2225	63.0	441.0	10
	CEA Misoperation (Dropped Rod)	14.2	390,000	578.5	2225	63.0	441.0	0
	Startup of an Inactive Loop at an Incorrect Temperature	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	CVCS Malfunction That Results in a Decrease In The Boron Concentration in the Reactor Coolant	N/A	N/A	581.5 532.0	2250	N/A	N/A	10%
	CEA Ejection	N/A	375,000	581.5 532.0	2180.0	N/A	N/A	N/A

Table 2.8.5.0-2
Summary of Initial Conditions and Computer Codes

Event	Computer Codes Used	Moderator Density Coefficient ($\Delta k/gm/cc$)	Moderator Temperature Coefficient (pcm/ $^{\circ}F$)	Doppler Power Coefficient	DNB Correlation	Revised Thermal Design Procedure	Initial Core Thermal Power (MWt)
Increase in Coolant Inventory							
Inadvertent Emergency Core Cooling System (ECCS) Operation at Power	Precluded by SIS Design	N/A	N/A	N/A	N/A	N/A	N/A
CVCS Malfunction	RETRAN	0.43	-2.9	Lower Curve of Figure 2.8.5.0-5	N/A	No	3030
Decrease in Coolant Inventory							
Inadvertent RCS Depressurization	RETRAN	N/A	See Figure 2.8.5.0-6	Upper Curve of Figure 2.8.5.0-5	ABB-NV	Yes	3020
Steam Generator Tube Rupture	RETRAN	0.0	See Figure 2.8.5.0-6	Upper Curve of Figure 2.8.5.0-5	N/A	No	3030
Other Events							
Anticipated Transients Without Scram	Precluded by DSS, DTT, & DAFAS	N/A	N/A	N/A	N/A	N/A	N/A
DSS: Diverse Scram System DTT: Diverse Trip System DAFAS: Diverse Auxiliary Feedwater Actuation Signal							

Table 2.8.5.0-2
Summary of Initial Conditions and Computer Codes

	Event	Reactor Coolant Pump Heat (MWt)	Reactor Vessel Flow Rate (gpm)	Vessel T-avg (°F)	Pressurizer Pressure (psia)	Pressurizer Water Level (%)	Feedwater Temp. (°F)	SG Tube Plugging Level (%)
Increase in Coolant Inventory								
	Inadvertent ECCS Operation at Power	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	CVCS Malfunction	20.0	375,000	581.5	2180	60.0	441.0	10
Decrease in Coolant Inventory								
	Inadvertent RCS Depressurization	14.2	390,000	578.5	2225	63.0	441.0	10
	Steam Generator Tube Rupture	20.0	375,000	581.5	2395	71.0	441.0	10
Other Events								
	Anticipated Transients Without Scram	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Notes: 1. The following MTC values were assumed in the analysis of the CEA Ejection event: Beginning of life (BOL), hot zero power (HZIP) MTC = 5.0 pcm/°F BOL, hot full power (HFP) MTC = 0.0 pcm/°F End of life (EOL), HZIP ITC = -5.0 pcm/°F EOL, HFP ITC = -20.0 pcm/°F								

Table 2.8.5.0-3
Nominal Values of Pertinent Plant Parameters Utilized in the Accident Analyses

Equivalent Steam Generator Tube Plugging Level (all loops)	Current Hi-T _{avg}		Current Lo-T _{avg}		EPU Hi-T _{avg}		EPU Lo-T _{avg}	
	0%	30%	0%	30%	0%	10%	0%	10%
NSSS Thermal Power (MWt) ¹	2720	2720	2720	2720	3040	3040	3040	3040
Reactor Core Power (MWt) ²	2700	2700	2700	2700	3020	3020	3020	3020
HFP Core Inlet Temperature (°F)	549.0	549.0	535.0	535.0	551.0	551.0	535.0	535.0
HFP Vessel Average Temperature (°F)	576.5	576.5	563.0	563.0	578.5	578.5	563.0	563.0
Zero Load Temperature (°F)	532.0	532.0	532.0	532.0	532.0	532.0	532.0	532.0
Pressurizer Pressure (psia)	2250	2250	2250	2250	2250	2250	2250	2250
Total Reactor Vessel Inlet Flow (TDF, gpm) ³	335,000	335,000	335,000	335,000	375,000	375,000	375,000	375,000
Total Reactor Coolant Flow (10 ⁶ lb/hr)	126.1	126.1	128.4	128.4	140.8	140.8	143.8	143.8
Steam Flow from NSSS (10 ⁶ lb/hr)	11.87	11.83	11.82	11.79	13.42	13.41	13.36	13.35
Steam Pressure at Steam Generator Outlet (psia)	857	766	755	672	895	873	775	756
Maximum Steam Moisture Content (%)	0.25	0.25	0.25	0.25	0.10	0.10	0.10	0.10
Assumed Feedwater Temperature at Steam Generator Inlet (°F)	435.0	435.0	435.0	435.0	441.0	441.0	441.0	441.0
Notes: 1. Includes maximum reactor coolant pump heat (20 MWt). Nominal pump heat is 14.2 MWt. 2. Power measurement uncertainty not included. 3. Minimum measured flow is 349,500 gpm for 30% SGTP, minimum measured flow is 390,000 gpm for EPU.								

Table 2.8.5.0-4
Safety Analysis RPS and ESFAS Trip Setpoints and Delay Times

RPS Trip Function	Technical Specification Trip Setpoint	Analysis Setpoint
Variable Power Level – High (% Above Initial Power Level)	9.61	11.7 RTP>35%<100% 13.6 RTP ≤ 35%
Variable Power Level – Ceiling (% Rated Thermal Power)	107.0	112.0 ⁽¹⁾
Variable Power Level – Floor (% Rated Thermal Power)	15.0	24.5
Pressurizer Pressure – High (psia) Normal Environment Harsh Environment ⁽²⁾	2370	2415 2460
Pressurizer Pressure – Low (psia) (Floor of Thermal Margin/Low Pressure) Normal Environment Harsh Environment ⁽²⁾	1900	1855 1810
Steam Generator Pressure – Low (psia) Normal Environment Harsh Environment ⁽²⁾	626	586 546
Steam Generator Pressure – High Difference (psid)	120	230
Steam Generator Level – Low (% Narrow Range Tap Span)	20.5	1.0
Reactor Coolant Flow – Low (% of Thermal Design Flow)	95.4	Normal 88.4 ⁽³⁾ Harsh 84.5 ⁽³⁾
Notes: 1. Rod shadowing and downcomer temperature decalibration effects on excore detector signals are applied independently. 2. Harsh environment setpoints apply to inside containment steamline and feedwater line breaks. 3. Setpoint is equivalent to 91.9% of thermal design flow (normal environment) & 87.9% (harsh environment).		

Table 2.8.5.0-4 (continued)
Safety Analysis RPS and ESFAS Trip Setpoints and Delay Times

Engineered Safety Feature Actuation System (ESFAS) Function	Technical Specification Trip Setpoint	Analysis Setpoint
Safety Injection Actuation Signal (SIAS) on Pressurizer Pressure – Low (psia) Normal Environment Harsh Environment ⁽²⁾	1736	1683 1638
Main Steamline Isolation Signal (MSIS) on Steam Generator Pressure – Low (psia) Normal Environment Harsh Environment ⁽²⁾	600	527 487
Main Feedwater Isolation on Steam Generator Pressure – Low (psia) Normal Environment Harsh Environment ⁽²⁾	600	527 487
Auxiliary Feedwater Isolation on Steam Generator Pressure Difference – High (psid)	275	441
Notes: 2. Harsh environment setpoints apply to inside containment steamline and feedwater line breaks.		

Table 2.8.5.0-4 (continued)
Safety Analysis RPS and ESFAS Trip Setpoints and Delay Times

RPS Trip Function	Sensor Response Time Constant (sec)	Processing Delay (sec)	Total Delay Time (sec)
Variable High Power		0.4	0.4
Excore Neutron Power Detectors	<0.01 ⁽⁴⁾		0.4
Hot-Leg and Cold-Leg Resistive Thermal Devices (RTDs) (Thermal Power Calculation)	8.0		8.4
Pressurizer Pressure – High	0.75	0.4	1.15
Thermal Margin/Low Pressure		0.4	
Pressurizer Pressure	0.75		1.15
Hot-Leg and Cold-Leg RTDs (Thermal Power Calculation)	8.0		8.4
Excore Neutron Power detectors (ASI Calculation)	N/A		-
Steam Generator Pressure – Low	0.75	0.4	1.15
Steam Generator Pressure – High Difference	0.75	0.4	1.15
Steam Generator Level – Low	0.75	0.4	1.15
Reactor Coolant Flow – Low	0.50	0.4	0.90
ESFAS Function			Total Delay Time (sec)
Pressurizer Pressure – Low (Safety Injection (SI)) → To achieve full SI flowrate			30.0 ⁽⁵⁾
Steam Generator Pressure – Low → To complete MSIV closure			6.75
Steam Generator Pressure – Low → To complete Main Feedwater Isolation Valve (MFIV) closure			5.15
Auxiliary Feedwater Isolation On Steam Generator Pressure Difference – High → To complete auxiliary feedwater isolation to affected SG			120
Notes:			
4. Typical response time is 50 μ seconds.			
5. Response time for loss of offsite power; 20.0 second response time with power available			

Table 2.8.5.0-5
Non-LOCA Transients Classification and Analysis Result Summary

LR Section	UFSAR Section	Event	Event Description	Result Parameter	Analysis Limit	Analysis Result
2.8.5.1.1	15.1.1, 15.1.2, 15.1.3, 15.1.4	AOO	Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve	Minimum Departure from Nucleate Boiling Ratio (mDNBR) (Increase in Feedwater (FW) Flow)	1.42	1.96
				mDNBR (Reduced FW Temperature)	1.42	1.97
				Max. Post-trip Reactivity, β (HZIP)	N/A	-3.005
2.8.5.1.2	15.1.5, 15.1.6	PA	Steam System Piping Failures Inside and Outside Containment	mDNBR (Pre-Trip, FFBT)	1.42	1.63
				Peak Linear Heat Rate (PLHR), kW/ft (Pre-Trip, FFBT)	22	17.677
				mDNBR (Pre-Trip, LOOP)	1.42	1.76
				PLHR, kW/ft (Pre-Trip, LOOP)	22	<17.677
				mDNBR (Post-Trip) W-3 Correlation	1.30	4.286
				PLHR kW/ft (Post-Trip)	22	7.25
2.8.5.2.1	15.2.1, 15.2.2, 15.2.3, 15.2.5	AOO	Loss of External Load, Turbine Trip, and Loss of Condenser Vacuum	mDNBR, Loss of Condenser Vacuum (LOCV)	1.42	2.23
				Peak Primary Pressure, psia (LOCV)	2750	2669.14
				Peak Secondary Pressure, psia (LOCV)	1100	1093.97

Table 2.8.5.0-5 (Continued)
Non-LOCA Transients Classification and Analysis Result Summary

LR Section	UFSAR Section	Event	Event Description	Result Parameter	Analysis Limit	Analysis Result
2.8.5.2.2	15.2.6	AOO	Loss of Non-Emergency AC Power to the Station Auxiliaries	mDNBR	1.42	Bounded by LR Section 2.8.5.3.1
				Peak Primary Pressure, psia	2750	Bounded by LR Section 2.8.5.2.1
				Peak Secondary Pressure, psia	1100	Bounded by LR Section 2.8.5.2.1
2.8.5.2.3	15.2.7	AOO	Loss of Normal Feedwater Flow	mDNBR	1.42	Bounded by LR Section 2.8.5.3.1
				Peak Primary Pressure, psia	2750	Bounded by LR Section 2.8.5.2.1
				Peak Secondary Pressure, psia	1100	Bounded by LR Section 2.8.5.2.1
2.8.5.2.4	15.2.8	PA	Feedwater System Pipe Breaks Inside and Outside Containment	mDNBR	1.42	2.21
				Peak Primary Pressure, psia	2750	2704.2
				Peak Secondary Pressure, psia	1100	1094

Table 2.8.5.0-5 (Continued)
Non-LOCA Transients Classification and Analysis Result Summary

LR Section	UFSAR Section	Event	Event Description	Result Parameter	Analysis Limit	Analysis Result
2.8.5.2.5	15.2.9	AOO	Asymmetric Steam Generator Transient	mDNBR (0% SGTP)	1.42	2.229
				Peak Primary Pressure, psia (0% SGTP)	2750	2371
				Peak Secondary Pressure, psia (0% SGTP)	1100	1081
				mDNBR (10% SGTP)	1.42	2.229
				Peak Primary Pressure, psia (10% SGTP)	2750	2392
				Peak Secondary Pressure, psia (10% SGTP)	1100	1080
2.8.5.3.1	15.3.1, 15.3.2	AOO	Loss of Forced Reactor Coolant Flow	mDNBR	1.42	1.445
				Peak Primary Pressure, psia	2750	2405.7
				Peak Secondary Pressure, psia	1100	1039.5
2.8.5.3.2	15.3.3, 15.3.4	PA	Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break	Peak Clad Temperature, °F	2375	1589.8
				Max Reacted Zirconium, %	16	0.3
				Peak Primary Pressure, psia	2750	2650.03
				Rods-in-DNB, %	10	< 1.0
2.8.5.4.1	15.4.1	AOO	Uncontrolled Control Rod Assembly Withdrawal from a Subcritical or Low Power Startup Condition	mDNBR	1.26	1.28
				Peak Fuel Centerline Temperature, °F	4717	3432
				Peak Fuel Average Temperature, °F	N/A	2761

Table 2.8.5.0-5 (Continued)
Non-LOCA Transients Classification and Analysis Result Summary

LR Section	UFSAR Section	Event	Event Description	Result Parameter	Analysis Limit	Analysis Result
2.8.5.4.2	15.4.2	AOO	Uncontrolled Control Rod Assembly Withdrawal at Power	mDNBR	1.42	1.74
				Core Heat Flux, Fraction of Nominal (FON)	1.27	1.246
				PLHR, kW/ft	22	14.9
				Peak Primary Pressure, psia	2750	2485.2
				Peak Secondary Pressure, psia	1100	1090
				Pressurizer Overfill, ft ³	1519	1483.4
2.8.5.4.3	15.4.3	AOO	Control Element Assembly Misoperation	mDNBR	1.42	>1.42
				PLHR, kW/ft	22	<22.0
2.8.5.4.4	15.4.4	AOO	Startup of an Inactive Loop at an Incorrect Temperature	N/A	N/A	N/A
2.8.5.4.5	15.4.6	AOO	Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant	Minimum Time to Loss of Shutdown Margin, minutes (Modes 1-5)	>15	>15
				Minimum Time to Loss of Shutdown Margin, minutes (Mode 6)	>30	>30

Table 2.8.5.0-5 (Continued)
Non-LOCA Transients Classification and Analysis Result Summary

LR Section	UFSAR Section	Event	Event Description	Result Parameter	Analysis Limit	Analysis Result
2.8.5.4.6	15.4.8	PA	Spectrum of Rod Ejection Accidents	Max. Fuel Pellet Enthalpy, cal/g Beginning of Cycle (BOC)	200	151.4 (HFP), 78.2 (HZIP)
				Max. Clad Average Temperature, Deg F (BOC)	3000	1941.0 (HFP), 1373.0 (HZIP)
				Max Reacted Zirconium,% (BOC)	16	0.33 (HFP), 0.09 (HZIP)
				Rods-in-DNB,% (BOC)	9.5	< 9.5 (HFP and HZIP)
				Max Fuel Melted,% (BOC)	0.5	< 0.5 (HFP and HZIP)
				Max. Fuel Pellet Enthalpy, cal/g End of Cycle (EOC)	200	141.3 (HFP), 88.7 (HZIP)
				Max. Clad Average Temperature, Deg F (EOC)	3000	1832.0 (HFP), 1509.0 (HZIP)
				Max Reacted Zirconium,% (EOC)	16	0.24 (HFP), 0.09 (HZIP)
				Rods-in-DNB,% (EOC)	9.5	< 9.5 (HFP and HZIP)
				Max Fuel Melted,% (EOC)	0.5	< 0.5 (HFP and HZIP)

Table 2.8.5.0-5 (Continued)
Non-LOCA Transients Classification and Analysis Result Summary

LR Section	UFSAR Section	Event	Event Description	Result Parameter	Analysis Limit	Analysis Result
2.8.5.5	15.5.1	AOO	Inadvertent Operation of Emergency Core Cooling System (ECCS) and Chemical and Volume Control System (CVCS) Malfunction that Increases Reactor Coolant Inventory	mDNBR	1.42	Bounded by LR Section 2.8.5.4.2
				Peak Primary Pressure, psia	2750	Bounded by LR Section 2.8.5.2.1
				Peak Secondary Pressure, psia	1100	Bounded by LR Section 2.8.5.2.1
				Pressurizer Overfill, ft ³	1519	1512.3
2.8.5.6.1	15.6.1	AOO	Inadvertent Opening of a Pressurizer Pressure Relief Valve	mDNBR	1.42	1.73

Table 2.8.5.0-5 (Continued)
Non-LOCA Transients Classification and Analysis Result Summary

LR Section	UFSAR Section	Event	Event Description	Result Parameter	Analysis Limit	Analysis Result
2.8.5.6.2	15.6.2	PA	Steam Generator Tube Rupture	Steam Releases via Turbine to Condenser Prior to Trip (50.1% Affected SG/49.9% Intact SG), lbm	---	1,050,872
				Affected / Intact SG Steam Releases, lbm (from Reactor Trip to Operator Action)	---	131,269 / 103,333
				Affected SG Tube Leakage Before Trip, lbm	---	17,190
				Affected SG Tube Leakage from Reactor Trip to Operator Action, lbm	---	90,347
				RCS to Affected SG Total Tube Leakage, lbm	---	107,537
				Total Intact SG Steam Releases via ADV (from operator action to 2 hrs), lbm	---	492,200
				Total Intact SG Steam Releases via ADV (from 2 hrs to 8 hrs), lbm	---	911,300
2.8.5.7	15.9	N/A	Anticipated Transients Without Scram	N/A	N/A	N/A

Figure 2.8.5.0-1
Power Measurement Uncertainty Used in Accident Analysis

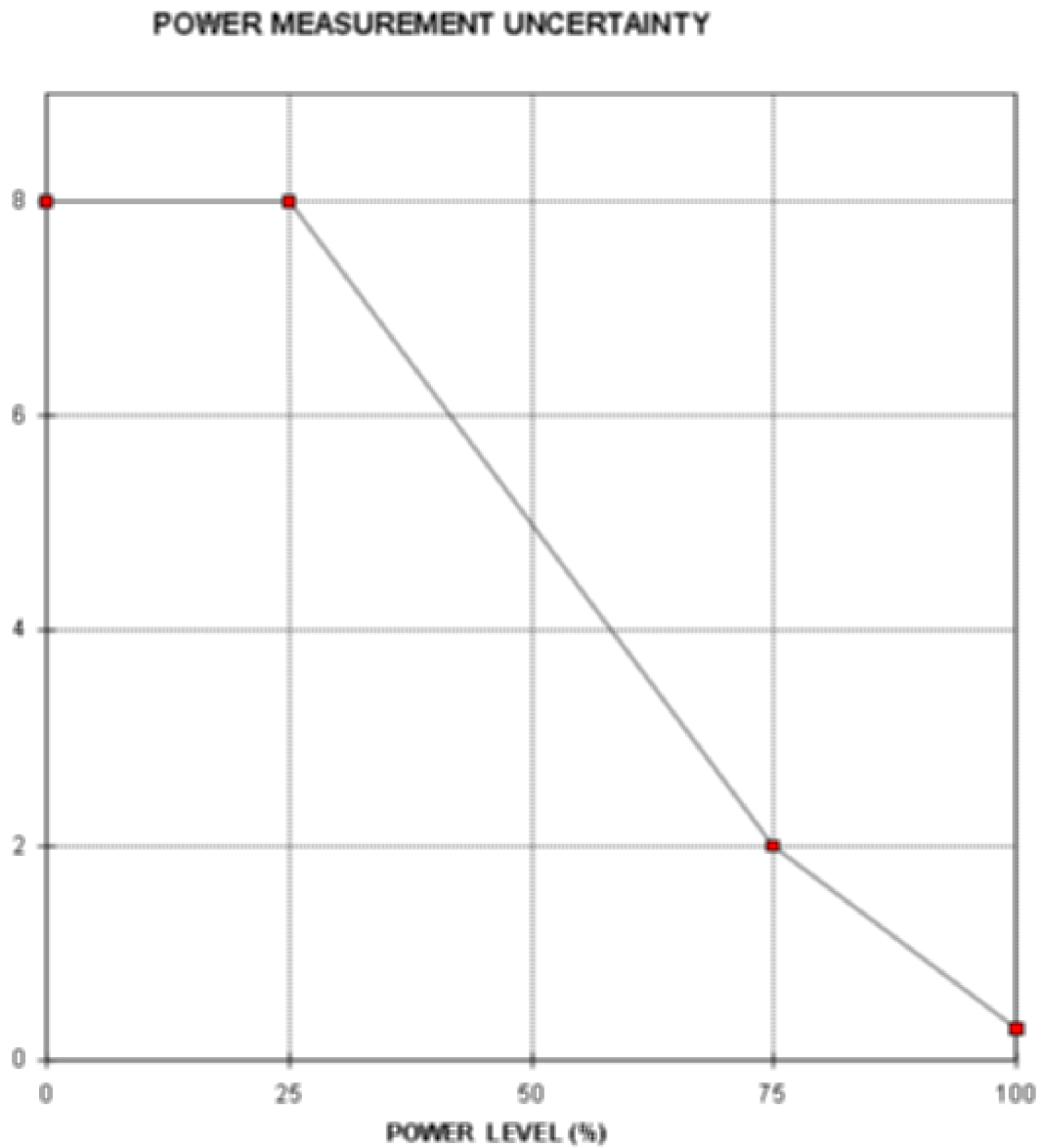


Figure 2.8.5.0-2
Illustration of the Thermal Margin / Low Pressure Reactor Trip Function
And the Core Thermal Limits
(Axial Power Distribution = 1.55 Cosine, ASI – 15%)

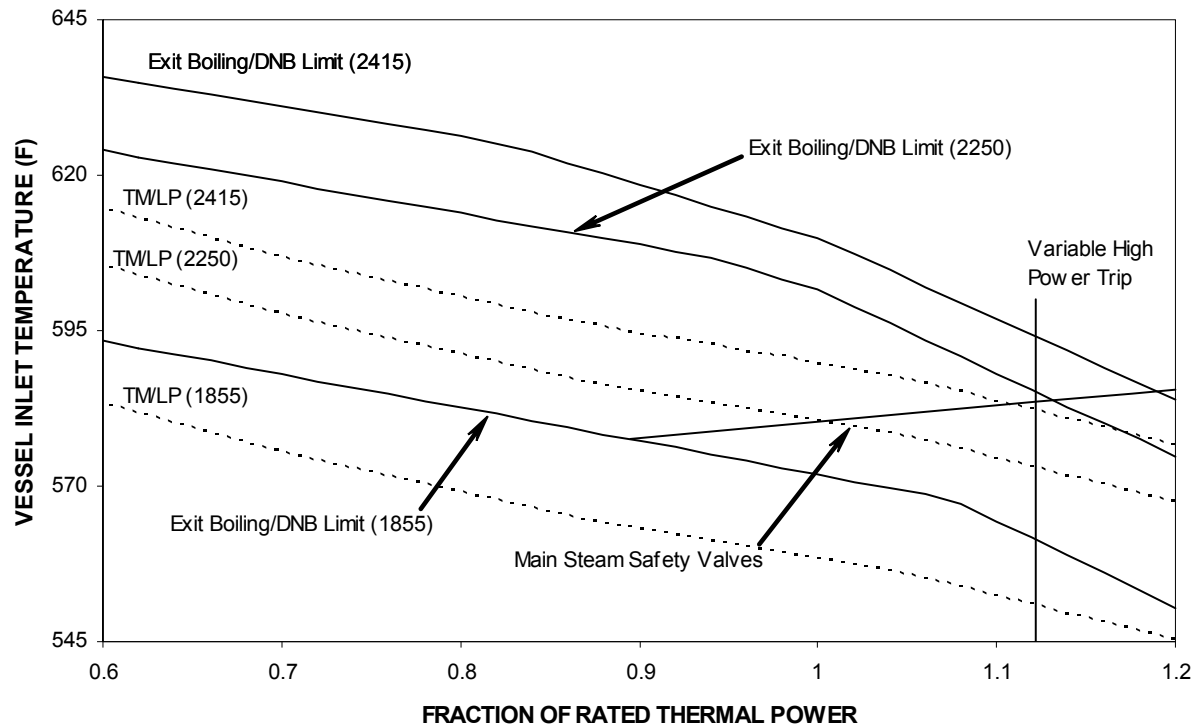


Figure 2.8.5.0-3
Normalized CEA Position vs. Normalized Time Following CEA Release from Reactor Trip

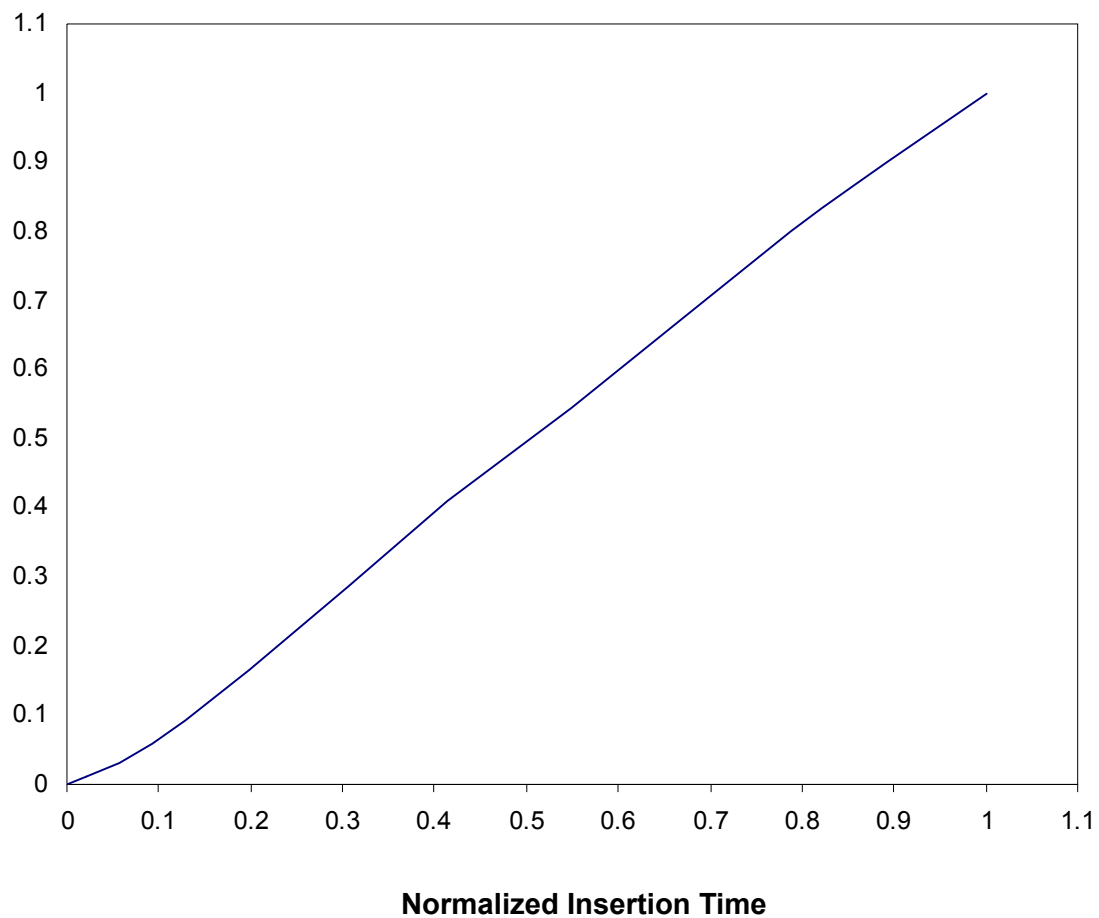


Figure 2.8.5.0-4
Normalized CEA Worth vs. Normalized Position Following CEA Release from Reactor Trip

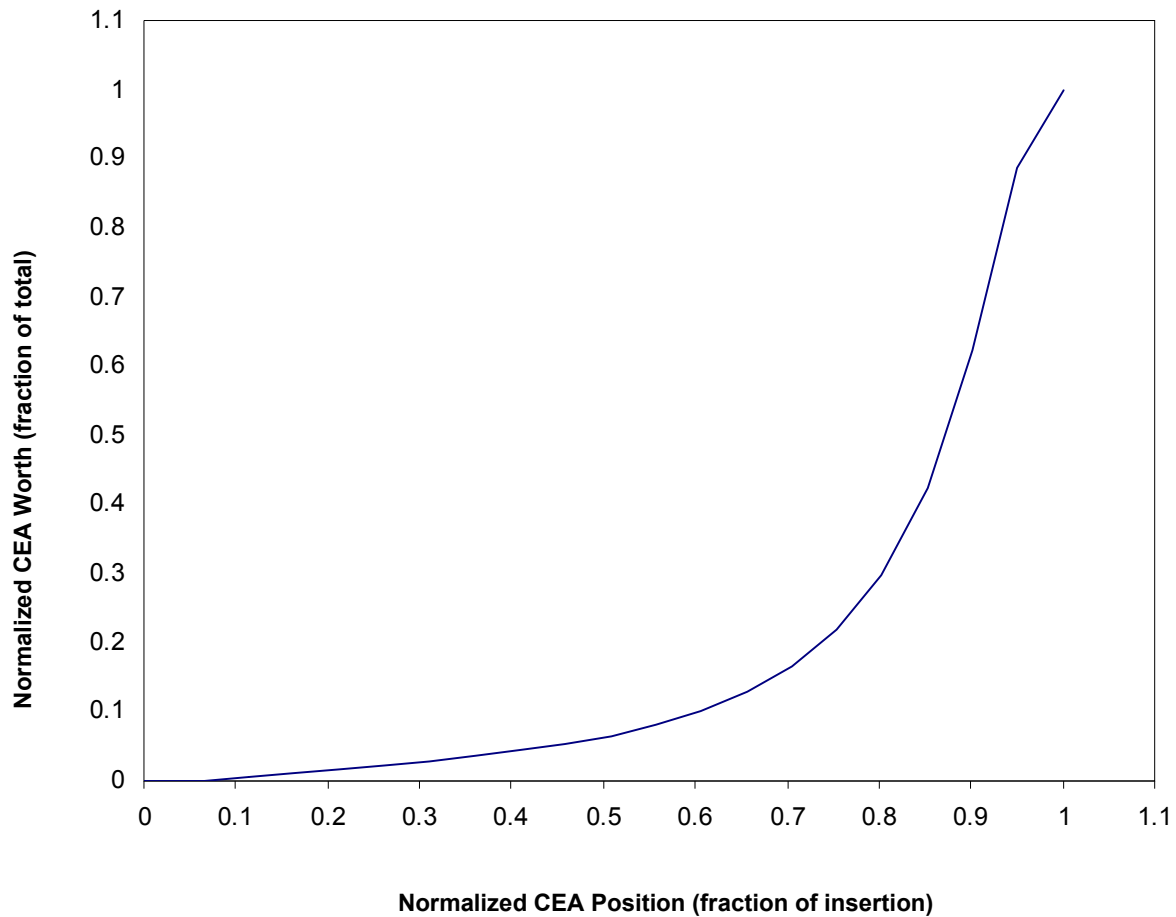


Figure 2.8.5.0-5
Doppler Power Coefficient Used in Accident Analyses

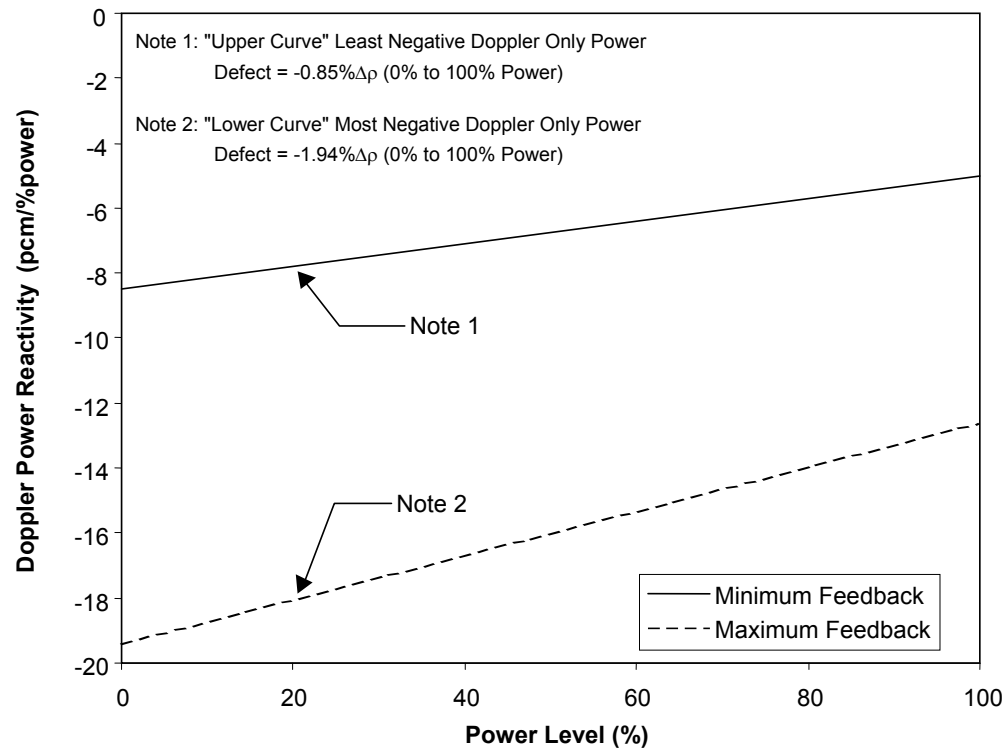


Figure 2.8.5.0-6
Moderator Temperature Coefficient Used in Accident Analyses

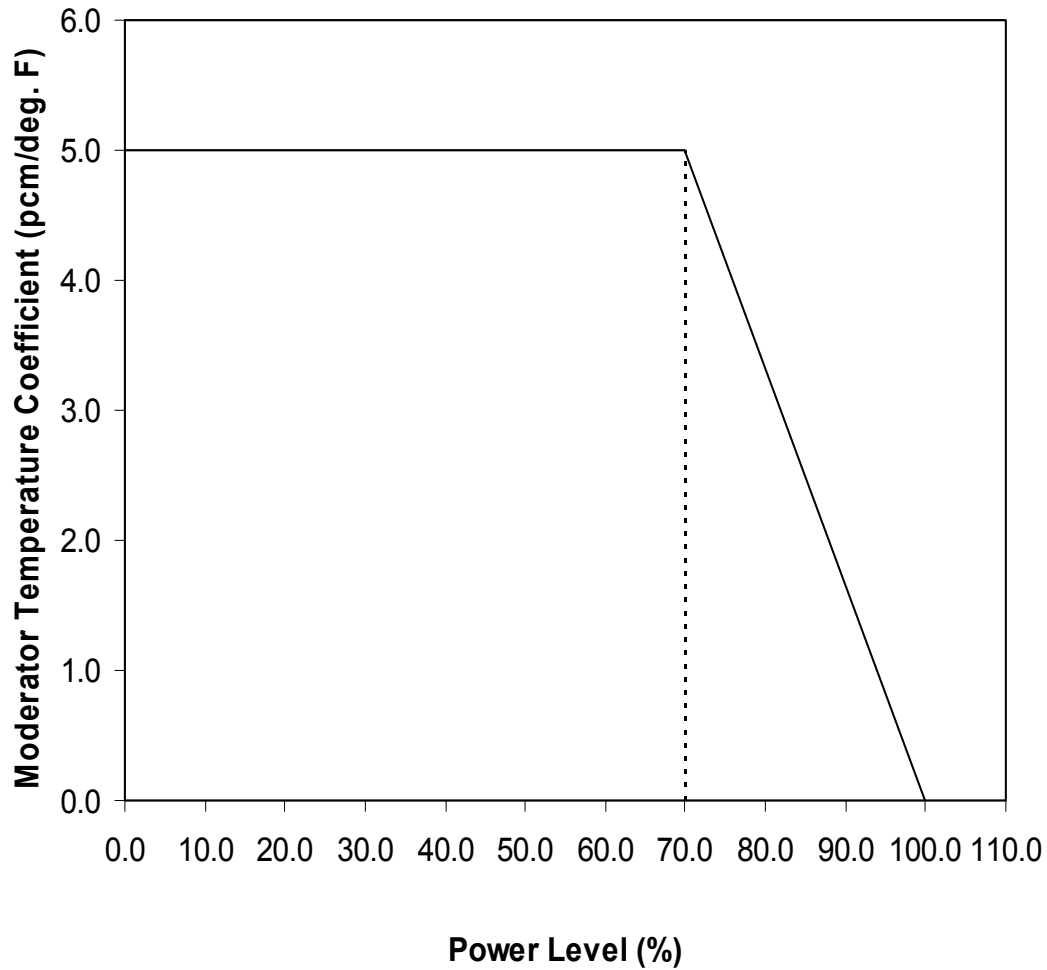


Figure 2.8.5.0-7
Variation of Keff with Core Temperature (3.6% Δ k SDM, 900 psia)

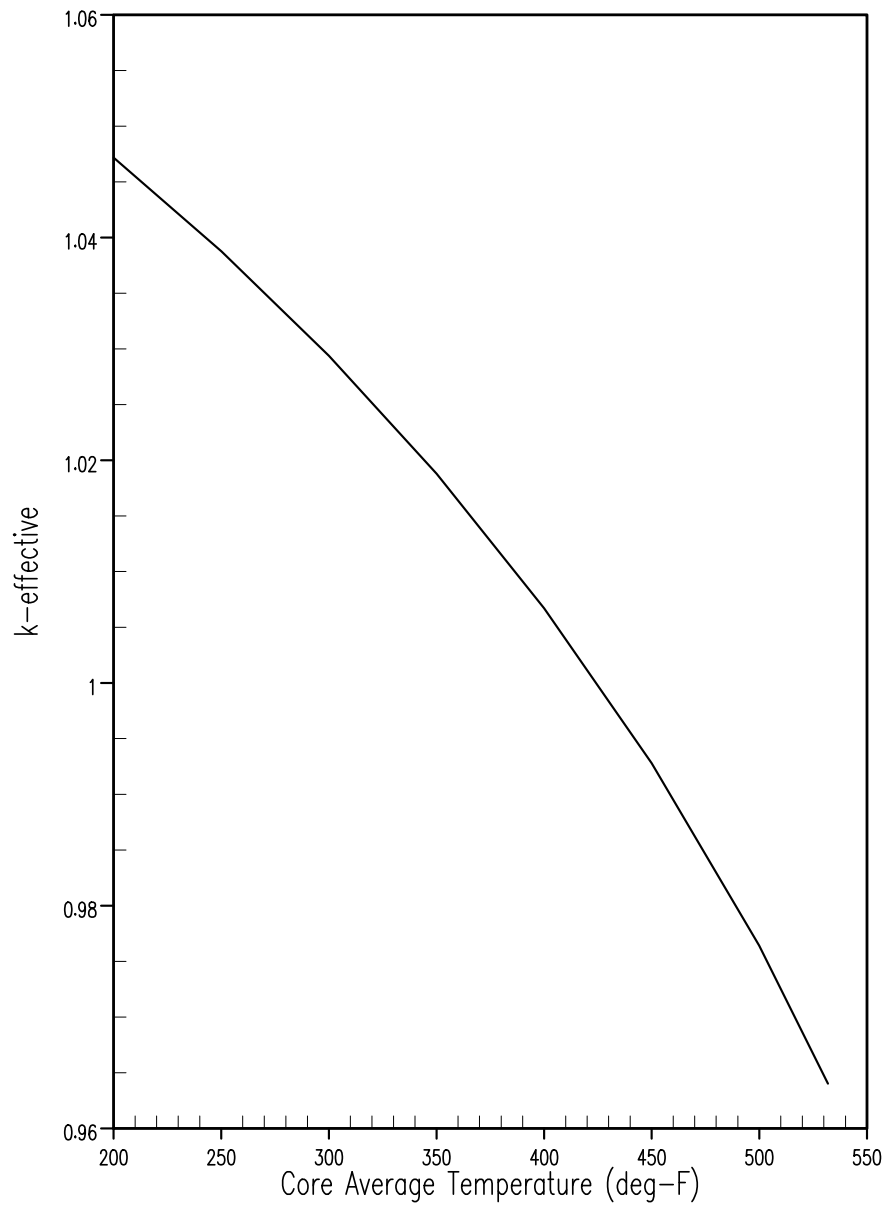
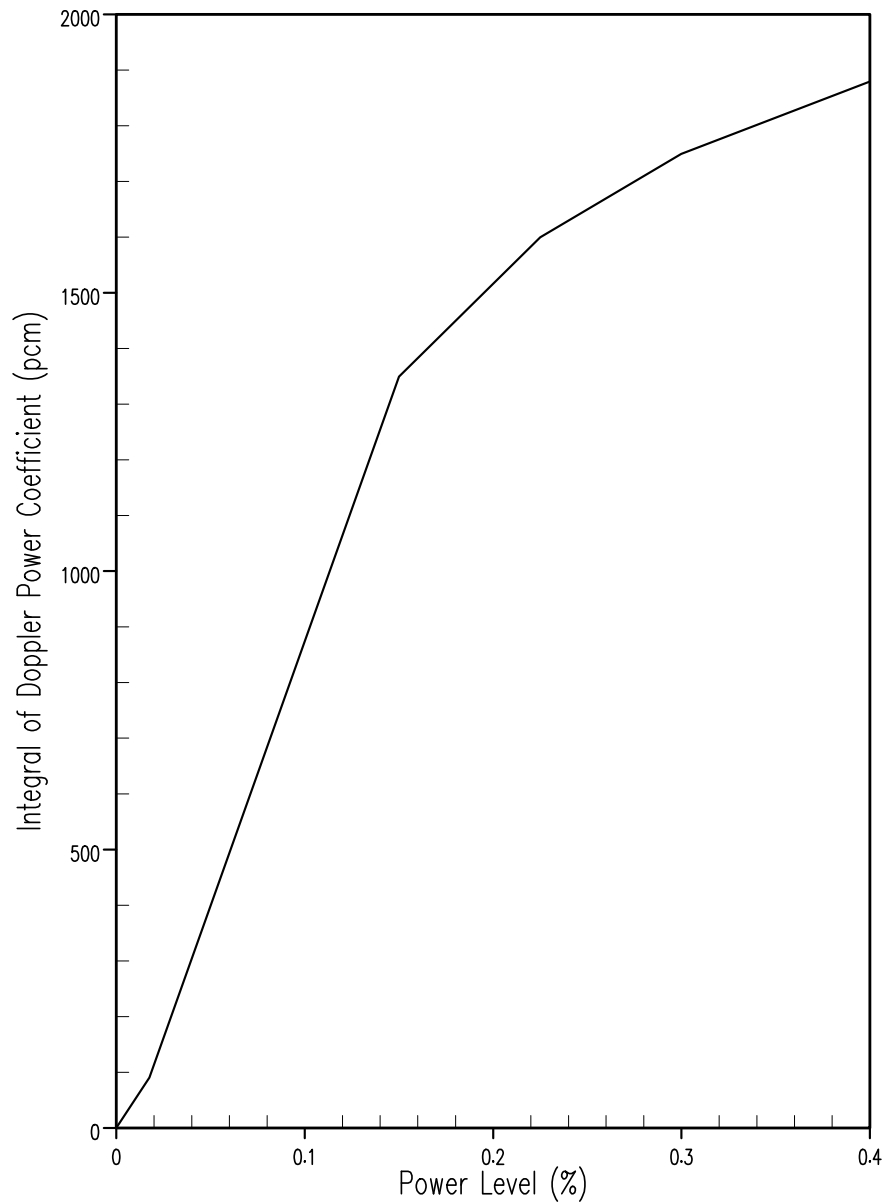


Figure 2.8.5.0-8
Stuck CEA Doppler Power Feedback
Integral of Doppler Power Coefficient vs. Power Level



2.8.5.1 Increase in Heat Removal by the Secondary System

2.8.5.1.1 Decrease In Feedwater Temperature, Increase In Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve

2.8.5.1.1.1 Regulatory Evaluation

Excessive heat removal causes a decrease in moderator temperature which 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 Florida Power and Light (FPL) review covered:

- postulated initial core and reactor conditions,
- methods of thermal and hydraulic analyses,
- the sequence of events,
- assumed reactions of reactor system components,
- functional and operational characteristics of the reactor protection system,
- operator actions, and
- the results of the transient analyses.

The NRC's acceptance criteria are based on:

- General Design Criterion (GDC)-10, insofar as it requires that the reactor coolant system (RCS) be designed with appropriate margin to ensure that specified acceptable fuel design limits (SAFDLs) are not exceeded during normal operations including anticipated operational occurrences (AOOs);.
- 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 reactor coolant pressure boundary (RCPB) are not exceeded during any condition of normal operation;
- GDC-20, insofar as it requires that the reactor protection system (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
- 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 Standard Review Plan (SRP) Section 15.1.1-4 and other guidance provided in Matrix 8 of RS-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in St. Lucie Unit 2 Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDC's for the decrease in feedwater temperature, increase in feedwater flow, increase in steam flow, and inadvertent opening of a steam generator relief or safety valve are as follows:

- GDC-10 is described in UFSAR 3.1.10 Criterion 10 - Reactor Design.

The reactor core and associated coolant, control and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

SAFDLs are stated in UFSAR Section 4.3. Minimum margins to SAFDLs are prescribed in the technical specifications (limiting conditions for operations) which support UFSAR Chapters 4 and 15.

- GDC-15 is described in UFSAR 3.1.15 Criterion 15 - Reactor Coolant System Design.

The Reactor Coolant System and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.

The operating conditions for normal steady state and transient plant operations are established conservatively. Normal operating limits are selected so that an adequate margin exists between operating and design limits. The plant control systems are designed to ensure that plant variables are maintained well within the established operating limits. The plant transient response characteristics and pressure and temperature distributions during normal operations are considered in the design as well as the accuracy and response of the instruments and controls. These design techniques ensure that a satisfactory margin is maintained between the plant's normal operating conditions, including design transients, and the design limits for the RCPB.

The plant control systems function to minimize deviations from normal operating limits in the event of most AOOs. Where control systems response would be inadequate or fail upon demand, the RPS and the engineered safety features actuation system (ESFAS) function to mitigate the consequences of such events.

The RPS and ESFAS function to mitigate the consequences of accidents such that the design limits for the RCPB are not exceeded.

GDC-20 is described in UFSAR 3.1.20 Criterion 20 - Protection System Functions.

The protection system shall be designed (1) to initiate automatically the operation of appropriate systems including the reactivity control systems, to assure that specified

acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and to initiate the operation of systems and components important to safety.

The RPS monitors reactor operating conditions and automatically initiates a reactor trip when the monitored variable or combination of variables exceeds a prescribed operating range. The reactor trip setpoints are selected to ensure that AOOs do not cause SAFDLs to be violated. Specific reactor trips are described in UFSAR Section 7.2.

The ESFAS monitors potential accident conditions and automatically initiates engineered safety features and their supporting systems when the monitored variables reach prescribed setpoints. The parameters which automatically actuate engineered safety features are described in UFSAR Section 7.3. Manual actuation is provided to the operator.

- GDC-26 is described in UFSAR 3.1.26 Criterion 26 - Reactivity Control System Redundancy And Capability.

Two independent reactivity control systems of different design principles shall be provided. One of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margin for malfunctions such as stuck rods, specified acceptable fuel design limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure acceptable fuel design limits are not exceeded. One of the systems shall be capable of holding the reactor core subcritical under cold conditions.

Two independent reactivity control systems of different design principles are provided. The first system, using CEAs, includes a positive means (gravity) for inserting CEAs and is capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including specified AOOs SAFDLs are not exceeded. The CEAs can also be mechanically driven into the core. The appropriate margin for stuck rods is provided by assuming in the analyses of anticipated operational occurrences that the highest worth CEA does not fall into the core.

The second system, the chemical and volume control system (CVCS), using neutron absorbing soluble boron, is capable of reliably compensating for the rate of reactivity changes resulting from planned normal power changes (including xenon burnout) such that SAFDLs are not exceeded. This system is capable of holding the reactor subcritical under cold conditions. For a further description, see UFSAR Section 9.3.4.

Either system is capable of making the core subcritical from a hot operating condition. For further discussion, see UFSAR Sections 7.4 and 7.7.

A number of events have been postulated which could result in an increase in heat removal from the RCS by the secondary system. Detailed analyses are presented for several such events, which have been identified as limiting cases.

Discussions relative to the following RCS cooldown events are presented in the noted UFSAR sections:

1. Feedwater system malfunctions that result in a decrease in feedwater temperature (UFSAR Section 15.1.1),
2. Feedwater system malfunctions that result in an increase in feedwater flow (UFSAR Section 15.1.2),
3. Excessive increase in secondary steam flow (excess load) (UFSAR Section 15.1.3), and
4. Inadvertent opening of a steam generator relief or safety valve (UFSAR Section 15.1.4).

NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Power Plant Units 1 and 2, dated September 2003, defines the scope of license renewal. Specific design transient analyses are not within the scope of license renewal.

2.8.5.1.1.2 Technical Evaluation

2.8.5.1.1.2.1 Increase in Feedwater Flow

2.8.5.1.1.2.1.1 Introduction

A change in steam generator feedwater conditions that results in an increase in feedwater flow could result in excessive heat removal from the RCS. Such changes in feedwater flow are a result of a failure of a feedwater control valve, feedwater bypass valve, failure in the feedwater control system or operator error.

The occurrence of these failures that result in an excessive heat removal from the RCS cause the primary-side temperature and pressure to decrease significantly. In the existence of a negative moderator and fuel temperature reactivity coefficients, the reduction in the primary system temperature results in an increase in core reactivity, a subsequent increase in core power and a decrease in RCS pressure. In the absence of the RPS reactor trip or other protective action, this increase in core power, coupled with the decrease in primary-side pressure, can challenge the core thermal limits. Therefore, the Excessive heat removal due to feedwater system malfunctions event is analyzed to ensure that the minimum departure from nucleate boiling ratio (DNBR) limit is not violated.

An example of an increase in feedwater flow event resulting in excessive heat removal is the accidental opening of the feedwater regulating valves which results in an increase in feedwater flow to both steam generators. At power, excess feedwater flow causes a greater load demand on the primary side due to increased subcooling in the steam generator and a subsequent over cooling of the primary RCS. With the plant at zero-power conditions, the addition of relatively cold feedwater will cause a decrease in primary-side temperature. The resultant decrease in the average moderator temperature in both cases causes an increase in core power due to moderator reactivity feedback effects. This transient is attenuated by the thermal capacity of the primary and secondary sides. If the increase in reactor power is large enough, the primary RPS

trip functions will prevent any power increase that can lead to a DNBR less than the safety analysis limit value. However, if the increase in power is not large enough, to trip the RPS, the reactor will reach a new steady state condition at the increased core power level.

2.8.5.1.1.2.1.2 Input Parameters, Assumptions and Acceptance Criteria

The feedwater malfunction analysis resulting from an increase in feedwater flow is performed to demonstrate that the DNB design basis is satisfied. This is accomplished by showing that the calculated minimum DNBR is greater than the DNBR safety analysis limit.

Feedwater system failures, including the accidental opening of the feedwater regulating valves, have the potential of allowing increased feedwater flow to each steam generator that will result in excessive heat removal from the RCS. Therefore, it is assumed that the feedwater regulating valves fail in the full-open position allowing the maximum feedwater flow to both steam generators. Also addressed is the initiation of a feedwater malfunction event from a hot zero-power (HZP) condition.

To produce conservative results during the transient, the following assumptions are made for the analysis of the feedwater malfunction event involving the accidental opening of the feedwater regulating valves at the EPU conditions consistent with the approved methodology for the current analysis. See LR [Section 2.8.5.0](#), Accident and Transient Analyses, for additional inputs and assumptions.

- The plant is operating at full power (and no-load for the HZP case) conditions with the initial reactor power, RCS pressure, and RCS average temperatures assumed to be at the nominal values with uncertainties applied as noted, below. The full power pressurizer level is 63.0 percent, zero power is 33.1 percent.
- For the full power case, uncertainties in initial conditions noted above are included in the determination of the DNBR limit using the revised thermal design procedure (RTDP) methodology ([Reference 2](#)), and are therefore not included in the initial conditions. Because the uncertainty on the initial conditions are not included in the determination of the safety analysis DNBR limit for the zero power case, uncertainties are included in the initial power, pressure, temperature and RCS flow rate for the HZP case.
- The feedwater enthalpy for the at-power cases is consistent with normal plant conditions at full rated thermal power and is equal to 420.5 Btu/lbm. The feedwater enthalpy assumed at HZP conditions is 210.0 Btu/lbm.
- The excessive feedwater flow event assumes accidental opening of the feedwater regulating valves. The feedwater flow malfunction results in a step increase to 120 percent of the nominal full-power feedwater flow to both steam generators.
- Maximum (end-of-life) reactivity feedback conditions with a minimum Doppler-only power defect is conservatively assumed. Trip reactivity assuming the most reactive rod stuck out of the core is modeled for the full power case. Shutdown margin also assuming the most reactive rod stuck out of the core for the HZP case.
- The heat capacity of the RCS metal and steam generator shell are ignored, thereby maximizing the temperature reduction of the RCS coolant.

- The feedwater flow resulting from a fully open control valve is terminated by the steam generator high water level signal that closes all main feedwater control and feedwater control-bypass valves.
- The impact of steam generator tube plugging (SGTP) is addressed in the analysis by modeling the minimum SGTP level which is conservative for the event.

The automatic rod control system is not modeled as it is disabled at the plant. The RPS functions to trip the reactor on the appropriate signal. No single active failure will prevent the RPS from functioning properly.

Protection against undesirable conditions is provided by steam generator water level alarms with automatic or manual control actions to reduce feedwater flow, and in extreme cases by reactor trips due to variable high power trip (VHPT), low pressurizer pressure, thermal margin/low pressure (TM/LP), or low steam generator pressure.

Acceptance Criteria

Based on its frequency of occurrence, the feedwater malfunction event analyzed is categorized as an AOO. The specific criteria for this event analysis are as follows:

- The event shall be accommodated with, at most, a shutdown of the reactor with the plant capable of returning to operation after corrective action,
- By itself, the event cannot generate a more serious incident without other incidents occurring independently, and
- A single event shall not cause consequential loss of function of any barrier to prevent the escape of radioactive products.

2.8.5.1.1.2.1.3 Description of Analyses and Evaluation

The feedwater system malfunction transient is analyzed using the RETRAN code. The RETRAN computer code is a flexible, transient thermal-hydraulic digital computer code that has been reviewed and approved by the NRC for PWR licensing applications ([Reference 1](#)). The main features of the program include a point kinetics and one-dimensional kinetics model, one-dimensional homogeneous equilibrium mixture thermal-hydraulic model, control system models, and two-phase natural convection heat transfer correlations. The results from the RETRAN computer code are used to determine if the departure from nucleate boiling (DNB) safety analysis limits for the excessive heat removal due to feedwater malfunction event are met.

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

As discussed above, the design transient analyses were determined to be outside the scope of License Renewal; therefore, with respect to the design basis accidents and transients, the EPU does not impact any License Renewal evaluations.

2.8.5.1.1.2.1.5 Results

The results of the analysis, as shown in LR [Table 2.8.5.1.1.2-3](#), demonstrate that the at-power case meets the applicable DNBR acceptance criterion.

The limiting case is the excessive feedwater flow from full power initial conditions. This case gives the largest reactivity feedback and results in the greatest power increase. The peak power, core heat flux, and minimum DNBR conditions are reached shortly after the CEAs begin to fall. The consequences of the event are mitigated prior to reaching a high steam generator water level condition in either steam generator. However, feedwater will be terminated after reaching the high-high steam generator water level setpoint. The limiting feedwater flow increase conditions were analyzed and it was confirmed that the calculated minimum DNBR is above the safety analysis DNBR limit. Therefore, the applicable DNBR acceptance criterion is met.

The excessive feedwater flow from a zero power condition models a HZP post-trip condition (i.e., worst stuck rod and minimum shutdown margin) with maximum reactivity feedback conditions (end of life). The effects of an increased feedwater flow and combined reactivity feedback effect at post-trip conditions is not sufficient to overcome the shutdown margin of the CEAs. As a result, there is no return to power, and therefore, no challenge to the minimum DNBR criterion.

LR [Table 2.8.5.1.1.2-1](#) shows the time sequence of events for the at-power feedwater malfunction transient case resulting in an increase in feedwater flow. LR [Figures 2.8.5.1.1.2-1](#) through [2.8.5.1.1.2-7](#) show transient responses for various system parameters during a feedwater system malfunction causing a feedwater flow increase initiated from at-power conditions. As shown in LR [Table 2.8.5.1.1.2-2](#), the increased feedwater flow at zero power conditions does not result in an appreciable return to power condition as the peak reactivity remains negative.

A comparison of the feedwater malfunction results for each case supporting the EPU program to the values from the current analysis has been provided in LR [Tables 2.8.5.1.1.2-4](#) and [2.8.5.1.1.2-5](#). This comparison serves to ensure that expected trends were observed. The results demonstrated that the applicable safety analysis criteria identified are satisfied.

2.8.5.1.1.2.2 Decrease in Feedwater Temperature

2.8.5.1.1.2.2.1 Introduction

The bounding initiator for the feedwater malfunction event resulting from a decrease in feedwater temperature, which causes an increase in primary-to-secondary heat transfer, is the loss of a train of the high-pressure feedwater heaters. In the event of a loss of high-pressure feedwater heaters, there will be an immediate reduction in feedwater temperature to the steam generators. At power, the increased subcooling will create a greater load demand on the RCS due to the increased heat transfer in the steam generator and result in a decrease in the primary RCS temperature. The resultant decrease in the average moderator temperature causes an increase in core power due to moderator reactivity feedback effects.

The net effect on the RCS due to a reduction in feedwater temperature is similar to the effect of increasing secondary steam flow. If the increase in core power is large enough, the primary RPS

trip functions (e.g., VHPT) will prevent any power increase that can lead to a DNBR less than the safety analysis limit value. Otherwise, the core power level will reach a new, higher, steady state condition.

2.8.5.1.1.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The feedwater malfunction analysis resulting in a feedwater temperature reduction is performed to demonstrate that the DNB design basis is satisfied. This is accomplished using the same input parameters, assumptions and acceptance criteria described in the feedwater flow increase analysis (LR [Section 2.8.5.1.1.2.1.2](#)) with the following additional assumptions.

1. At full power conditions, the feedwater enthalpy is reduced to correspond to a reduced feedwater temperature of 341.0 °F, and
2. The feedwater temperature reduction case assumes that the full power feedwater flow is maintained to both steam generators.

The protection systems used in the feedwater malfunction analysis resulting in a feedwater temperature reduction are the same for those used in the increased feedwater flow event discussed in LR [Section 2.8.5.1.1.2.1.2](#).

2.8.5.1.1.2.2.3 Description of Analyses and Evaluations

The feedwater system malfunction transient is analyzed using the RETRAN code. The RETRAN computer code is a flexible, transient thermal-hydraulic digital computer code that has been reviewed and approved by the NRC for PWR licensing applications ([Reference 1](#)). The main features of the program include point kinetics and one-dimensional kinetics model, one-dimensional homogeneous equilibrium mixture thermal-hydraulic model, control system models, and two-phase natural convection heat transfer correlations. The results from the RETRAN computer code are used to determine if the DNB safety analysis limits for the excessive heat removal due to feedwater malfunction event are met.

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

As discussed above, the design transient analyses were determined to be outside the scope of License Renewal; therefore, with respect to the design basis accidents and transients, the EPU does not impact any License Renewal evaluations.

2.8.5.1.1.2.2.5 Results

The loss of high-pressure feedwater heaters causes a reduction in feedwater temperature, which increases the thermal load on the primary system. The power increases until reactor trip is actuated when the VHPT setpoint is reached. The peak core heat flux and minimum DNB condition is reached shortly after the CEAs begin to drop into the core. The limiting at-power feedwater temperature reduction conditions were analyzed and it was confirmed that the

calculated minimum DNBR is above the DNBR safety analysis limit as shown in LR [Table 2.8.5.1.1.2-3](#). Therefore, the applicable DNBR acceptance criterion is met.

LR [Table 2.8.5.1.1.2-6](#) shows the time sequence of events for the at-power feedwater malfunction transient case resulting in a reduction in feedwater temperature. LR [Figures 2.8.5.1.1.2-8 through 2.8.5.1.1.2-14](#) show transient responses for various system parameters during a feedwater system malfunction causing a feedwater temperature reduction.

The results of the analyses show that the RPS trip functions provide adequate protection against the feedwater malfunction transient. No fuel or cladding damage is predicted for this accident. All applicable acceptance criteria are satisfied. LR [Table 2.8.5.1.1.2-7](#) provides the hot full power (HFP) reduced feedwater temperature comparison to the current analysis of record.

2.8.5.1.1.2.3 Increase in Secondary Steam Flow

An increase in secondary steam flow results in a power mismatch between the reactor core power and steam generator load demand. Typically, a steam flow increase of no more than 10 percent of the initial value is examined for an excess load increase event and flow up to and exceeding 58 percent is considered for a failure of the steam dump and bypass control system. The increased steam flow draws more heat from the primary side. Like the steam line break (SLB) event, this reduces the primary coolant temperature and pressure which can result in a power increase. Thus, in the absence of any protection system actions, the consequence of this accident is a DNB with subsequent fuel damage. This event is bounded by the pre-trip SLB with fast bus transfer (FFBT) (See LR [Section 2.8.5.1.2](#), Steam System Piping Failures Inside and Outside Containment) event which meets the acceptance criteria associated with an AOO. Therefore, an explicit analysis of the excessive increase in main steam flow event is not required.

2.8.5.1.1.2.4 Inadvertent Opening of a Steam Generator Relief or Safety Valve

The inadvertent opening of a main steam relief or safety valve results in a transient similar to a steamline break event. Upon the inadvertent opening of a main steam relief or safety valve, steam flow increases causing a mismatch between the reactor core power and the steam generator load demand. This event is bounded by the analysis of the SLB event, which for both the pre-trip SLB with FFBT and the post-trip SLB are analyzed (See LR [Section 2.8.5.1.2](#)) to meet the acceptance criteria associated with an AOO. Therefore, an explicit analysis of the inadvertent opening of a main steam relief or safety valve event is not required.

2.8.5.1.1.3 Conclusion

FPL has reviewed the effects of the proposed EPU regarding the excess heat removal events described above and concludes that it has adequately accounted for operation of the plant at the proposed power level and that the analyses were performed using acceptable analytical models. FPL further concludes 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, FPL concludes that the plant will continue to meet the requirements of GDCs -10, -15, -20 and -26 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to the events stated.

2.8.5.1.1.4 References

1. WCAP-14882-P-A (Proprietary) and WCAP-15234-A (Nonproprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, April 1999.
2. WCAP-11397-P-A (Proprietary), WCAP-11397-A (Non-Proprietary), Revised Thermal Design Procedure, April 1989.

Table 2.8.5.1.1.2-1
Feedwater System Malfunction Event at Power, Increased Feedwater Flow
Sequence of Events and Transient Results

Event	Time (seconds)⁽¹⁾
Main feedwater control valves fail full open	100.0
VHPT setpoint is reached	139.446
Reactor Trip Occurs	139.846
CEAs begin to drop into core	140.586
Minimum DNBR occurs	140.600
Results	
Peak Nuclear Power, fraction of nominal	1.12769
Peak Core Heat Flux, fraction of nominal	1.12505
Minimum DNBR	1.96
1. The time sequence includes a 100 second steady state, therefore subtract 100 seconds in order to obtain the transient time.	

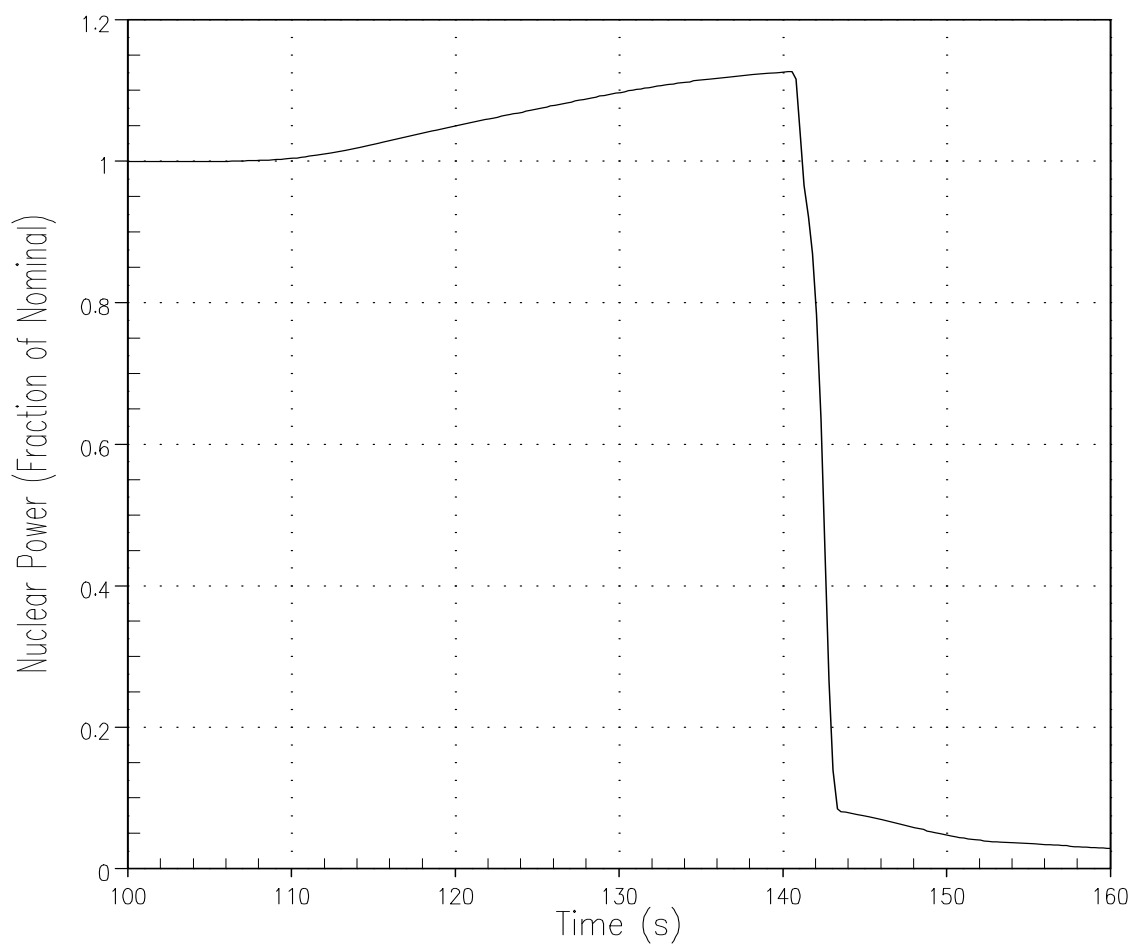
Table 2.8.5.1.1.2-2
Feedwater System Malfunction Event at Zero Power, Increased Feedwater Flow
Sequence of Events and Transient Results

Event/Parameter	Time (Seconds)⁽¹⁾
End of Steady-State, Transient Begins, seconds	10.0
Time of Manual Reactor Trip, seconds	10.1
Time Main Feedwater Control Valves Fail Fully Open	10.1
Time SG Water Level Reaches the High Setpoint of 84% (79%+5%) NRS, seconds	38.7
Time Feedwater Isolation Signal Occurs (On SG High Level Setpoint)	38.7
Time SG Water Level Reaches the High-High Setpoint of 88% (83%+5%) NRS, seconds	42.4
Time SG Fills (100% NRS), seconds	60.2 ⁽²⁾
Time of Low Pressurizer Pressure (Safety Injection) setpoint reached (1683 psia), seconds	96.5
Time Feedwater Isolation Occurs, seconds	118.7 ⁽²⁾
Results	
Max Post-Trip Reactivity, (\$)	-3.005
1. The time sequence includes a 10 second steady state, therefore subtract 10 seconds in order to obtain the transient time. 2. To maximize the cooldown, feedwater flow was continued even after the SG High-High setpoint was reached.	

Table 2.8.5.1.1.2-3
Minimum DNBR Values and Corresponding DNB SAFDL for HFP Cases

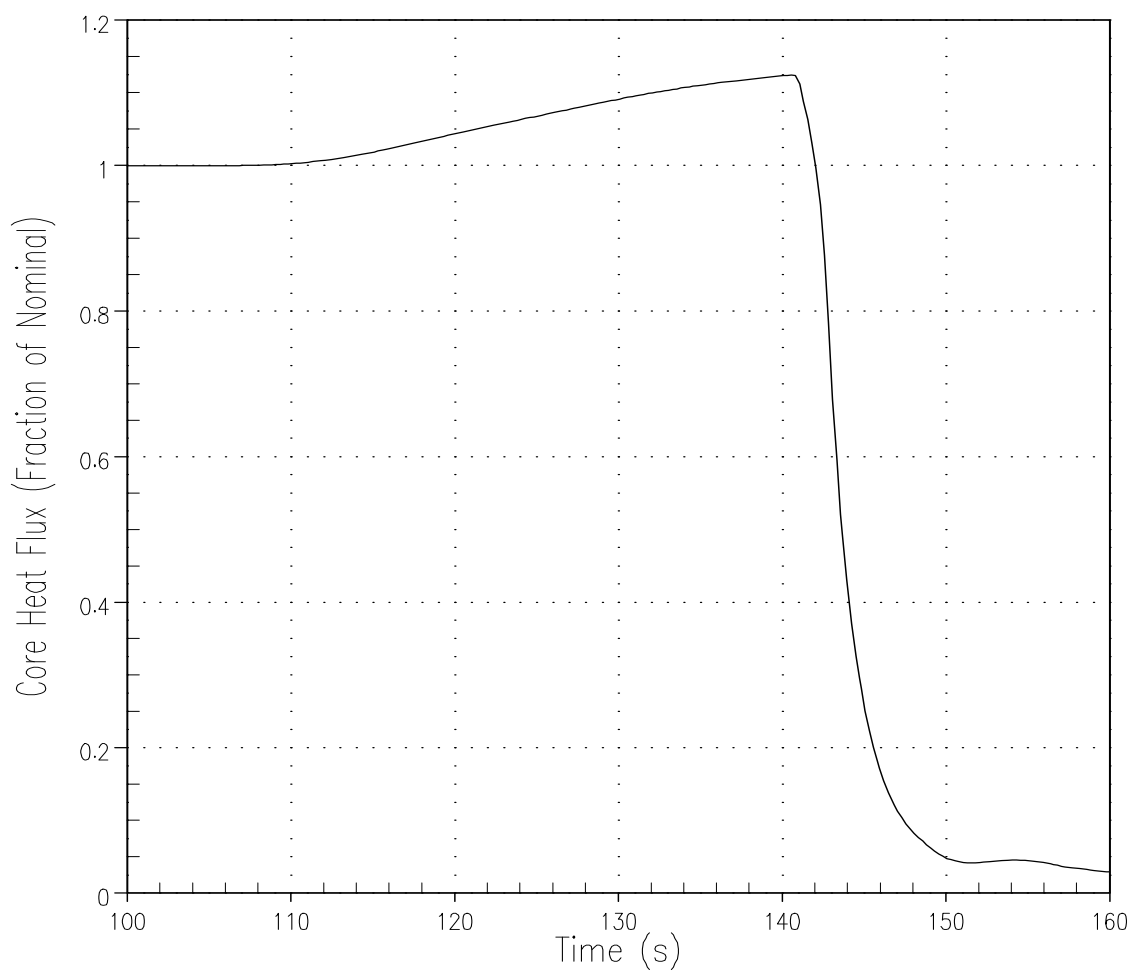
Case Analyzed	EPU Minimum DNBR	DNBR Limit
HFP Reduced FW Temperature	1.97	1.42
HFP Increased FW Flow	1.96	1.42

Figure 2.8.5.1.1.2-1 *
Feedwater Malfunction Increased Feedwater Flow at Power
Nuclear Power



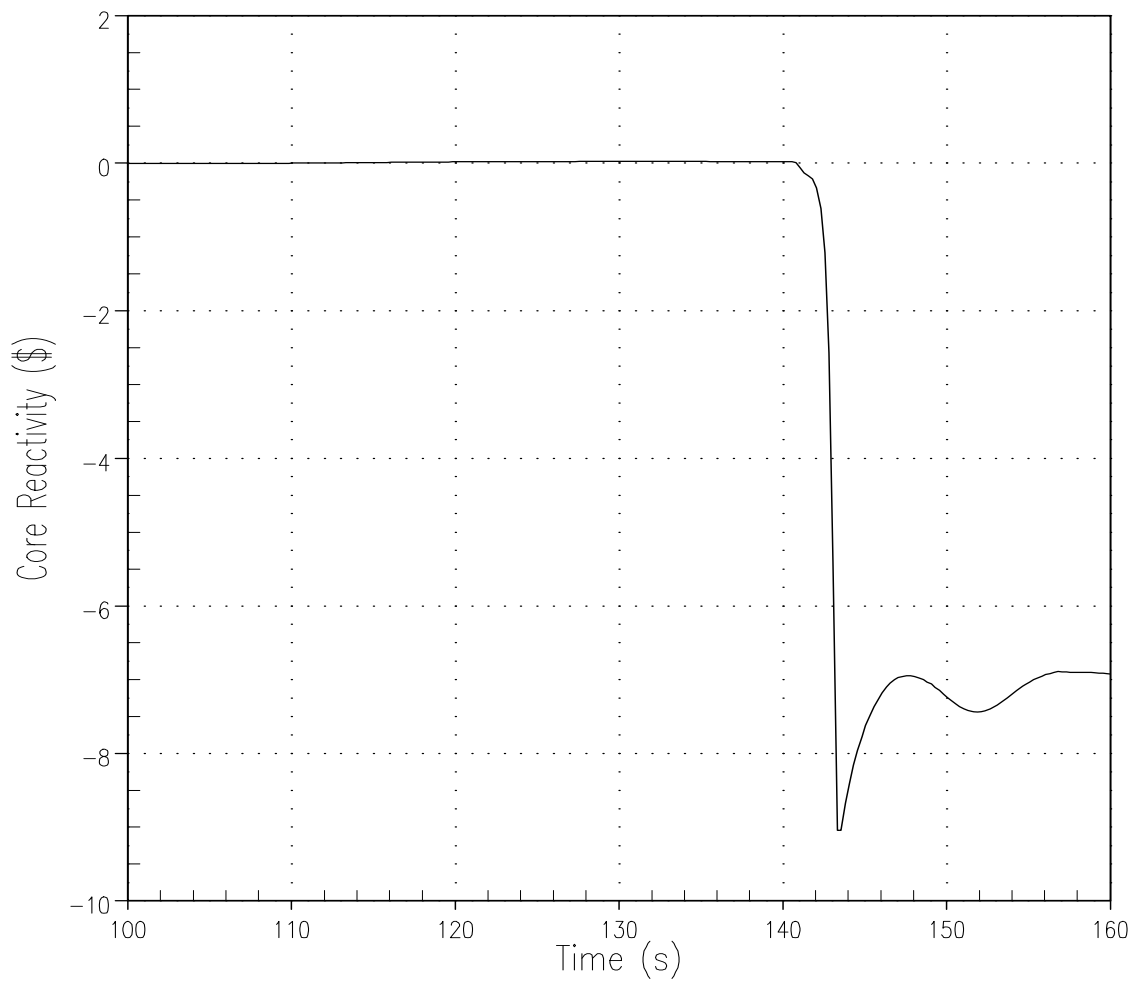
*The 100 second steady state has been removed from the plot

Figure 2.8.5.1.1.2-2 *
Feedwater Malfunction Increased Feedwater Flow at Power Core
Heat Flux



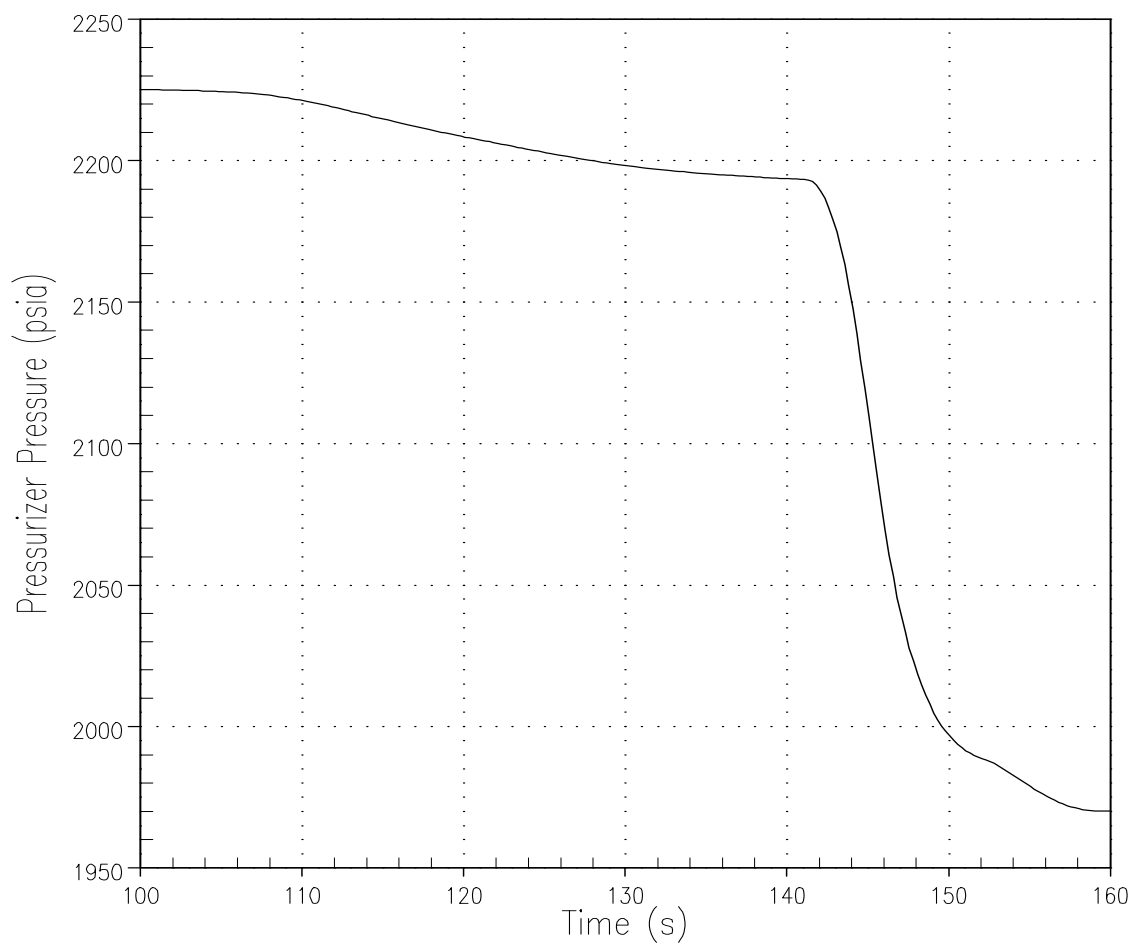
*The 100 second steady state has been removed from the plot

Figure 2.8.5.1.1.2-3 *
Feedwater Malfunction Increased Feedwater Flow at Power
Core Reactivity



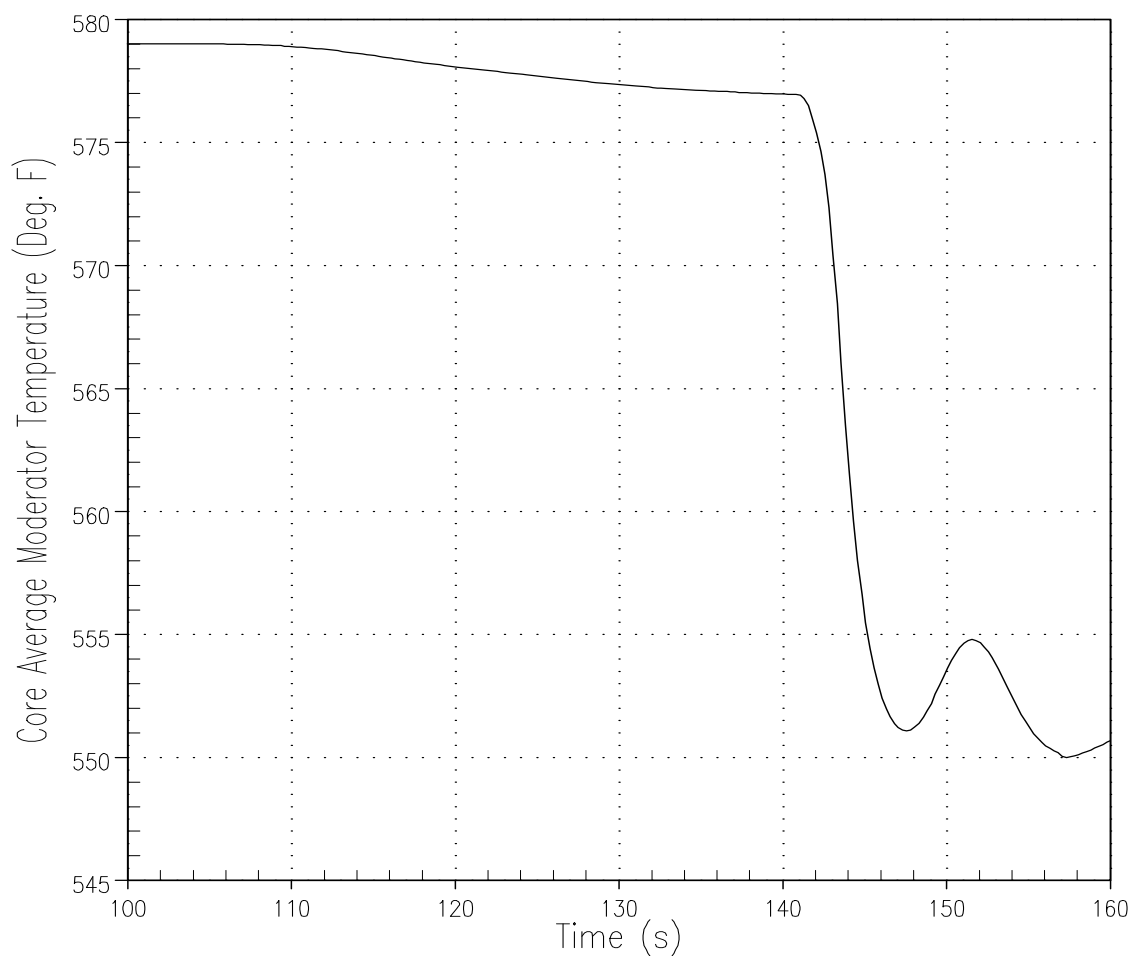
*The 100 second steady state has been removed from the plot

Figure 2.8.5.1.1.2-4 *
Feedwater Malfunction Increased Feedwater Flow at Power
Pressurizer Pressure



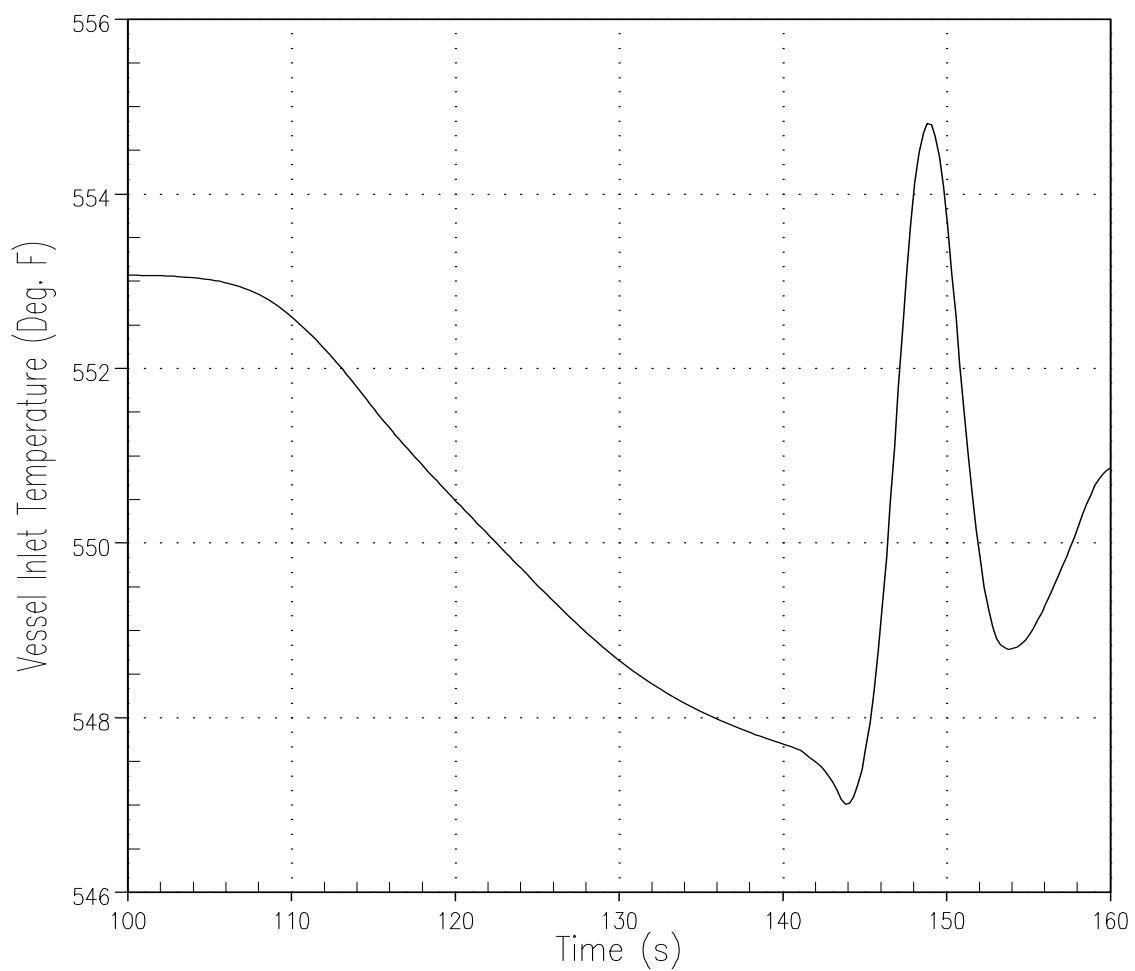
*The 100 second steady state has been removed from the plot

Figure 2.8.5.1.1.2-5 *
Feedwater Malfunction Increased Feedwater Flow at Power
Core Average Moderator Temperature



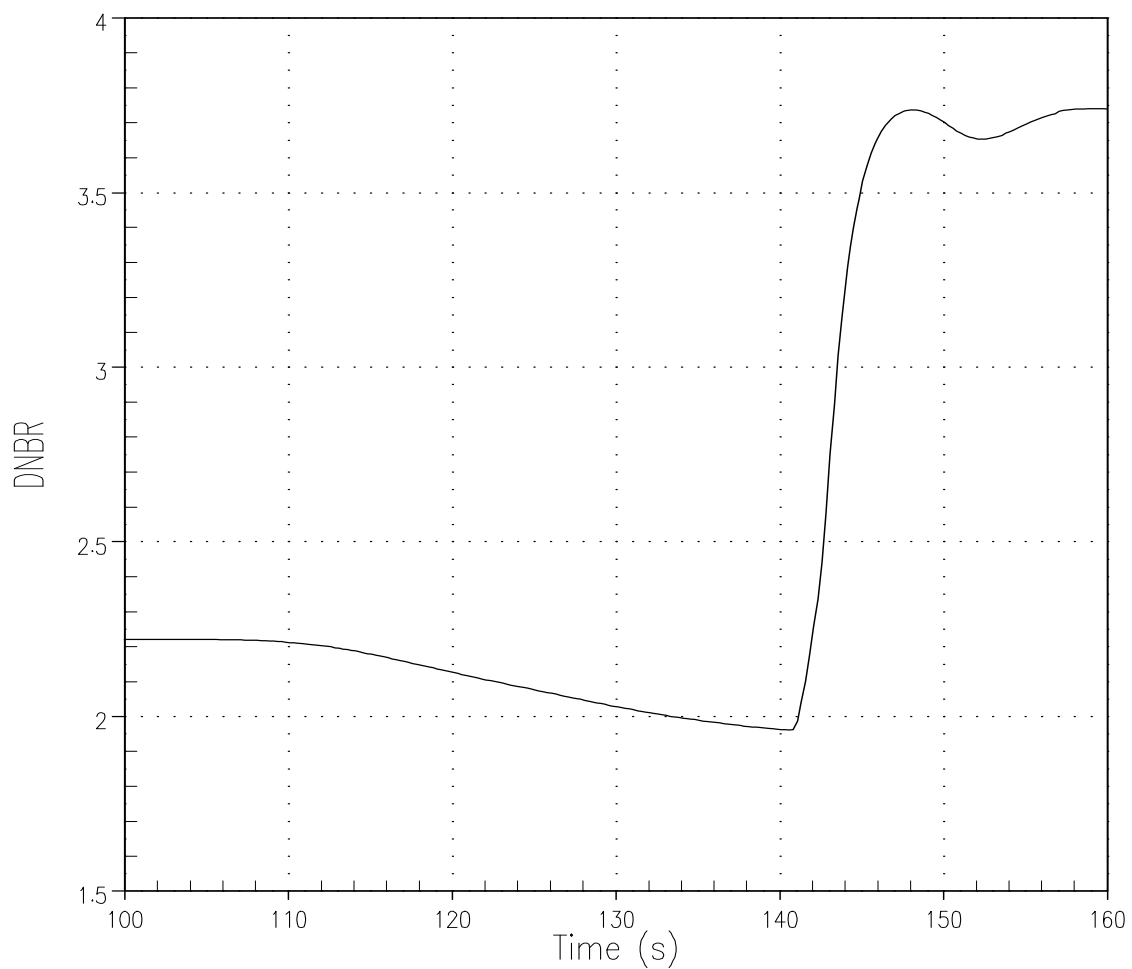
*The 100 second steady state has been removed from the plot

Figure 2.8.5.1.1.2-6 *
Feedwater Malfunction Increased Feedwater Flow at Power
Vessel Inlet Temperature



*The 100 second steady state has been removed from the plot

Figure 2.8.5.1.1.2-7 *
Feedwater Malfunction Increased Feedwater Flow at Power
DNBR



*The 100 second steady state has been removed from the plot

Table 2.8.5.1.1.2-4
Feedwater Malfunction, HFP
Feedwater Flow Increase Analysis Results Summary

Event/Parameter	EPU Results⁽¹⁾	Current Analysis Results⁽¹⁾
Steady-State Run Begins, seconds	0.00	0.00
Time FWM Transient Initiated, <i>seconds</i>	100.00	100.00
Time MFW Flow in Loops 1 and 2 Reaches 120% of the Nominal HFP Value, <i>seconds</i>	100.01	100.01
Time Variable High Power Trip Setpoint Reached, <i>seconds</i>	139.446	138.432
Time Reactor Trip Occurs, <i>seconds</i>	139.846	138.832
Time CEAs Begin to Drop into Core, <i>seconds</i>	140.586	139.572
Time Peak Nuclear Power Reached, <i>seconds</i>	140.600	139.750
Time Minimum DNBR Reached, <i>seconds</i>	140.600	140.000
Time Peak Core Heat Flux Reached, <i>seconds</i>	140.600	140.000
Peak Nuclear Power, <i>fraction of nominal</i>	1.12769	1.13609
Peak Core Heat Flux, <i>fraction of nominal</i>	1.12505	1.13337
Minimum DNBR	1.96	1.97228
1. The time sequence includes a 100 second steady state, therefore subtract 100 seconds in order to obtain the transient time.		

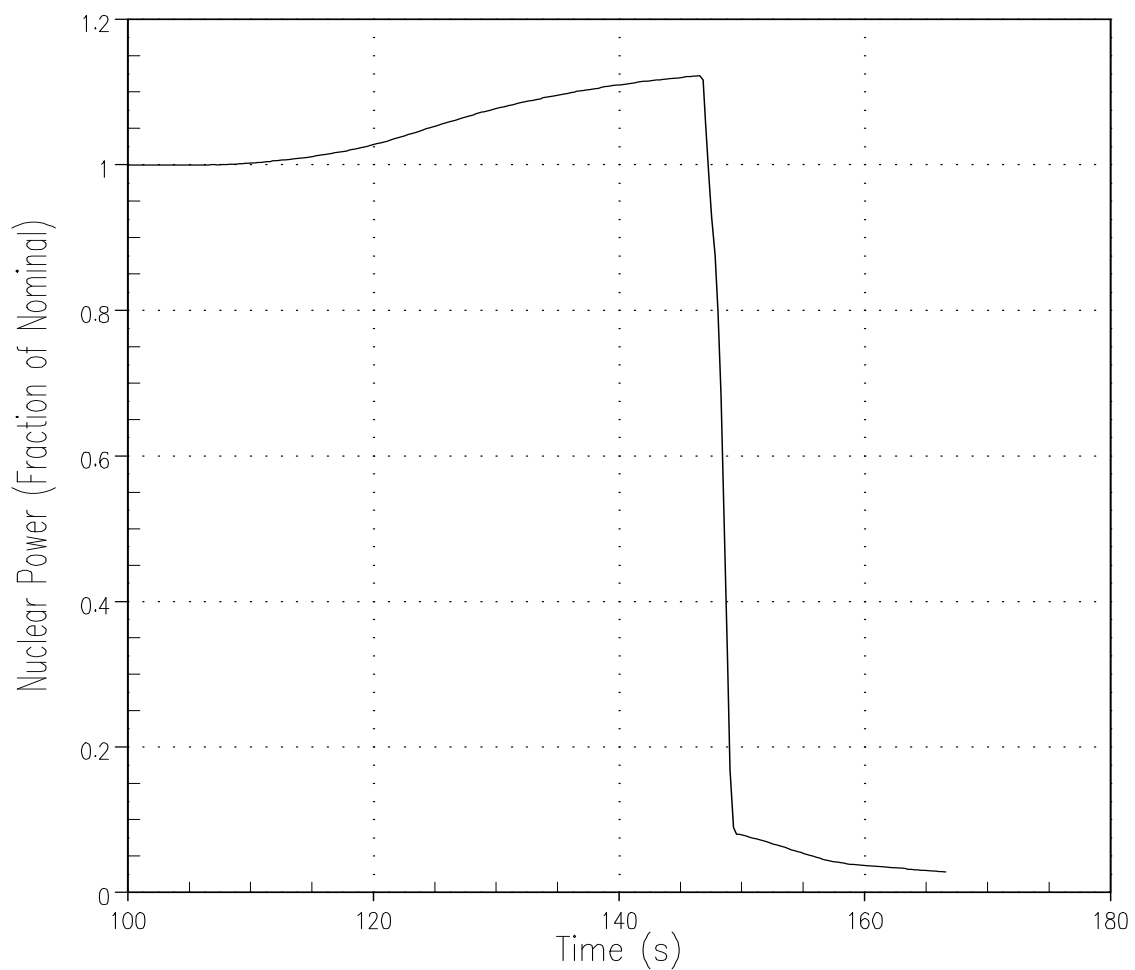
**Table 2.8.5.1.1.2-5
Feedwater Malfunction, HZP
Feedwater Flow Increase Analysis Results Summary**

Event/Parameter	EPU Results⁽¹⁾	Current Analysis Results⁽¹⁾
Steady-State Condition where Transient Begins, seconds	0.0	3000.0
Initial Core Power Level, MWt	16.2420	15.8249
Initial Core heat flux, fraction of nominal	0.00536031	0.00586098
Initial Nuclear power, fraction of nominal	0.0053604	0.00586108
Time of Manual Reactor Trip, seconds	10.1	3000.01
Time SG Water Level Reaches the High-High Setpoint of 88% NRS, seconds	42.4	3016.982 (SG2)/ 3016.999 (SG1)
Time SG Fills (100% NRS indicated level), seconds	60.2	3029.25
Time of Low Pressurizer Pressure (Safety Injection) setpoint reached, seconds	96.5	3057.161
Time Feedwater Isolation Occurs, seconds	118.7	3087.108 (SG2)/ 3087.124 (SG1)
Max Post-Trip Reactivity, (\$)	-3.005 ⁽²⁾	-3.202
1. For the EPU HZP case the transient begins at 10.1 seconds after a 10 second steady state. The current analysis case begins at time = 3000 seconds. 2. The difference between the EPU and current analysis max post-trip reactivity is due to an increased feedwater flow and a lower enthalpy in the current analysis.		

Table 2.8.5.1.1.2-6
Feedwater System Malfunction Event at Power, Reduced Feedwater Temperature
Sequence of Events and Transient Results

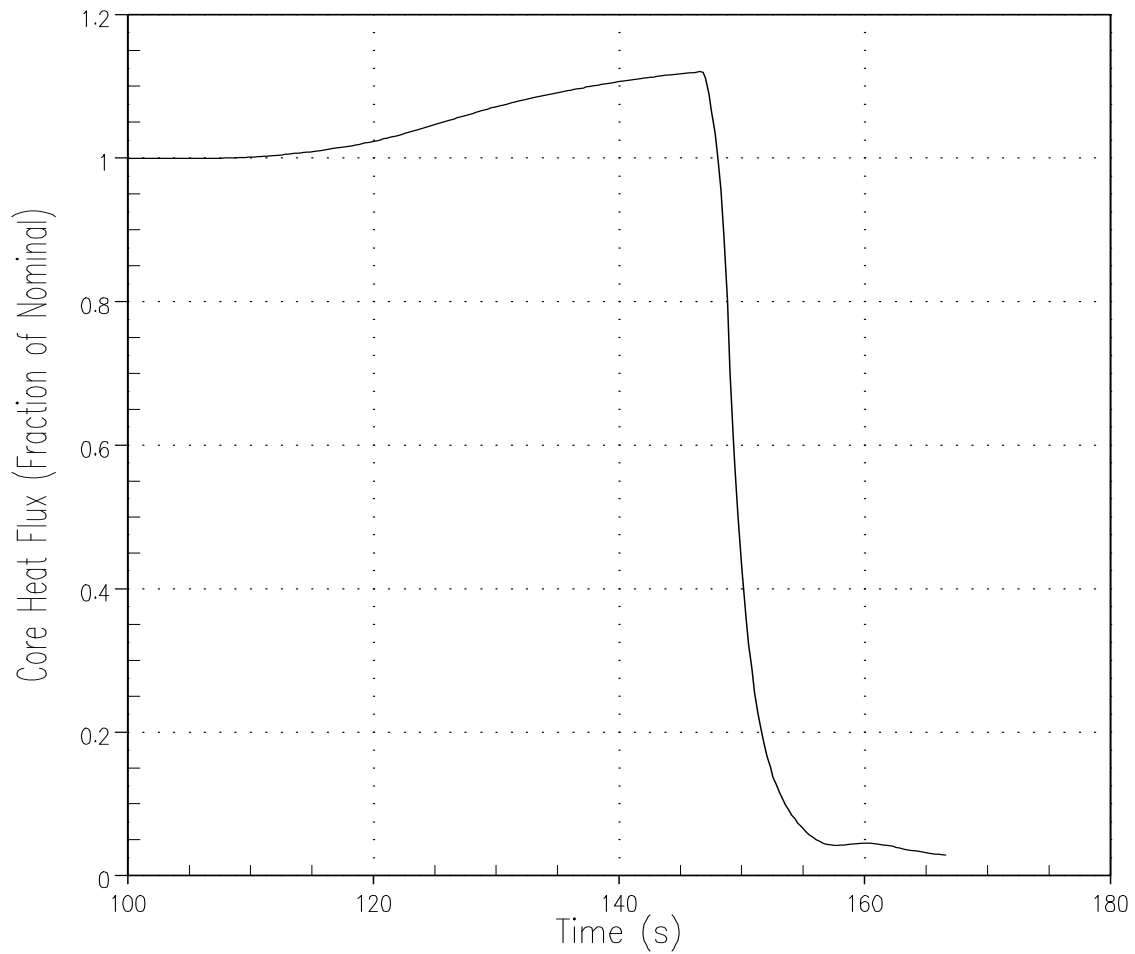
Event	Time (seconds)⁽¹⁾
Loss of feedwater heater occurs	100.0
Variable High Power Trip setpoint is reached	145.498
Reactor Trip Occurs	145.898
CEAs begin to drop into core	146.638
Minimum DNBR occurs	146.600
Results	
Peak Nuclear Power, fraction of nominal	1.12297
Peak Core Heat Flux, fraction of nominal	1.12080
Minimum DNBR	1.97
1. The time sequence includes a 100 second steady state, therefore subtract 100 seconds in order to obtain the transient time.	

Figure 2.8.5.1.1.2-8 *
Feedwater Malfunction Reduced Feedwater Temperature at Power
Nuclear Power



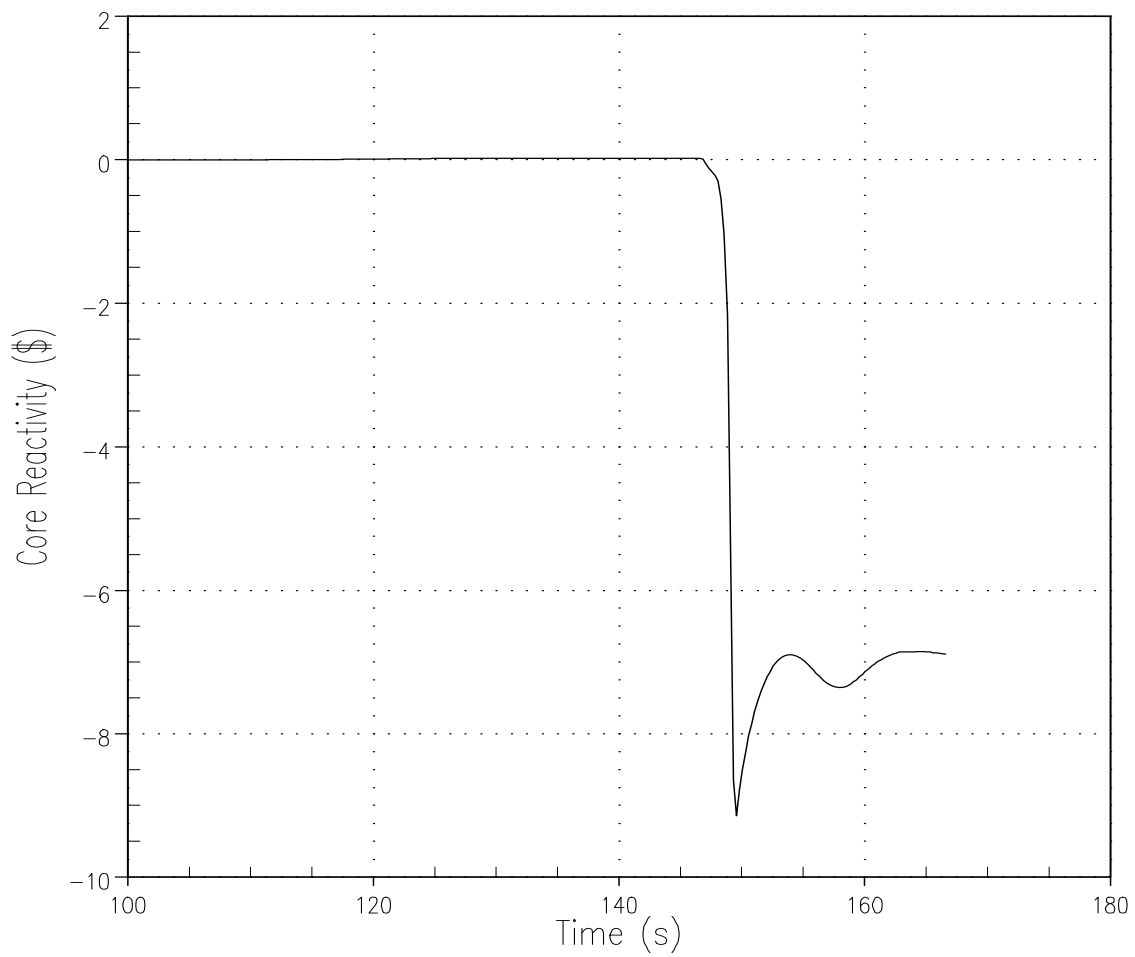
*The 100 second steady state has been removed from the plot

Figure 2.8.5.1.1.2-9 *
Feedwater Malfunction Reduced Feedwater Temperature at Power
Core Heat Flux



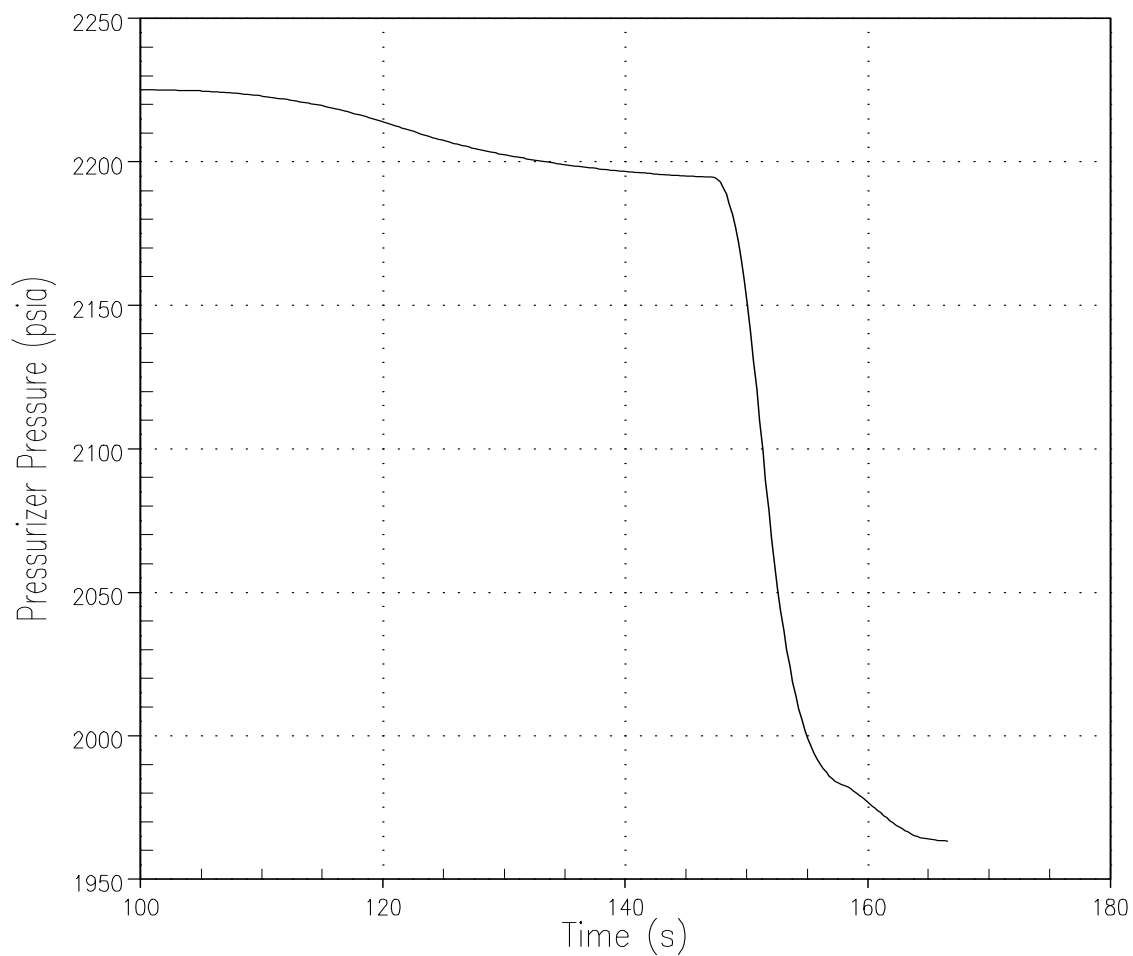
*The 100 second steady state has been removed from the plot

Figure 2.8.5.1.1.2-10 *
Feedwater Malfunction Reduced Feedwater Temperature at Power
Core Reactivity



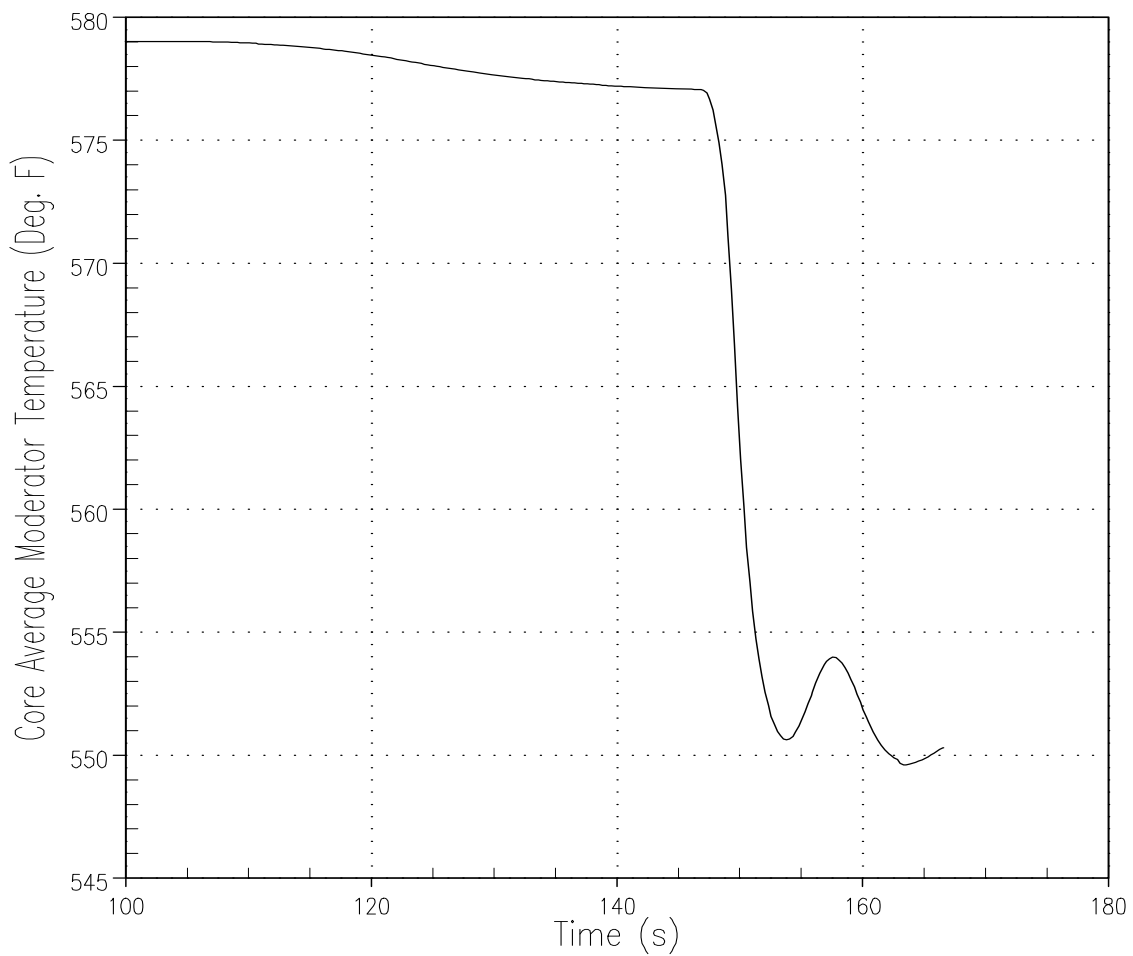
*The 100 second steady state has been removed from the plot

Figure 2.8.5.1.1.2-11 *
Feedwater Malfunction Reduced Feedwater Temperature at Power
Pressurizer Pressure



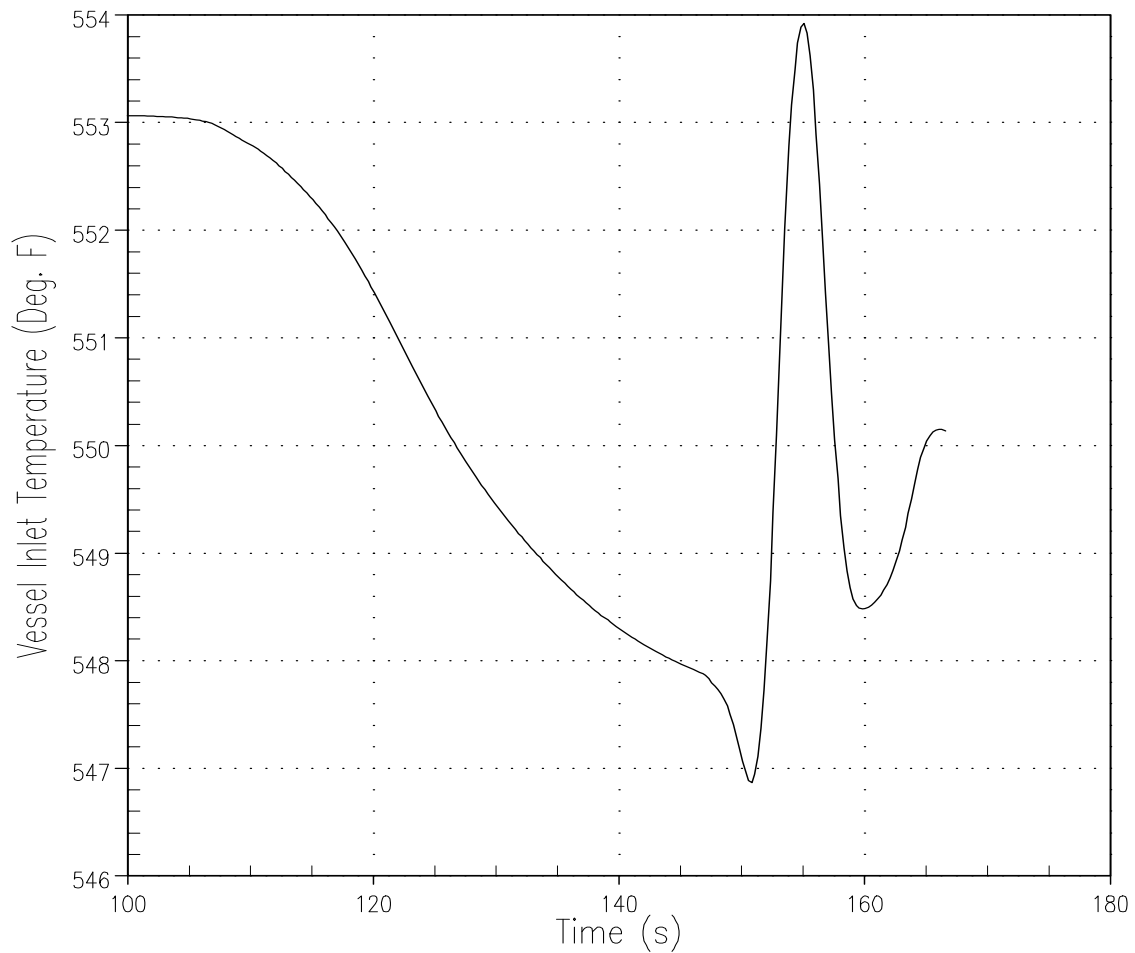
*The 100 second steady state has been removed from the plot

Figure 2.8.5.1.1.2-12 *
Feedwater Malfunction Reduced Feedwater Temperature at Power
Core Average Moderator Temperature



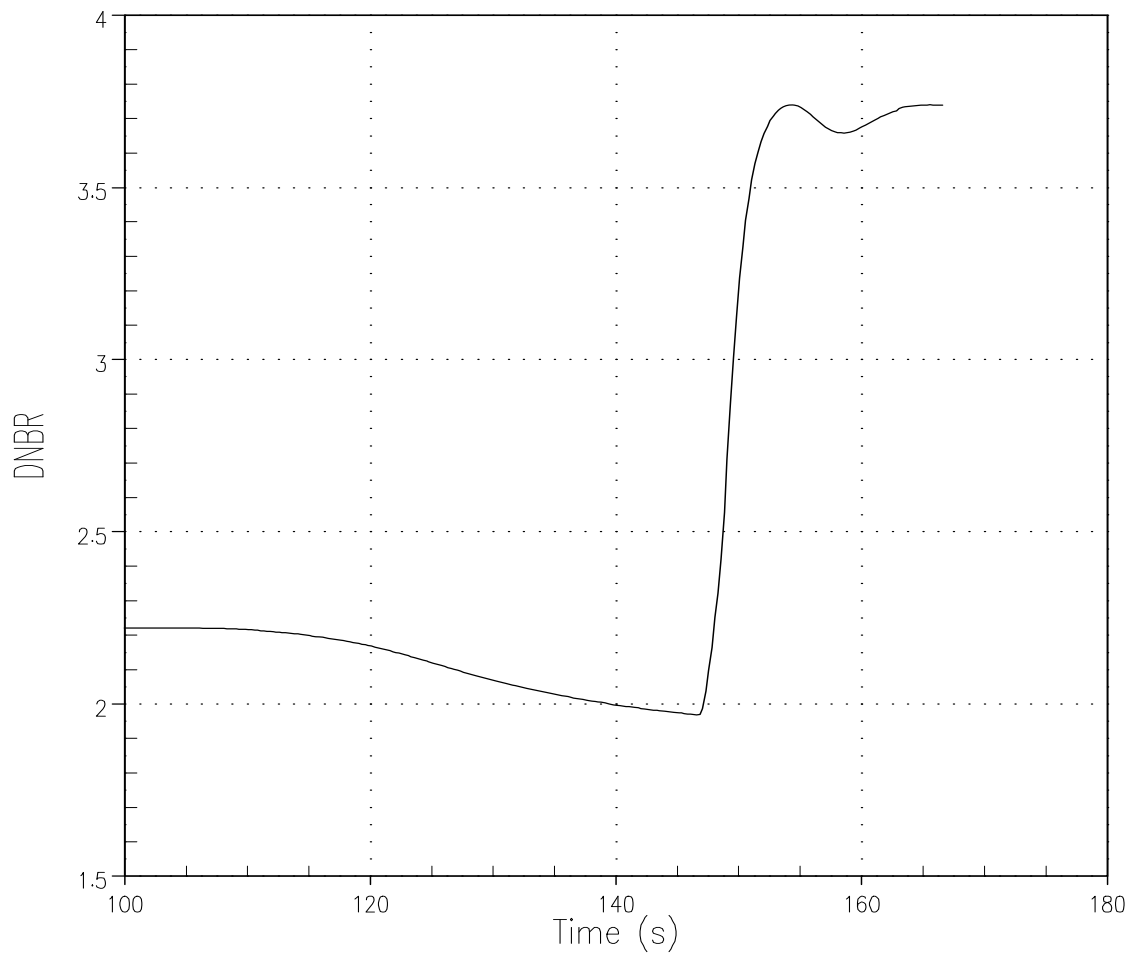
*The 100 second steady state has been removed from the plot

Figure 2.8.5.1.1.2-13 *
Feedwater Malfunction Reduced Feedwater Temperature at Power
Vessel Inlet Temperature



*The 100 second steady state has been removed from the plot

Figure 2.8.5.1.1.2-14 *
Feedwater Malfunction Reduced Feedwater Temperature at Power
DNBR



*The 100 second steady state has been removed from the plot

**Table 2.8.5.1.1.2-7
Feedwater Malfunction, HFP
Feedwater Temperature Reduction Analysis Results Comparison**

Event/Parameter	EPU Results⁽¹⁾	Current Analysis Results⁽¹⁾
Steady-State Run Begins, <i>seconds</i>	0.00	0.00
Time FWM Transient Initiated, <i>seconds</i>	100.00	100.00
Time MFW Temperature reduced in Loops 1 and 2, <i>seconds</i>	100.01	100.01
Time Variable High Power Trip Setpoint Reached, <i>seconds</i>	145.498	136.701
Time Reactor Trip Occurs, <i>seconds</i>	145.898	137.101
Time CEAs Begin to Drop into Core, <i>seconds</i>	146.638	137.841
Time Peak Nuclear Power Reached, <i>seconds</i>	146.600	138.000
Time Peak Core Heat Flux Reached, <i>seconds</i>	146.600	138.250
Time Minimum DNBR Reached, <i>seconds</i>	146.600	138.250
Peak Nuclear Power, <i>fraction of nominal</i>	1.12297	1.14437
Peak Core Heat Flux, <i>fraction of nominal</i>	1.12080	1.14038
Minimum DNBR	1.97	1.95842
1. The time sequence includes a 100 second steady state, therefore subtract 100 seconds in order to obtain the transient time.		

2.8.5.1.2 Steam System Piping Failures Inside and Outside Containment

2.8.5.1.2.1 Regulatory Evaluation

The steam release resulting from a rupture of a main steam pipe will result in an increase in steam flow, a reduction of coolant temperature and pressure, and an increase in core reactivity. The core reactivity increase may cause a power level increase and a decrease in shutdown margin. Reactor protection and safety systems are actuated to mitigate the transient.

The Florida Power and Light (FPL) review covered:

- Postulated initial core and reactor conditions,
- Methods of thermal and hydraulic analyses,
- The sequence of events,
- Assumed responses of the reactor coolant and auxiliary systems,
- Functional and operational characteristics of the reactor protection system (RPS)
- Operator actions,
- Core power excursion due to power demand created by excessive steam flow,
- Variables influencing neutronics, and
- The results of the transient analyses.

The NRC's acceptance criteria are based on:

- General Design Criterion (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 emergency core cooling system (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 reactor coolant pressure boundary (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; and
- GDC-35, insofar as it requires the reactor cooling system and associated auxiliaries be designed to provide abundant emergency core cooling.

Specific review criteria are contained in Standard Review Plan (SRP) Section 15.1.5 and other guidance provided in Matrix 8 of RS-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 2 conforms with the Nuclear Regulatory Commission (NRC) General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDCs for steam system piping failures inside and outside containment are as follows:

- GDC-27 is described in UFSAR Section 3.1.27 Criterion 27 - Combined Reactivity Control Systems Capability.

The reactivity control systems shall be designed to have a combined capability, in conjunction with poison addition by the emergency core cooling system, of reliably controlling reactivity changes to assure that under postulated accident conditions and with appropriate margin for stuck rods, the capability to cool the core is maintained.

The reactivity control systems that provide the means for making and holding the core subcritical under postulated accident conditions are discussed in UFSAR Sections 9.3 and 4.3. Combined use of control element assemblies (CEAs) and chemical shim control by the Chemical and Volume Control System (CVCS) provides the shutdown margin required for plant cooldown and long-term xenon decay, assuming the highest worth CEA is stuck out of the core.

During an accident, the Safety Injection System (SIS) functions to inject concentrated boric acid into the Reactor Coolant System (RCS) for short term and long term cooling and for reactivity control. Details of the system are given in UFSAR Section 6.3.

- GDC-28 is described in UFSAR Section 3.1.28 Criterion 28 - Reactivity Limits.

The reactivity control systems shall be designed with appropriate limits on the potential amount and rate of reactivity increase to assure that the effects of postulated reactivity accidents can neither (1) result in damage to the RCPB greater than limited local yielding nor (2) sufficiently disturb the core, its support structures, or other reactor pressure vessel internals to impair significantly the capability to cool the core. These postulated reactivity accidents shall include consideration of rod ejection (unless prevented by positive means), rod dropout, steam line rupture, changes in reactor coolant temperature and pressure, and cold water addition.

The bases for CEA design include ensuring that the reactivity worth of any one CEA is not greater than a preselected maximum value. The CEAs are divided into two sets: a shutdown set and a regulating set. These sets are further subdivided into groups as necessary. Administrative procedures and control interlocks ensure that the amount and rate of reactivity increase is limited to predetermined values. The regulating groups are withdrawn only after the shutdown groups are fully withdrawn. The regulating groups are programmed to move in sequence and within limits which prevent the rate of reactivity addition and the worth of individual CEAs from exceeding limiting values (see UFSAR Sections 4.3 and 7.7).

The maximum rate of reactivity addition that may be produced by the CVCS is too low to induce any significant pressure forces that might rupture the RCPB or disturb the reactor vessel internals.

The RCPB (UFSAR Chapter 5) and the reactor internals (UFSAR Chapter 4) are designed to appropriate codes and accommodate the static and dynamic loads associated with an inadvertent, sudden release of energy, such as that resulting from a CEA ejection or a steam line break, without rupture and with limited deformation which will not impair the capability of cooling the core.

- GDC-31 is described in UFSAR Section 3.1.31 Criterion 31 - Fracture Prevention of Reactor Coolant Pressure Boundary.

The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions (1) the boundary behaves in a non-brittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing, and postulated accident conditions and the uncertainties in determining (1) material properties, (2) the effects of irradiation on material properties, (3) residual, steady-state and transient stresses, and (4) size of flaws.

The RCPB components are designed and constructed in accordance with American Society of Mechanical Engineers (ASME) Code Section III, and comply with the test and inspection requirements of this code. These test and inspection requirements assure that flaw sizes are limited so that the probability of failure by rapid propagation is extremely remote. Particular emphasis is placed on the quality control applied to the reactor vessel, on which tests and inspections exceeding ASME Code requirements are performed. The tests and inspections performed on the reactor vessel are summarized in UFSAR Sections 5.2 and 5.3.

- GDC-35 is described in UFSAR Section 3.1.35 Criterion 35 - Emergency Core Cooling.

A system to provide abundant emergency core cooling shall be provided. The system safety function shall be to transfer heat from the reactor core following any loss of reactor coolant at a rate such that (1) fuel and clad damage that could interfere with continued effective core cooling is prevented and (2) clad metal-water reaction is limited to negligible amounts.

Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

The SIS provides cooling water at a rate sufficient (1) to assure that the zirconium-water reaction is limited to a negligible rate of less than one percent and (2) to assure that the fuel remains in a coolable geometry. Therefore, compliance with the intent of the acceptance criteria for ECCS for light water power reactors of 10 CFR 50, paragraph 50.46(b) is satisfied.

The SIS design includes adequate provisions to ensure that the required safety functions are provided with a single active failure relying on either onsite or offsite electrical power supply (see UFSAR Section 6.3).

UFSAR Section 15.1.5 describes the analysis of a steam system piping failure occurring from an at-power initial condition. Two analyses are presented: one that assumes the failure of the fast bus transfer (FFBT) of a 6.9 kV bus, at the time of reactor trip, which results in losing power to two of the four reactor coolant pumps, and one that assumes the steam line break (SLB) with coincident loss of offsite power (LOOP).

UFSAR Section 15.1.6 describes a steam system piping failure accident analysis performed assuming a hot zero power initial condition with the control rods inserted in the core, except for the most reactive rod in the fully withdrawn position, out of the core.

NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant Units 1 and 2, dated September 2003, defines the scope of license renewal. Specific transient analyses are not within the scope of license renewal.

2.8.5.1.2.2 Technical Evaluation

2.8.5.1.2.2.1 Pre-Trip Steam System Piping Failure

2.8.5.1.2.2.1.1 Introduction

A rupture in the main steam system piping (SLB) from an at-power condition creates an increased steam load, which extracts an increased amount of heat from the RCS via the steam generators. This results in a reduction in RCS temperature and pressure. In the presence of a strong negative moderator temperature coefficient (MTC), typical of end-of-cycle life conditions, the colder core inlet coolant temperature causes the core power to increase from its initial level due to the positive reactivity insertion. The power approaches a level equal to the total steam flow. Depending on the break size, a reactor trip occurs due to overpower conditions or as a result of low steam generator pressure.

The steam system piping failure accident evaluation described in LR [Section 2.8.5.1.2.2](#) addresses a hot zero power initial condition with the control rods inserted in the core, except for the most reactive rod in the fully withdrawn position, out of the core. That condition can occur while the reactor is at hot shutdown at the minimum required shutdown margin or after the plant has been tripped manually or by the reactor protection system following a SLB from an at-power condition.

An at-power break addresses the limiting condition with respect to core protection for the time period immediately following reactor trip. The purpose of this section is to describe the analysis of a steam system piping failure occurring from an at-power initial condition and to demonstrate that core protection is maintained prior to and immediately following reactor trip. Various pre-trip SLB cases are analyzed, including inside and outside breaks with a FFBT at the time of reactor trip, and an inside break with a LOOP at the time of break initiation, consistent with the current analysis of record.

2.8.5.1.2.2.1.2 Input Parameters, Assumptions, and Acceptance Criteria

To produce conservative results during the transient, the following assumptions are made in the transient analysis for the pre-trip SLB with FFBT case at the EPU conditions consistent with the approved methodology for the current analysis of record:

- Initial Conditions - The initial core power, reactor coolant temperature, and RCS pressure are assumed to be at their EPU values. The RCS Minimum Measured Flow is used. Uncertainties in initial conditions are included in the departure from nucleate boiling ratio (DNBR) limit as described in [Reference 2](#).
- Break Size - A spectrum of break sizes is analyzed ranging from 0.1 ft² to 6.305 ft². Small breaks do not result in a reactor trip. Intermediate and large size breaks result in a reactor trip on variable high power trip (VHPT) due to the implementation of integral flow restrictors with the steam generators. A low steam generator pressure trip is also available.
- Break Slow - In computing the steam flow during a steam line break, the Moody curve ([Reference 3](#)) for $fL/D = 0$ is used.
- Reactivity Coefficients - The analysis is performed over a range of moderator density coefficients (MDC's) which bound end-of-cycle reactivity feedback coefficients with the minimum Doppler power feedback to maximize the power increase following the break.
- Protection System - This analysis only considers the initial phase of the transient initiated from an at-power condition. Protection in this phase of the transient is provided by a reactor trip. Other protection system features are actuated to mitigate the effects of the SLB for a post-trip condition.
- Control Systems - The results of the analysis would not be more severe as a result of control system actuation; therefore their effects have been ignored in the analysis. Control systems are not credited in mitigating the effects of the transient.
- Fast Bus Transfer Failure – The FFBT at the time of turbine trip (0.0 seconds following reactor trip breaker opening) is modeled, which results in two of the four reactor coolant pumps coasting down. The remaining two reactor coolant pumps are assumed to coast down 3 seconds following the time of reactor trip breaker opening due to the loss of offsite power.

The following assumptions are made in the transient analysis for the case of pre-trip SLB with coincident LOOP (at break initiation time) for the EPU conditions. Note that these assumptions are consistent with the approved methodology for the current analysis of record:

- Initial Conditions - The initial core power, reactor coolant temperature, and RCS pressure are assumed to be at their EPU values. The RCS minimum measured flow is used. Uncertainties in initial conditions are included in the DNBR limit as described in [Reference 2](#).
- Break Size – A break size of 1.910 ft², corresponding to the maximum flow area of the steam generator (SG) integral flow restrictors, is analyzed. The analyzed break size was confirmed to be the most limiting by the FFBT case break size parametric study and then examined for the LOOP case.

- Break Flow - In computing the steam flow during a steam line break, the Moody curve (Reference 3) for $fL/D = 0$ is used.
- Reactivity Coefficients – The least negative value of the Doppler-only power coefficient is used, along with the most-negative moderator temperature coefficient (MTC) limit for EPU conditions. These assumptions maximize the core power during the initial part of the transient when the minimum DNBR is reached. These assumptions are also used in this analysis since the cooler primary system water from the steam generator, due to the steam piping rupture, does not have sufficient time to result in a core water density increase prior to the reactor trip.
- Trip Reactivity – A conservatively low trip reactivity value is used to minimize the effect of rod insertion following reactor trip and to maximize the heat flux statepoint used in the DNBR evaluation for this event. The value is based on the assumption that the highest worth CEA is stuck in its fully withdrawn position.
- Protection System - This analysis only considers the initial phase of the transient initiated from an at-power condition. Reactor trip is provided by a low RCS flow trip with a conservative setpoint using harsh environment uncertainty.
- Control Systems - The results of the analysis would not be more severe as a result of control system actuation. Therefore, their effects have been ignored in the analysis. Control systems are not credited in mitigating the effects of the transient.
- Loss of Offsite Power - This analysis assumes that a loss of offsite power occurs concurrent with the steam line break causing the four RCPs to start coastdown prior to rod motion. The statepoints from this case, which include, power, pressure, temperature, and core flow are used to determine the resulting DNBR, as calculated by the VIPRE code.

The following fuel failure limits for a steamline rupture postulated accident, as taken from the U.S. Nuclear Regulatory Commission (USNRC) Standard Review Plan, NUREG-0800, Section 15.1.5, Revision 3, are as follows:

The potential for core damage is evaluated on the basis that it is acceptable if the minimum DNBR remains above the 95/95 DNBR limit for PWRs based on acceptable correlations. If the DNBR falls below these values, fuel failures (rod perforation) must be assumed for all rods that do not meet these criteria ... Any fuel damage calculated to occur must be of sufficiently limited extent that the core will remain in place and geometrically intact with no loss of core cooling capability.

The rods-in-DNB limits for the inside and outside containment breaks for EPU, discussed in LR Section 2.9.2, Radiological Consequences Analyses Using Alternative Source Terms (AST), are 21 percent and 1.2 percent, respectively. From this analysis, it has been calculated that for all the events analyzed, there are no rods in DNB. Therefore, the assumptions used in the dose analysis are conservative and bounding with respect to the rods in DNB.

2.8.5.1.2.2.1.3 Description of Analyses and Evaluations

The analysis of the SLB is performed in the following stages:

1. The RETRAN code ([References 1 and 4](#)) is used to calculate the nuclear power, core heat flux, and RCS temperature and pressure transients resulting from the cooldown following the steam line break. RETRAN has been reviewed and approved by the NRC.
2. The RETRAN code is also used in the analysis of the steamline rupture with FFBT to calculate the primary flow coastdown initiated at the turbine trip, which results in two of the four reactor coolant pumps coasting down.
3. The RETRAN code is also used to calculate the primary flow coastdown following loss of offsite power at the time of break initiation, which results in all four of the reactor coolant pumps coasting down.
4. The core radial and axial peaking factors are determined using the thermal-hydraulic conditions from the transient analysis as input to the nuclear core models. The VIPRE code ([Reference 5](#)) is then used to calculate the DNBR for the limiting time during the transient.

This accident is analyzed with the revised thermal design procedure ([Reference 2](#)).

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

As discussed above, the design transient analyses were determined to be outside the scope of License Renewal; therefore, with respect to the design basis accidents and transients, the EPU does not impact any License Renewal evaluations.

2.8.5.1.2.2.1.5 Results

SLB with FFBT at Reactor Trip Time

The inside containment pre-trip SLB FFBT analysis examines a spectrum of break sizes ranging from 0.1 ft² to 6.305 ft² and a spectrum of MDC's ranging from 0.0 Δ k/g/cc to 0.43 Δ k/g/cc. The break is modeled on the steamline upstream of the main steam isolation valve (MSIV), which renders the break unisolable. The SLB is modeled to occur after a 10-second steady-state run. No reactor trip is predicted for cases modeling the smallest break sizes; thus, the power reaches equilibrium based on the increased steam load. For increasingly larger break sizes, the power increases until the reactor trips on the VHPT signal.

The limiting case for demonstrating DNB protection is the lowest DNBR and highest peak heat flux, which corresponds to the 1.910 ft² break at a MDC of 0.30 Δ k/g/cc.

The calculated time sequence of events for this case is shown in LR [Table 2.8.5.1.2-1](#). LR [Figure 2.8.5.1.2-1](#) shows the heat flux behavior over a range of break sizes for each MDC examined. LR [Figures 2.8.5.1.2-2 through 2.8.5.1.2-9](#) show the transient response for the limiting case.

The outside containment pre-trip SLB FFBT at the time of reactor trip analysis is bounded by the inside containment break. The time sequence of events for the limiting outside containment break is provided in LR [Table 2.8.5.1.2-2](#). It is seen that the inside containment case yields a higher peak heat flux.

SLB with Coincident LOOP (at time of break initiation)

The pre-trip SLB (with coincident LOOP) inside containment break analysis is performed assuming a LOOP at time of break initiation. The case is examined at the limiting most negative MTC.

The DNB and fuel centerline melting criteria are met. The calculated minimum DNBR value for the inside break case is above the limit value and the FFBT at reactor trip time case bounds the coincident LOOP case with respect to the maximum peak linear heat rate (PLHR). Since the FFBT case yields a PLHR which is below the limit value, all applicable acceptance criteria are met.

The outside containment pre-trip SLB with coincident LOOP analysis is bounded by the inside containment break because the same trip function as credited for the inside containment break are available for the outside containment break without harsh environment uncertainties.

The results of the analysis show that the calculated minimum DNBR value is above the limit. All applicable acceptance criteria are met. The calculated time sequence of events for this case is shown in LR [Table 2.8.5.1.2-3](#). LR [Figures 2.8.5.1.2-10](#) through [2.8.5.1.2-15](#) shows the transient response for this case.

LR [Table 2.8.5.1.2-4](#) presents a comparison of results including calculated DNBR and peak linear heat rate between the current and the EPU analyses.

2.8.5.1.2.2.2 Post-Trip Steam System Piping Failures

2.8.5.1.2.2.2.1 Introduction

A steamline break transient results in an uncontrolled increase in steam flow release from the steam generators, with the flow decreasing as the steam pressure drops. This steam flow release increases the heat removal from the RCS, which decreases the RCS temperature and pressure. In the presence of a negative MTC, the RCS cooldown results in a positive reactivity insertion, and consequently a reduction of the core shutdown margin for the post-trip condition. With the most reactive CEA assumed to be stuck in its fully withdrawn position after reactor trip, there is an increased possibility that the core will become critical and subsequently return to power. A return to power following a steamline break from the post-trip condition is a concern with the high-power peaking factors that exist when the most reactive CEA is stuck in its fully withdrawn position. Following a steamline break, the core is ultimately shut down by the boric acid injected into the RCS by either the emergency core cooling system (ECCS) (i.e., safety injection (SI)) or the actuation of the safety injection tanks (SITs). Additionally, the event may be terminated due to reaching a dry-out condition in the affected steam generator, effectively terminating the RCS cooldown and the uncontrolled steam release.

2.8.5.1.2.2.2.2 Input Parameters, Assumptions and Acceptance Criteria

The SLB analysis discussed herein was performed to demonstrate that a coolable core geometry is maintained. Assuming the most reactive CEA is stuck in its fully withdrawn position, and applying the most limiting single failure of one safety injection train, SLB core response cases were examined. Although DNB and fuel cladding damage are not necessarily unacceptable consequences of a SLB transient, the analysis described herein demonstrates that there is no consequential damage to the primary system, and that the core remains in place and intact, by showing that the DNB design-basis is satisfied.

The systems and components that provide the necessary protection against a SLB are listed as follows:

- Safety injection system actuation by any of the following:
 - Pressurizer pressure - low
 - Containment pressure - high
- Closure of the MSIVs after receipt of any of the following:
 - Steam generator pressure - low
 - Containment pressure - high
- Closure of the main feedwater isolation valves.

Each main steamline is connected to a steam generator through an exit nozzle with an integral flow restrictor and an effective flow area of 1.91 ft². This flow restrictor limits the steam release rate during a SLB event.

To produce conservative results during the transient, the following assumptions were made in the analysis of the SLB at the EPU conditions consistent with the approved methodology for the current analysis of record:

- A hypothetical double-ended rupture (DER) of a main steamline was postulated at Hot Zero Power (HZIP) / hot shutdown conditions. The DER of the steamline is modeled to occur at the steam generator outlet nozzle and steamline interface, therefore the maximum break size is modeled as the equivalent flow area of the main steam line. However, the steam flow is limited by the area of the steam generator outlet nozzle integral flow restrictors, which are modeled in both the faulted and unfaulted loop steam generators.
- The initial conditions correspond to a subcritical reactor, an initial vessel average temperature at the no-load value and no core decay heat. These conditions are conservative, compared to hot full power, for a SLB transient because the resultant RCS cooldown does not have to remove any latent heat. Also, the steam generator water inventory is greatest at no-load conditions, which increases the capability for cooling the RCS. Thus, the analysis of the Hot Zero Power (HZIP) case bounds the case of a post-trip analysis from Hot Full Power (HFP).
- One DER case was analyzed. The post-trip SLB case assuming a loss of offsite power is bounded by the case that assumes offsite power is maintained throughout the event due to

including RCS pump heat and forced convection heat transfer from the primary to secondary side.

- Perfect moisture separation within the steam generators was assumed to preclude liquid discharge through postulated steam system pipe breaks.
- An end-of-life shutdown margin corresponding to no-load, equilibrium xenon conditions, with the most reactive CEA stuck in its fully withdrawn position was assumed. The stuck CEA was assumed to be in the core location exposed to the greatest cooldown; that is, related to the faulted loop. The reactivity feedback model included a positive MDC corresponding to an end-of-life rodded core with the most reactive CEA in its fully withdrawn position. The variation of the MDC due to changes in coolant density and boron concentration was accounted for in the model. LR [Figure 2.8.5.1.2-16](#) presents the k_{eff} versus temperature relationship corresponding to the MDC plus the Doppler temperature feedback effect. The Doppler power feedback corresponding to the stuck CEA conditions is provided in LR [Figure 2.8.5.1.2-17](#).

The reactivity and power predicted by RETRAN were compared to those predicted by the advanced nodal core design code (ANC) ([Reference 6](#)). The ANC core analysis considered the following:

- Doppler reactivity feedback from the high fuel temperature near the stuck CEA
- Moderator feedback from the water conditions near the stuck CEA
- Power redistribution effects
- Non-uniform core inlet temperature effects

The ANC core analysis confirmed that the RETRAN-predicted reactivity is acceptable.

- The Moody critical flow curve was applied to conservatively maximize the break flow rate assuming no frictional losses.
- The closure of the MSIV of the intact/unfaulted loop was conservatively modeled to be complete at 6.75 seconds after receipt of a low steam generator pressure (487 psia) signal from the same loop.
- The safety injection pumps provide flow to the RCS after receipt of a safety injection signal on low pressurizer pressure (1638 psia). A delay of 20 seconds is assumed for signal processing and pump startup.
- The minimum capability for the injection of boric acid solution, corresponding to the most restrictive single active failure in the SIS, was assumed. The assumed safety injection flow (see LR [Figure 2.8.5.1.2-18](#)) corresponds to the operation of one high-head safety injection pump. Boric acid solution from the refueling water tank (RWT), with a conservative minimum concentration of 1720 ppm and a minimum temperature of 51°F, was the assumed source of the safety injection flow. The safety injection lines downstream of the RWT were assumed to initially contain unborated water to conservatively maximize the time it takes to deliver the highly concentrated RWT boric acid solution to the reactor coolant loops.

- Main feedwater flow equal to the nominal (100 percent power) value was assumed to initiate coincident with the postulated break.
- A minimum SGTP level of 0 percent was assumed to maximize the heat transfer capabilities of the steam generators and therefore maximize the cooldown of the RCS.
- Due to the design of the auxiliary feedwater system which automatically isolates the auxiliary feedwater from the broken loop, no auxiliary feedwater was assumed to be delivered during the event.
- A thermal design flow of 375,000 gallons per minute was assumed.

The following fuel failure limits for a steamline rupture postulated accident, as taken from the U.S. Nuclear Regulatory Commission (USNRC) Standard Review Plan, NUREG-0800, Section 15.1.5, Revision 3, are as follows:

“The potential for core damage is evaluated on the basis that it is acceptable if the minimum DNBR remains above the 95/95 DNBR limit for PWRs based on acceptable correlations. If the DNBR falls below these values, fuel failures (rod perforation) must be assumed for all rods that do not meet these criteria ... Any fuel damage calculated to occur must be of sufficiently limited extent that the core will remain in place and geometrically intact with no loss of core cooling capability.”

For this analysis, neither the calculated minimum DNBR nor the calculated PLHR exceed their respective safety analysis limit. Thus, there is no fuel failure.

2.8.5.1.2.2.2.3 Description of Analysis and Evaluation

Using the RETRAN code ([References 1 and 4](#)), transient values of key plant parameters identified as statepoints (core average heat flux, core pressure, core inlet temperature, RCS flow rate, and core boron concentration) were calculated first. Next, the ANC core design code was used to:

- Evaluate the nuclear response to the RCS cooldown so as to verify the RETRAN transient prediction of the average core power/reactivity, and
- Determine the peaking factors associated with the return to power in the region of the stuck CEA.

Finally, using the RETRAN-calculated statepoints and the ANC-calculated peaking factors, the detailed thermal and hydraulic computer code VIPRE was used to calculate the minimum DNBR based on the W-3 DNB correlation. The peak linear heat rate is calculated based on the results of the ANC analysis.

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

As discussed above, the design transient analyses were determined to be outside the scope of License Renewal; therefore, with respect to the design basis accidents and transients, the EPU does not impact any License Renewal evaluations.

2.8.5.1.2.2.2.5 Results

The results of the statepoint evaluation demonstrate that the post-trip steamline break event meets the applicable DNBR and peak linear heat rate acceptance criteria. The time sequence of events is presented in LR [Table 2.8.5.1.2-5](#).

LR [Figures 2.8.5.1.2-16](#) through [2.8.5.1.2-26](#) show the post-trip SLB results which include the steam pressure, steam flow, pressurizer pressure, pressurizer water volume, reactor vessel inlet temperature, core heat flux, core boron concentration, and core reactivity following a double-ended rupture of a main steamline at initial no-load conditions with offsite power available (full reactor coolant flow). The maximum break area of the assumed guillotine rupture of the main steam line was set to the cross sectional flow area of the steamline (6.31 ft²). However, the steam flow from both the faulted and unfaulted steam generators is restricted by the cross sectional flow area of the steam generator outlet nozzle integral flow restrictor (1.910 ft²). Steam flow from the unfaulted steam generator continues to discharge through the break due to the cross connect through the main steamline header until steamline isolation occurs.

LR [Table 2.8.5.1.2-6](#) presents a comparison of results including peak core heat flux, calculated DNBR, and peak linear heat rate between the current and the EPU analyses. The results confirm that the post-trip SLB event, analyzed using the replacement steam generator features, provides additional margin at the EPU conditions. The main reason for the improvement in results is the integral flow restrictor in the exit nozzle of the SGs. This flow restrictor limits the effective break flow area to 1.910 ft², which is significantly smaller than the current analysis break flow area of 6.305 ft² for the faulted SG and 2.27 ft² for the unfaulted SG. This reduction in break flow area slows the cooldown rate and minimizes the asymmetry between the faulted and non-faulted loops (LR [Figure 2.8.5.1.2-23](#)), which is a benefit to SLB events. The less severe cooldown rate also results in a significantly smaller return to power enabling the system to mitigate the consequences of the event prior to the delivery of any borated water from Safety Injection. Furthermore, the reactivity effects calculated for the EPU are less severe (i.e., the core feedback and peaking as a result of the cooldown is not as limiting as they were in the current analysis). Also, since this is an RCS cooldown event, the pressure in the RCS decreases after the initiation of the event and therefore there is no challenge to the RCPB.

2.8.5.1.2.3 Conclusion

FPL has reviewed steam system piping failure events and concludes that the reviews have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. FPL further concludes that the review 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 a propagating fracture of the RCPB is minimized, and abundant core cooling will be provided. Based on this, FPL concludes that the plant will continue to meet the requirements of GDCs -27, -28, -31, and -35 following implementation of the proposed EPU and finds the proposed EPU acceptable with respect to steam system piping failures.

2.8.5.1.2.4 References

1. WCAP-14882-P-A and WCAP-14882-A (Non-Proprietary), Rev. 0, RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, April, 1999.
2. WCAP-11397-P-A and WCAP-11397-A (Non-Proprietary), Revised Thermal Design Procedure, April 1989.
3. Moody, F. S., Transactions of the ASME Journal of Heat Transfer, Figure 3, page 134, February 1965.
4. EPRI NP-1850-CCM, Rev. 6, RETRAN-02-A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, December 1995.
5. WCAP-14565-P-A (Proprietary) and WCAP-14565-NP-A (Non-Proprietary), VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, Sung, Y., et al, October 1999.
6. WCAP-10965-P-A and WCAP-10965 (Non-Proprietary), ANC: A Westinghouse Advanced Nodal Computer Code, Y. S. Liu, et al., September 1986.

Table 2.8.5.1.2-1
Pre-Trip SLB Analysis with FFBT Inside Containment
Sequence of Events

Event	Time (sec)	Value
SLB Transient Initiated	10.01	---
Variable High Power (Thermal Power) Trip Setpoint Reached	21.29	112%
Reactor Trip Generated	21.69	0.40 second delay from setpoint
Turbine Trip on Reactor Trip	21.69	0.0 sec. delay from reactor trip
Coastdown of 2 pumps initiated	21.70	FFBT assumed coincident with reactor trip breaker opening
Peak Linear Heat Rate Reached	22.35	17.677 kW/ft
Peak Heat Flux	22.35	122.9%
Minimum DNBR Reached	22.35	1.63
CEA Release	22.68	0.99 second delay conservatively used instead of 0.74 second delay design basis value

Table 2.8.5.1.2-2
Pre-Trip SLB Analysis with FFBT Outside Containment
Sequence of Events

Event	Time (sec)	Value
SLB Transient Initiated	10.01	---
Variable High Power (Thermal Power) Trip Setpoint Reached	20.03	112%
Reactor Trip Generated	20.43	0.40 second delay from setpoint
Turbine Trip on Reactor Trip	20.43	0.0 sec. delay from reactor trip
Coastdown of 2 pumps initiated	20.45	FFBT assumed coincident with reactor trip breaker opening
CEA Release	21.42	0.99 second delay conservatively used instead of 0.74 second delay design basis value
Peak Heat Flux	21.60	120.8%

Table 2.8.5.1.2-3
Pre-Trip SLB Analysis with a LOOP at Break Initiation Sequence of Events

Event	Time (sec)	Value
SLB Transient Initiated & Loss of Offsite Power (All RCPs begin to coastdown)	10.01	---
Low RCS Flow Trip Setpoint Reached	11.77	0.6992
Reactor Trip Generated	12.67	0.90 second delay from setpoint
CEA Release	13.66	0.99 second delay conservatively used instead of 0.74 second delay design basis value
Minimum DNBR Reached	14.10	1.768

**Table 2.8.5.1.2-4
Comparison of Results Pre-Trip SLB**

Criterion	Current Limit	Current Value	EPU Limit	EPU Value
FFBT				
Minimum DNBR	1.32	1.423	1.42	1.63
Peak Linear Heat Rate (kW/ft)	22.0	20.312	22.0	17.677
LOOP (break initiation)				
Minimum DNBR	1.42	>1.42	1.42	1.76
Peak Linear Heat Rate (kW/ft)	22.0	<22.0	22.0	<17.677

Table 2.8.5.1.2-5
Post-Trip Steamline Break Analysis Sequence of Events

Event	Time (sec)	Value
MSLB (6.305 ft ² DER) Transient Initiated	10.0	---
Manual Reactor Trip Initiated	10.0	---
MSIV/MFIV Closure Signal on Low Steam Generator Pressure	23.2	487 psia
Feedwater Isolation (MFIV Closure) on Loop 2	28.4	5.15 sec. delay
Steamline Isolation (MSIV Closure) on Loops 1 and 2	30.0	6.75 sec. delay
Core Criticality Attained	37.0	---
SI Actuation Signal on Low Pressurizer Pressure	61.0	1638 psia
Peak Heat Flux Reached	68.25	5.6%
Minimum DNBR Reached	68.25	4.307
Peak Linear Heat Rate Reached	68.25	7.25 kW/ft

Table 2.8.5.1.2-6
Comparison of Results Post-Trip SLB

Criterion	AOR Limit	AOR Value	EPU Limit	EPU Value
Peak Core Heat Flux (%)	---	18.3	---	5.6
Minimum DNBR (W-3)	1.45	1.50	1.30	4.286
Peak Linear Heat Rate (kW/ft)	22.0	21.08	22.0	7.25

Figure 2.8.5.1.2-1
Pre-Trip SLB - FFBT
Peak Heat Flux (Fraction of Nominal (FON)) vs.
Break Size for a Spectrum of MDCs

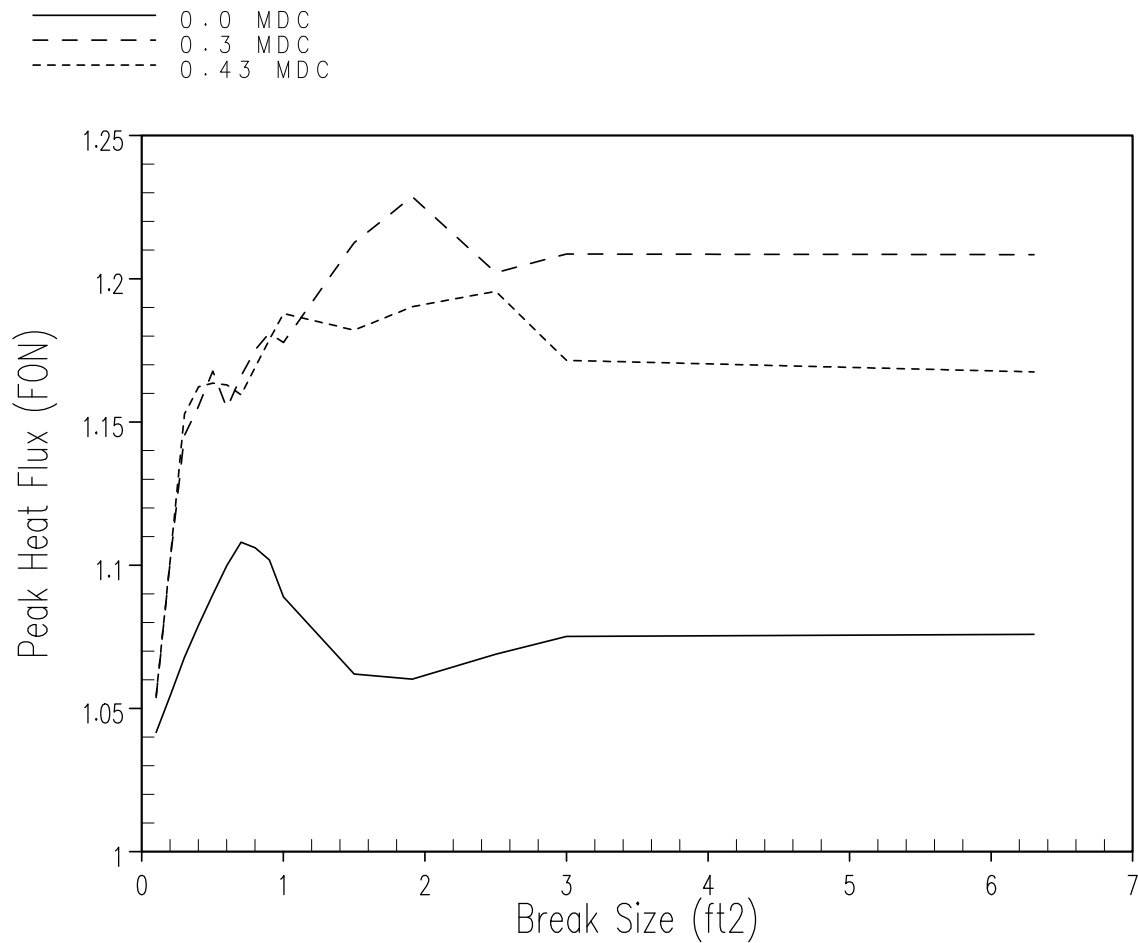


Figure 2.8.5.1.2-2
Pre-Trip SLB - FFBT
Nuclear Power vs. Time

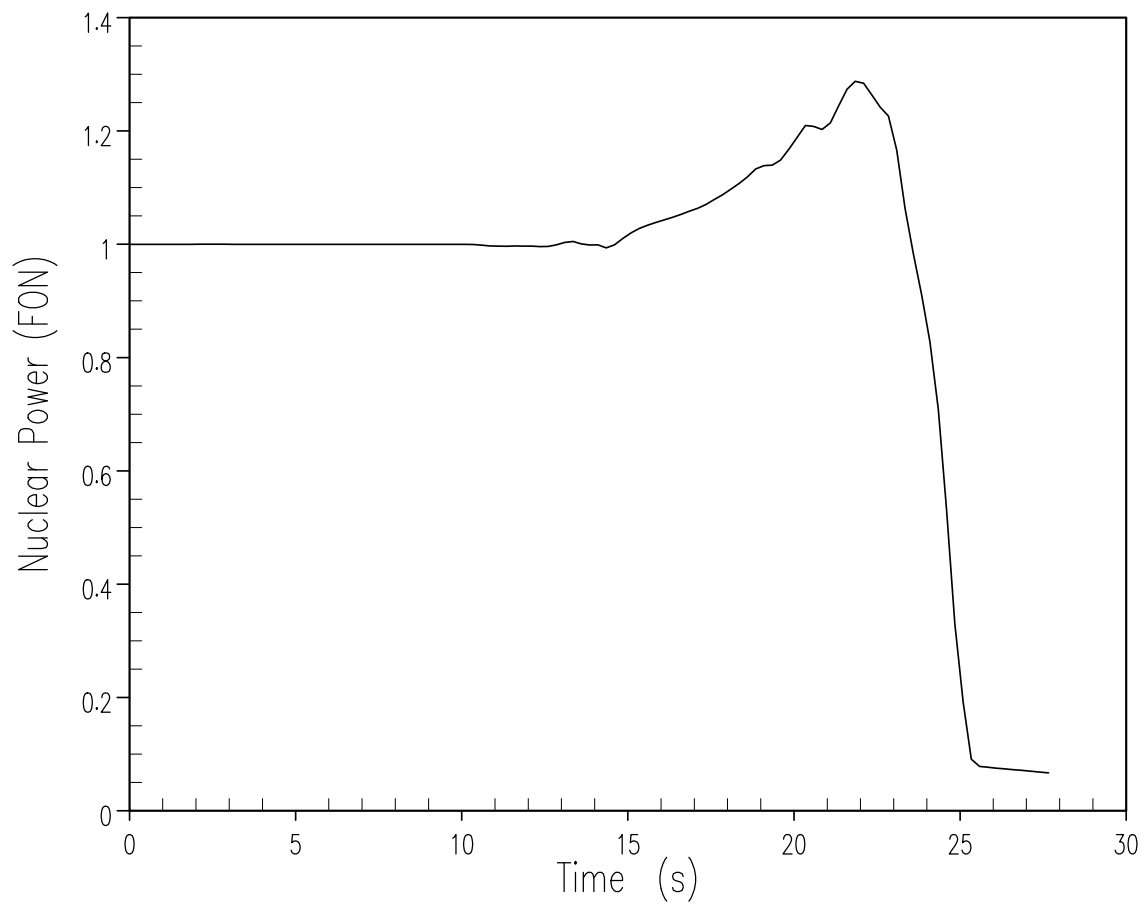


Figure 2.8.5.1.2-3
Pre-Trip SLB – FFBT
Core Heat Flux vs. Time

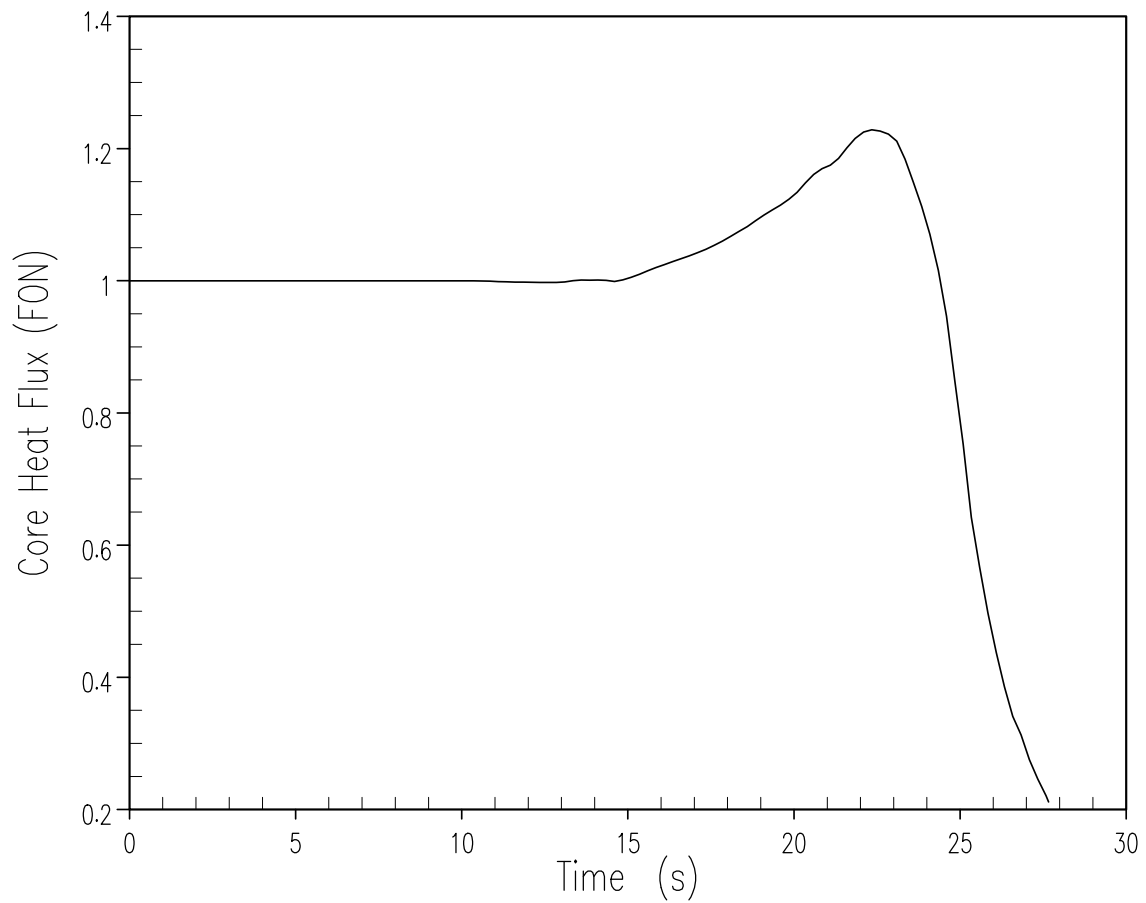


Figure 2.8.5.1.2-4
Pre-Trip SLB – FFBT
Pressurizer Pressure vs. Time

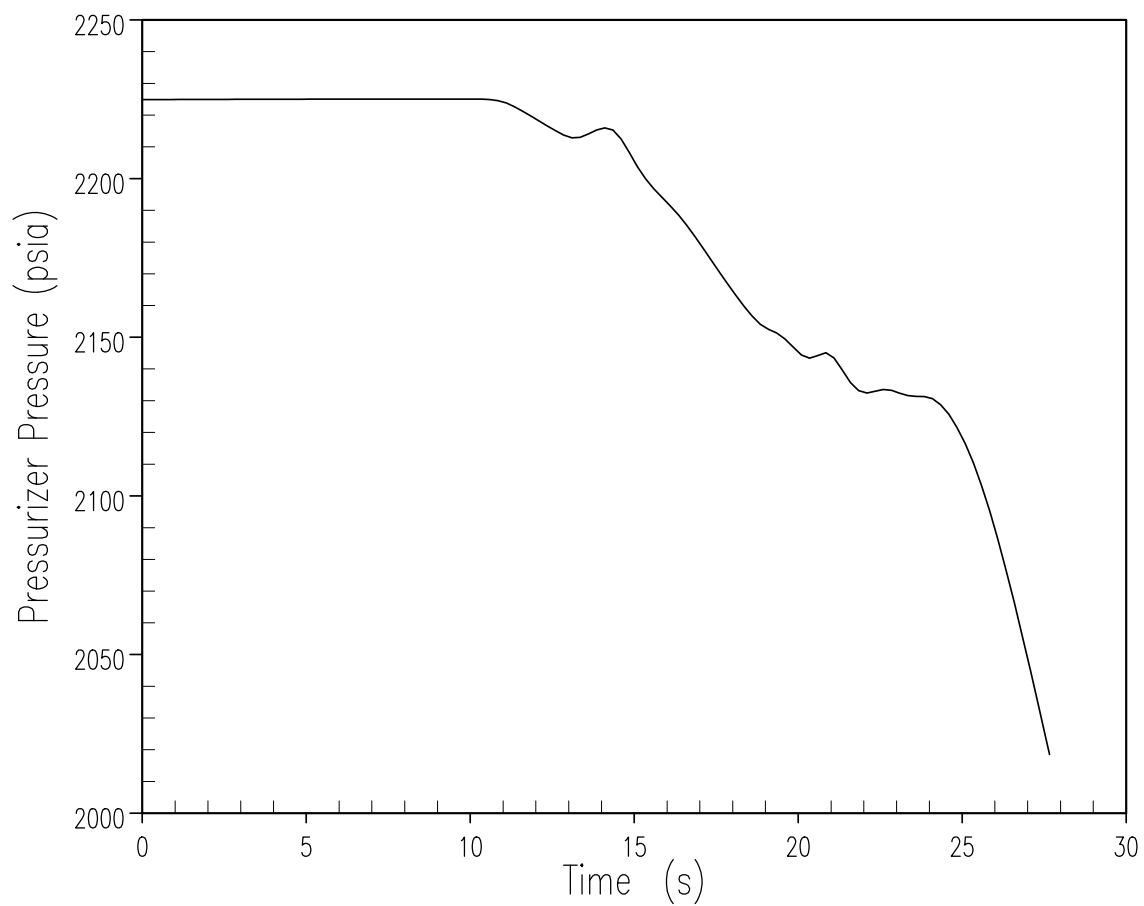


Figure 2.8.5.1.2-5
Pre-Trip SLB – FFBT
Pressurizer Water Volume vs. Time

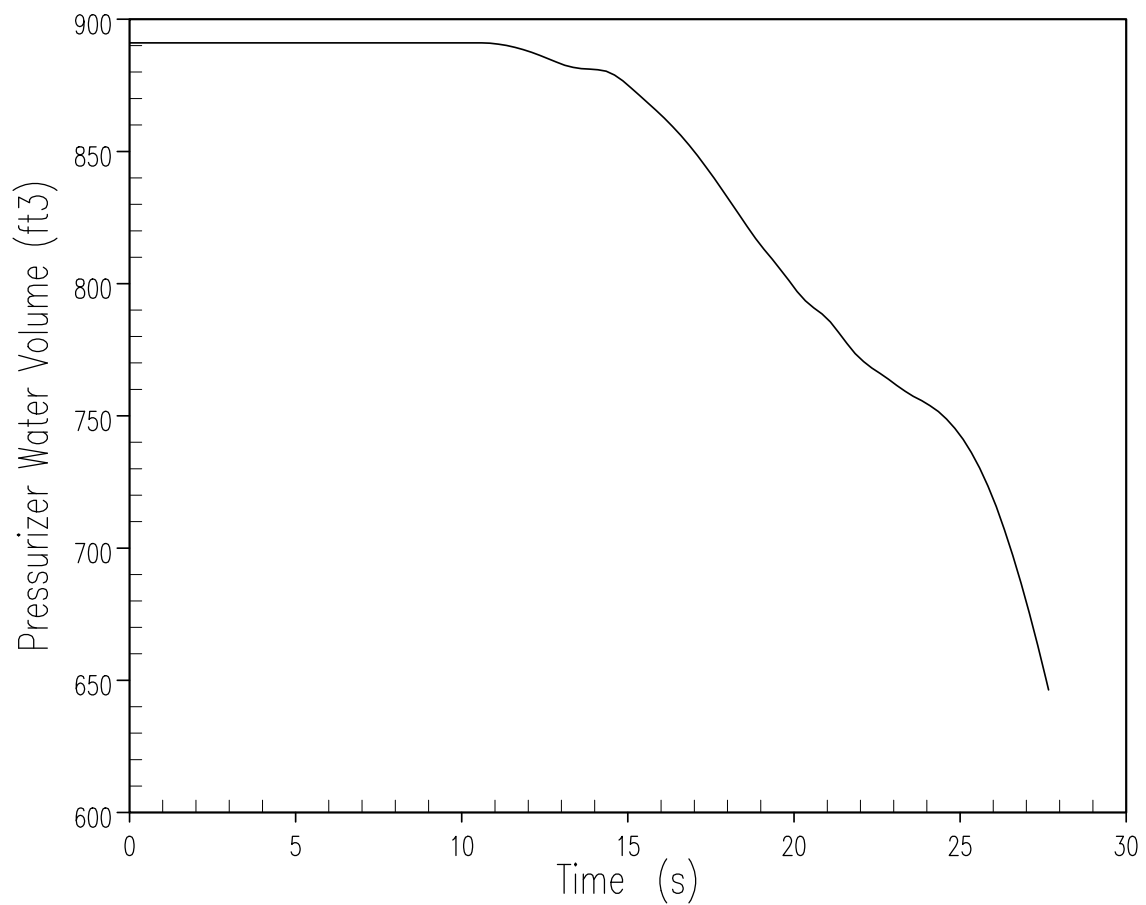


Figure 2.8.5.1.2-6
Pre-Trip SLB – FFBT
Reactor Vessel Inlet Temperature vs. Time

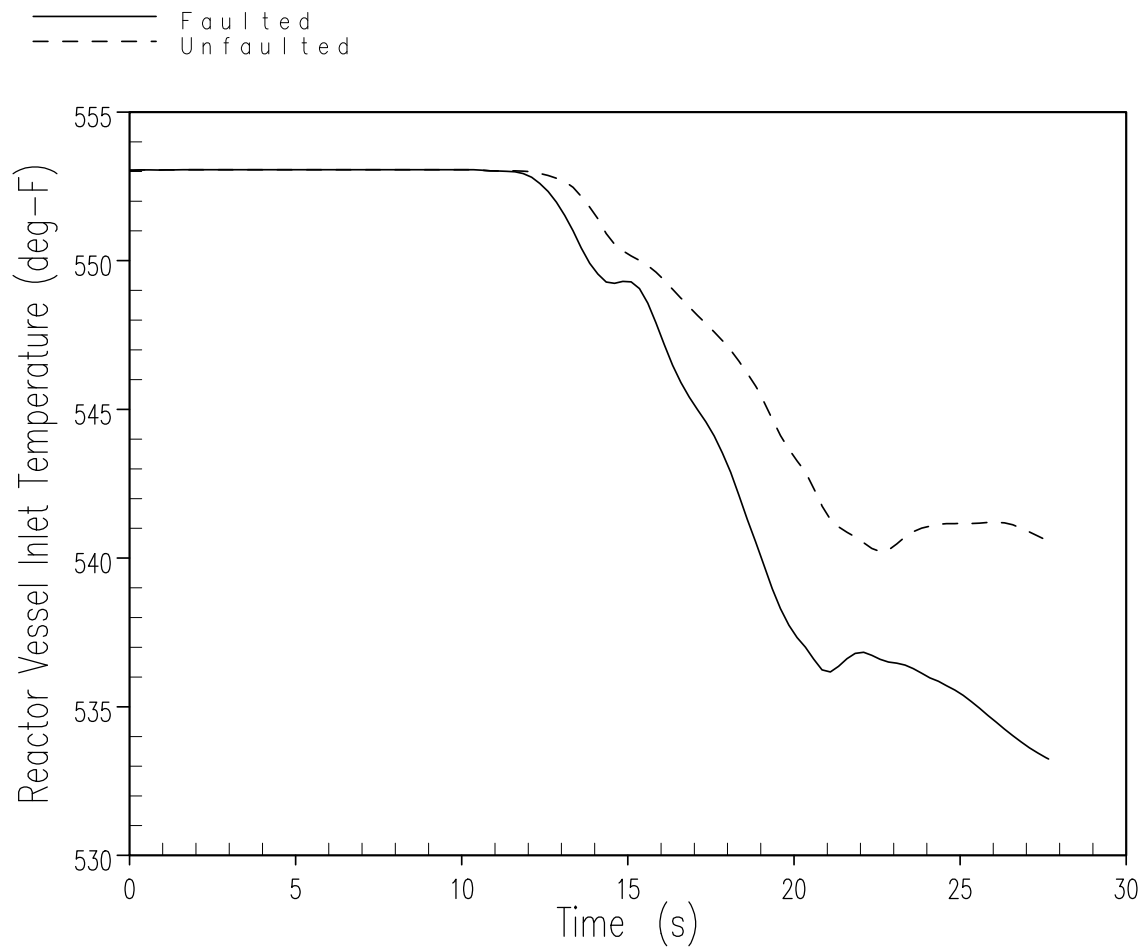


Figure 2.8.5.1.2-7
Pre-Trip SLB – FFBT
Steam Generator Steam Pressure vs. Time

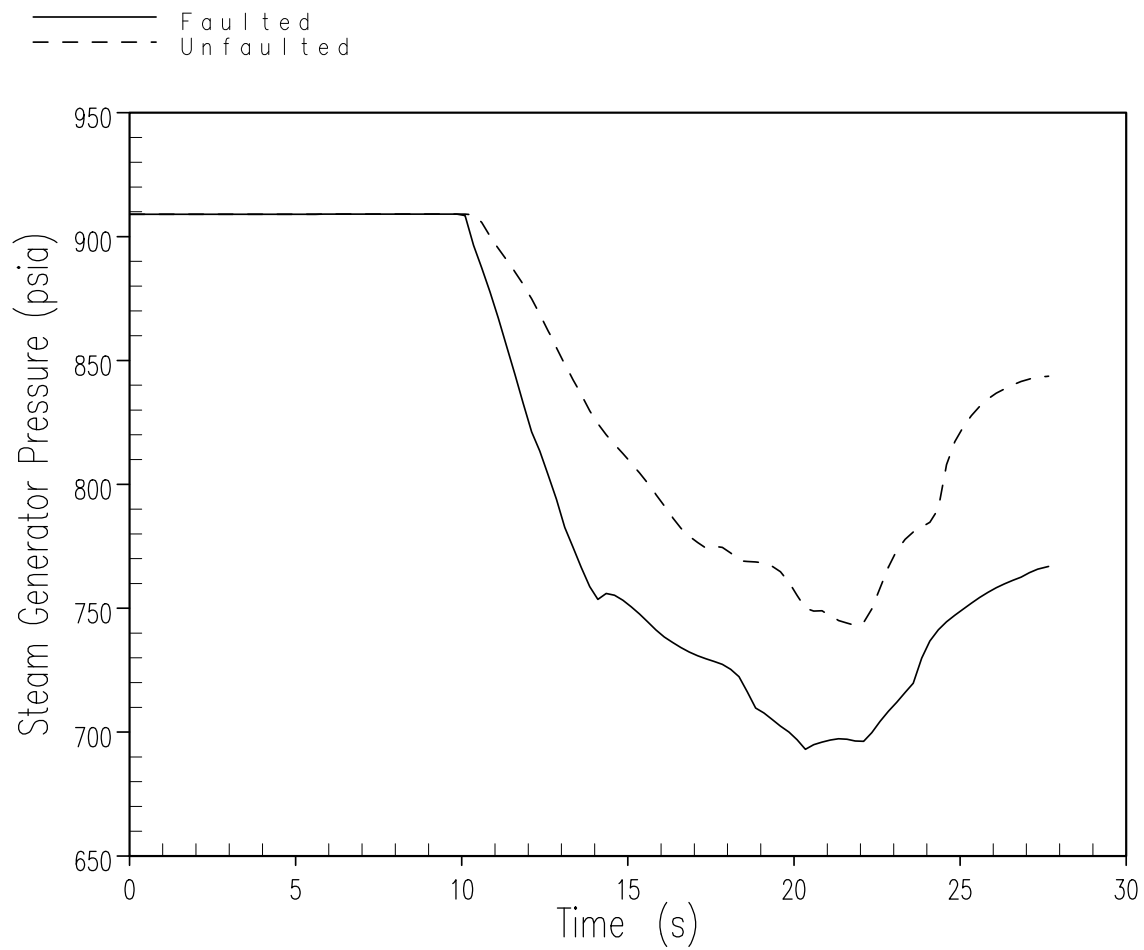


Figure 2.8.5.1.2-8
Pre-Trip SLB – FFBT
Loop Steam Rate vs. Time

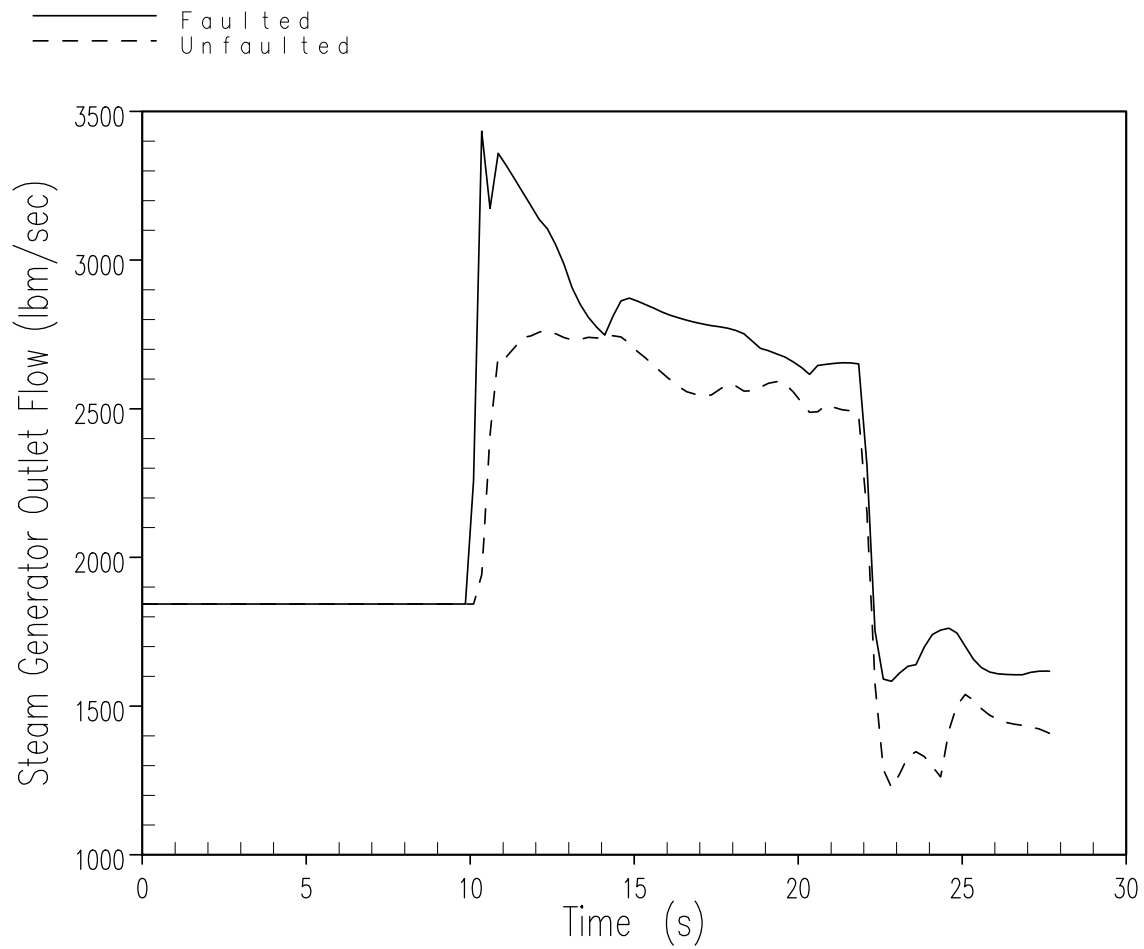


Figure 2.8.5.1.2-9
Pre-Trip SLB – FFBT
Total Core Inlet Flow vs. Time

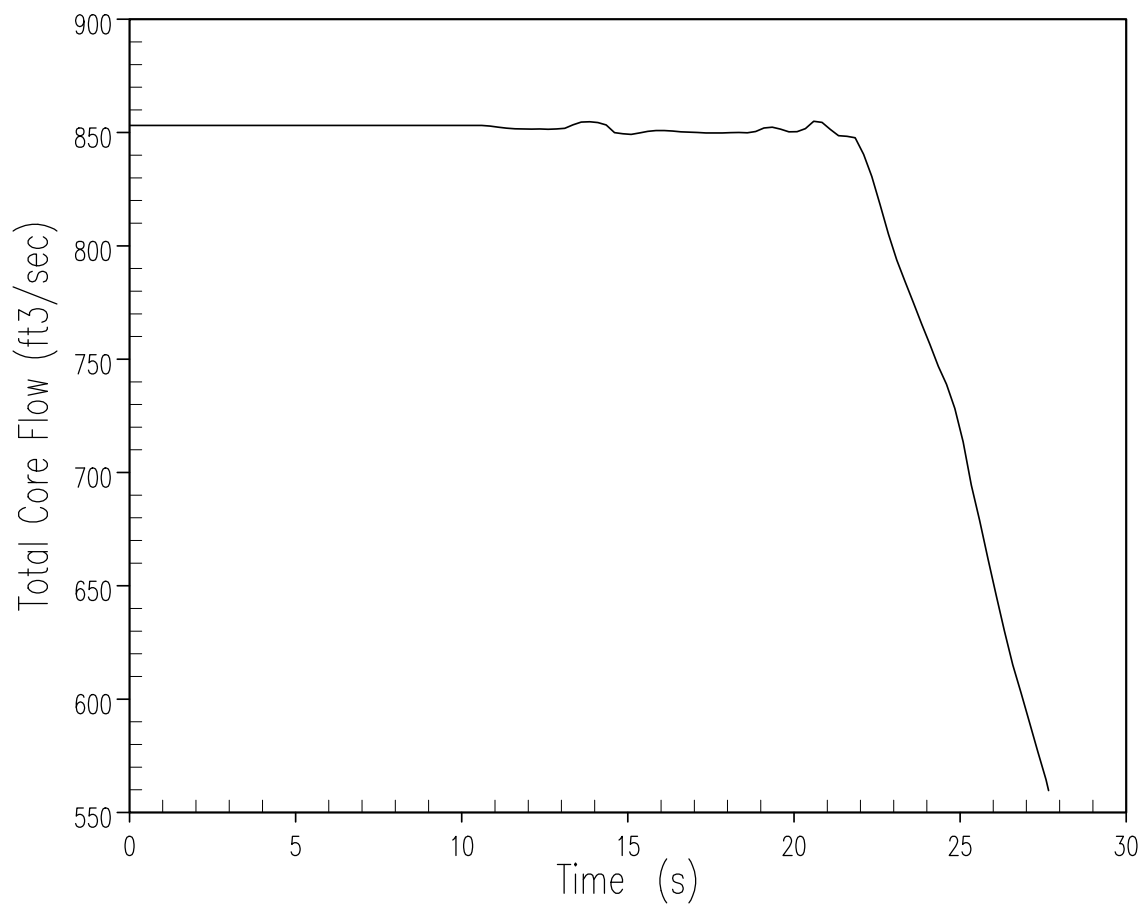


Figure 2.8.5.1.2-10
Pre-Trip SLB with LOOP at Break Initiation
Total Core Inlet Flow vs. Time

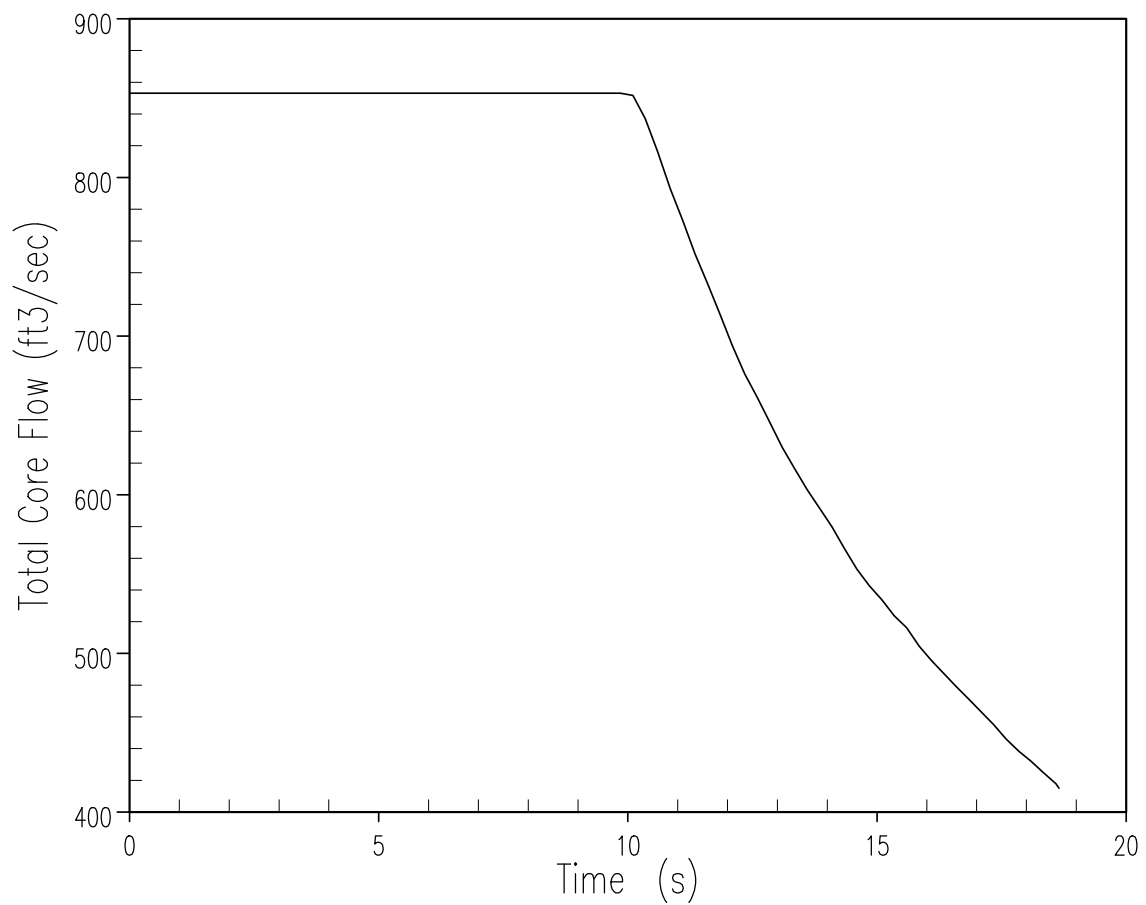


Figure 2.8.5.1.2-11
Pre-Trip SLB with LOOP at Break Initiation
RCS Loop Volumetric Flow vs. Time

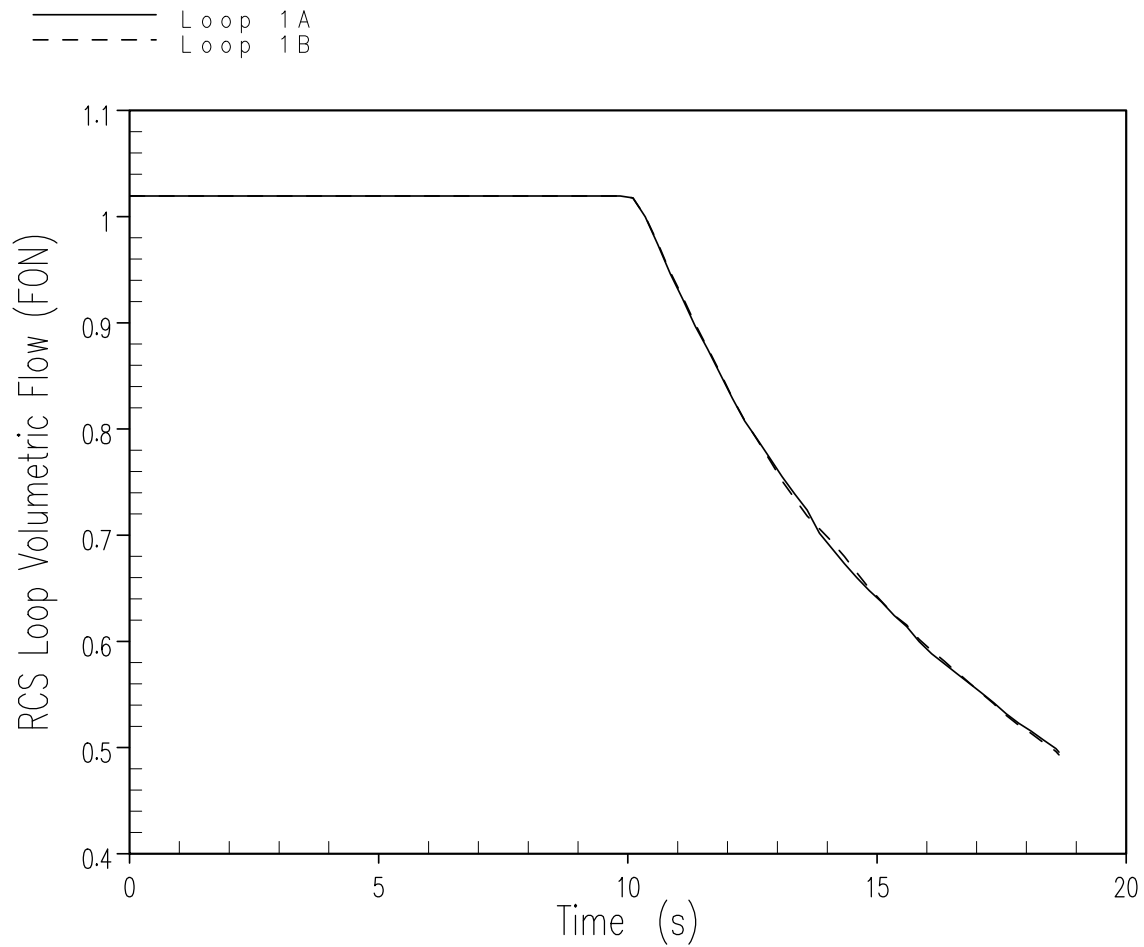


Figure 2.8.5.1.2-12
Pre-Trip SLB with LOOP at Break Initiation
Nuclear Power vs. Time

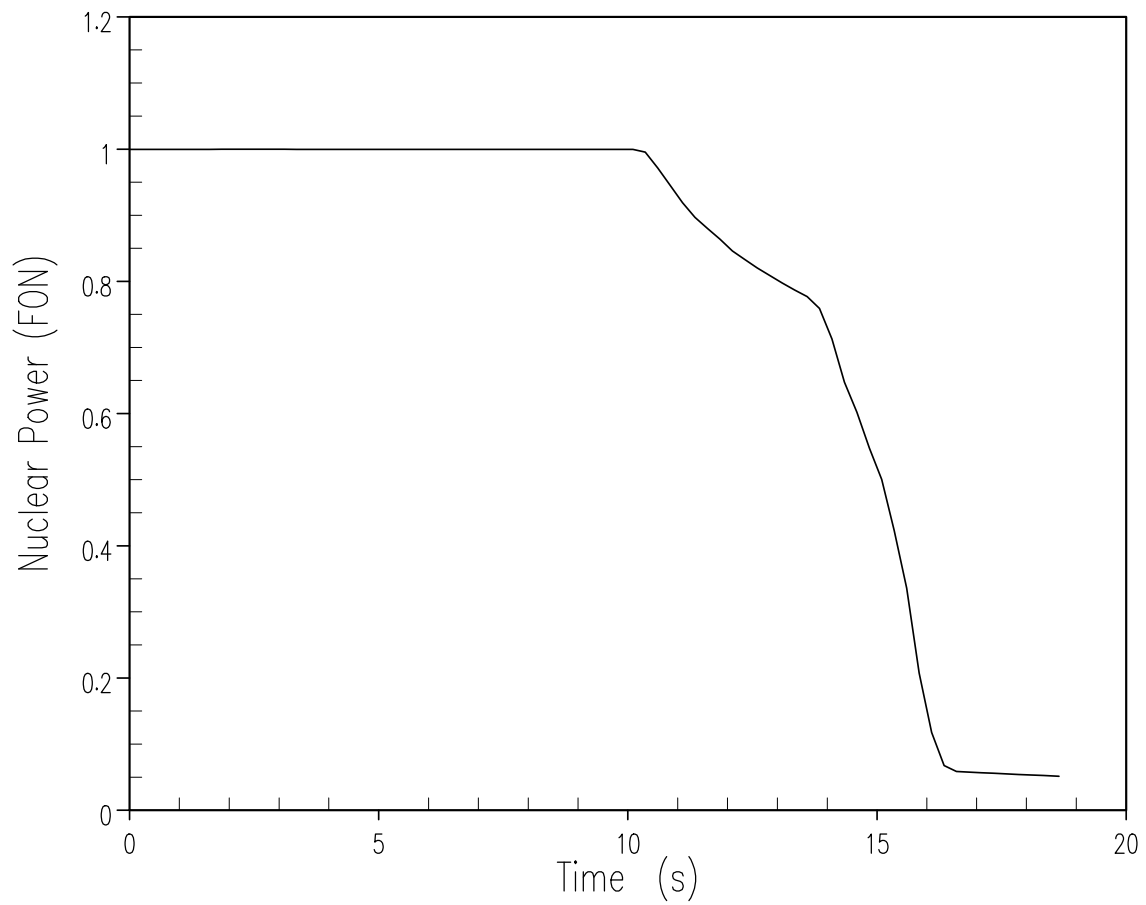


Figure 2.8.5.1.2-13
Pre-Trip SLB with LOOP at Break Initiation
Pressurizer Pressure vs. Time

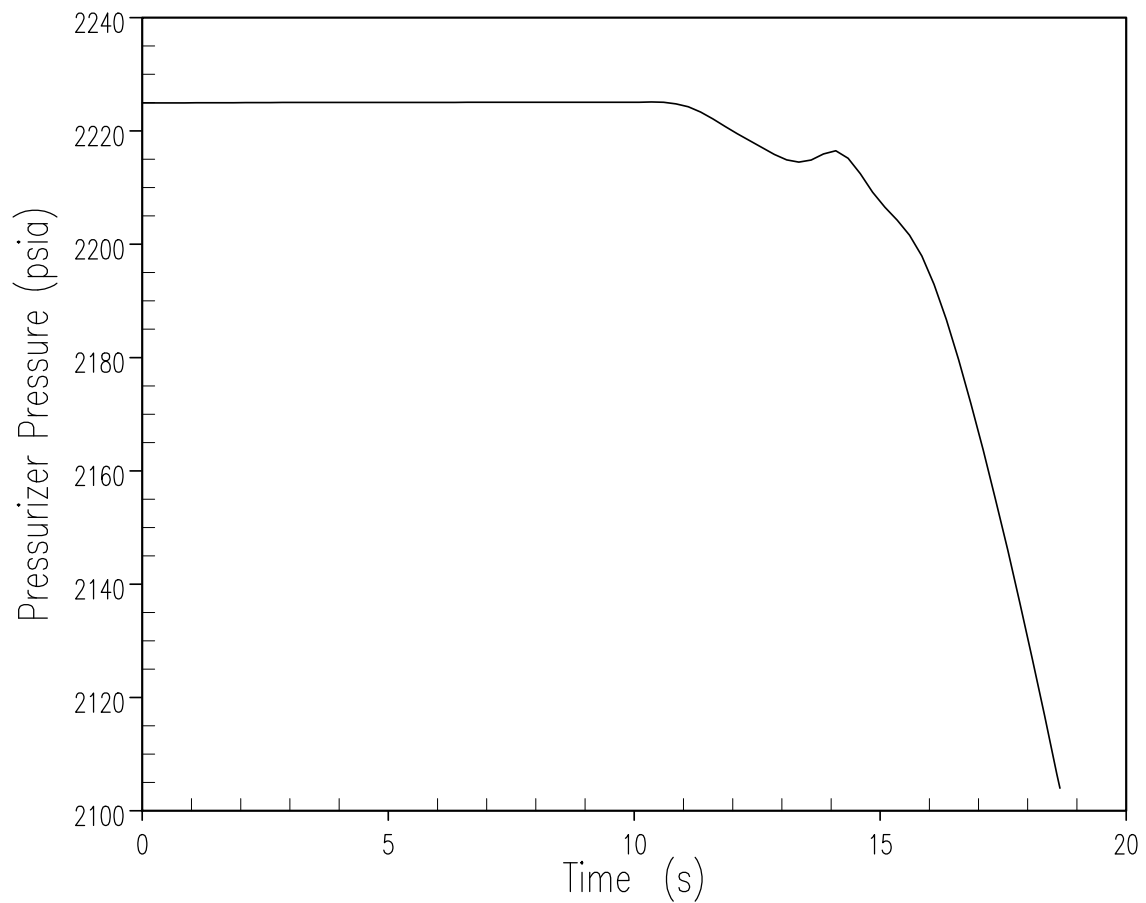


Figure 2.8.5.1.2-14
Pre-Trip SLB with LOOP at Break Initiation
Reactor Vessel Inlet Temperature vs. Time

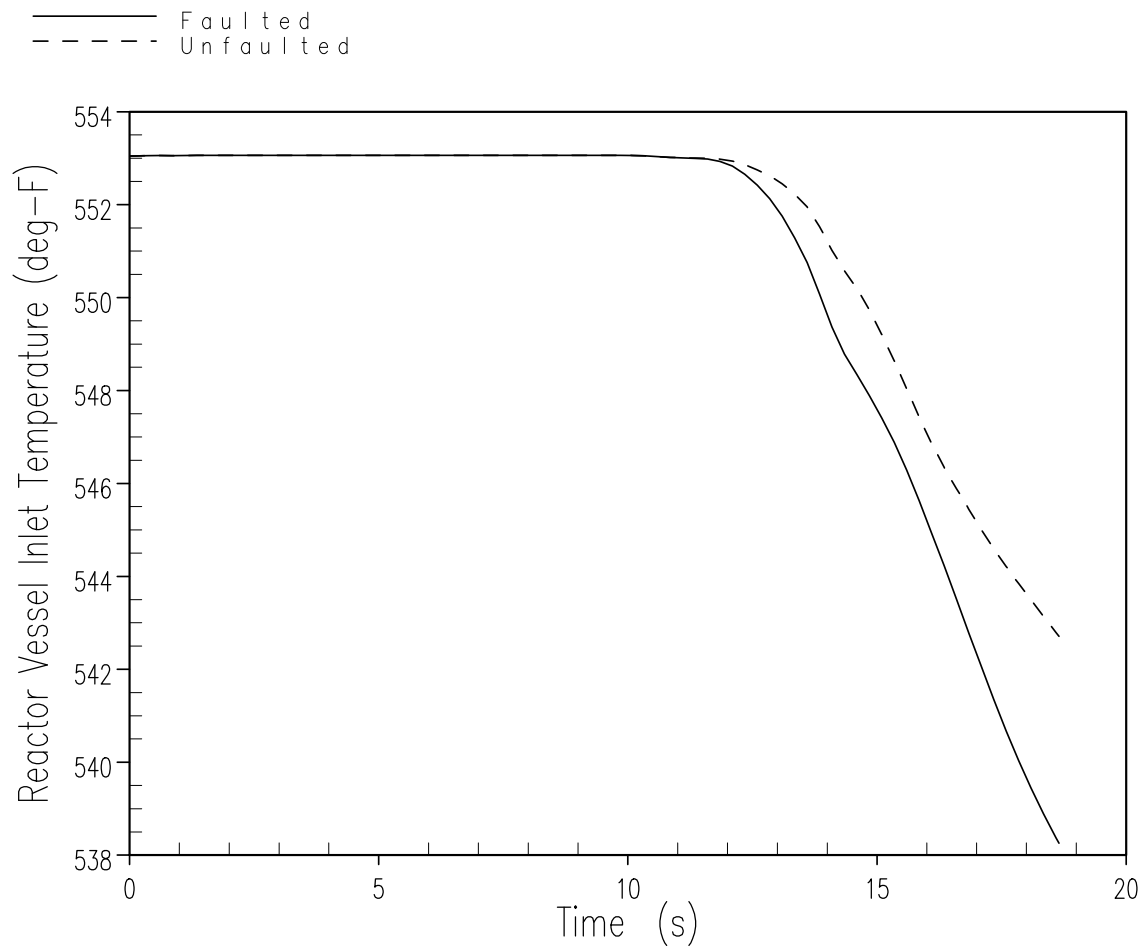


Figure 2.8.5.1.2-15
Pre-Trip SLB with LOOP at Break Initiation
Steam Generator Steam Flow vs. Time

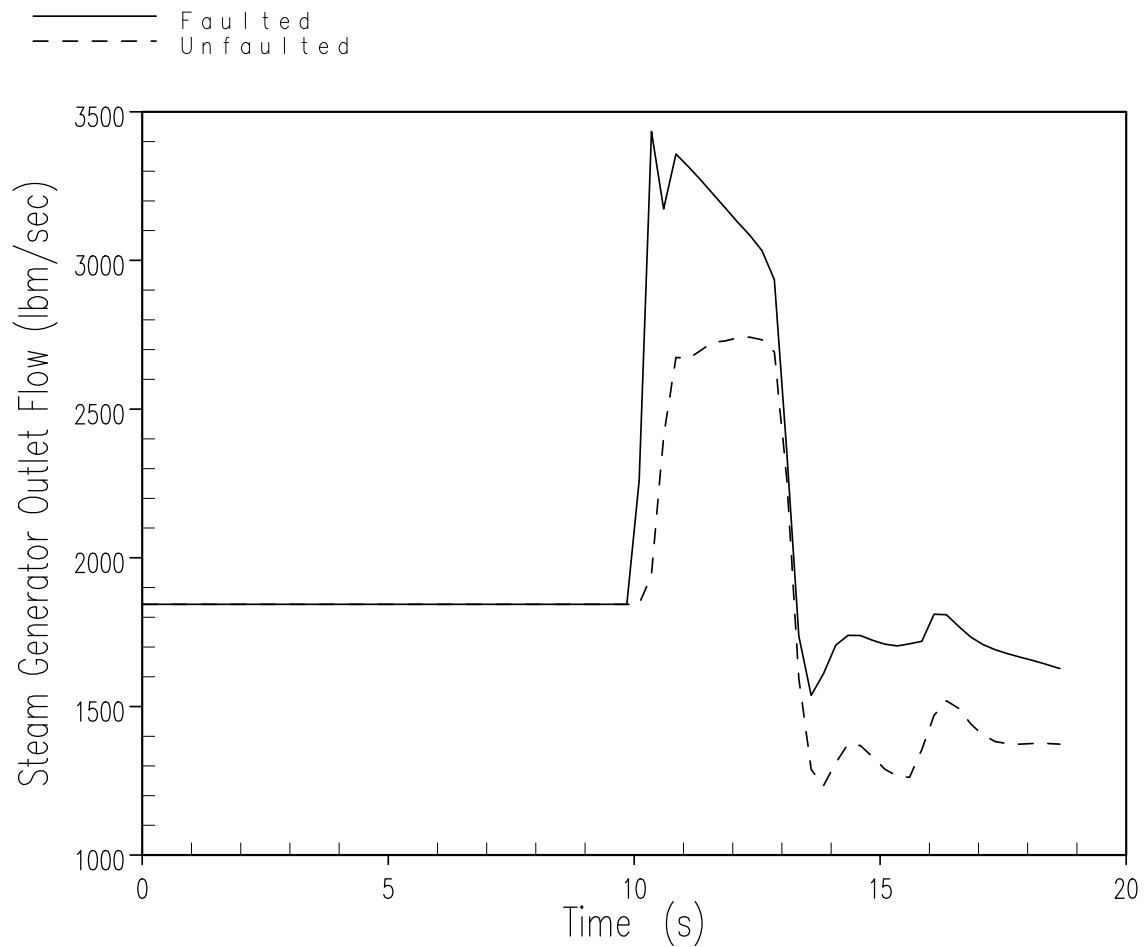


Figure 2.8.5.1.2-16
Post-Trip SLB
Variation of Keff with Core Temperature

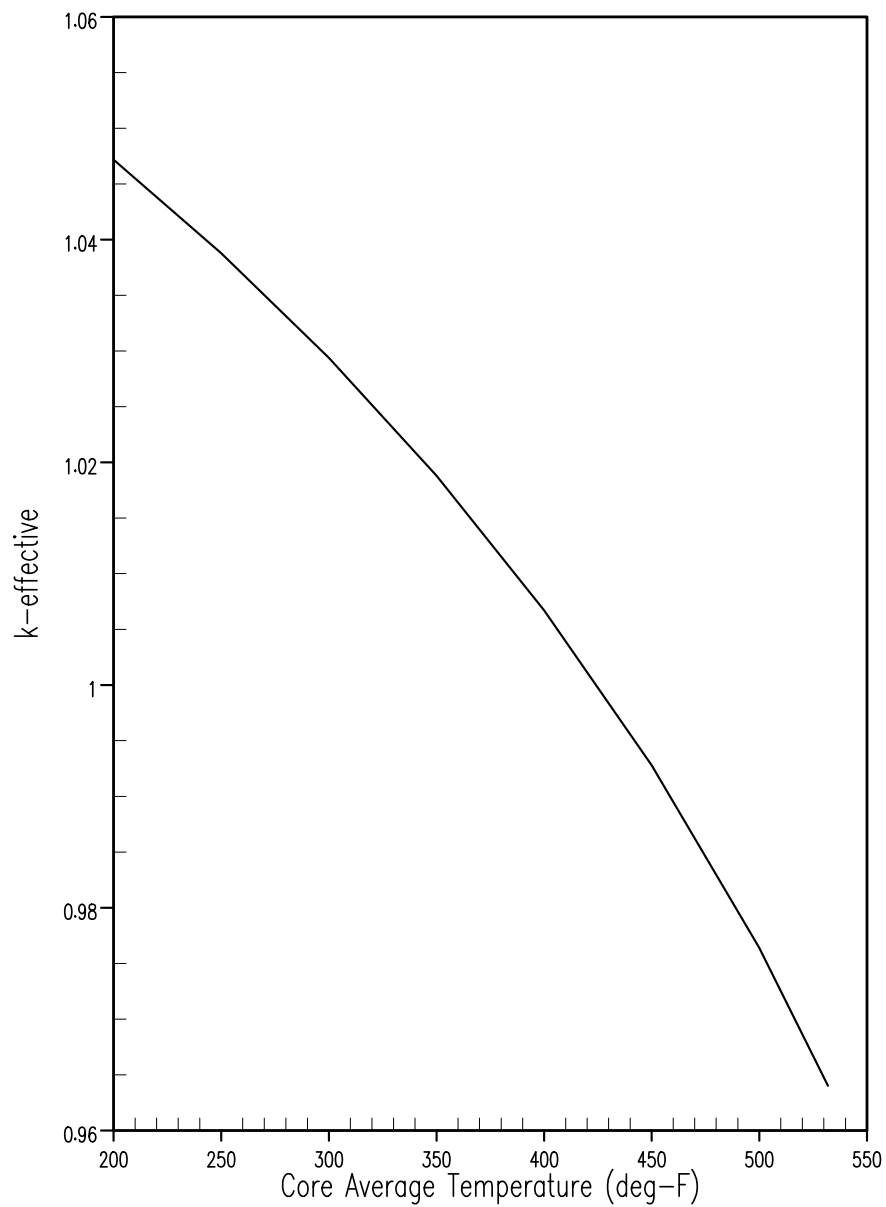


Figure 2.8.5.1.2-17
Post-Trip SLB
Stuck CEA Doppler Power Feedback vs. Power Level

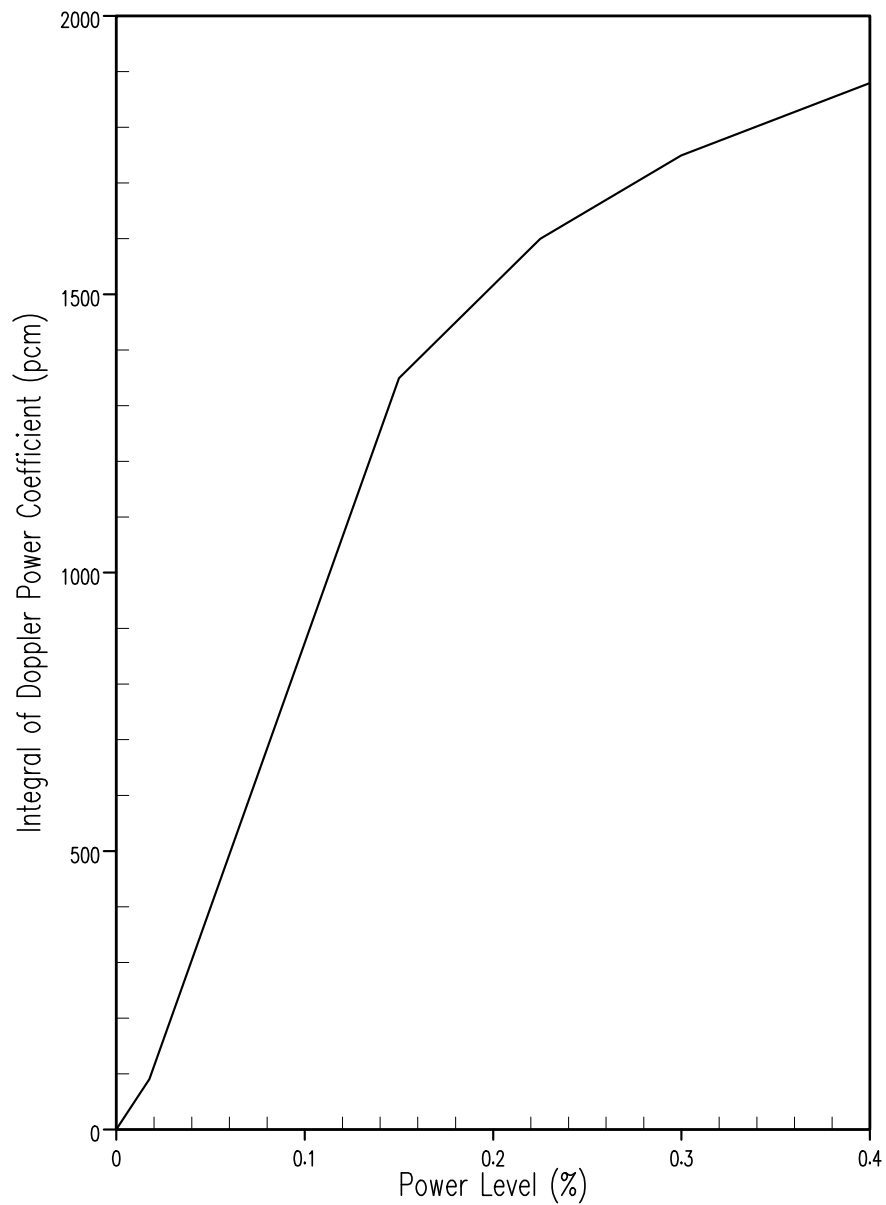


Figure 2.8.5.1.2-18
Post-Trip SLB
Safety Injection Curve

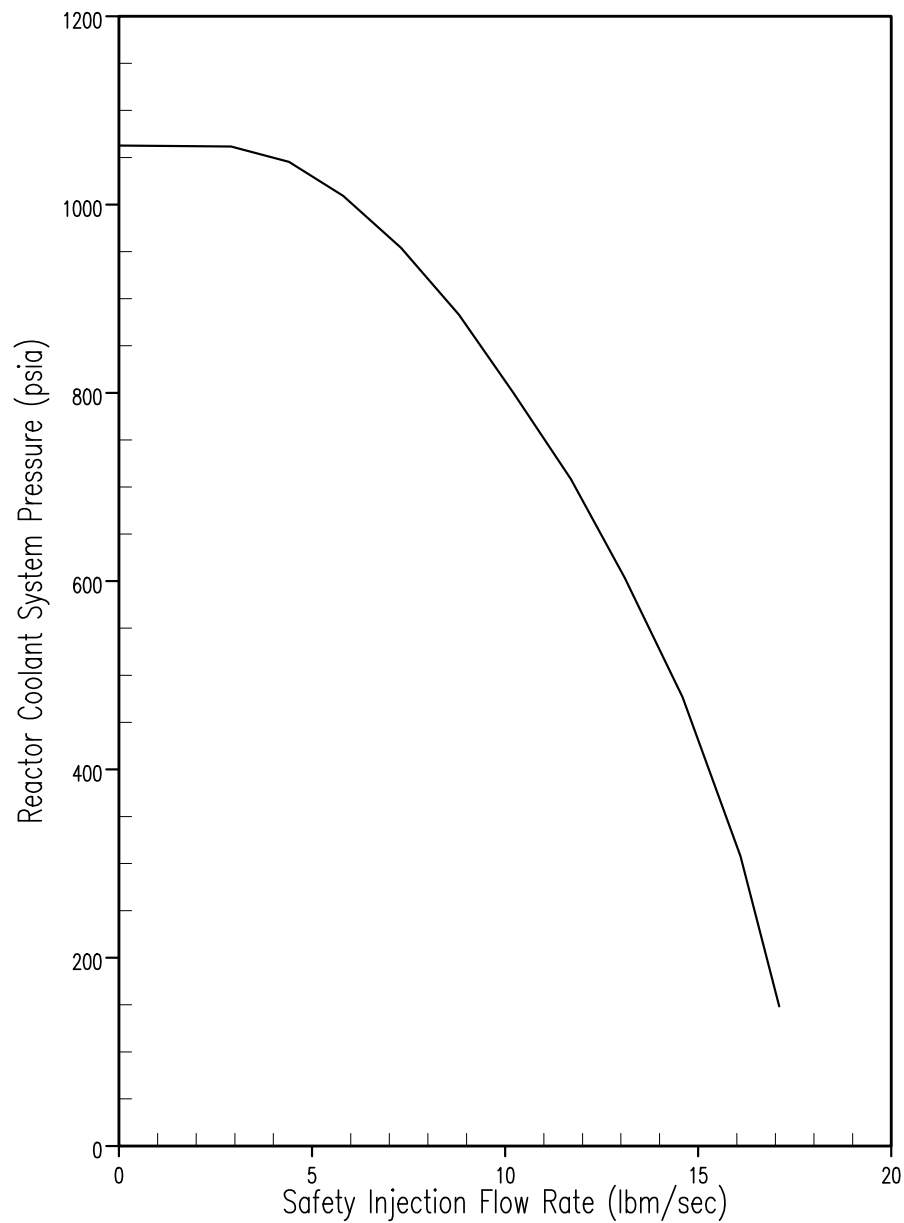


Figure 2.8.5.1.2-19
Post-Trip SLB
Steam Generator Steam Pressure vs. Time

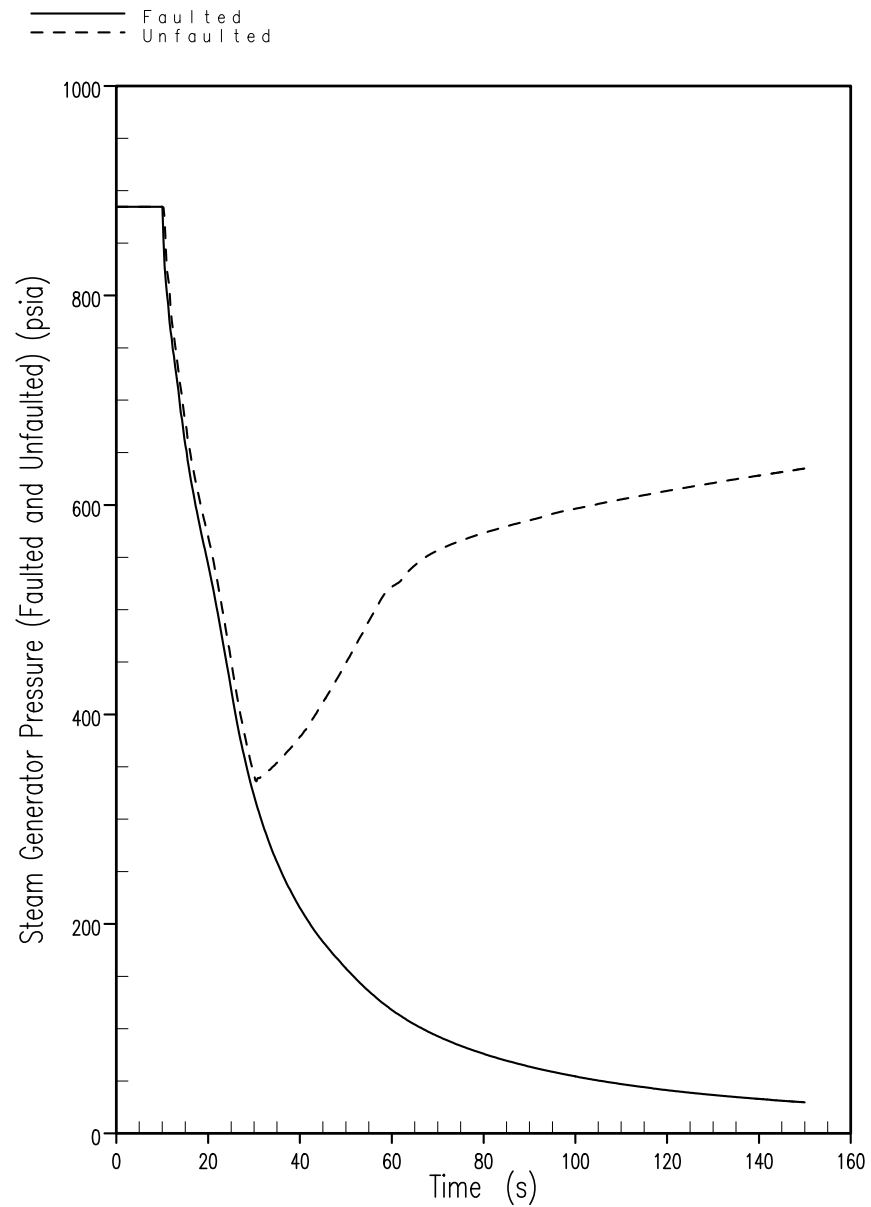


Figure 2.8.5.1.2-20
Post-Trip SLB
Break Mass Flow Rate vs. Time

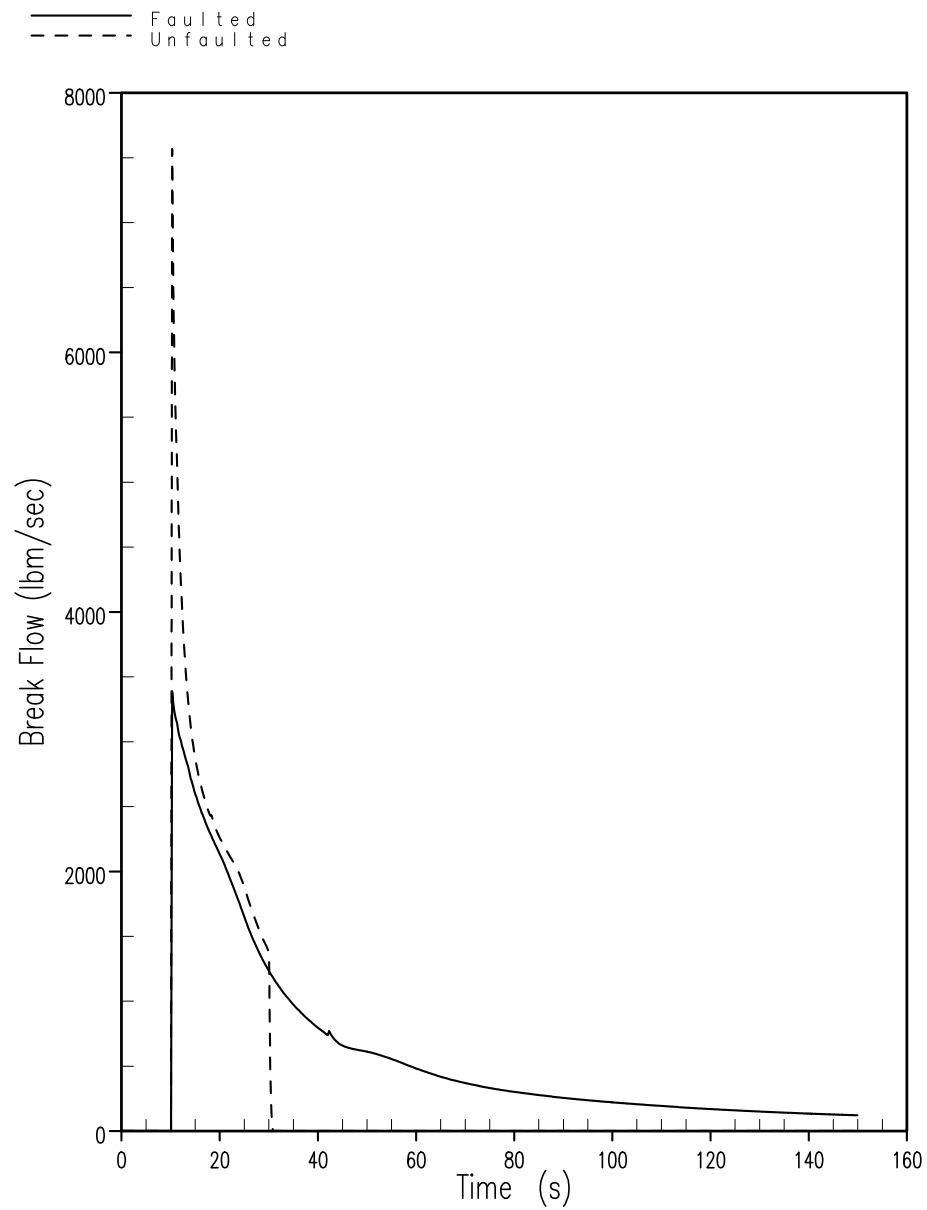


Figure 2.8.5.1.2-21
Post-Trip SLB
Pressurizer Pressure vs. Time

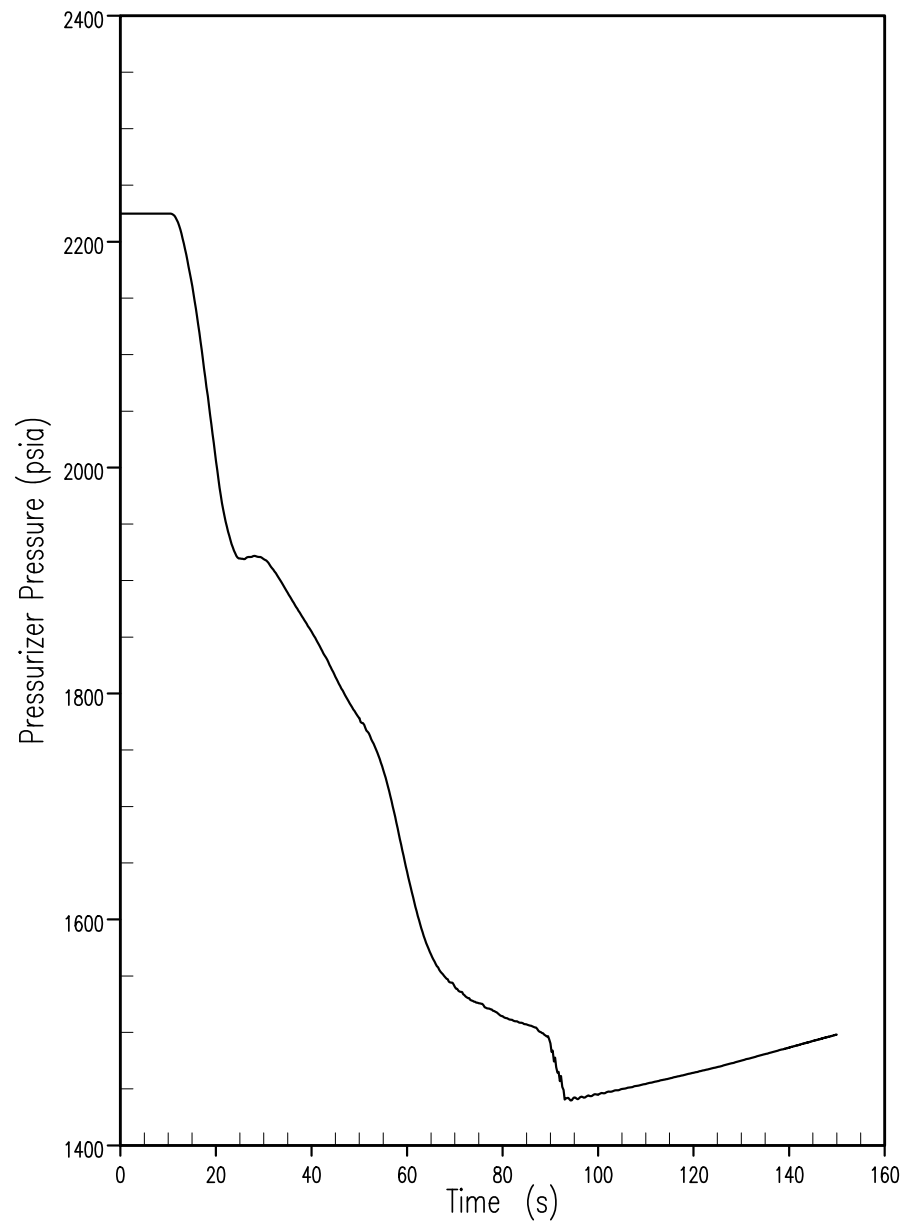


Figure 2.8.5.1.2-22
Post-Trip SLB
Pressurizer Water Volume vs. Time

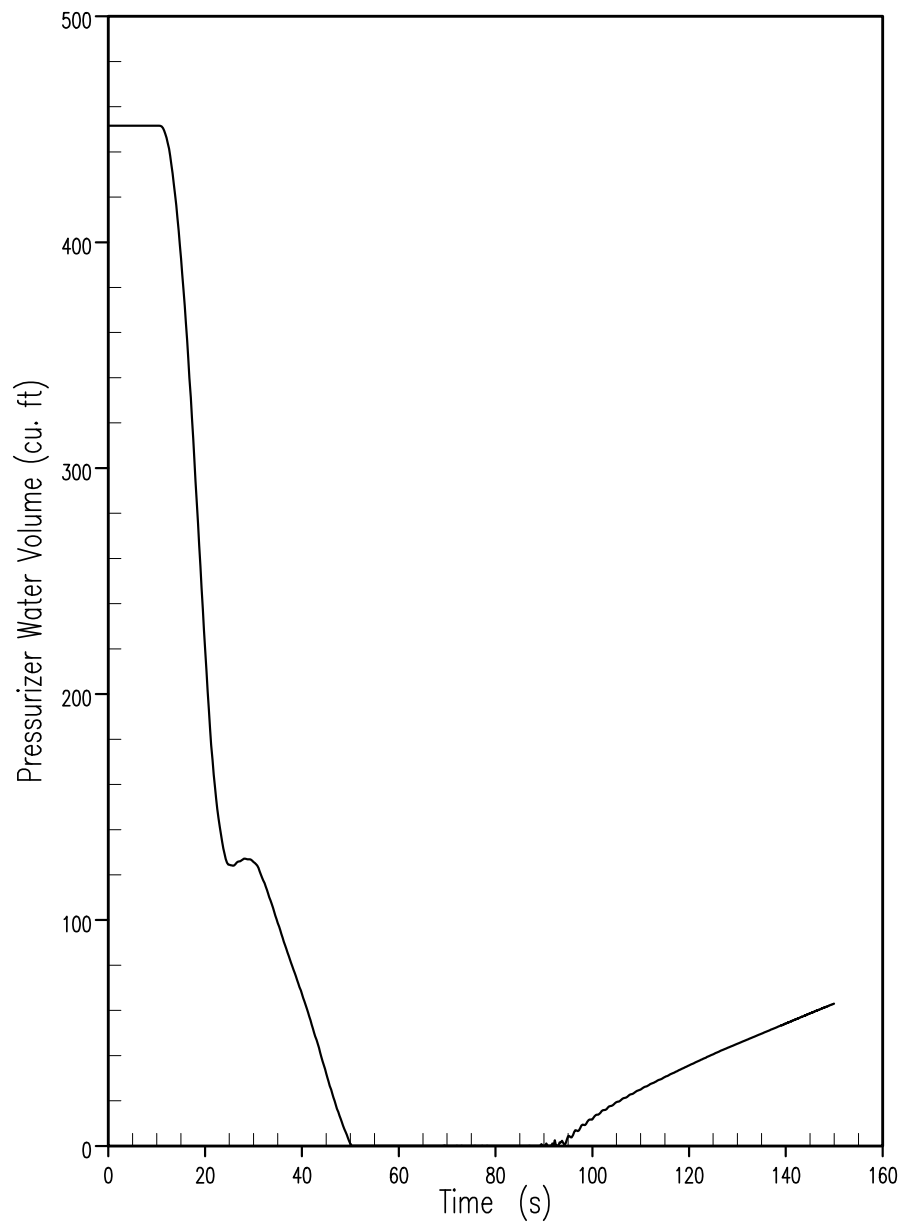


Figure 2.8.5.1.2-23
Post-Trip SLB
Cold Leg Temperature vs. Time

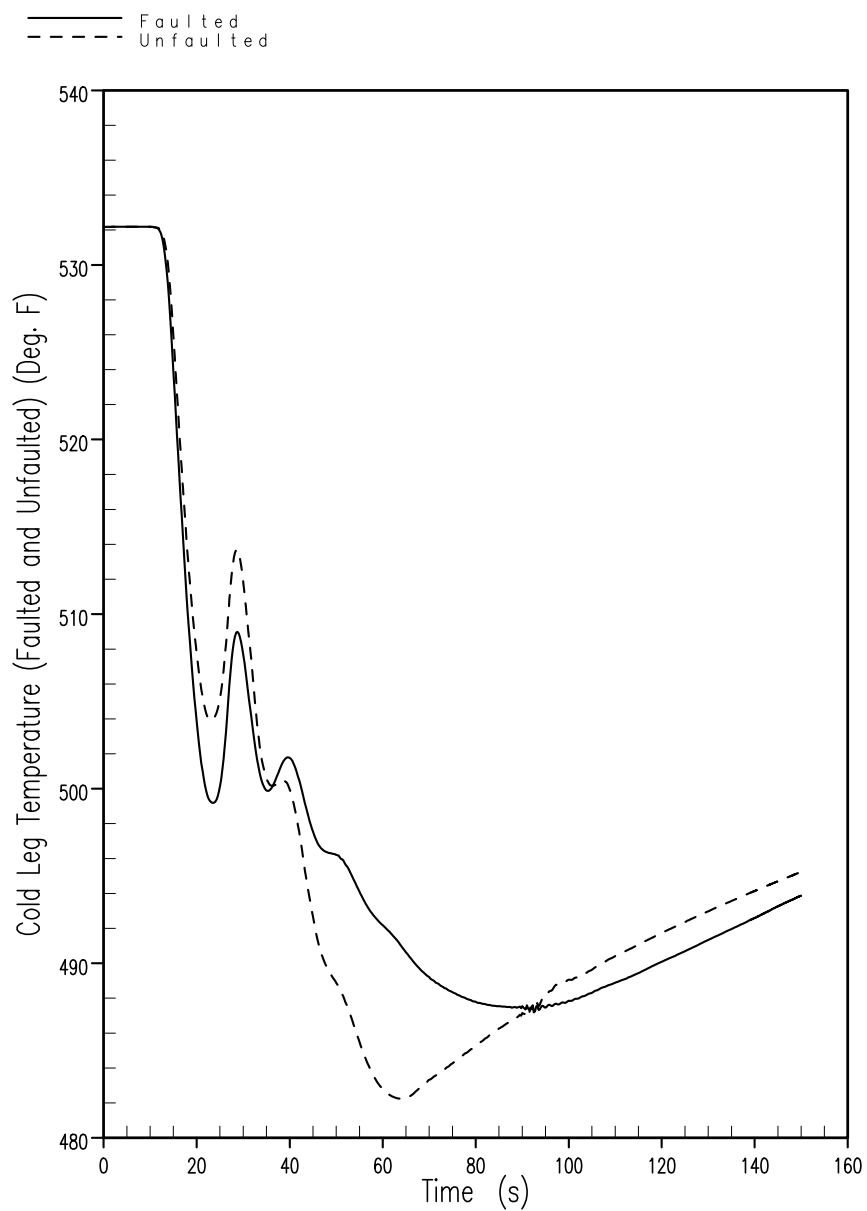


Figure 2.8.5.1.2-24
Post-Trip SLB
Core Heat Flux vs. Time

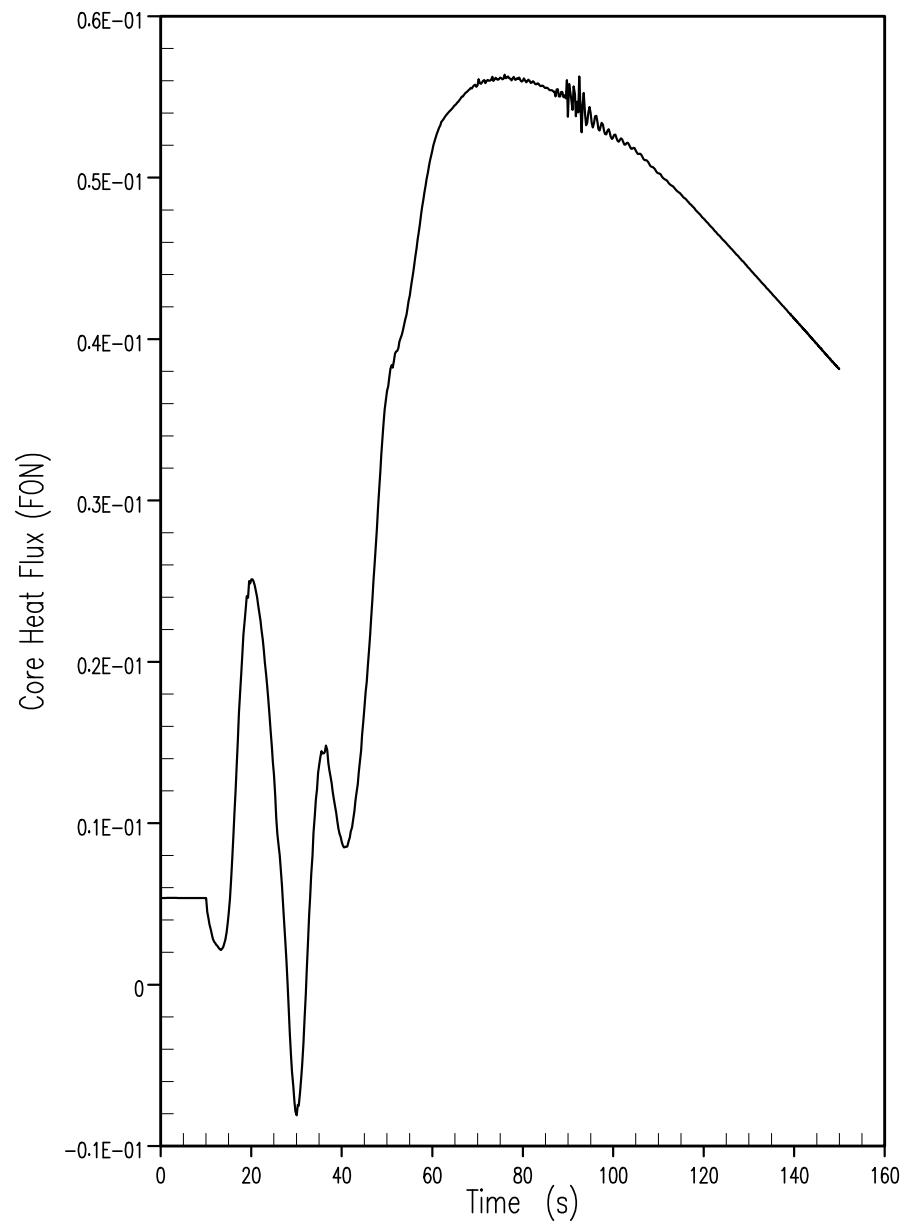


Figure 2.8.5.1.2-25
Post-Trip SLB
Core Averaged Boron Concentration vs. Time

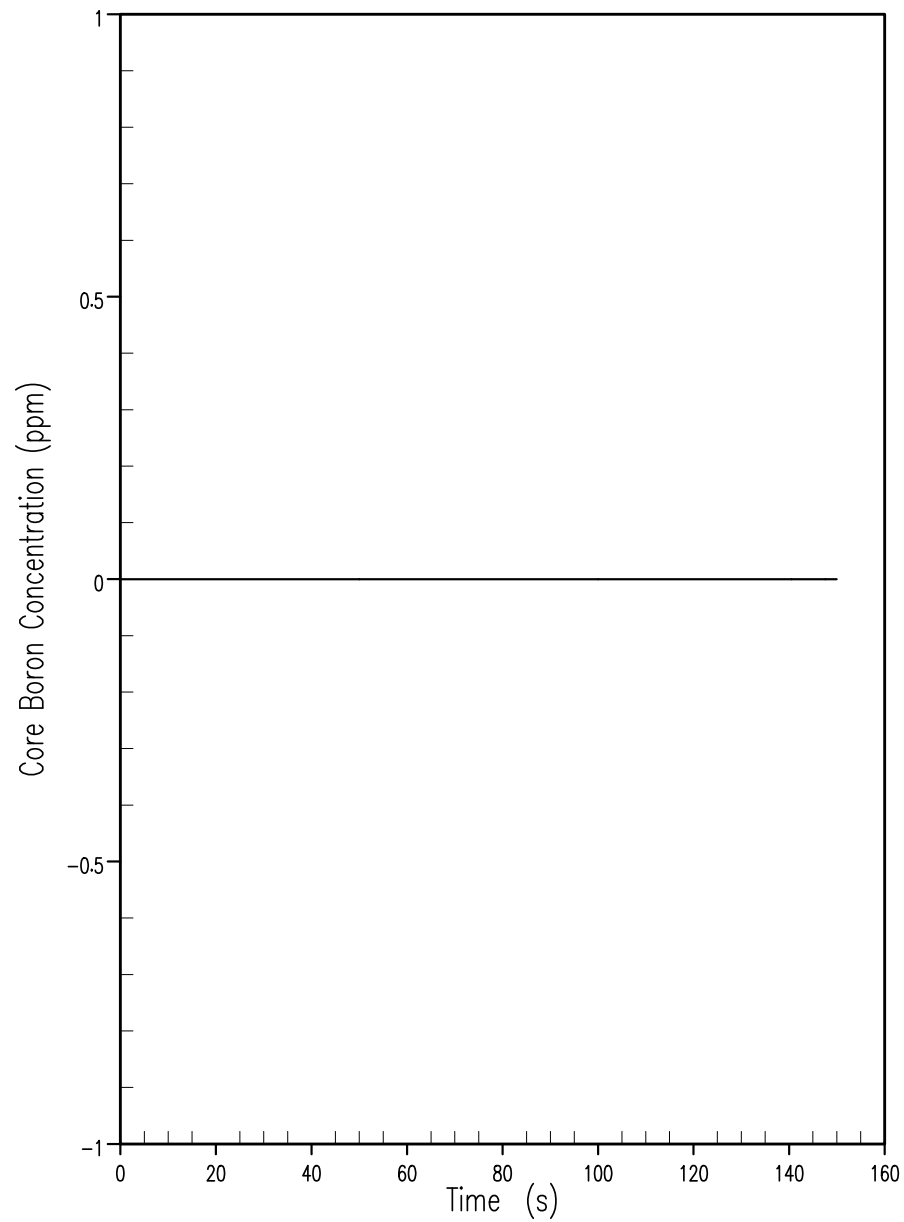
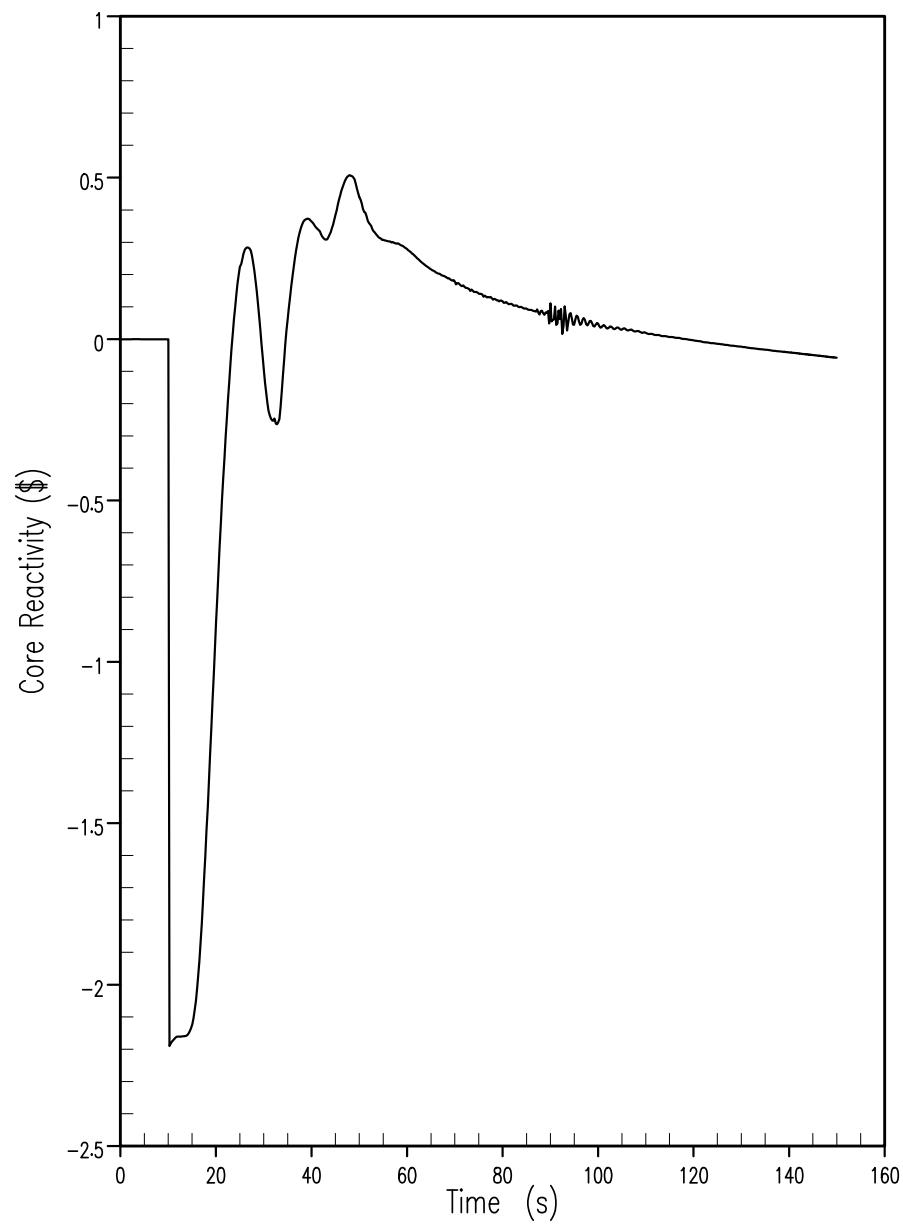


Figure 2.8.5.1.2-26
Post-Trip SLB
Reactivity vs. Time



2.8.5.2 Decrease in Heat Removal By the Secondary System

2.8.5.2.1 Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum

2.8.5.2.1.1 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 transient.

The Florida Power and Light (FPL) 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:

- General Design Criterion (GDC)-10, insofar as it requires that the reactor coolant system (RCS) be designed with appropriate margin to ensure that specified acceptable fuel design limits (SAFDLs) are not exceeded during normal operations, including anticipated operational occurrences (AOOs);
- 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 reactor coolant pressure boundary (RCPB) are not exceeded during any condition of normal operation;
- 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 Standard Review Plan (SRP) Section 15.2.1-5 and other guidance provided in Matrix 8 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDCs for the loss of external load; turbine trip, and loss of condenser vacuum are as follows:

- GDC-10 is described in UFSAR Section 3.1.10 Criterion 10 - Reactor Design.

The reactor core and associated coolant, control and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

SAFDLs are stated in UFSAR Section 4.3. Minimum margins to SAFDLs are prescribed in the technical specifications (TS) (limiting conditions for operations (LCO)) which support UFSAR Chapters 4 and 15.

- GDC-15 is described in UFSAR Section 3.1.15 Criterion 15 - Reactor Coolant System Design Criterion.

The reactor coolant system and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.

The operating conditions for normal steady state and transient plant operations are established conservatively. Normal operating limits are selected so that an adequate margin exists between operating and design limits. The plant control systems are designed to ensure that plant variables are maintained well within the established operating limits. The plant transient response characteristics and pressure and temperature distributions during normal operations are considered in the design as well as the accuracy and response of the instruments and controls. These design techniques ensure that a satisfactory margin is maintained between the plant's normal operating conditions, including design transients, and the design limits for the RCPB.

The plant control systems function to minimize deviations from normal operating limits in the event of most AOOs. Where control systems response would be inadequate or fail upon demand, the reactor protection system (RPS) and the engineered safety features (ESF) system function to mitigate the consequences of such events.

The RPS and ESFS function to mitigate the consequences of accidents such that the design limits for the RCPB are not exceeded.

- GDC-26 is described in UFSAR Section 3.1.26 Criterion 26 - Reactivity Control System Redundancy and Capability

Two independent reactivity control systems of different design principles shall be provided. One of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margin for malfunctions such as stuck rods, specified acceptable fuel design limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure acceptable fuel design limits are not exceeded. One of the systems shall be capable of holding the reactor core subcritical under cold conditions.

Two independent reactivity control systems of different design principles are provided. The first system, using control element assemblies (CEAs) includes a positive means (gravity) for inserting CEAs and is capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including specified AOOs and SAFDLs are not exceeded. The CEAs can also be mechanically driven into the core. The appropriate margin for stuck rods is provided by assuming in the analyses of AOOs that the highest worth CEA does not fall into the core.

The second system, the chemical and volume control system (CVCS), using neutron absorbing soluble boron, is capable of reliably compensating for the rate of reactivity changes resulting from planned normal power changes (including xenon burnout) such that SAFDLs are not exceeded. This system is capable of holding the reactor subcritical under cold conditions. For a further description, see UFSAR Section 9.3.4.

Either system is capable of making the core subcritical from a hot operating condition. For further discussion, see UFSAR Sections 7.4 and 7.7.

UFSAR Sections 15.2.1, 15.2.2, and 15.2.3 provide the analyses of the loss of external electrical load, turbine trip, and loss of condenser vacuum, respectively.

NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plants, Units 1 and 2, dated September, 2003 defines the scope of license renewal. This specific transient analysis is not within the scope of License Renewal.

2.8.5.2.1.2 Technical Evaluation

2.8.5.2.1.2.1 Loss of Condenser Vacuum

2.8.5.2.1.2.1.1 Introduction

The loss of condenser vacuum (LOCV) event is the limiting “loss of load” event since it is assumed that the LOCV results in the loss of the feedwater pumps concurrent with the turbine trip.

The LOCV event (UFSAR Section 15.2.3) is defined as a complete loss of steam load or a turbine trip from full power without a direct reactor trip. This anticipated transient is analyzed as a turbine trip from full power with a simultaneous loss of feedwater to both steam generators due to low suction pressure on the feedwater pumps. The atmospheric dump valves (ADVs) and the steam dump and bypass system valves are assumed to be unavailable which minimizes the amount of cooling and maximizes the RCS and secondary peak pressures during the event. The LOCV event bounds the following scenarios:

- Loss of external electrical load (UFSAR Section 15.2.1) as caused by abnormal variations in the electrical distribution network or other adverse network conditions, and
- Turbine trip (UFSAR Section 15.2.2).

In the event of a large loss of load in which the steam dump valves fail to open, the main steam safety valves (MSSVs) lift and the reactor trips by either of the following signals: high pressurizer pressure or the thermal margin / low pressure (TM/LP) trip. The steam generator (SG) shell-side pressure and reactor coolant temperatures will increase rapidly. However, the pressurizer safety valves (PSVs) and MSSVs are sized to protect the RCS and SGs against overpressure for all load losses without assuming the operation of the steam dump system. The RCS and main steam system (MSS) steam relieving capacities were designed to ensure safety of the unit without requiring pressurizer pressure control, steam bypass control systems, or a reactor trip on turbine trip.

2.8.5.2.1.2.1.2 Input Parameters, Assumptions, and Acceptance Criteria

Three cases were analyzed for the LOCV event from full-power conditions:

- Minimum departure from nucleate boiling ratio (DNBR) case – With automatic pressurizer pressure control and maximum steam generator tube plugging (SGTP),
- Peak MSS pressure case – With automatic pressurizer pressure control and minimum SGTP, and
- Peak RCS pressure case – Without automatic pressurizer pressure control and maximum SGTP.

For the minimum DNBR case, it must be shown that the calculated DNBR remains above the safety analysis DNBR limit. For the peak primary RCS and MSS pressure cases, it must be shown that the pressures remain below 110 percent of their respective design pressures.

To produce conservative results during the transient, the following assumptions were made in the LOCV Analysis at the EPU conditions. See LR [Section 2.8.5.0](#), Accident and Transient Analyses, for additional inputs and assumptions.

1. The minimum DNBR case was analyzed using the revised thermal design procedure (RTDP) ([Reference 1](#)). The initial reactor power and RCS temperature are assumed to be at values consistent with 100 percent of rated thermal power and nominal pump heat, the initial RCS flow rate is assumed to be the minimum measured flow rate and the initial RCS pressure is assumed to be the minimum value allowed by the plant TS. The uncertainties in the initial conditions were addressed in the determination of the safety analysis DNBR limit as described in [Reference 1](#).
2. The peak primary and secondary pressure cases were analyzed using the standard thermal design procedure (STDP). The STDP includes uncertainties on nuclear steam supply system (NSSS) power, reactor coolant flow, RCS temperature and pressure applied in the most conservative direction to determine the initial plant conditions for the transient. As such, both cases modelled thermal design flow.
3. The total LOCV was analyzed conservatively with minimum reactivity feedback (beginning of core life) and maximum Beta. All cases used the least-negative Doppler power coefficient and a 0 pcm/°F moderator temperature coefficient (MTC). These reactivity conditions were conservatively selected based on the fact that the reactor power was maintained at the full power condition until the time of reactor trip, which exacerbated the calculated minimum DNBR and maximum RCS and MSS pressures.
4. The rod control system is assumed to be in manual for all cases as the automatic rod withdrawal control function has been disabled. If the reactor had been in automatic rod

control, the control rod banks would have driven into the core prior to reactor trip, due to the increasing core temperature, thereby reducing the severity of the transient.

5. The LOCV was analyzed both with and without automatic pressure control. The pressurizer power operated relief valves (PORVs) and sprays were assumed to be operable for the minimum DNBR case to minimize the increase in primary pressure, which is conservative relative to the DNBR criterion. The pressurizer PORVs and sprays were also assumed to be operable for the peak secondary pressure case to minimize the increase in primary pressure, which delayed reactor trip, resulting in a conservatively high calculated peak secondary side pressure. The peak primary pressure case was analyzed without pressurizer pressure control to conservatively maximize the RCS pressure increase. In all cases, the PSVs were assumed to be operable and include the maximum negative safety valve setpoint tolerance (-3 percent) for the departure from nucleate boiling (DNB) case and the maximum positive safety valve setpoint tolerance (+3 percent) for the primary overpressurization case.
6. Main feedwater flow to the SGs is assumed to be lost at the time of turbine trip. No credit is taken for auxiliary feedwater (AFW) flow during the early part of the transient, since a stabilized plant condition will be reached before AFW initiation will occur.
7. Only high-pressurizer pressure and low SG level trips were assumed to be operable for this analysis. No credit was taken for a reactor trip on turbine trip. The minimum DNBR case, peak MSS pressure case and peak RCS pressure case all trip on the high pressurizer pressure signal.
8. No credit was taken for the operation of the steam dump and bypass system or the ADVs. This assumption maximizes secondary pressure. The MSSV model for all cases includes the maximum safety valve setpoint tolerance (+/- 3% for Bank 1 and +/- 2% for Bank 2).
9. The limiting single failure is failure of one train of the reactor protection system. The remaining (operable) train trips the reactor.
10. Maximum (10%) SGTP is assumed in the minimum DNBR case and peak primary pressure case since it maximizes the primary side temperature transient following event initiation. However, the peak secondary pressure case is analyzed at minimum (zero) SGTP since this conservatively maximizes the primary-to-secondary heat transfer and maximizes the initial SG pressure. This assumption is slightly more limiting with respect to the secondary side pressure transient.

In addition to the three full power cases described above, three part power cases were run with 1, 2, and 3 inoperable MSSVs respectively in accordance with TS Table 3.7-1. The most limiting LOCV analysis with respect to inoperable MSSVs is the secondary overpressurization case, as it places the greatest demand on the relief capacity of the MSSVs. The acceptance criteria for these inoperable MSSV cases are identical to that for the full power LOCV analyses.

Acceptance Criteria

The LOCV accident is an AOO event and the specific criteria for this accident are as follows:

- Pressures in the RCS and MSS are maintained below 110 percent of their respective design pressures,
- Fuel cladding integrity is maintained by demonstrating that the minimum DNBR remains above the 95/95 DNBR limit for PWRs, and
- The incident does not generate a more serious plant condition without other faults occurring independently. This criterion is satisfied by verifying that the pressurizer does not fill.

2.8.5.2.1.2.1.3 Description of Analyses and Evaluations

A detailed analysis using the RETRAN ([Reference 2](#)) computer code was performed to determine the plant transient conditions following a total loss of load due to turbine trip without a direct reactor trip. The code is NRC approved and models the core neutron kinetics, RCS, pressurizer, pressurizer PORVs and sprays, SGs, MSSVs, and the AFW system. RETRAN computes pertinent variables, including the pressurizer pressure, SG pressure, and reactor coolant average temperature. Additional discussion of the RETRAN code is contained in LR [Section 2.8.5.0.9](#).

The calculated sequence of events tables for the three LOCV cases analyzed are presented in LR [Tables 2.8.5.2.1-1](#) through [2.8.5.2.1-3](#). The limiting values for each case from the EPU analysis along with a comparison to the previous analysis results are shown in LR [Tables 2.8.5.2.1-4](#) through [2.8.5.2.1-6](#). For the peak MSS pressure case, the EPU analysis results are more limiting than the previous analysis results. For the minimum DNBR and peak RCS pressure cases, the EPU analysis results are less limiting than the previous analysis results, which was expected due to the larger heat removal capacity of the replacement steam generators.

Case 1: Minimum DNBR Case

The transient response calculated for the total loss-of-load event (minimum DNBR case) is shown in LR [Figures 2.8.5.2.1-1](#) through [2.8.5.2.1-5](#).

The reactor was tripped via a high pressurizer pressure signal. The nuclear power remained relatively constant until the reactor was tripped. The pressurizer PORVs and sprays minimized the primary pressure transient, which was conservative for DNBR. The DNBR value remained well above the safety analysis limit throughout the entire transient. The peak pressurizer water volume remained below the total volume of the pressurizer, demonstrating that this event did not generate a more serious plant condition.

Case 2: Peak Primary Pressure Case

The transient response calculated for the total loss-of-load event (peak primary pressure case) is shown in LR [Figures 2.8.5.2.1-6](#) through [2.8.5.2.1-10](#).

The reactor was tripped via a high pressurizer pressure signal. The nuclear power remained relatively constant until the reactor was tripped. The PSVs actuated and it was confirmed that the

primary side pressure remained below 110 percent of the design value. The peak pressurizer water volume remained below the total volume of the pressurizer, demonstrating that this event did not generate a more serious plant condition.

Case 3: Peak Secondary Pressure Case

The transient response calculated for the total loss-of-load event (peak secondary pressure case) is shown in LR [Figures 2.8.5.2.1-11](#) through [2.8.5.2.1-15](#).

The reactor was tripped via a high pressurizer pressure signal. The nuclear power remained relatively constant until the reactor was tripped. The pressurizer PORVs and sprays minimized the primary pressure transient, which was conservative to delay the reactor trip and exacerbate the peak secondary side pressure. The MSSVs actuated to maintain the secondary side pressure below 110% of the design value. The peak pressurizer water volume remained below the total volume of the pressurizer, demonstrating that this event did not generate a more serious plant condition.

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

As discussed above, the design transient analyses were determined to be outside the scope of License Renewal; therefore, with respect to the design basis accidents and transients, the EPU does not impact any License Renewal evaluations

2.8.5.2.1.2.1.5 Results

The results of the LOCV analysis utilizing the RETRAN computer code demonstrate that all acceptance criteria are met assuming conditions consistent with implementation of the EPU. The minimum DNBR remained greater than the applicable safety analysis limit value (as seen in LR [Table 2.8.5.2.1-1](#)) and the peak primary and secondary pressures remained below 110 percent of their respective design pressures at all times as shown in LR [Tables 2.8.5.2.1-2](#) and [2.8.5.2.1-3](#).

The minimum DNBR is slightly less limiting for the EPU. This is consistent with expectations since the replacement SGs have better heat transfer characteristics than the original SGs, which provides a benefit for DNB. The peak primary pressurization case improved for EPU due to the higher heat transfer of the replacement SGs compared to the original SGs. The secondary pressurization case is more limiting for EPU, again due to the higher heat transfer ability of the replacement SGs and the EPU conditions.

The results of the three inoperable MSSV cases analyzed for secondary overpressurization are shown in LR [Table 2.8.5.2.1-7](#).

2.8.5.2.1.2.2 Additional Events

Turbine Trip

A turbine trip is caused by an electrical or mechanical malfunction of the turbine, which produces a reduction of steam flow from the SGs to the turbine due to the closure of the turbine stop

valves. The core and system performance following a turbine trip would be no more adverse than those following a LOCV. Therefore, a detailed analysis of the turbine trip event is not necessary.

Loss of External Electrical Load

A loss of external load is caused by abnormal events in the electrical distribution network which produces a reduction of steam flow from the SGs to the turbine due to the closure of the turbine stop valves. The core and system performance following a loss of external load would be no more adverse than those following a LOCV. Therefore, a detailed analysis of the loss of external load event is not necessary.

2.8.5.2.1.3 Conclusion

FPL reviewed the decrease in heat removal events described above 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. FPL further concludes that the review 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, FPL concludes that the plant will continue to meet the requirements of GDCs -10, -15, and -26 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to the events stated.

2.8.5.2.1.4 References

1. WCAP-11397-P-A (Proprietary), WCAP-11397-A (Non-Proprietary), Revised Thermal Design Procedure, April 1989.
2. WCAP-14882-P-A (Proprietary) and WCAP-15234-A (Non-Proprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, D. S. Huegel, et al., April 1999.

Table 2.8.5.2.1-1
Sequence of Events and Transient Results for the LOCV Event with Pressurizer Pressure Control (for Minimum DNB)

Event	Time (sec)
Turbine Trip ⁽¹⁾	10.100
Main Feedwater Terminates (both loops)	10.100
First MSSV Opens	13.900
HPPT Setpoint Reached	15.600
HPPT Trip Signal Obtained	16.373
Pressurizer PORV Opens	16.373
Reactor Trip on High Pressurizer Pressure	16.773
Rod Motion Begins	17.513
Time of Minimum DNBR	0.00 ⁽²⁾
Results	
Minimum DNBR Value	2.23
DNBR Minimum Limit (side thimble)	1.42
1. The time sequence includes a ten second steady state, therefore subtract 10 seconds in order to obtain the transient time. 2. Note the DNBR improves over the duration of the transient, thus the minimum DNBR occurs at the beginning of the transient.	

Table 2.8.5.2.1-2
Loss of External Load
Sequence of Events and Transient Results for the LOCV Event

Event	Time (sec)
Turbine Trip ⁽¹⁾	10.110
Main Feedwater Terminates (both loops)	10.110
HPPT Setpoint Reached	16.300
HPPT Trip Signal Obtained	17.055
Reactor trip on High Pressurizer Pressure	17.455
Rod Motion Begins	18.195
PSV Opens	18.195
Time of Peak RCS Pressure	18.700
First MSSV Opens	20.281
Results	
Peak RCS Pressure	2669.14 psia
RCS Pressure Maximum Limit	2750 psia
1. The time sequence includes a ten second steady state, therefore subtract 10 seconds in order to obtain the transient time.	

Table 2.8.5.2.1-3
Sequence of Events and Transient Results for the LOCV Event

Event	Time (sec)
Turbine Trip ⁽¹⁾	10.110
Main Feedwater Terminates (both loops)	10.110
First MSSV Opens	11.153
HPPT Setpoint Reached	17.000
HPPT Trip Signal Obtained	17.781
Pressurizer PORV Opens	17.781
Reactor Trip on High Pressurizer Pressure	18.181
Rod Motion Begins	18.921
Time of Peak MSS Pressure	23.500
Results	
Peak MSS Pressure	1093.97 psia
MSS Pressure Maximum Limit	1100 psia
1. The time sequence includes a ten second steady state, therefore subtract 10 seconds in order to obtain the transient time.	

**Table 2.8.5.2.1-4
Comparison of Results for the DNBR Case**

DNBR Case	Current Analysis Results	EPU Results⁽¹⁾
DNBR	2.19	2.23
Maximum Primary Pressure	2533 psia	2558.18 psia
Maximum Secondary Pressure	1080 psia	1082.30 psia
1. Note that the improvement in DNBR results for the EPU case is attributed to the improvement in heat transfer of the replacement steam generators over the original steam generators.		

Table 2.8.5.2.1-5
Comparison of Results for the Primary Overpressure Case

RCS Overpressure Case	Current Analysis Results	EPU Results⁽¹⁾
Maximum Primary Pressure	2691 psia	2669.14 psia
Maximum Secondary Pressure	1081 psia	1069.50 psia
1. Note that the improvement in RCS overpressurization results for the EPU case is attributed to the improvement in heat transfer of the replacement steam generators over the original steam generators.		

Table 2.8.5.2.1-6
Comparison of Results for the Secondary Overpressure Case

MSS Overpressure Case	Current Analysis Results	EPU Results
Maximum Primary Pressure	2485 psia	2543.61 psia
Maximum Secondary Pressure	1091.1 psia	1093.97 psia

**Table 2.8.5.2.1-7
Inoperable MSSV Secondary Overpressure Results**

Maximum Number of Inoperable Safety Valves on Any Operating Steam Generator	Maximum Allowable Power Level – High Trip Setpoint (% rated Thermal Power)	UFSAR Secondary Peak Pressure Limit (psia)	Analysis Results (psia)	UFSAR Primary Peak Pressure Limit (psia)	Analysis Results (psia)
1	92.8	1100	1079.8	2750	2631.2
2	79.6	1100	1073.8	2750	2628.8
3	66.3	1100	1070.5	2750	2629.3

Figure 2.8.5.2.1-1
Loss of Condenser Vacuum (DNBR Case)
Nuclear Power

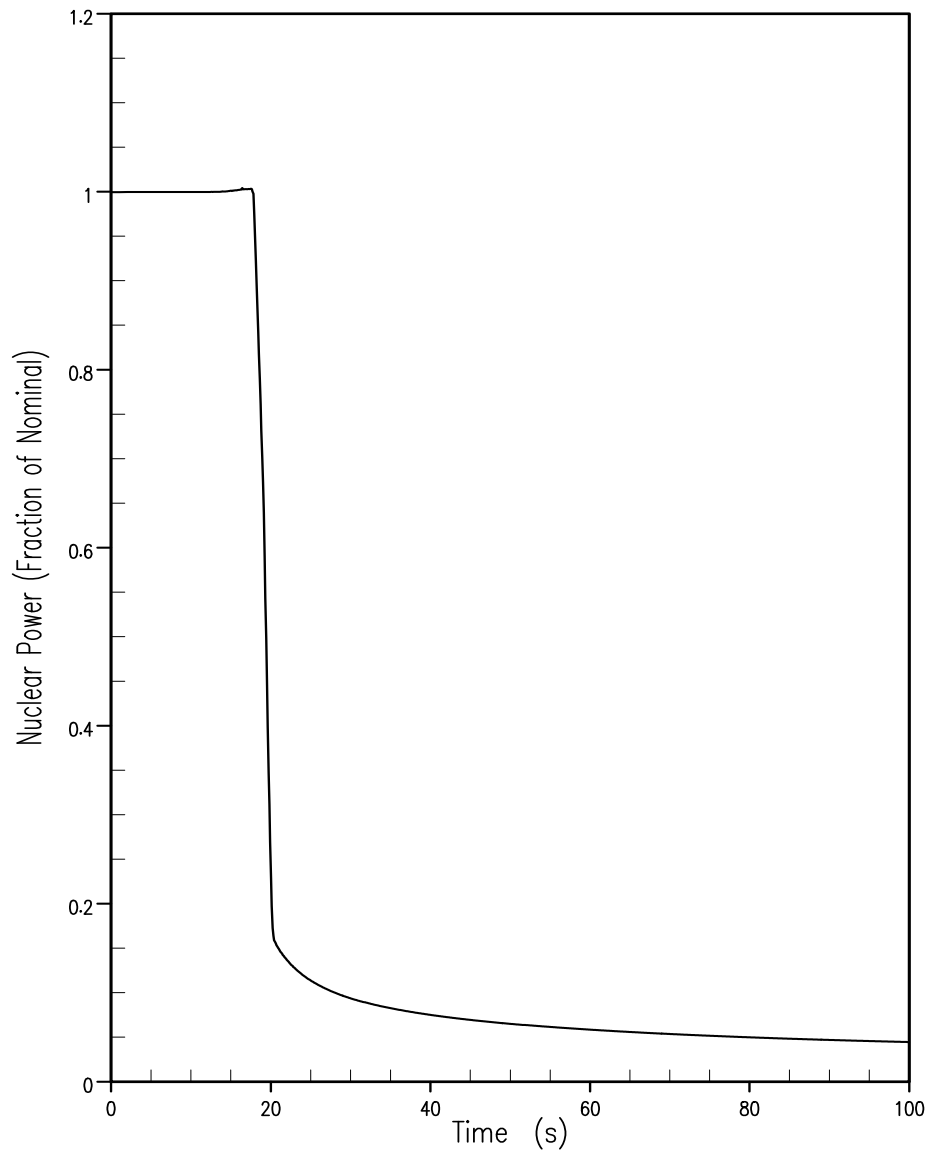


Figure 2.8.5.2.1-2
Loss of Condenser Vacuum (DNBR Case)
RCS Pressure (Vessel Lower Plenum Pressure)

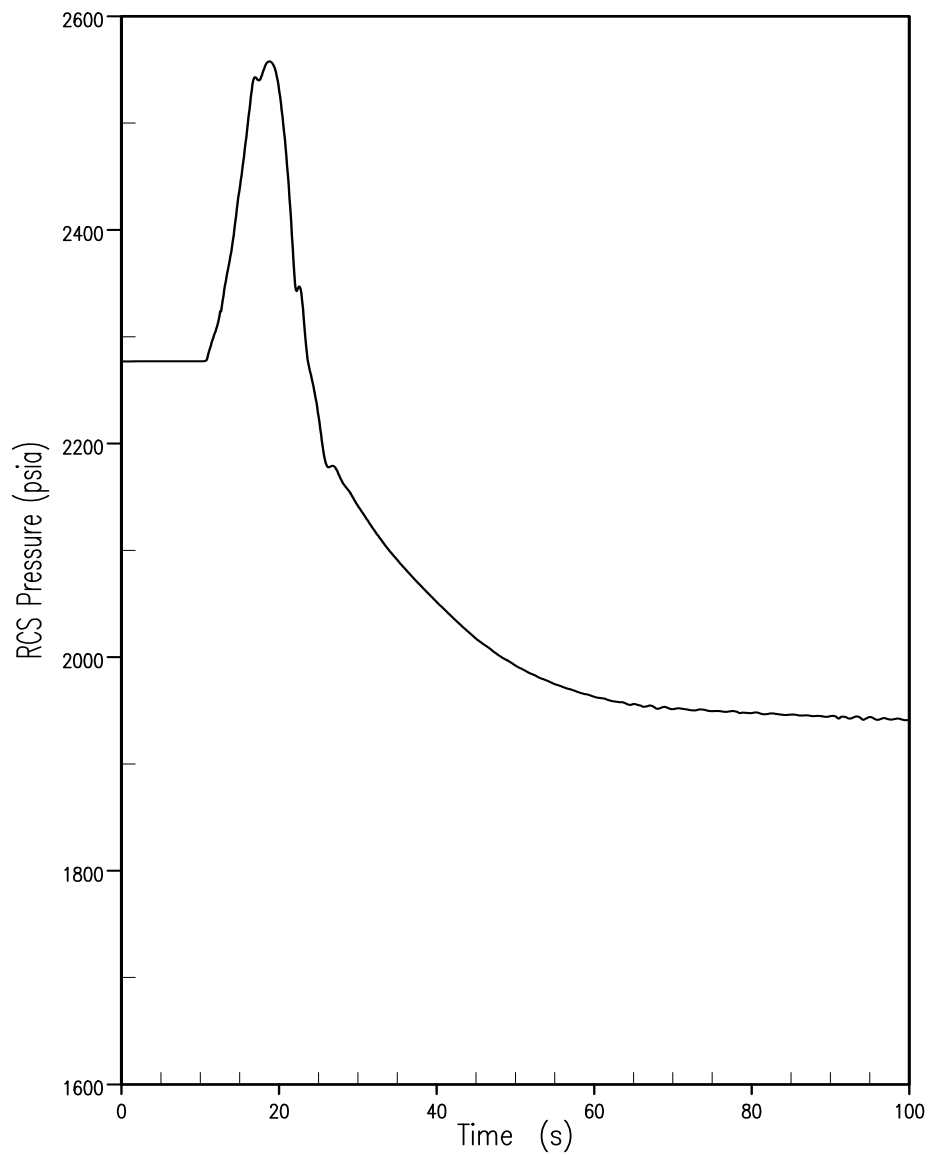


Figure 2.8.5.2.1-3
Loss of Condenser Vacuum (DNBR Case)
Pressurizer Water Volume

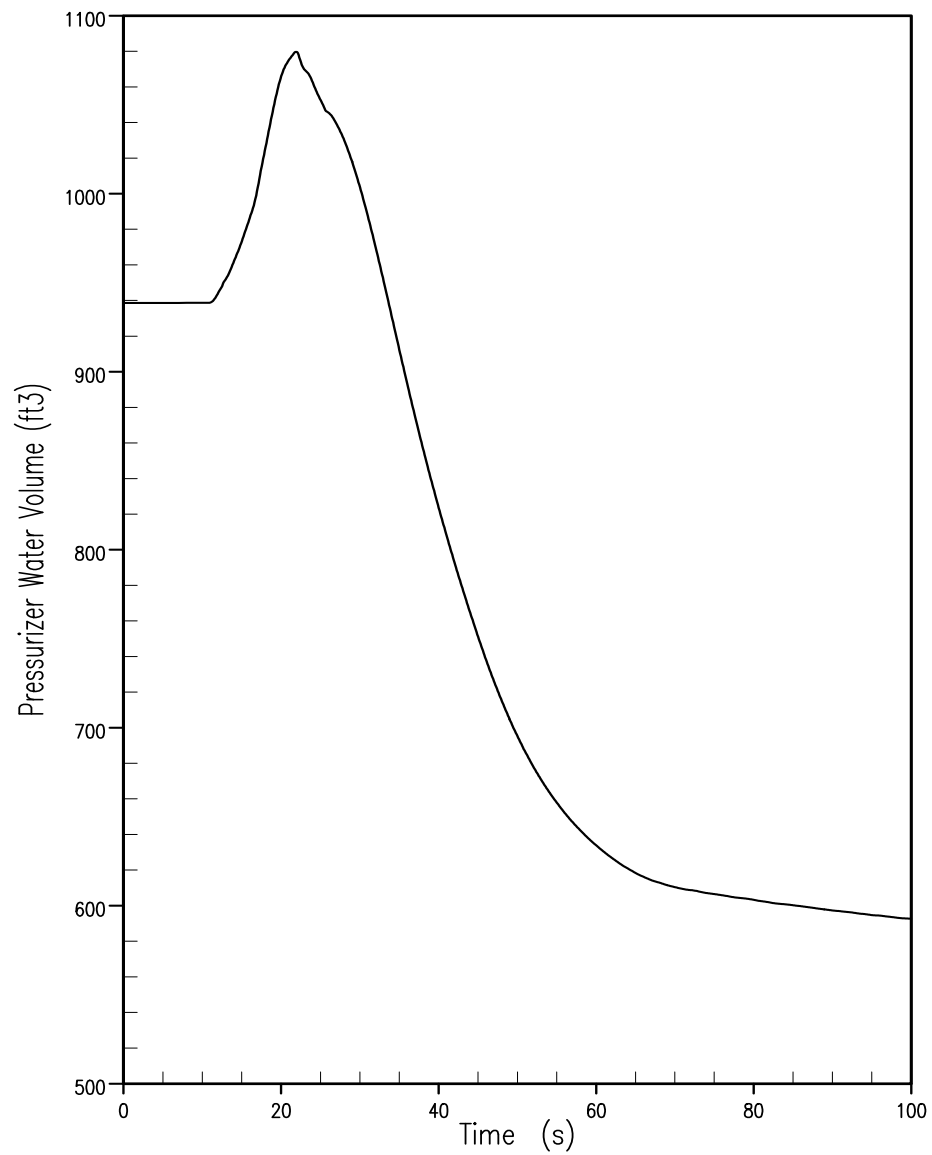


Figure 2.8.5.2.1-4
Loss of Condenser Vacuum (DNBR Case)
Vessel Average Temperature

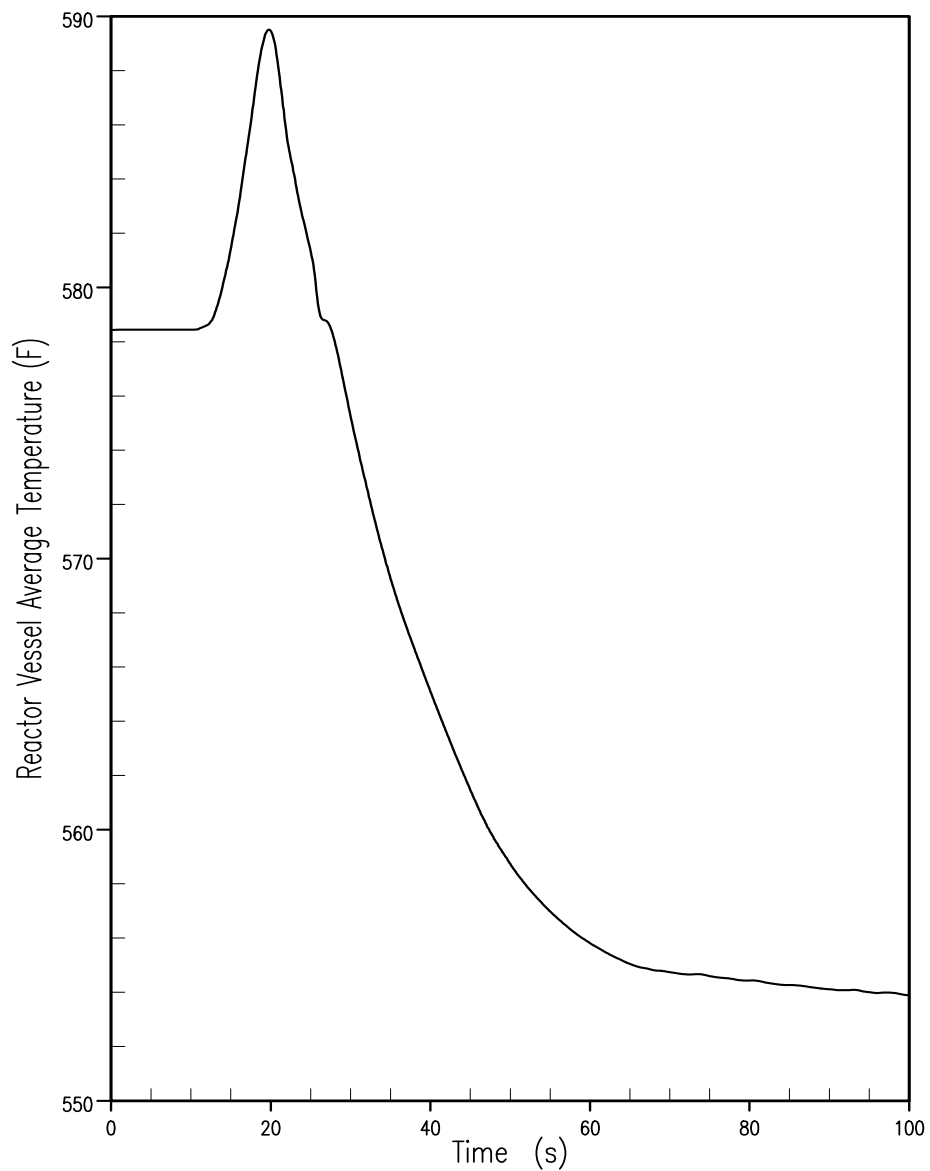


Figure 2.8.5.2.1-5
Loss of Condenser Vacuum (DNBR Case)
DNBR

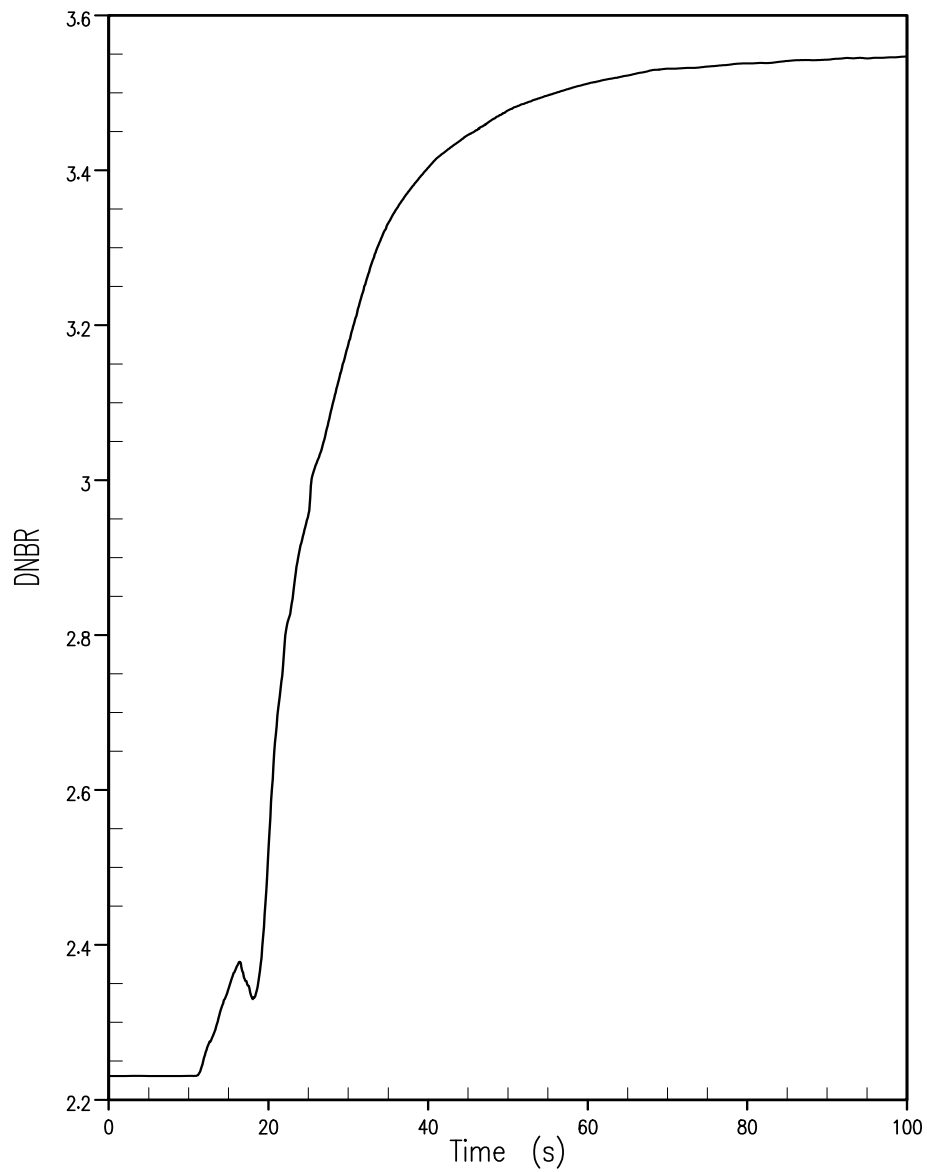


Figure 2.8.5.2.1-6
Loss of Condenser Vacuum (Primary Overpressure Case)
Nuclear Power

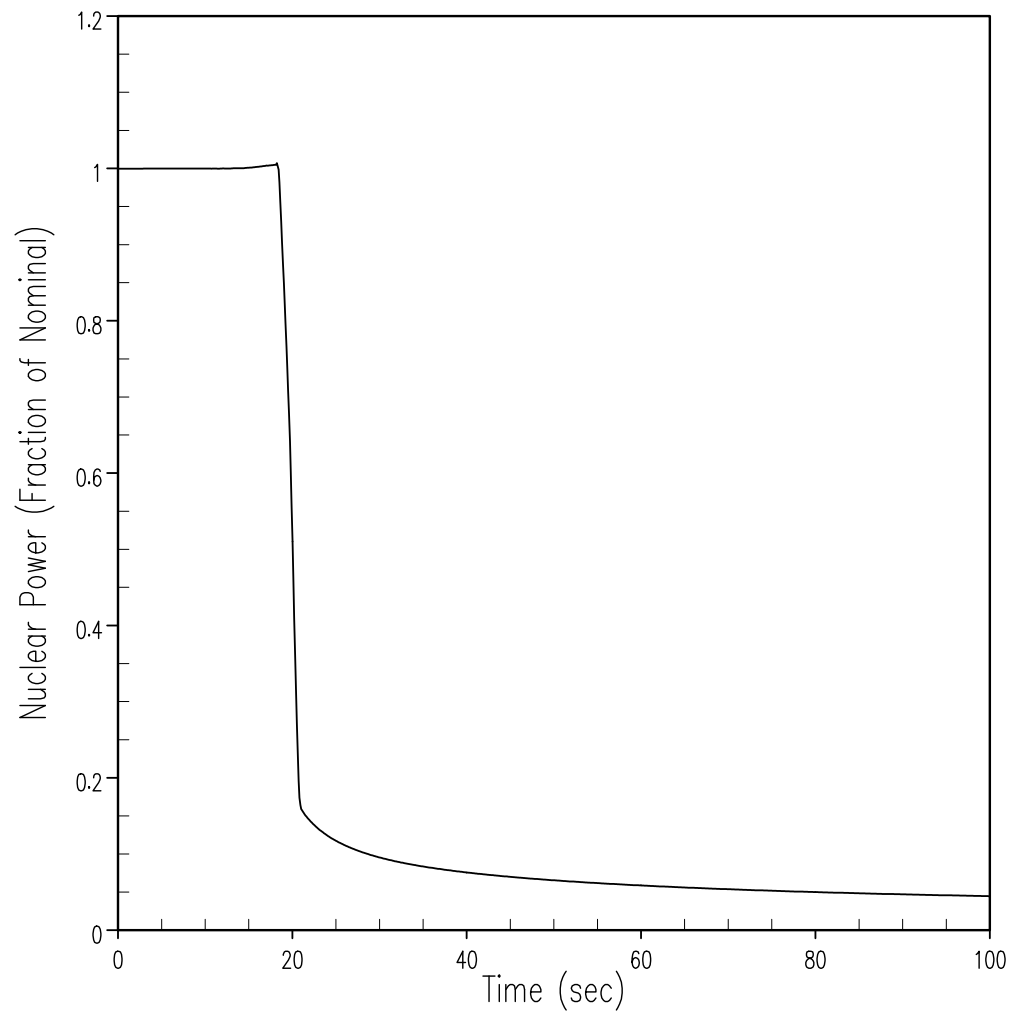


Figure 2.8.5.2.1-7
Loss of Condenser Vacuum (Primary Overpressure Case)
RCS Pressure (Vessel Lower Plenum Pressure)

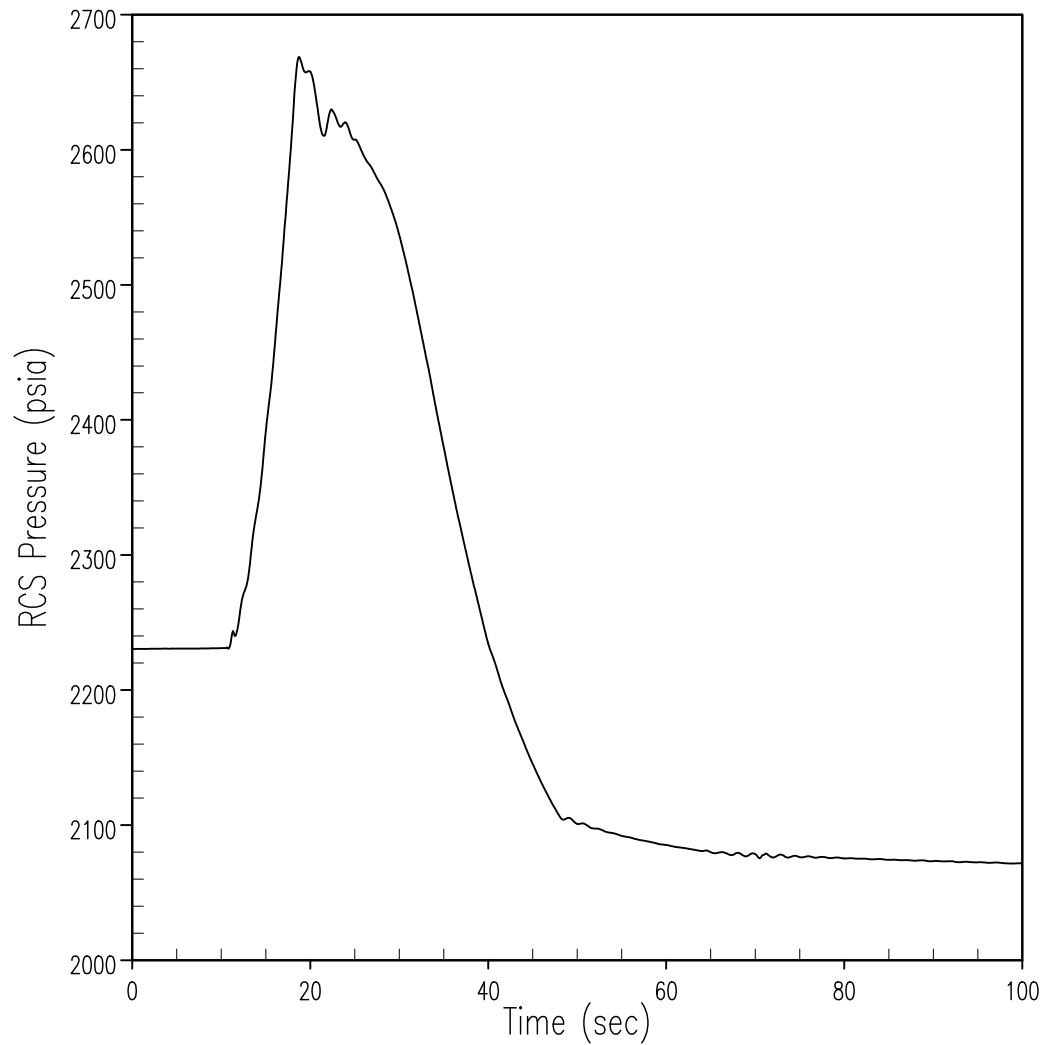


Figure 2.8.5.2.1-8
Loss of Condenser Vacuum (Primary Overpressure Case)
Pressurizer Water Volume

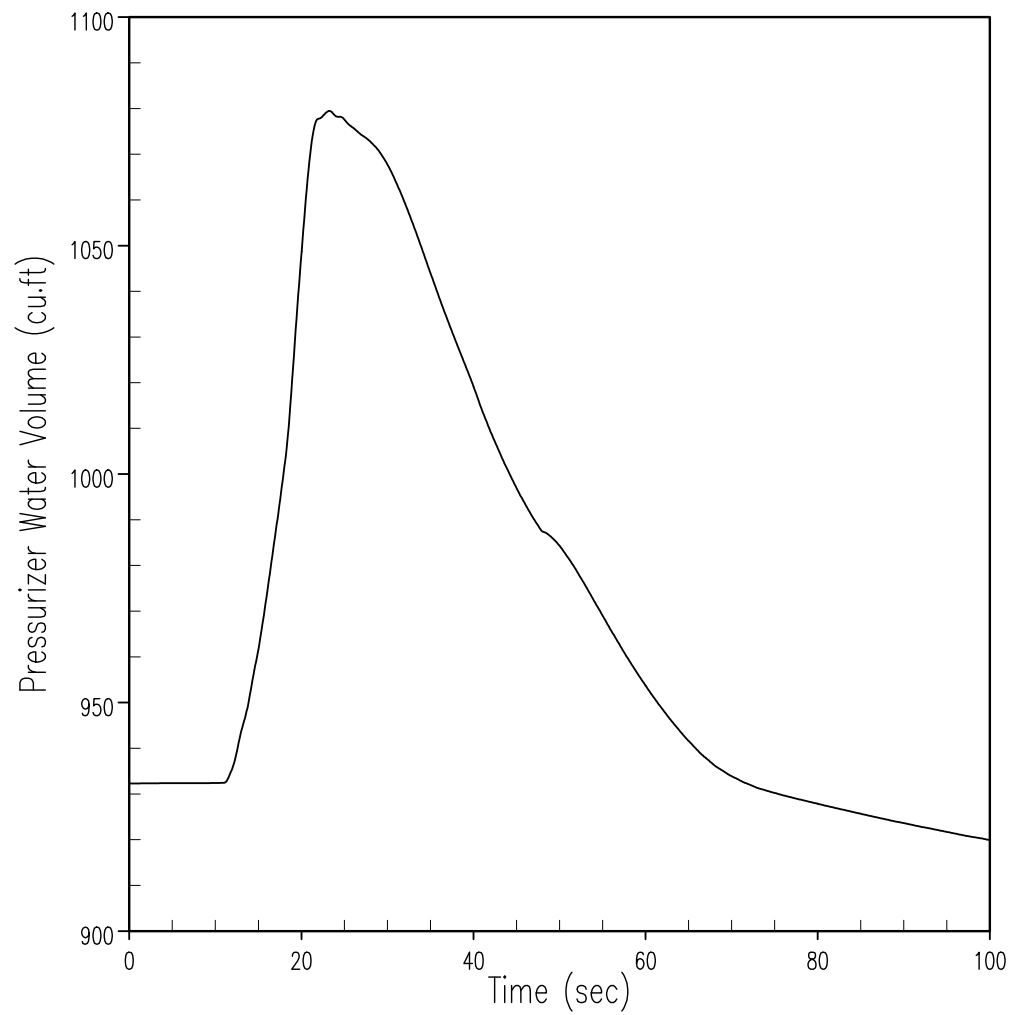


Figure 2.8.5.2.1-9
Loss of Condenser Vacuum (Primary Overpressure Case)
Vessel Average Temperature

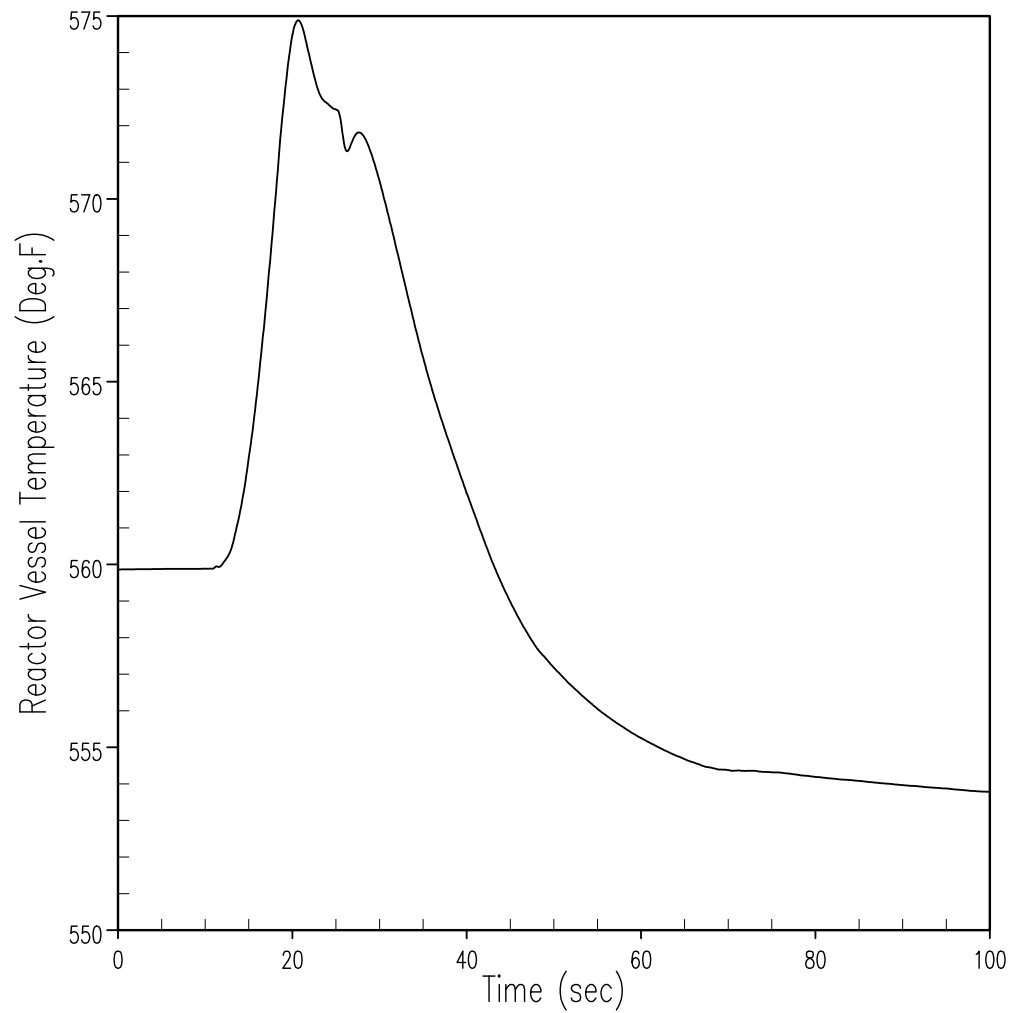


Figure 2.8.5.2.1-10
Loss of Condenser Vacuum (Primary Overpressure Case)
Steam Generator Pressure

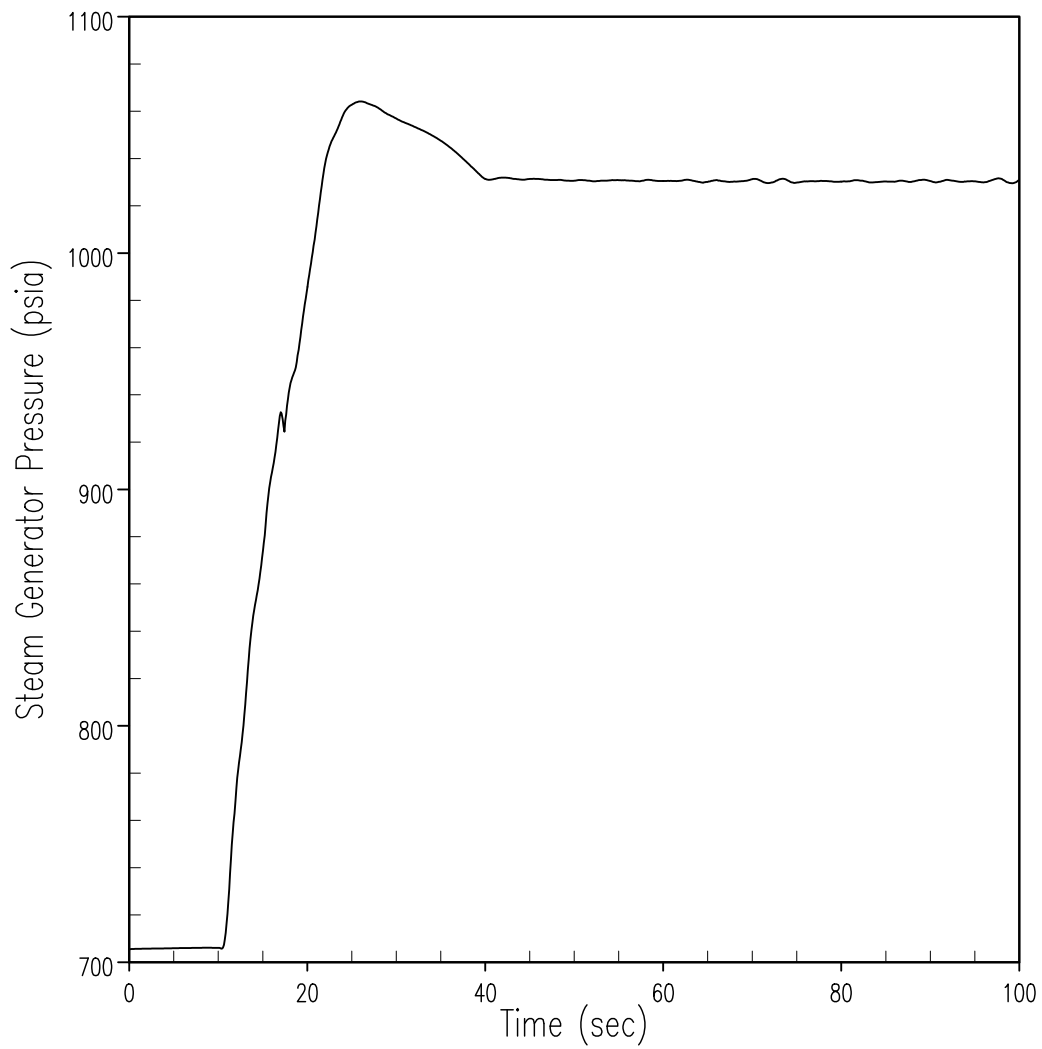


Figure 2.8.5.2.1-11
Loss of Condenser Vacuum (Secondary Overpressure Case)
Nuclear Power

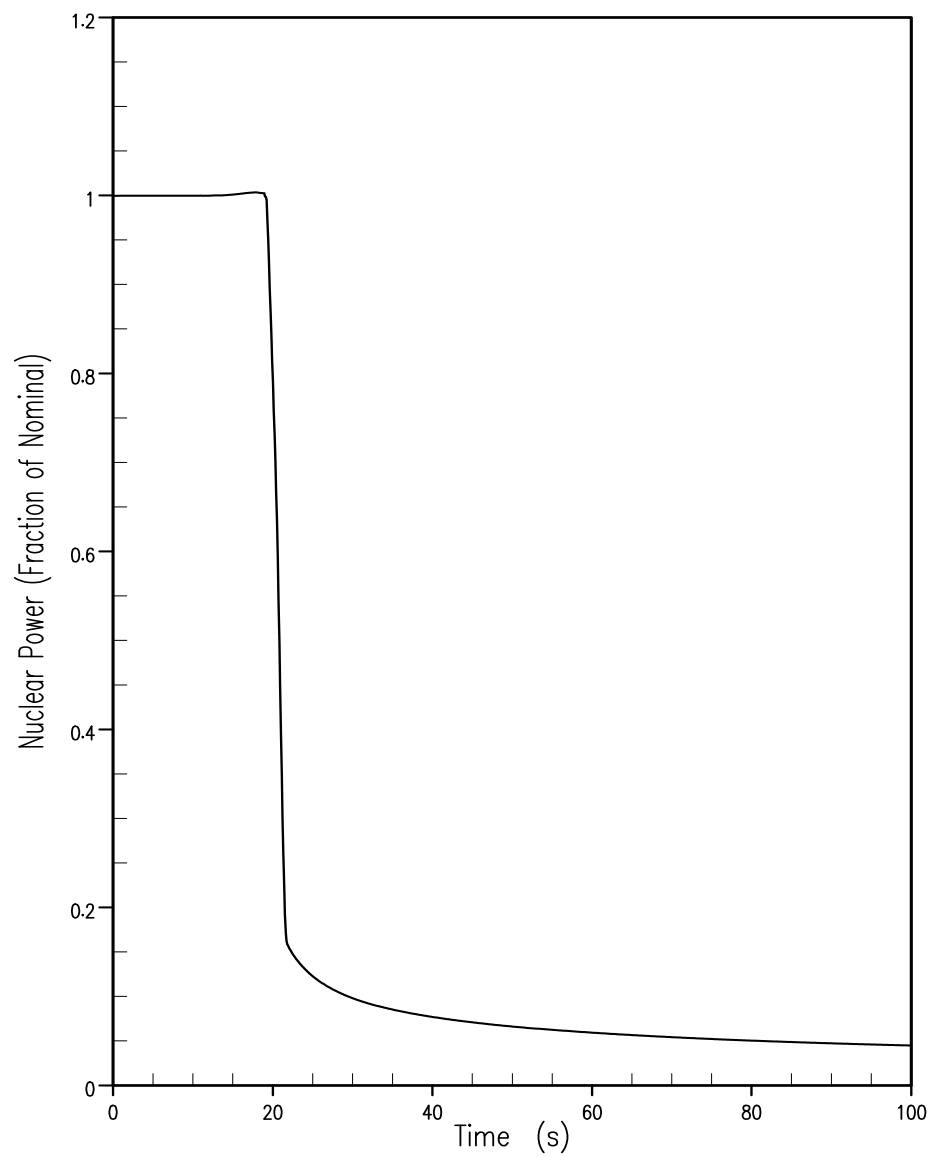


Figure 2.8.5.2.1-12
Loss of Condenser Vacuum (Secondary Overpressure Case)
RCS Pressure (Vessel Lower Plenum Pressure)

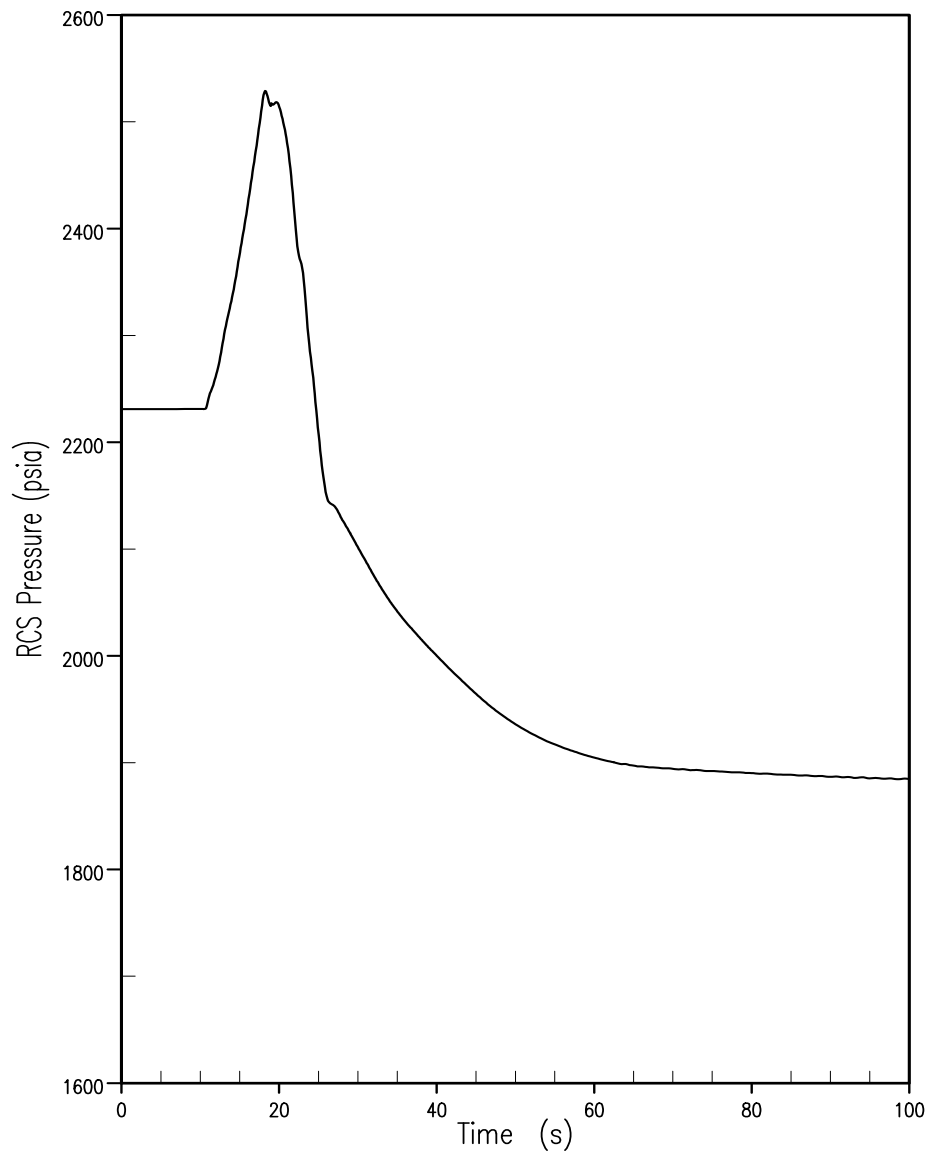


Figure 2.8.5.2.1-13
Loss of Condenser Vacuum (Secondary Overpressure Case)
Pressurizer Water Volume

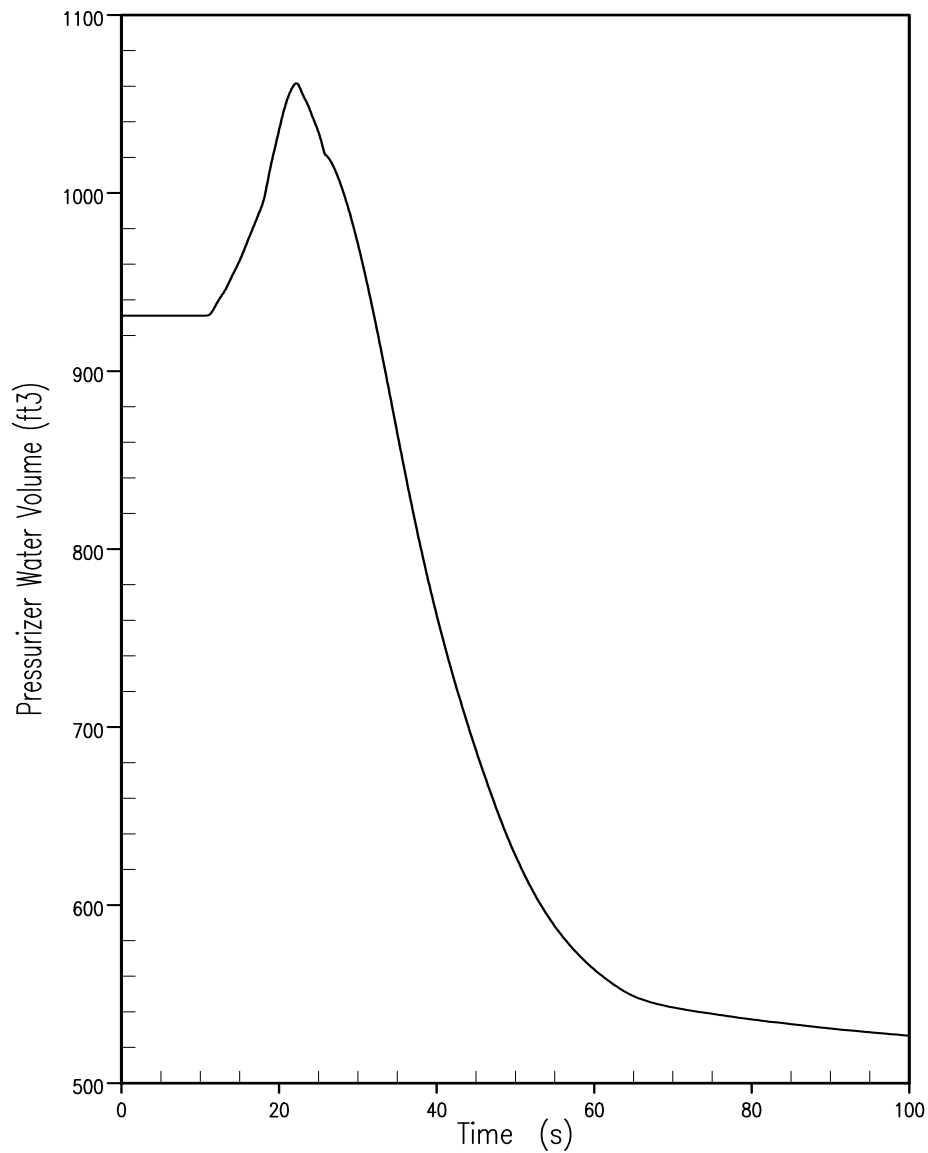


Figure 2.8.5.2.1-14
Loss of Condenser Vacuum (Secondary Overpressure Case)
Vessel Average Temperature

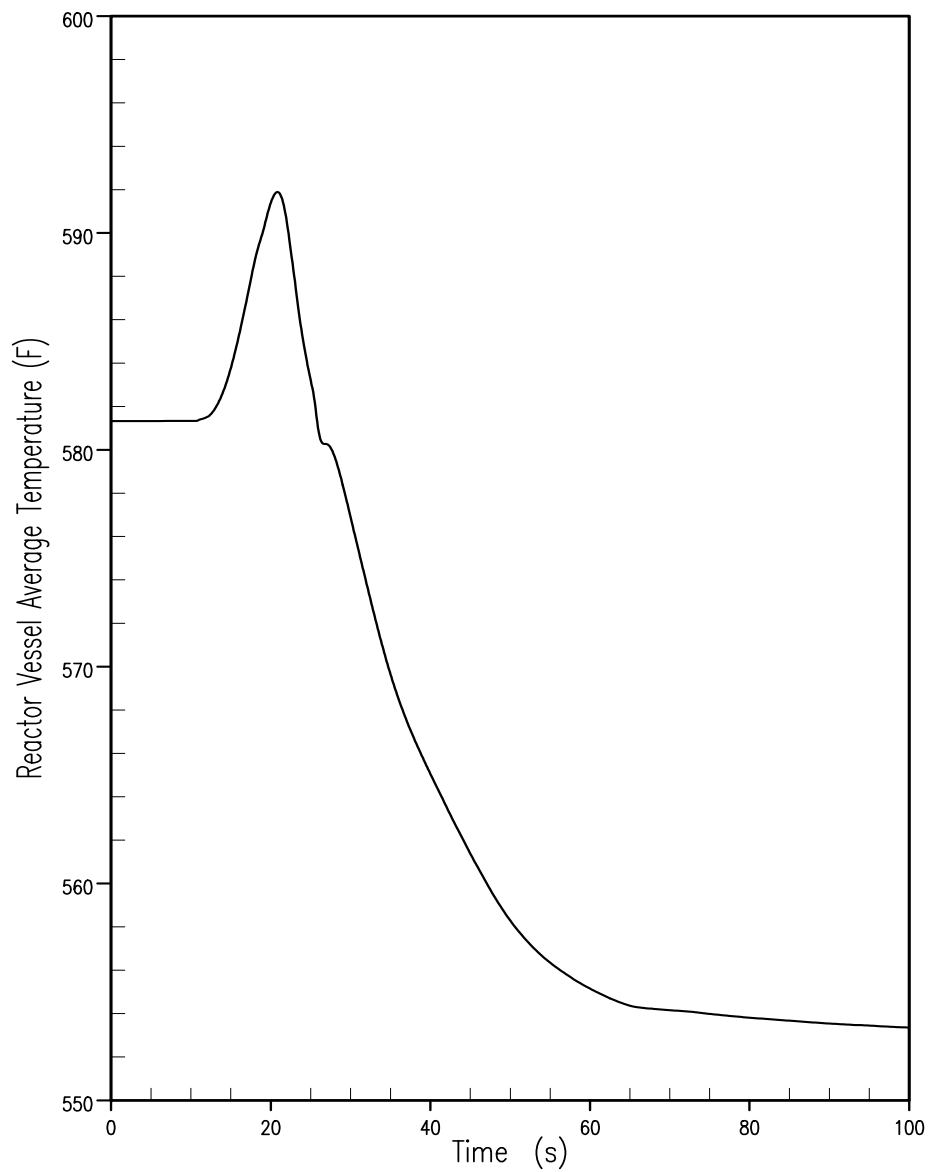
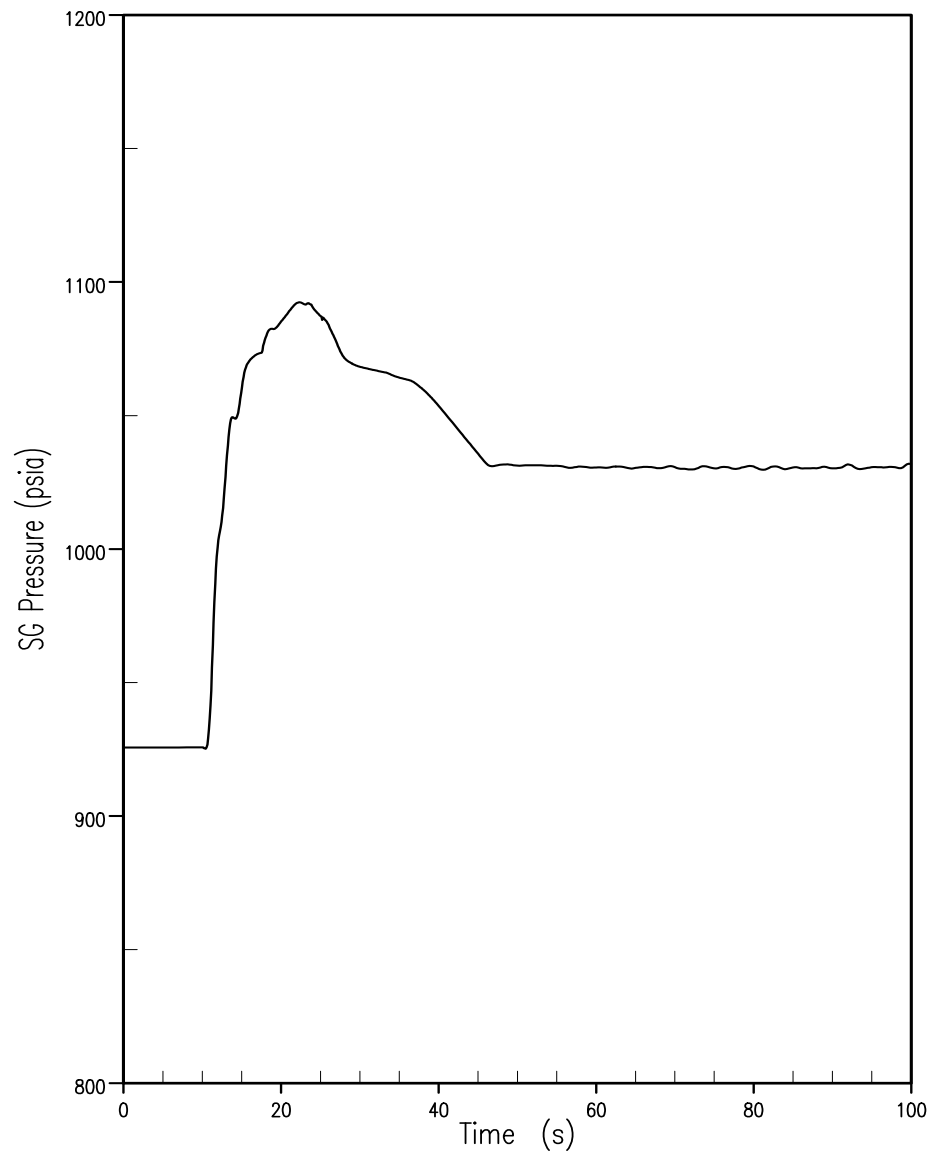


Figure 2.8.5.2.1-15
Loss of Condenser Vacuum (Secondary Overpressure Case)
Steam Generator Pressure



2.8.5.2.2 Loss of Non-Emergency AC Power to the Station Auxiliaries

2.8.5.2.2.1 Regulatory Evaluation

The loss of non-emergency AC power (LOAC) is assumed to result in the loss of all power to the station auxiliaries and the simultaneous tripping of all reactor coolant circulation pumps. This causes a flow coastdown as well as a decrease in heat removal by the secondary system, a turbine trip, an increase in pressure and temperature of the coolant, and a reactor trip. Reactor protection and safety systems are actuated to mitigate the transient.

The Florida Power and Light (FPL) review covered:

- the sequence of events,
- the analytical model used for analyses,
- the values of parameters used in the analytical model, and
- the results of the transient analyses.

The NRC's acceptance criteria are based on:

- General Design Criteria (GDC)-10, insofar as it requires that the reactor coolant system (RCS) be designed with appropriate margin to ensure that specified acceptable fuel design limits (SAFDLs) are not exceeded during normal operations, including anticipated operational occurrences (AOOs);
- 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 reactor coolant pressure boundary (RCPB) are not exceeded during any condition of normal operation; and
- 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 Standard Review Plan (SRP) Section 15.2.6 and other guidance provided in Matrix 8 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in the Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

- GDC-10 is described in UFSAR Section 3.1.10 Criterion 10 - Reactor Design.

The reactor core and associated coolant, control and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

SAFDLs are stated in UFSAR Section 4.3. Minimum margins to SAFDLs are prescribed in the Technical Specifications (Limiting Conditions for Operations) which support UFSAR Chapters 4 and 15.

- GDC-15 is described in UFSAR Section 3.1.15 Criterion 15 - Reactor Coolant System Design.

The Reactor Coolant System and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.

The operating conditions for normal steady state and transient plant operations are established conservatively. Normal operating limits are selected so that an adequate margin exists between operating and design limits. The plant control systems are designed to ensure that plant variables are maintained well within the established operating limits. The plant transient response characteristics and pressure and temperature distributions during normal operations are considered in the design as well as the accuracy and response of the instruments and controls. These design techniques ensure that a satisfactory margin is maintained between the plant's normal operating conditions, including design transients, and the design limits for the RCPB.

The plant control systems function to minimize deviations from normal operating limits in the event of most anticipated operational occurrences. Where control systems response would be inadequate or fail upon demand, the reactor protective system (RPS) and the engineered safety features actuation system (ESFAS) function to mitigate the consequences of such events.

The RPS and ESFAS function to mitigate the consequences of accidents such that the design limits for the RCPB are not exceeded.

- GDC-26 is described in UFSAR Section 3.1.26 Criterion 26 - Reactivity Control System Redundancy and Capability.

Two independent reactivity control systems of different design principles shall be provided. One of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margin for malfunctions such as stuck rods, specified acceptable fuel design limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure acceptable fuel design limits are not exceeded. One of the systems shall be capable of holding the reactor core subcritical under cold conditions.

Two independent reactivity control systems of different design principles are provided. The first system, using control element assemblies (CEAs), includes a positive means (gravity) for inserting CEAs and is capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including specified AOOs; SAFDLs are not exceeded. The CEAs can also be mechanically driven into the core. The appropriate margin for stuck rods is provided by assuming in the analyses of AOOs that the highest worth CEA does not fall into the core.

The second system, the chemical and volume control system (CVCS), using neutron absorbing soluble boron, is capable of reliably compensating for the rate of reactivity changes resulting from planned normal power changes (including xenon burnout) such that acceptable fuel design limits are not exceeded. This system is capable of holding the reactor subcritical under cold conditions. For a further description, see UFSAR Section 9.3.4.

Either system is capable of making the core subcritical from a hot operating condition. For further discussion, see UFSAR Sections 7.4 and 7.7.

UFSAR Section 15.2.6 states that the loss of non-emergency AC power to the station auxiliaries event (LOAC) is discussed with the loss of normal feedwater (LONF) event in UFSAR Section 15.2.7. A LOAC event is identical to the LONF event except that a loss of power to the reactor coolant pumps (RCPs) occurs simultaneously with the loss of feedwater flow. Therefore, the post-trip heat removal relies upon natural circulation in the RCS loops.

The consequences of these events are bounded by other analyzed events as follows:

- With respect to core consequences, the LONF and LOAC events are not as limiting as the complete loss of flow event, which is analyzed to demonstrate that the departure from nucleate boiling (DNB) design basis is satisfied;
- With respect to overpressurization, the Loss of condenser vacuum/turbine trip event (LOCV) will be more limiting than either the LONF or LOAC events; and
- With respect to long-term cooling, the ability of the auxiliary feedwater system (AFW) to remove decay heat following reactor trip is demonstrated by the analyses presented in UFSAR Chapter 10.

NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September, 2003, defines the scope of license renewal. Specific transient analyses are not within the scope of License Renewal.

2.8.5.2.2.2 Technical Evaluation

2.8.5.2.2.2.1 Introduction

As discussed in UFSAR Section 15.2.7, a LOAC is identical to the LONF event discussed in LR [Section 2.8.5.2.3](#), Loss of Normal Feedwater Flow, except that for the LOAC event, a loss of offsite power is assumed to occur simultaneously with the loss of feedwater flow. All systems which are not powered by the emergency diesel generators are unavailable after the LOAC. This includes the RCPs; thus, the RCPs will coast down immediately in addition to the loss of feedwater flow, and the heat removal from the core relies upon natural circulation in the RCS loops.

2.8.5.2.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

An evaluation was performed for EPU to demonstrate that other events bound the LOAC event. Therefore, no accident specific input parameters are analyzed for this event.

Power to the RCPs is lost upon a LOAC event.

The LOAC event is an AOO event and will result in a reactor shutdown with the plant capable of returning to operation when the fault is cleared. The following items summarize the acceptance criteria associated with this event:

- Maximum pressure in the primary RCS and main steam system (MSS) will be maintained below 110 percent of the design pressure,
- The SAFDLs are not exceeded, in particular the departure from nucleate boiling ratio (DNBR), and
- The event does not propagate to a more serious event. In this case, long term cooling must be verified by demonstrating the pressurizer does not become water solid. This ensures that a more limiting event is not generated.

2.8.5.2.2.2.3 Description of Analysis and Evaluations

The consequences of the LOAC event are evaluated against other events to demonstrate that these transients bound the LOAC event. The cases that are evaluated against the LOAC event are included in the following LR Sections:

- Loss of Forced Reactor Coolant Flow (LR [Section 2.8.5.3.1](#)), and
- Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum (LR [Section 2.8.5.2.1](#)).

The results presented in LR [Section 2.8.5.2.2.2.5](#) demonstrate that the LOAC event is bounded by other analyzed events. It is concluded that a LOAC event-specific analysis is not required for the EPU program.

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

As discussed above, the design transient analyses were determined to be outside the scope of License Renewal; therefore, with respect to the design basis accidents and transients, the EPU does not impact any License Renewal evaluations.

2.8.5.2.2.2.5 Results

The consequences of the LOAC events are bounded by other analyzed events as follows:

- With respect to core consequences, the LOAC event is less limiting than the loss of forced reactor coolant flow event (LR [Section 2.8.5.3.1](#)), which demonstrates that the DNB design basis is satisfied. In the case of the LOAC event, the RCPs would coast down immediately in addition to the loss of feedwater flow. This transient would be identical to the complete loss of flow event with the only exception that the reduction in feedwater flow will eventually reduce the cooling of the primary system which would result in an increased RCS pressure thereby increasing the DNBR in comparison to the complete loss of flow analysis. The increase in steam generator primary side exit temperature would not have sufficient time to transport to the core inlet to adversely affect the DNBR calculation. Therefore, the LOAC event has similar RCS conditions to the complete loss of flow event with the exception of a higher RCS

pressure caused by the loss of feedwater flow. As such, the minimum DNBR conditions are bounded by the complete loss of flow event. In addition, since there is no appreciable power increase in the LOAC event and since the fuel centerline melting is primarily driven by the core power, that is, kW/ft, the fuel centerline melt limits will not be challenged. Therefore, the DNB and fuel centerline melting criteria continue to be satisfied for the LOAC events.

- With respect to RCS and MSS overpressurization, the LOCV (LR [Section 2.8.5.2.1](#)) event is more limiting than the LOAC event. The LOCV presents a more significant reduction in the heat removal capability of the steam generators than the LOAC event because the LOCV event combines the loss of normal feedwater with a turbine trip. This causes the LOCV to have a faster pressurization of the RCS compared to the LOAC event. The net result for the LOCV event is a total loss of the secondary heat sink, which results in the greatest challenge to primary and secondary overpressurization. Therefore, the LOCV remains the most limiting event with respect to primary and secondary overpressurization.
- With respect to long-term cooling, the ability of the auxiliary feedwater system to remove decay heat following reactor trip, and to show that pressurizer does not reach water solid state, is demonstrated by the analyses presented in LR [Section 2.5.4.5](#), Auxiliary Feedwater System.

The consequences above show that all criteria are bounded by other events. Therefore, no new analysis is required to support the EPU program.

2.8.5.2.2.3 Conclusion

FPL has reviewed the loss of non-emergency AC power to station auxiliaries event and concludes that the event remains bounded by other events analyzed at EPU conditions. FPL thus concludes 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 this event. Based on this, FPL concludes that the plant will continue to meet its current licensing basis with respect to the requirements of GDCs -10, -15, and -26 following implementation of the proposed EPU. Therefore, FPL 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 Feedwater Flow

2.8.5.2.3.1 Regulatory Evaluation

A loss of normal feedwater (LONF) flow could occur from pump failures, valve malfunctions, or a loss of offsite power (LOOP). Loss of feedwater flow results in an increase in reactor coolant temperature and pressure which eventually requires a reactor trip to prevent fuel damage. Decay heat must be transferred from fuel following a loss of normal feedwater flow. Reactor protection and safety systems are actuated to provide this function and mitigate other aspects of the transient.

The NRC's acceptance criteria are based on:

- General Design Criterion (GDC)-10, insofar as it requires that the reactor coolant system (RCS) be designed with appropriate margin to ensure that specified acceptable fuel design limits (SAFDLs) are not exceeded during normal operations, including anticipated operational occurrences (AOOs);
- 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 reactor coolant pressure boundary (RCPB) are not exceeded during any condition of normal operation; and
- 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 Standard Review Plan (SRP) Section 15.2.7 and other guidance provided in Matrix 8 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDC for the loss of normal feedwater flow are as follows:

- GDC-10 is described in UFSAR Section 3.1.10, Criterion 10 – Reactor Design.

The reactor core and associated coolant, control and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

SAFDLs are stated in UFSAR Section 4.3. Minimum margins to specified acceptable fuel design limits are prescribed in the Technical Specifications (Limiting Conditions for Operations) which support UFSAR Chapters 4 and 15.

- GDC-15 is described in UFSAR Section 3.1.15, Criterion 15 – Reactor Coolant System Design.

The Reactor Coolant System and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.

The design criteria and bases for the reactor coolant pressure boundary are described in the response to GDC-14.

The operating conditions for normal steady state and transient plant operations are established conservatively. Normal operating limits are selected so that an adequate margin exists between operating and design limits. The plant control systems are designed to ensure that plant variables are maintained well within the established operating limits. The plant transient response characteristics and pressure and temperature distributions during normal operations are considered in the design as well as the accuracy and response of the instruments and controls. These design techniques ensure that a satisfactory margin is maintained between the plant's normal operating conditions, including design transients, and the design limits for the reactor coolant pressure boundary.

The plant control systems function to minimize deviations from normal operating limits in the event of most anticipated operational occurrences. Where control systems response would be inadequate or fail upon demand, the reactor protective system (RPS) and the engineered safety features actuation system (ESFAS) function to mitigate the consequences of such events.

The RPS and ESFAS function to mitigate the consequences of accidents such that the design limits for the reactor coolant pressure boundary are not exceeded.

- GDC-26 is described in UFSAR Section 3.1.26, Criterion 26 – Reactivity Control System Redundancy and Capability.

Two independent reactivity control systems of different design principles shall be provided. One of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margin for malfunctions such as stuck rods, specified acceptable fuel design limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure acceptable fuel design limits are not exceeded. One of the systems shall be capable of holding the reactor core subcritical under cold conditions.

Two independent reactivity control systems of different design principles are provided. The first system, using control element assemblies (CEAs), includes a positive means (gravity) for inserting CEAs and is capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including specified anticipated operational occurrences, specified

acceptable fuel design limits are not exceeded. The CEAs can also be mechanically driven into the core. The appropriate margin for stuck rods is provided by assuming in the analyses of anticipated operational occurrences that the highest worth CEA does not fall into the core.

The second system, the chemical and volume control system (CVCS), using neutron absorbing soluble boron, is capable of reliably compensating for the rate of reactivity changes resulting from planned normal power changes (including xenon burnout) such that acceptable fuel design limits are not exceeded. This system is capable of holding the reactor subcritical under cold conditions. For a further description, see UFSAR Section 9.3.4.

Either system is capable of making the core subcritical from a hot operating condition. For further discussion, see UFSAR Sections 7.4 and 7.7.

UFSAR Section 15.2.7 describes the analysis pertaining to the loss of normal feedwater flow event.

NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, published September 2003 defines the scope of license renewal. Specific transient analyses are not within the scope of License Renewal.

2.8.5.2.3.2 Technical Evaluation

2.8.5.2.3.2.1 Introduction

The LONF event is defined as a complete loss of main feedwater flow while the reactor is operating at maximum power level. A loss of main feedwater flow may occur due to the following causes:

- Breaks in the main feedwater system piping upstream of the main feedwater check valves,
- Failure or trip of the main feedwater pumps, including loss of power (for motor driven feedwater pumps), and
- Spurious closure of main feedwater isolation valves or the main feedwater regulating valves.

The immediate consequences of a loss of main feedwater flow is a reduction in the steam generator water level, which if left unmitigated, will ultimately result in a reactor trip and AFW actuation on a low steam generator water level signal. Following reactor trip, the rate of heat generation in the RCS (decay heat plus reactor coolant pump heat input) may exceed the heat removal capability of the secondary system. In this case, there will be an increase in the steam generator pressure and an increase in RCS pressure, RCS temperature, and pressurizer water level. This trend continues until the RCS heat generation rate falls below the secondary-side heat removal capability. At that time, the primary pressure and temperature begin to decrease, thereby terminating the transient in terms of potential challenges to the applicable safety criteria.

2.8.5.2.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

An evaluation was performed for the EPU to demonstrate that other events bound the LONF event. Therefore, no accident specific input parameters are analyzed for this event.

The LONF event is an AOO event and will result in a reactor shutdown with the plant capable of returning to operation when the fault is cleared. The following items summarize the acceptance criteria associated with this event:

- Maximum pressure in the primary RCS and main steam system (MSS) will be maintained below 110 percent of the design pressure,
- The specified acceptable fuel design limits are not exceeded, in particular the departure from nucleate boiling ratio (DNBR), and
- The event does not propagate to a more serious event. In this case, long term cooling must be verified by demonstrating the pressurizer does not become water solid. This ensures that a more limiting event is not generated.

2.8.5.2.3.2.3 Description of Analyses and Evaluations

The consequences of the LONF event are evaluated against other events to demonstrate that other transients bound the LONF event. The analyses that are evaluated against the LONF event are analyses used to support the following LR sections:

- Loss of Forced Reactor Coolant Flow (LR [Section 2.8.5.3.1](#)),
- Loss of External Electrical Load, Turbine Trip, and Loss of Condenser Vacuum (LR [Section 2.8.5.2.1](#)), and
- Auxiliary Feedwater System (LR [Section 2.5.4.5](#)).

The evaluation presented in LR [Section 2.8.5.2.3.2.5](#) demonstrates that LONF event is bounded by other analyzed events. It is concluded that a LONF event specific analysis is not required for the EPU program.

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

As discussed above, the design transient analyses were determined to be outside the scope of License Renewal; therefore, with respect to the design basis accidents and transients, the EPU does not impact any License Renewal evaluations.

2.8.5.2.3.2.5 Results

The consequences of the LONF events are bounded by other analyzed events as follows:

- With respect to core consequences, the LONF event is less limiting than the loss of forced reactor coolant flow event (LR [Section 2.8.5.3.1](#)), which demonstrates that the DNB design basis is satisfied. The LONF event results in a slight increase in the RCS temperature prior to reactor trip with no appreciable increase in the core power while RCS flow is maintained. The loss of forced reactor coolant flow event is limiting with respect to demonstrating that the DNB design basis is satisfied since it results in a significant reduction in the RCS flow. The loss of forced reactor coolant flow event bounds the LONF event since the effect of the reduction in RCS flow is more significant than the effect of the increase in the RCS temperatures

observed for the LONF event prior to reactor trip. In addition, since there is no appreciable power increase in the LONF event, and since the fuel centerline melting is primarily driven by the core power (kW/ft), the fuel centerline melt limits will not be challenged. Therefore, the DNB and fuel centerline melting criteria continue to be satisfied for the LONF events.

- With respect to RCS and MSS overpressurization, the loss of condenser vacuum (LOCV) (LR [Section 2.8.5.2.1](#)) event is more limiting than the LONF event. The LOCV presents a much more significant reduction in the heat removal capability of the steam generators than the LONF event because the LOCV event combines the loss of normal feedwater with a turbine trip. This causes the LOCV to have a faster pressurization of the RCS compared to the LONF event. The net result for the LOCV event is a total loss of the secondary heat sink, which results in the greatest challenge to primary and secondary overpressurization. Therefore, the LOCV remains the most limiting event with respect to primary and secondary overpressurization.
- With respect to long-term cooling, the ability of the auxiliary feedwater system to remove decay heat following reactor trip, and to show that pressurizer does not reach water solid state, is demonstrated by the analyses presented in auxiliary feedwater system LR [Section 2.5.4.5](#).

The consequences above show that all criteria are bounded by other events. Therefore, no new analysis is required to support the EPU program.

2.8.5.2.3.3 Conclusions

FPL has reviewed the loss of normal feedwater flow event 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. FPL further concludes that the review 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 loss of normal feedwater flow. Based on this, FPL concludes that the plant will continue to meet its current licensing basis with respect to the requirements of GDCs -10, -15, and -26 following implementation of the proposed EPU, and therefore finds the proposed EPU acceptable with respect to the loss of normal feedwater flow event.

2.8.5.2.4 Feedwater System Pipe Breaks Inside and Outside Containment

2.8.5.2.4.1 Regulatory Evaluation

Depending upon the size and location of the feedwater line break (FLB) and the plant operating conditions at the time of the break, the break could cause either a reactor coolant system (RCS) cooldown (by excessive energy discharge through the break) or a RCS heatup (by reducing feedwater flow to the affected RCS). In either case, reactor protection and safety systems are actuated to mitigate the transient.

The Florida Power and Light (FPL) review covered:

- Postulated initial core and reactor conditions,
- The methods of thermal and hydraulic analyses,
- The sequence of events,
- The assumed response of the reactor coolant and auxiliary systems,
- The functional and operational characteristics of the reactor protection system (RPS),
- Operator actions, and
- The results of the transient analyses.

The NRC acceptance criteria are based on:

- General Design Criterion (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 emergency core-cooling systems (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 reactor coolant pressure boundary (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; and
- GDC-35, insofar as it requires the reactor cooling system and associated auxiliaries be designed to provide abundant emergency core cooling.

Specific review criteria are contained in Standard Review Plan (SRP) Section 15.2.8 and other guidance provided in Matrix 8 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in the Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC GDC for Nuclear Power Plants as specified in Appendix

A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDCs for feedwater system pipe breaks inside and outside containment are as follows:

- GDC-27 is described in UFSAR Section 3.1.27 Criterion 27 - Combined Reactivity Control Systems Capability.

The reactivity control systems shall be designed to have a combined capability, in conjunction with poison addition by the emergency core cooling system, of reliably controlling reactivity changes to assure that under postulated accident conditions and with appropriate margin for stuck rods the capability to cool the core is maintained.

The reactivity control systems that provide the means for making and holding the core subcritical under postulated accident conditions are discussed in UFSAR Sections 9.3 and 4.3. Combined use of control element assemblies (CEAs) and chemical shim control by the chemical volume control system (CVCS) provides the shutdown margin required for plant cooldown and long-term xenon decay, assuming the highest worth CEA is stuck out of the core.

During an accident, the safety injection system (SIS) functions to inject concentrated boric acid into the RCS for short term and long term cooling and for reactivity control. Details of the system are given in UFSAR Section 6.3.

- GDC-28 is described in UFSAR Section 3.1.28 Criterion 28 – Reactivity Limits.

The reactivity control systems shall be designed with appropriate limits on the potential amount and rate of reactivity increase to assure that the effects of postulated reactivity accidents can neither (1) result in damage to the RCPB greater than limited local yielding nor (2) sufficiently disturb the core, its support structures, or other reactor pressure vessel internals to impair significantly the capability to cool the core. These postulated reactivity accidents shall include consideration of rod ejection (unless prevented by positive means), rod dropout, steam line rupture, changes in reactor coolant temperature and pressure, and cold water addition.

The bases for CEA design include ensuring that the reactivity worth of any one CEA is not greater than a preselected maximum value. The CEAs are divided into two sets: a shutdown set and a regulating set. These sets are further subdivided into groups as necessary. Administrative procedures and control interlocks ensure that the amount and rate of reactivity increase is limited to predetermined values. The regulating groups are withdrawn only after the shutdown groups are fully withdrawn. The regulating groups are programmed to move in sequence and within limits which prevent the rate of reactivity addition and the worth of individual CEAs from exceeding limiting values (see UFSAR Sections 4.3 and 7.7).

The maximum rate of reactivity addition that may be produced by the CVCS is too low to induce any significant pressure forces that might rupture the RCPB or disturb the reactor vessel internals.

The RCPB (UFSAR Chapter 5) and the reactor internals (UFSAR Chapter 4) are designed to appropriate codes and accommodate the static and dynamic loads associated with an inadvertent, sudden release of energy, such as that resulting from a CEA ejection or a steam line break, without rupture and with limited deformation which will not impair the capability of cooling the core.

- GDC-31 is described in UFSAR Section 3.1.31 Criterion 31 - Fracture Prevention of Reactor Coolant Pressure Boundary

The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions (1) the boundary behaves in a non-brittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing, and postulated accident conditions and the uncertainties in determining (1) material properties, (2) the effects of irradiation on material properties, (3) residual, steady-state and transient stresses, and (4) size of flaws.

The RCPB components are designed and constructed in accordance with American Society of Mechanical Engineers (ASME) Code Section III, and comply with the test and inspection requirements of this code. These test and inspection requirements assure that flaw sizes are limited so that the probability of failure by rapid propagation is extremely remote. Particular emphasis is placed on the quality control applied to the reactor vessel, on which tests and inspections exceeding ASME Code requirements are performed. The tests and inspections performed on the reactor vessel are summarized in UFSAR Sections 5.2 and 5.3.

- GDC-35 is described in UFSAR Section 3.1.35 Criterion 35 – Emergency Core Cooling.

A system to provide abundant emergency core cooling shall be provided. The system safety function shall be to transfer heat from the reactor core following any loss of reactor coolant at a rate such that (1) fuel and clad damage that could interfere with continued effective core cooling is prevented and (2) clad metal-water reaction is limited to negligible amounts.

Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

The SIS provides cooling water at a rate sufficient (1) to assure that the zirconium-water reaction is limited to a negligible rate of less than one percent and (2) to assure that the fuel remains in a coolable geometry. Therefore, compliance with the intent of the acceptance criteria for ECCS for light water power reactors of 10 CFR 50, paragraph 50.46(b) is satisfied.

UFSAR Section 15.2.8 provides the analysis of the feedwater system pipe break event.

NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September, 2003, defines the scope of license renewal. Specific transient analyses are not within the scope of License Renewal.

2.8.5.2.4.2 Technical Evaluation

2.8.5.2.4.2.1 Introduction

A major feedwater line rupture is defined as a break in a feedwater line large enough to prevent the addition of sufficient feedwater to maintain shell-side fluid inventory in the steam generators (SGs). Depending upon the plant operating conditions and the size and location of the rupture, the event causes either a cooldown or a heatup of the RCS. The RCS cooldown portion of the FLB event is bounded by the steam line break (SLB) event (LR [Section 2.8.5.1.2](#), Steam System Piping Failures Inside and Outside Containment). The SLB event produces bounding cooldown results due to the larger break size and higher break flow enthalpy when compared to the FLB event discussed herein. A smaller break area and smaller break enthalpy for the FLB event results in a less severe primary system cooldown compared to the SLB event. As such, only the RCS heatup aspects of the FLB event are analyzed herein.

As explained above, in the current licensing basis, RCS cooldown related to a secondary system pipe break is discussed in the SLB event, LR [Section 2.8.5.1.2](#). The key system, subsequent to reactor trip, for mitigating the post-trip SLB event is the SIS (See LR [Section 2.8.5.1.2](#)). The same mitigating systems apply to both the SLB and FLB events.

A FLB reduces the capability of the secondary system to remove heat generated by the core from the RCS. The feedwater flow to the SGs is reduced or terminated, resulting in a decrease in the shell-side fluid inventory. If fluid from the faulted SG is expelled through the broken pipe, the capability of the SG to remove heat from the RCS is eliminated. Depending on break location, a broken feedwater line may also prevent the addition of main feedwater to the intact SG.

A FLB during full-power operation may also cause a short-term pressure increase in both the RCS and main steam system (MSS) challenging the integrity of the RCS and MSS pressure boundaries.

The FLB is also one of the events that defines the required minimum capacity of the AFW system for removing core residual heat following reactor trip. LR [Section 2.5.4.5](#), Auxiliary Feedwater System, discusses the adequacy of the AFW system for the EPU.

2.8.5.2.4.2.2 Input Parameters, Assumptions and Acceptance Criteria

The FLB analysis assumes a break in a feedwater line at the SG inlet nozzle. Such a break results in an uncontrolled discharge of fluid from the SG. A break upstream of the feedwater line check valve would affect the RCS only as a loss of normal feedwater.

This accident is analyzed: (1) to confirm that the pressurizer safety valves (PSVs) and the main steam safety valves (MSSVs) are adequately sized to prevent overpressurization of the primary RCS and MSS, respectively; and (2) to ensure that the departure from nucleate boiling (DNB) design basis is satisfied.

In order to give conservative results in calculating the departure from nucleate boiling ratio (DNBR) and maximum RCS and MSS pressures during the transient, the following assumptions

are made. See LR [Section 2.8.5.0](#), Accident and Transient Analyses, for additional inputs and assumptions.

1. The initial reactor power level is assumed to be at EPU power plus uncertainty, the initial RCS flow rate is assumed at a value consistent with the thermal design flow rate (for addressing overpressurization concerns) or minimum measured flow rate (for addressing DNBR concerns), and the initial RCS pressure is assumed at a value consistent with minimum value allowed by the plant Technical Specifications minus the pressure measurement uncertainty.
2. For maximum RCS pressure, the RCS temperature is assumed to be at low- T_{avg} conditions minus uncertainty. For maximum MSS pressure, the RCS temperature is assumed to be at high- T_{avg} conditions plus uncertainty.
3. For maximum RCS pressure and DNB, the initial steam generator tube plugging (SGTP) level is assumed to be at the maximum plugging level. For maximum MSS pressure, the initial SGTP is assumed to be at the minimum plugging level.
4. The initial SG water level is assumed to be at the minimum water level, consistent with the low-level alarm setpoint minus the SG level measurement uncertainty.
5. The high pressurizer pressure (HPP) and low steam generator pressure (LSGP) reactor trip setpoints for adverse conditions are assumed. The low steam generator level (LSGL) reactor trip is not credited.
6. The FLB is assumed to occur at the physical inlet nozzle location on the SG.
7. An fL/D of 0 (zero) is assumed for the break and the blowdown quality is calculated by the RETRAN code ([Reference 1](#)).
8. A break size spectrum is analyzed to determine the limiting size with respect to DNBR, RCS and MSS overpressurization.
9. Minimum reactivity feedback is assumed to maximize the energy input to the primary coolant.
10. No credit is taken for the effect of the pressurizer spray in reducing or limiting primary coolant pressure with respect to RCS overpressurization. PSVs are available and are modeled assuming a +3 percent setpoint tolerance. The power operated relief valve (PORV) is not considered since it would actuate after reactor trip on HPP and limit the pressure increase.
11. Credit is taken for the effect of the pressurizer spray in reducing primary coolant pressure and delaying reactor trip on HPP for the MSS overpressurization and DNB cases. PSVs are available and are modeled assuming a +3 percent setpoint tolerance. The PORV is assumed to actuate once reaching the HPP reactor trip setpoint. Note that per the technical

specifications, one PORV block valve is required to be closed during Modes 1, 2, and 3, thus allowing only one PORV to be operable.

A FLB is classified as an anticipated operational occurrence (AOO) or a postulated accident, depending on break size. The design criteria for AOO events are as follows:

- AOO incidents shall not cause more than a small fraction of the fuel elements in the reactor to be damaged, although sufficient fuel element damage might occur to preclude resumption of operation for a considerable outage time,
- The release of radioactive material due to AOO incidents may exceed guidelines of 10 CFR Part 20, "Standards of Protection Against Radiation," but shall not be sufficient to interrupt or restrict public use of those areas beyond the exclusion radius, and
- An AOO incident shall not, by itself, generate a postulated accident or result in a consequential loss of function of the reactor coolant system or reactor containment barriers.

The small break with and without failure of the fast bus transfer (FFBT) and the large break without FFBT events are analyzed to meet AOO acceptance criteria. This is done by ensuring that:

- The peak RCS pressure remains below 110 percent of design pressure for large break cases not assuming FFBT and all small break cases,
- The peak secondary pressure remains below 110 percent of design pressure.
- The minimum DNBR remains above the specified acceptable fuel design limit (SAFDL), and
- The large break with FFBT FLB event is analyzed to meet postulated accident acceptance criteria.

Postulated accident events are limiting faults that are not expected to occur, but are postulated because their consequences would include the potential for release of significant amounts of radioactive material. The design criteria for postulated accidents are as follows:

- Postulated accidents shall not cause a release of radioactive material that results in an undue risk to public health and safety exceeding the regulatory dose guidelines, and
- A single postulated accident shall not cause a consequential loss of required functions of systems needed to cope with the fault including those of the RCS and the reactor containment system.

This is done by ensuring all of the AOO acceptance criteria listed for the other break configurations, with the exception of the maximum RCS pressure limit are met. For a postulated accident, the peak RCS pressure must remain below 120 percent of the design limit.

2.8.5.2.4.2.3 Description of Analysis and Evaluation

The FLB transient is analyzed by employing the detailed digital computer code RETRAN (Reference 1). The RETRAN computer code is a flexible, transient thermal-hydraulic digital computer code that has been reviewed and approved by the NRC. The code simulates the

neutron kinetics, RCS, pressurizer, PORVs and PSVs, pressurizer spray, SG, and MSSVs. The code computes pertinent plant variables including temperatures, pressures, and power level.

The following break spectrums are analyzed for the FLB event:

- RCS overpressurization cases
 - Large break – 0.21 ft² to 0.375 ft²
 - Small break – 0.10 ft² to 0.20 ft²
- MSS overpressurization case – 0.05 ft² to 0.375 ft²
- DNBR case – 0.15 ft² to 0.375 ft²

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

As discussed above, the design transient analyses were determined to be outside the scope of License Renewal; therefore, with respect to the design basis accidents and transients, the EPU does not impact any License Renewal evaluations.

2.8.5.2.4.2.5 Results

LR [Table 2.8.5.2.4-1](#) summarizes the results of the break spectrum analysis for the three spectrums analyzed.

LR [Figures 2.8.5.2.4-1](#) through [2.8.5.2.4-7](#) show the transient results for RCS overpressurization, with a limiting large break size of 0.21 ft². In this case, the PSVs actuate and maintain the primary RCS pressure below 110 percent of the design value. LR [Table 2.8.5.2.4-2](#) provides the sequence of events and limiting conditions for this case.

LR [Table 2.8.5.2.4-3](#) provides the sequence of events and limiting conditions for the limiting small break size of 0.20 ft² case.

LR [Figures 2.8.5.2.4-8](#) through [2.8.5.2.4-14](#) show the transient results for the MSS overpressurization case. LR [Table 2.8.5.2.4-4](#) provides the associated sequence of events and limiting conditions for this case.

LR [Table 2.8.5.2.4-3](#) provides the sequence of events and limiting conditions for the limiting minimum DNBR case. The break spectrum was analyzed from 0.15 ft² to 0.375 ft² to ensure the minimum DNBR case is captured. The minimum DNBR was determined to be 2.21 which remained well above the safety analysis limit value, i.e., 1.42, for the limiting break size of 0.20 ft². LR [Figures 2.8.5.2.4-15](#) through [2.8.5.2.4-22](#) provide the transient results for the limiting break case.

The results of the analyses demonstrate that the plant design is such that a feedwater line break presents no hazard to the integrity of the primary RCS or MSS by meeting all applicable AOO acceptance criteria. Pressure relieving devices that have been incorporated into the plant design are adequate to limit the maximum pressures to within the safety analysis limits, i.e., 2750 psia or 3000 psia, as appropriate, for the primary RCS and 1100 psia for the MSS. The integrity of the

core is maintained by operation of the RPS, (i.e., the minimum DNBR is maintained above the safety analysis limit value).

The results for the EPU condition are compared to the results of the current analysis of record. The comparisons are shown in LR [Table 2.8.5.2.4-6](#).

The EPU case shows that RCS maximum pressure was lower than the current analysis of record. The larger heat transfer area (10 percent versus 30 percent SGTP) contributed to the reduction in the maximum RCS pressure. The maximum RCS pressure was found to be less than the design value limit.

For the MSS overpressurization case, higher SG heat transfer obtained from the clean zero SGTP conditions resulted in higher maximum MSS pressure than the current analysis. The SG pressure also initialized at a higher pressure than the previous case of record. The maximum MSS pressure for the EPU condition was found to be below the design limit.

For the DNB case, the analysis demonstrates that the value of the minimum DNBR for EPU conditions was found to be better than the current analysis. This is credited to increased primary to secondary heat transfer and reduced fuel related peaking factors (Fr).

2.8.5.2.4.3 Conclusions

FPL has reviewed the analyses of feedwater system pipe breaks 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. FPL further concludes that the review 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 abundant core cooling will be provided. Based on this, FPL concludes that St. Lucie Unit 2 will continue to meet the requirements of GDCs -27, -8, -31, and -35 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to feedwater system pipe breaks.

2.8.5.2.4.4 References

1. WCAP-14882-P-A (Proprietary) and WCAP-15234-A (Non-Proprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses.

**Table 2.8.5.2.4-1
Feedline Break Summary of Results**

RCS Overpressurization Results				
	Break Size (ft²)	Max. RCS Pressure (psia)	Limit (psia)	Reactor Trip ⁽¹⁾
Limiting Large Break (> 0.20 ft²) with FFBT	0.21	2704.2	3000	HPP
Limiting Large Break (> 0.20 ft²) without FFBT	0.21	2690.3	2750	HPP
Limiting Small Break (0.20 ft²) with FFBT	0.20	2700.3	2750	HPP
Limiting Small Break (0.20 ft²) without FFBT	0.10	2689.6	2750	HPP
MSS Overpressurization Results				
Break Size (ft²)	Maximum Steam Dome Pressure (psia)		Limit (psia)	Reactor Trip ⁽¹⁾
0.050	1094.2		1100	HPP
Minimum DNB Results				
Break Size (ft²)	Minimum DNBR		Limit	Reactor Trip ⁽¹⁾
0.20	2.211		1.42	HPP
1. HPP: High Pressurizer Pressure				

Table 2.8.5.2.4-2
Sequence of Events and Transient Results Feedwater Line Break, Large Break,
Limiting Break Size = 0.21 ft²
Without Pressurizer Pressure Control (for Primary RCS Overpressure)

Event	Time (seconds)
Initiation of Event	0.01
Manual Feedwater Isolation (both loops)	0.01
High Pressurizer Pressure Trip Setpoint Reached	31.04
Reactor Trip Breakers Open	32.19
Failure of Fast Bus Transfer resulting in the trip of two RCPs	32.19
Pressurizer Safety Valves Open	32.66
Rod Motion Begins (0.99 seconds after breaker opens)	33.18 ⁽¹⁾
Time of Peak RCS Pressure	34.99
Results	
Peak RCS Pressure	2704.2 psia
RCS Pressure Limit (120%)	3000 psia
1. A 0.99 second delay was conservatively used instead of the 0.74 second delay design basis value.	

Table 2.8.5.2.4-3
Sequence of Events and Transient Results Feedwater Line Break, Small Break,
Limiting Break Size = 0.20 ft²
Without Pressurizer Pressure Control (for Primary RCS Overpressure)

Event	Time (seconds)
Initiation of Event	0.01
Manual Feedwater Isolation (both loops)	0.01
High Pressurizer Pressure Trip Setpoint Reached	31.53
Reactor Trip Breakers Open	32.68
Failure of Fast Bus Transfer resulting in the trip of two RCPs	32.68
Pressurizer Safety Valves Open	33.20
Rod Motion Begins (0.99 seconds after breaker opens)	33.67 ⁽¹⁾
Time of Peak RCS Pressure	35.33
Results	
Peak RCS Pressure	2700.3 psia
RCS Pressure Limit (110%)	2750 psia
1. A 0.99 second delay was conservatively used instead of the 0.74 second delay design basis value.	

Table 2.8.5.2.4-4
Sequence of Events and Transient Results Feedwater Line Break Limiting Break
Size = 0.05 ft²
With Pressurizer Spray (for MSS Overpressure)

Event	Time (seconds)
Initiation of Event	0.01
Manual Feedwater Isolation (both loops)	0.01
Pressurizer Spray Initiation	11.99
High Pressurizer Pressure Trip Setpoint Reached	37.95
Reactor Trip Breakers Open	39.14
MSSVs (1 st Bank) Open	39.48
MSSVs (2 nd Bank) Open	39.75
Rod Motion Begins (0.74 seconds following Breaker opening)	39.88
Time of Peak SG Pressure	44.00
Results	
Peak MSS Pressure	1094.2 psia
MSS Pressure Limit	1100 psia

Table 2.8.5.2.4-5
Sequence of Events and Transient Results Feedwater Line Break
Break Size = 0.20 ft²
With Pressurizer Pressure Control (for Minimum DNB)

Event	Time (seconds)
Initiation of Event	0.01
Manual Feedwater Isolation (both loops)	0.01
Pressurizer Spray Initiation	12.93
Pressurizer PORV Opens	31.08 ⁽¹⁾
High Pressurizer Pressure Trip Setpoint Reached	31.88
Reactor Trip (Breakers open)	33.57
Rod Motion Begins (0.74 seconds following Breaker opening)	34.31
Time of Minimum DNBR	34.32
Results	
Minimum DNBR Value	2.21
DNBR Limit	1.42
1. It is conservative for the PORV to open prior to obtaining the HPPT reactor trip for the evaluation of DNB due to the lower RCS pressure obtained.	

**Table 2.8.5.2.4-6
Comparison of Results**

	Current Results	EPU Results
RCS Overpressurization Case		
Peak RCS pressure	2775 psia	2704.2 psia
Limiting break size	0.28 ft ²	0.21 ft ²
Reactor trip ⁽¹⁾	LSGP	HPP
Time of reactor trip (rod motion begin)	31.5 seconds	33.2 seconds
Time of peak RCS pressure	33.5 seconds	35.0 seconds
MSS Overpressurization Case		
Peak SG pressure	1090 psia	1094 psia
Limiting break size	0.05 ft ²	0.05 ft ²
Reactor trip ⁽¹⁾	HPP	HPP
Time of reactor trip (rod motion begin)	37.8 seconds	39.1 seconds
Time of peak SG pressure	41.2 seconds	44.0 seconds
Pressurizer Spray	Off	On
DNB Case		
Minimum DNBR	1.58	2.21
Limiting break size	0.25 ft ²	0.20 ft ²
Reactor trip ⁽¹⁾	LSGP	HPP
Time of reactor trip (rod motion begin)	41.6 seconds	33.6 seconds
Time of minimum DNBR	60.9 seconds	34.4 Seconds
1. HPP: High pressurizer pressure trip LSGP: Low steam generator pressure trip		

Figure 2.8.5.2.4-1
Feedwater Line Break RCS Overpressure Case
Limiting Break Size = 0.21 ft²
Nuclear Power

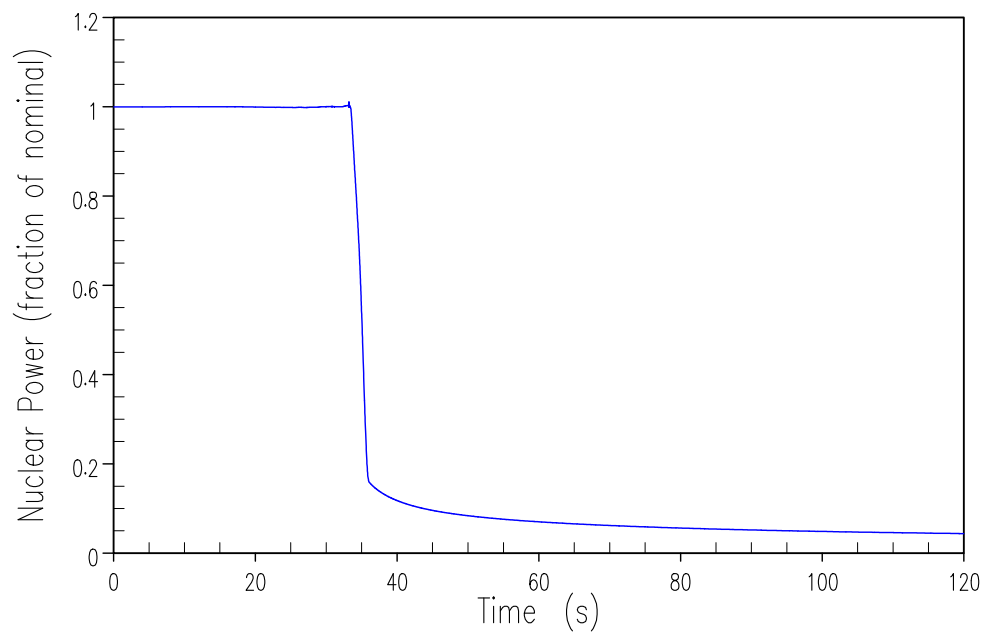


Figure 2.8.5.2.4-2
Feedwater Line Break RCS Overpressure Case
Limiting Break Size = 0.21 ft²
RCS Pressure

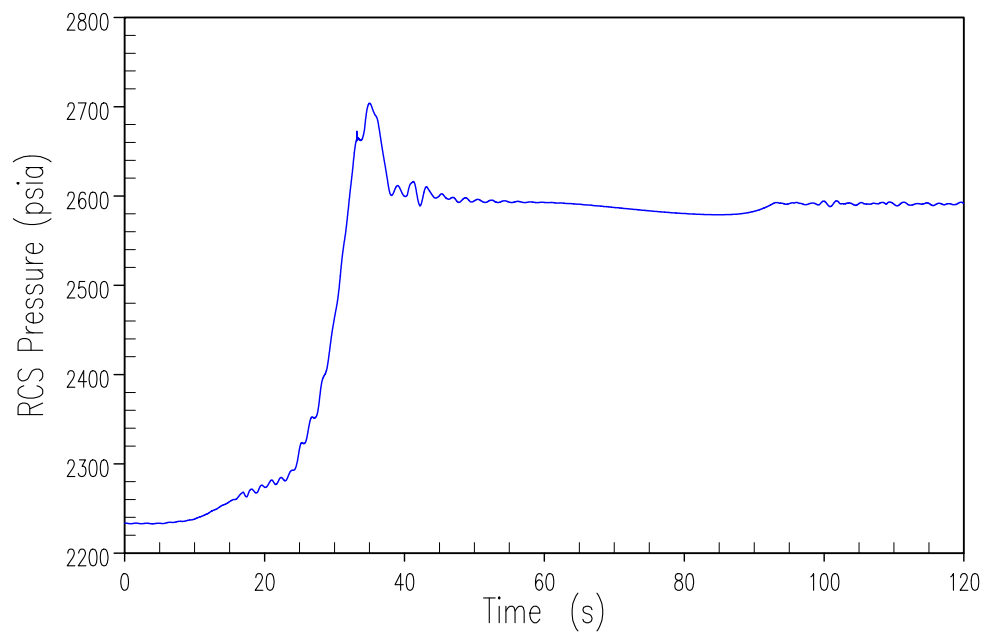


Figure 2.8.5.2.4-3
Feedwater Line Break RCS Overpressure Case
Limiting Break Size = 0.21 ft²
Vessel Average Temperature

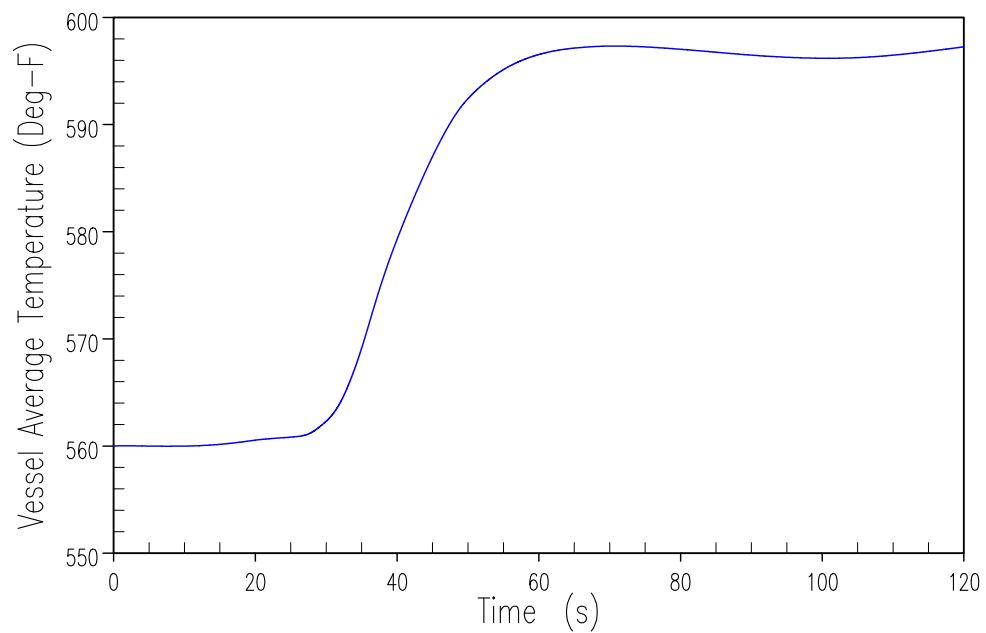


Figure 2.8.5.2.4-4
Feedwater Line Break RCS Overpressure Case
Limiting Break Size = 0.21 ft²
Steam Generator Mass

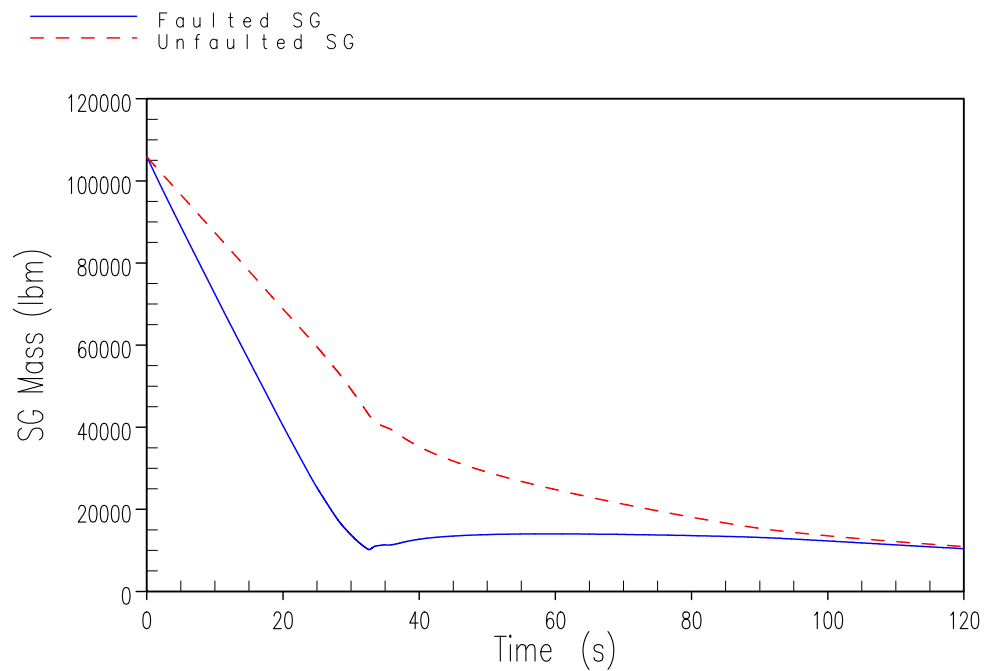


Figure 2.8.5.2.4-5
Feedwater Line Break RCS Overpressure Case
Limiting Break Size = 0.21 ft²
Steam Generator Pressure

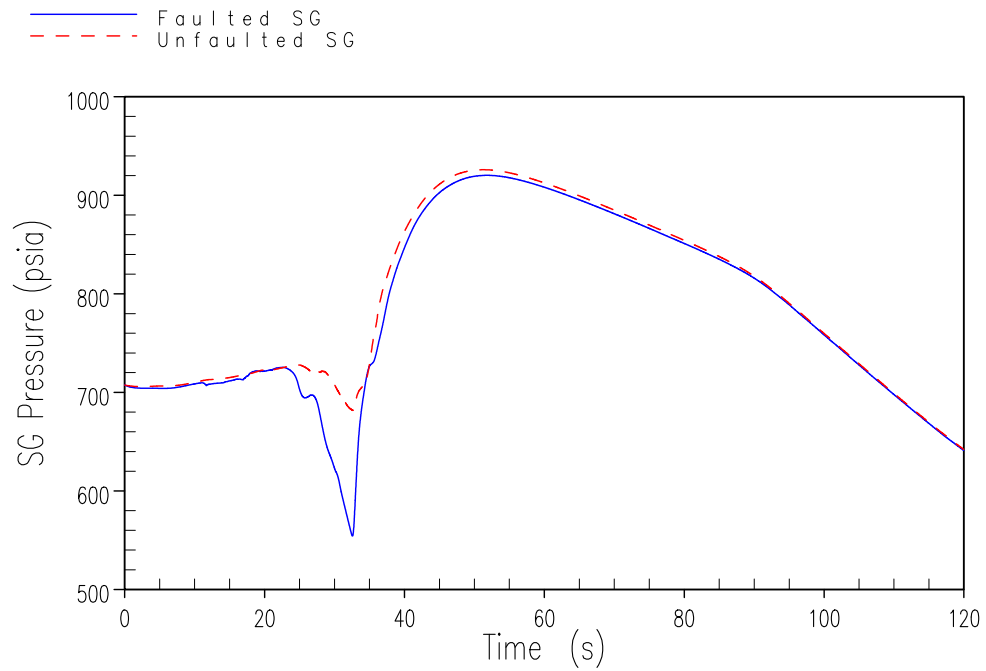


Figure 2.8.5.2.4-6 Feedwater Line Break RCS Overpressure Case
Limiting Break Size = 0.21 ft²
Break Flowrate

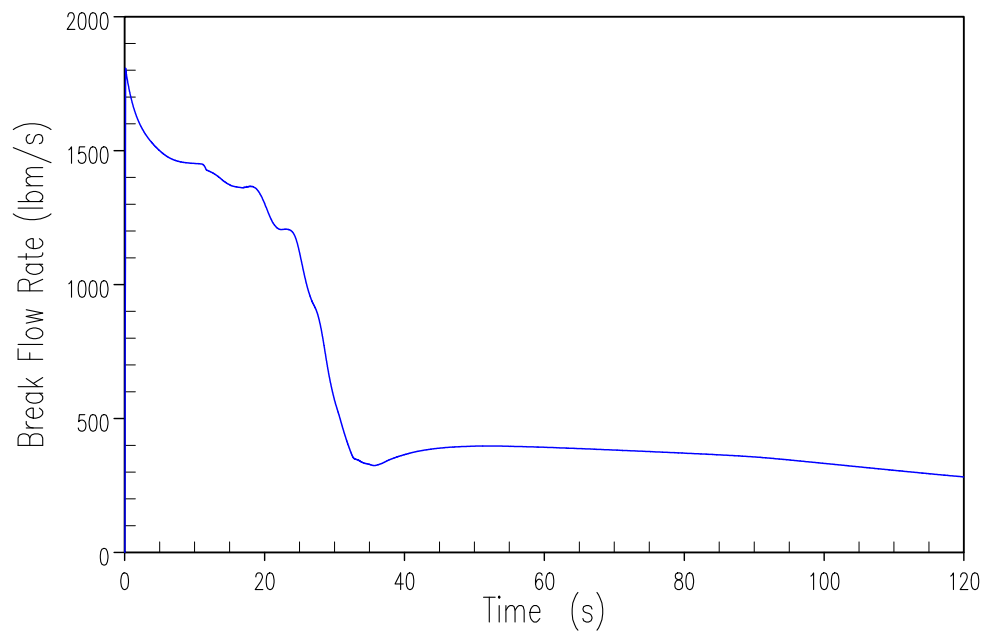


Figure 2.8.5.2.4-7
Feedwater Line Break RCS Overpressure Case
Limiting Break Size = 0.21 ft²
Break Quality

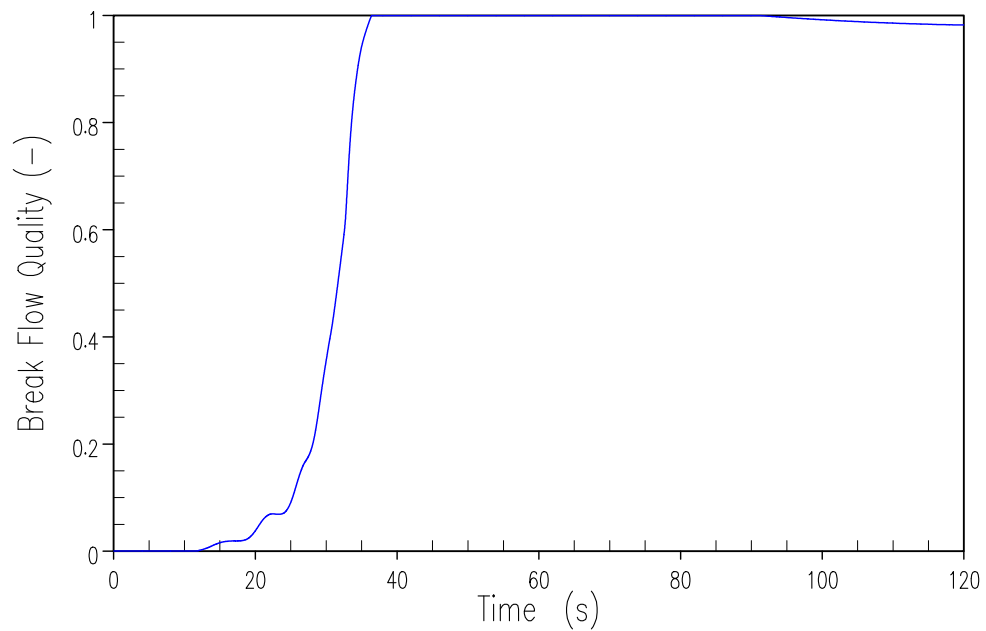


Figure 2.8.5.2.4-8
Feedwater Line Break MSS Overpressure Case
Limiting Break Size = 0.05 ft²
Nuclear Power

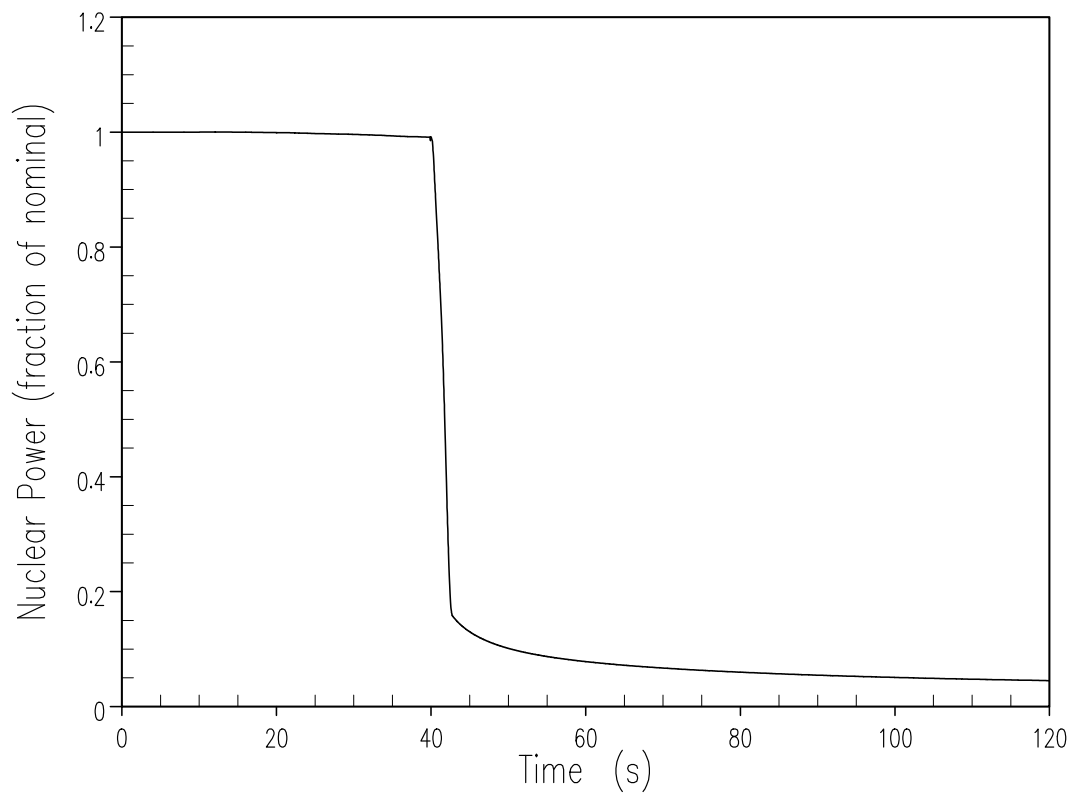


Figure 2.8.5.2.4-9
Feedwater Line Break MSS Overpressure Case
Limiting Break Size = 0.05 ft²
Pressurizer Pressure

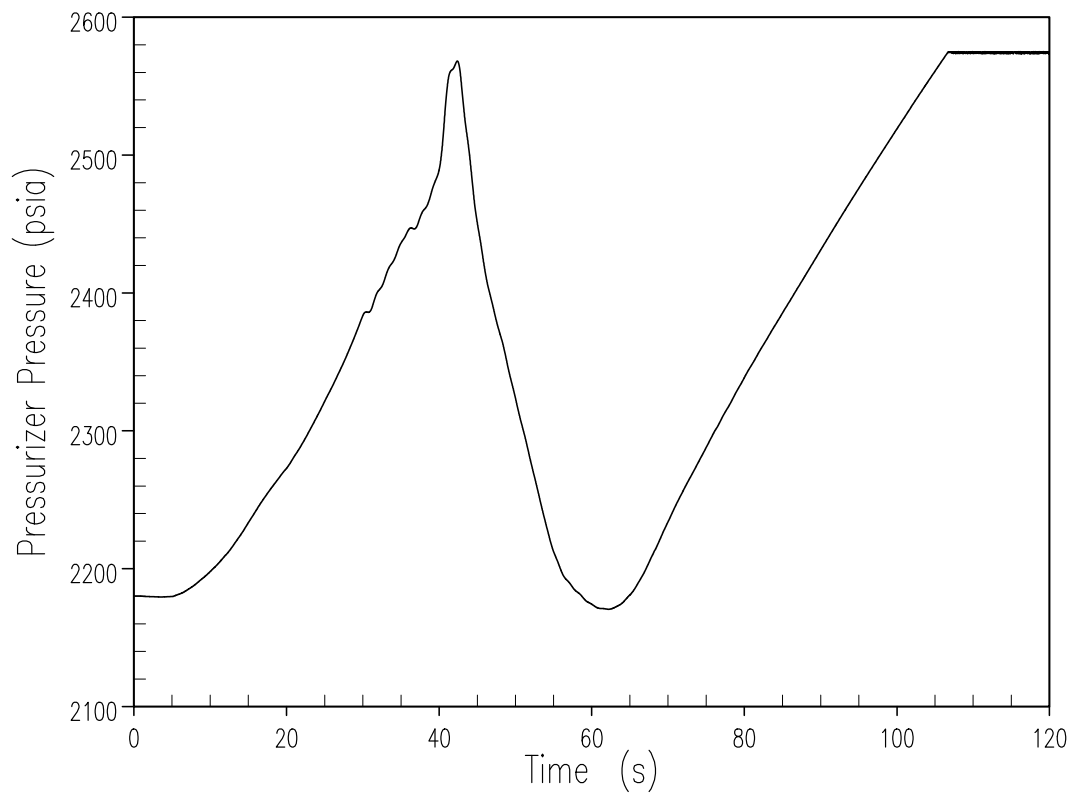


Figure 2.8.5.2.4-10
Feedwater Line Break MSS Overpressure Case
Limiting Break Size = 0.05 ft²
Vessel Average Temperature

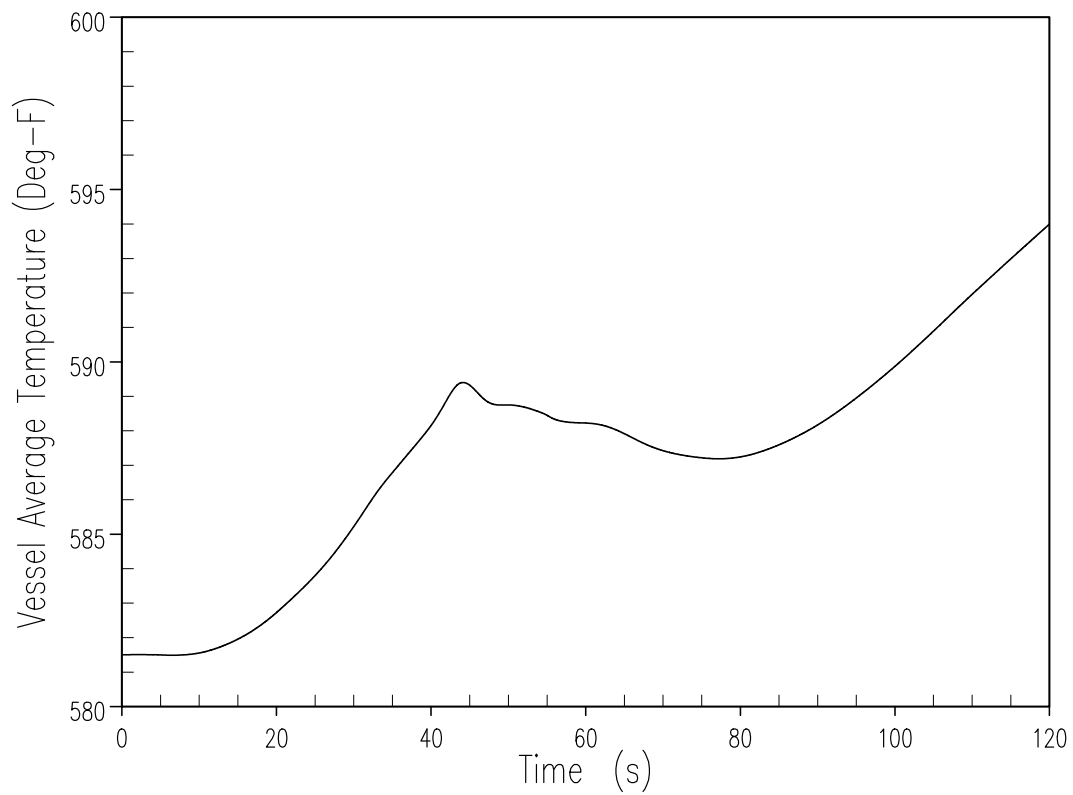


Figure 2.8.5.2.4-11
Feedwater Line Break MSS Overpressure Case
Limiting Break Size = 0.05 ft²
Steam Generator Mass

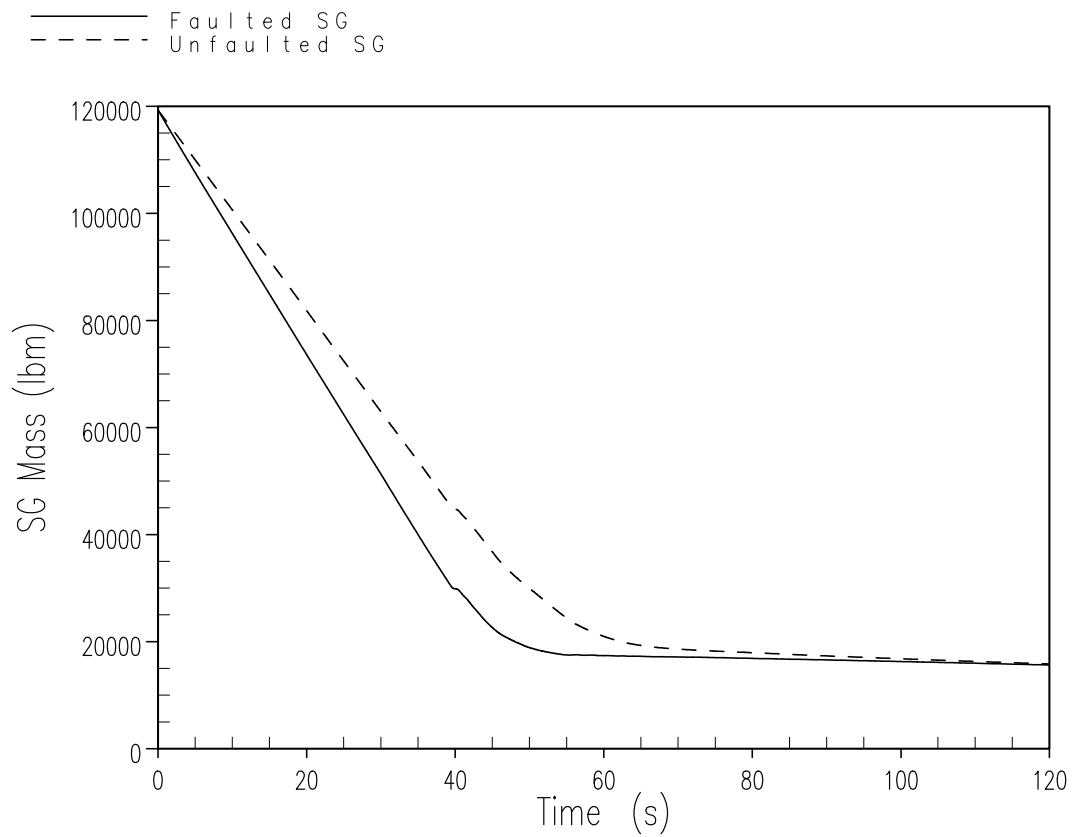


Figure 2.8.5.2.4-12
Feedwater Line Break MSS Overpressure Case
Limiting Break Size = 0.05 ft²
Steam Generator Pressure

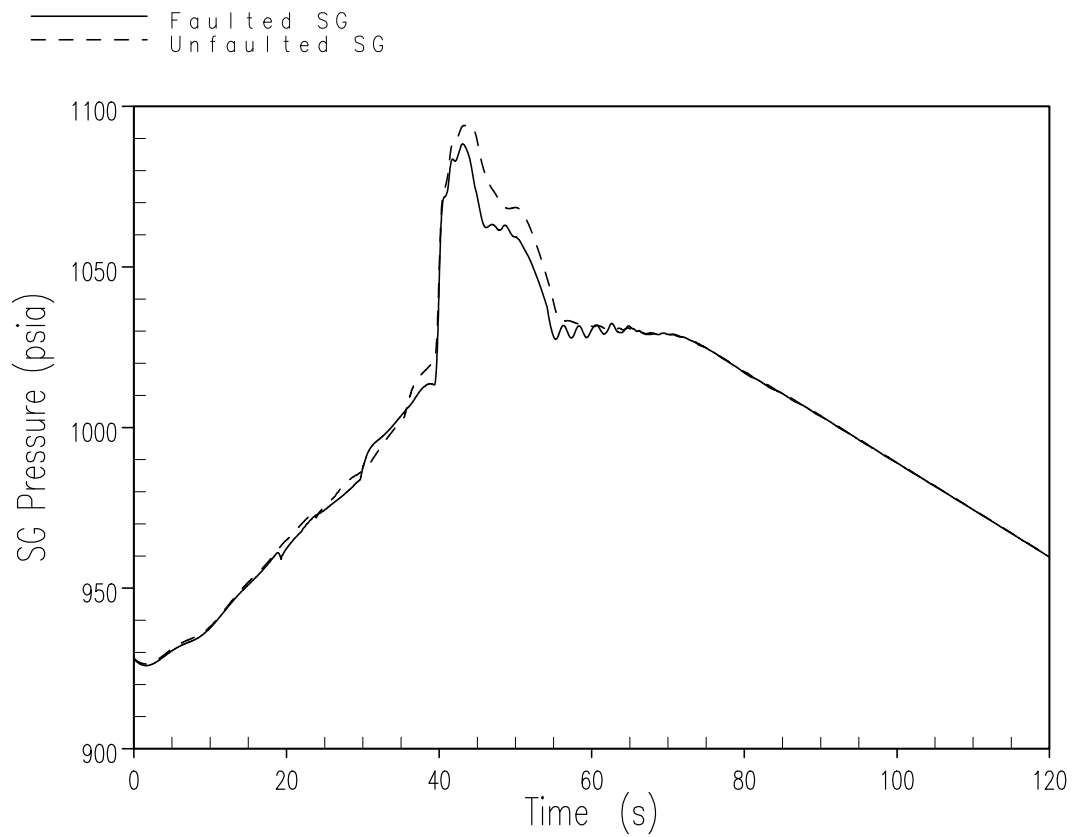


Figure 2.8.5.2.4-13
Feedwater Line Break MSS Overpressure Case
Limiting Break Size = 0.05 ft²
Break Flowrate

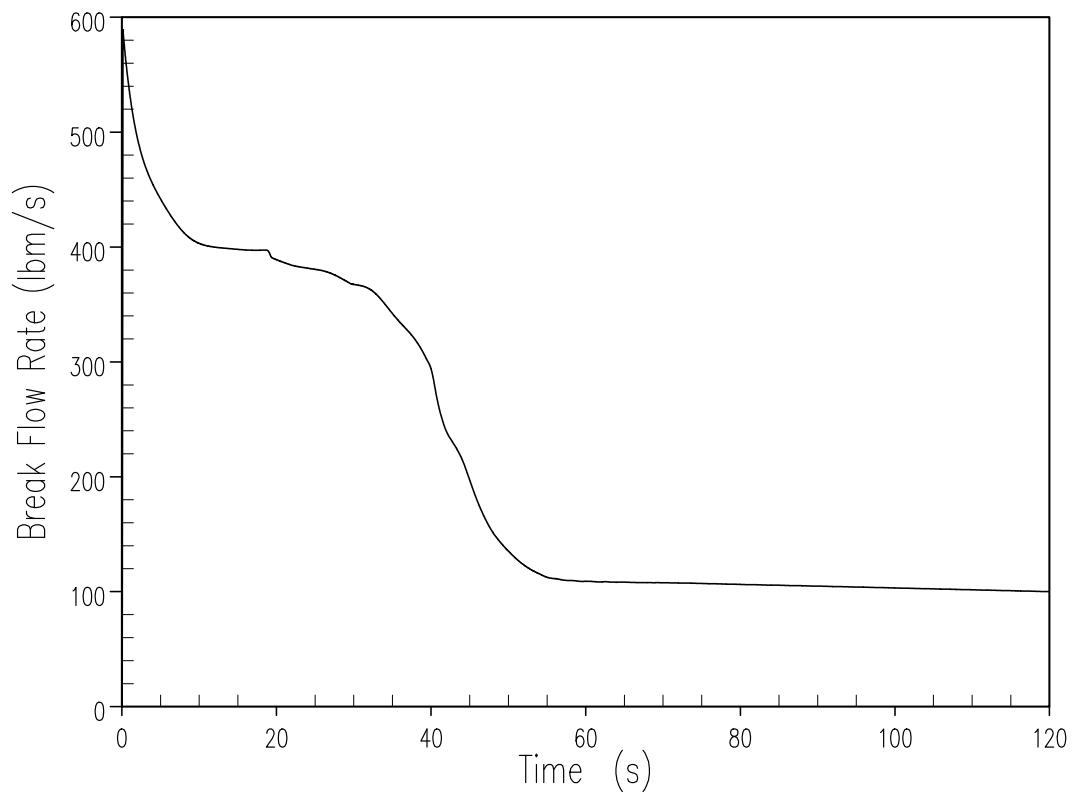


Figure 2.8.5.2.4-14
Feedwater Line Break MSS Overpressure Case
Limiting Break Size = 0.05 ft²
Break Quality

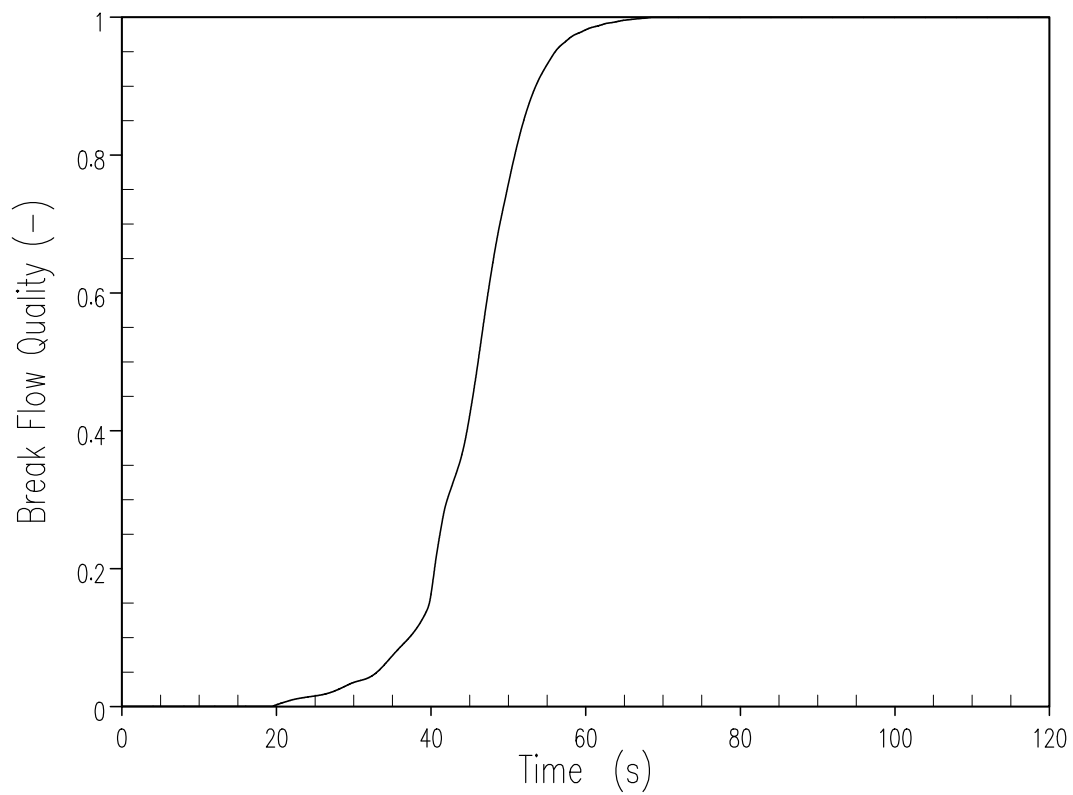


Figure 2.8.5.2.4-15
Feedwater Line Break DNB Case
Limiting Break Size = 0.20 ft²
Nuclear Power

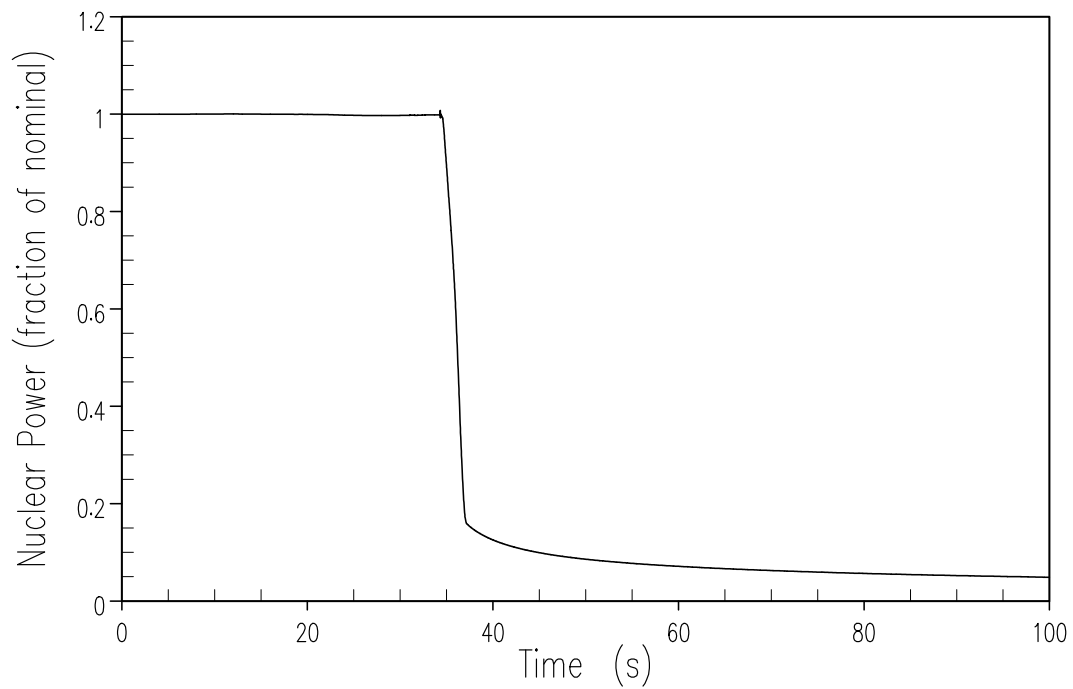


Figure 2.8.5.2.4-16
Feedwater Line Break DNB Case
Limiting Break Size = 0.20 ft²
DNBR

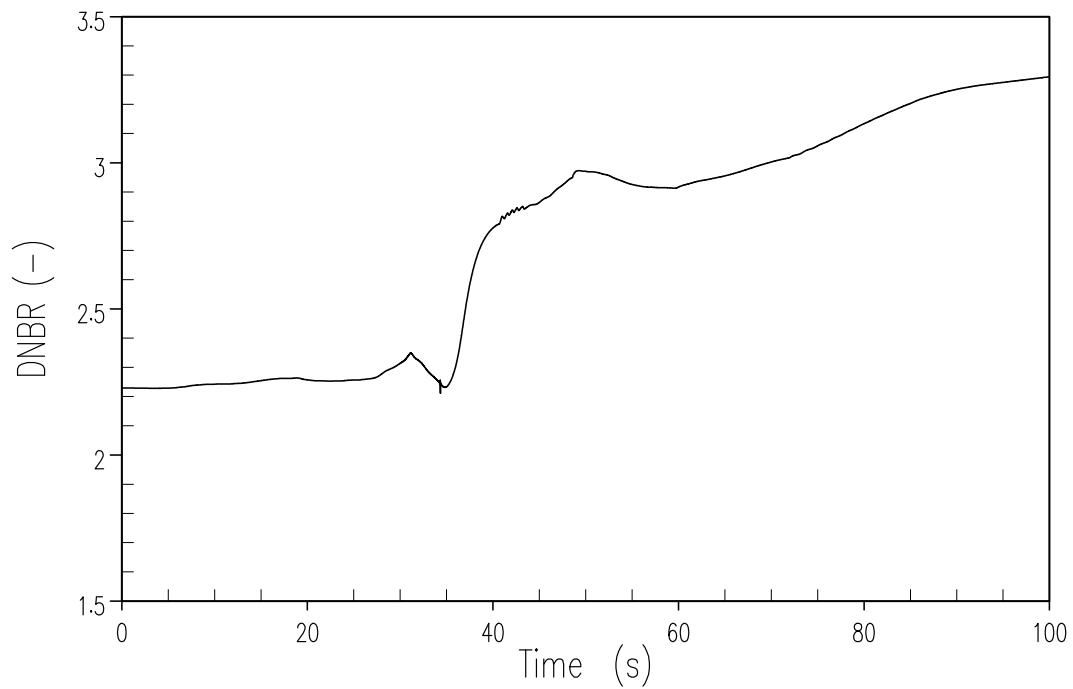


Figure 2.8.5.2.4-17
Feedwater Line Break DNB Case
Limiting Break Size = 0.20 ft²
Pressurizer Pressure

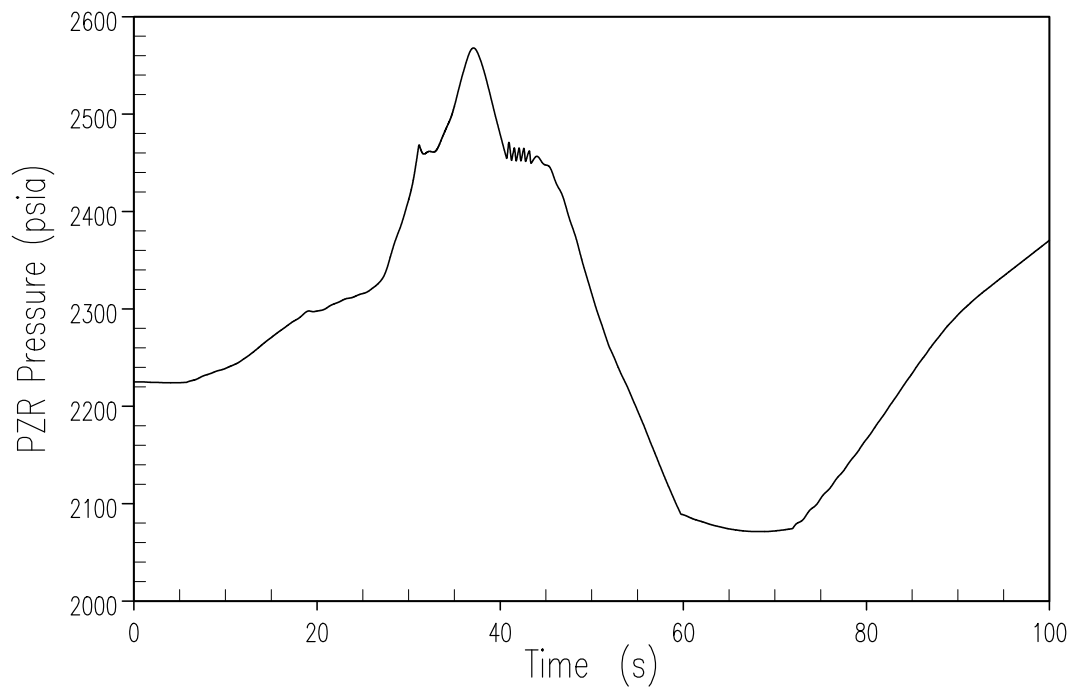


Figure 2.8.5.2.4-18
Feedwater Line Break DNB Case
Limiting Break Size = 0.20 ft²
Vessel Average Temperature

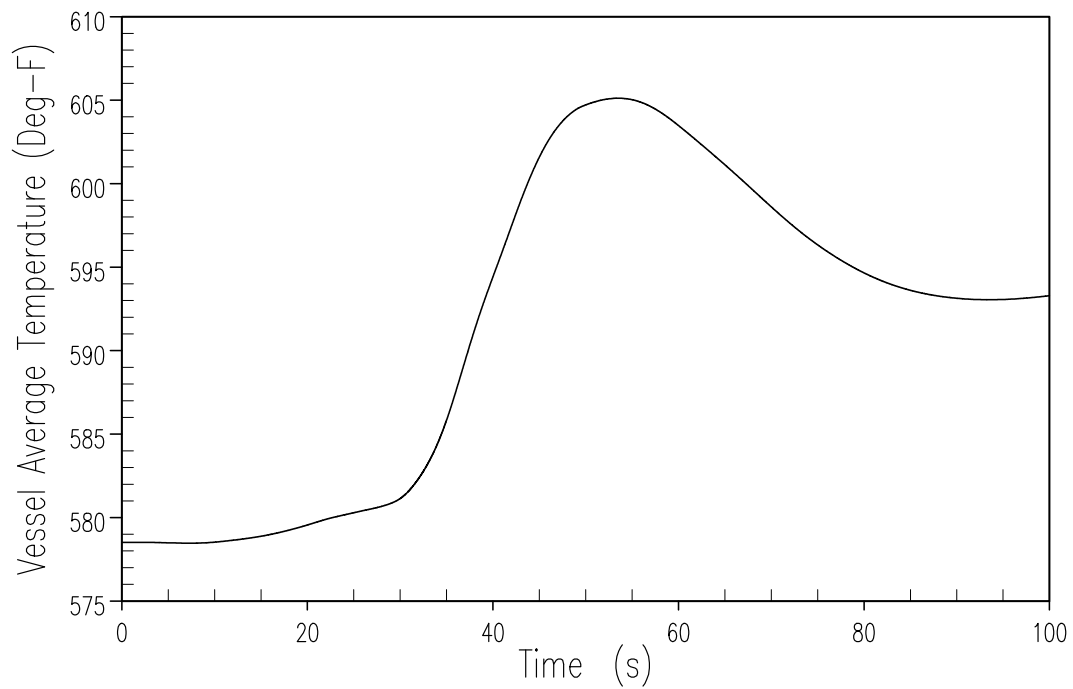


Figure 2.8.5.2.4-19
Feedwater Line Break DNB Case
Limiting Break Size = 0.20 ft²
Steam Generator Mass

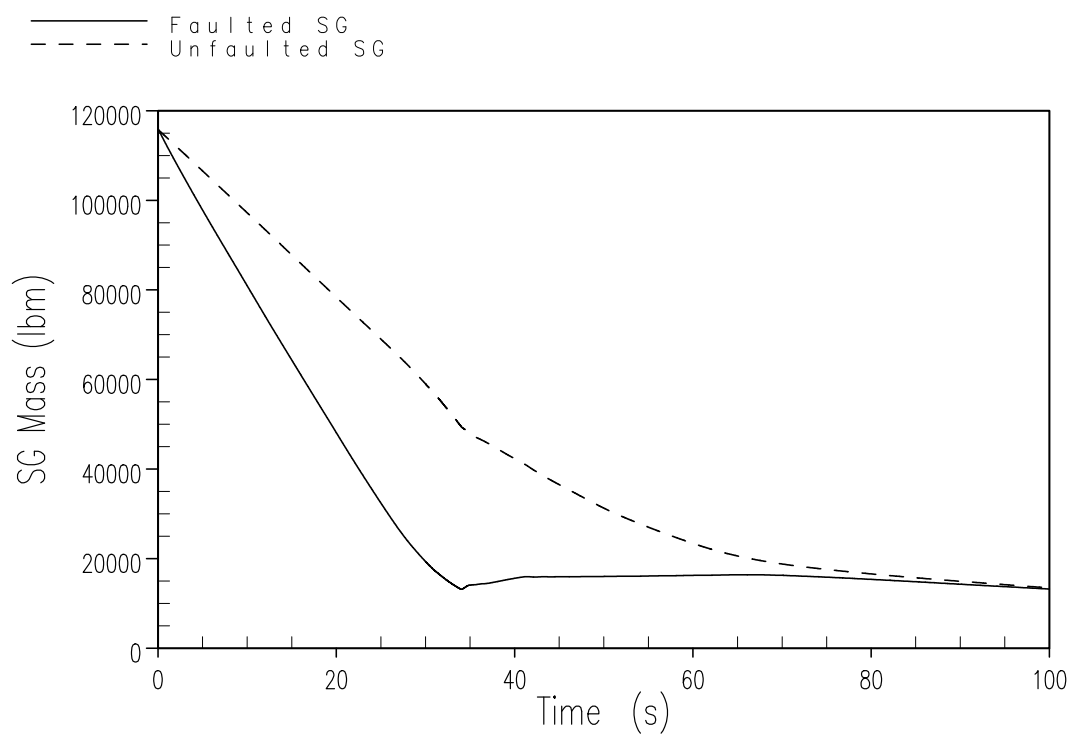


Figure 2.8.5.2.4-20
Feedwater Line Break DNB Case
Limiting Break Size = 0.20 ft²
Steam Generator Pressure

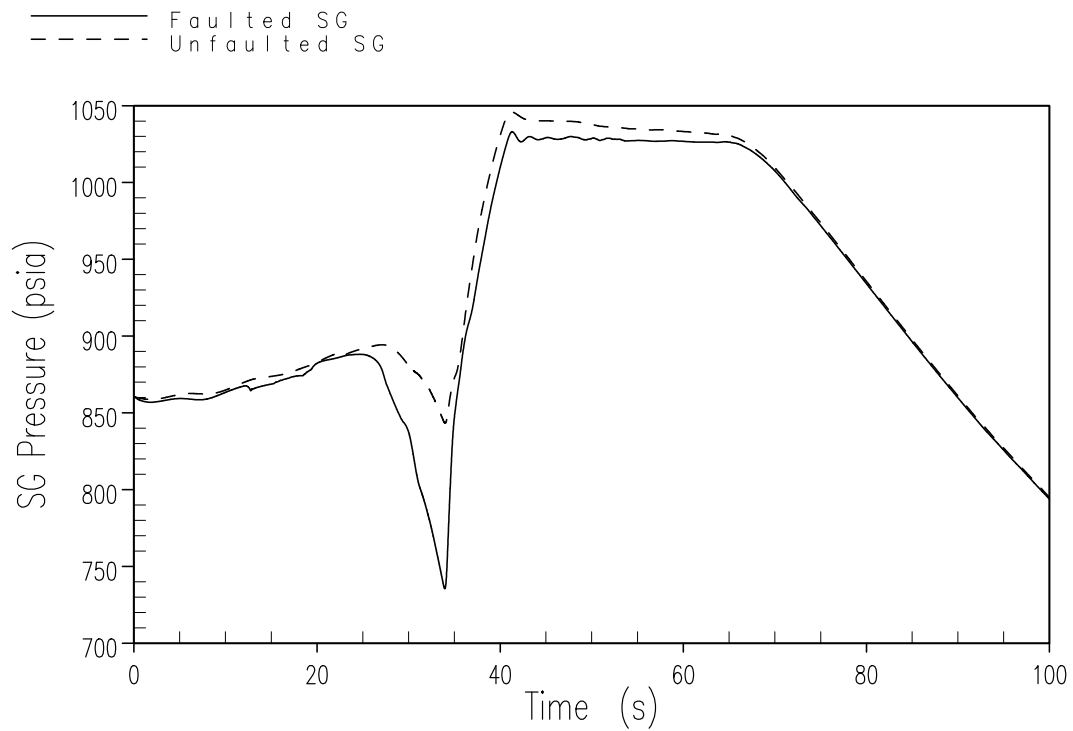


Figure 2.8.5.2.4-21
Feedwater Line Break DNB Case
Limiting Break Size = 0.20 ft²
Break Flow Rate

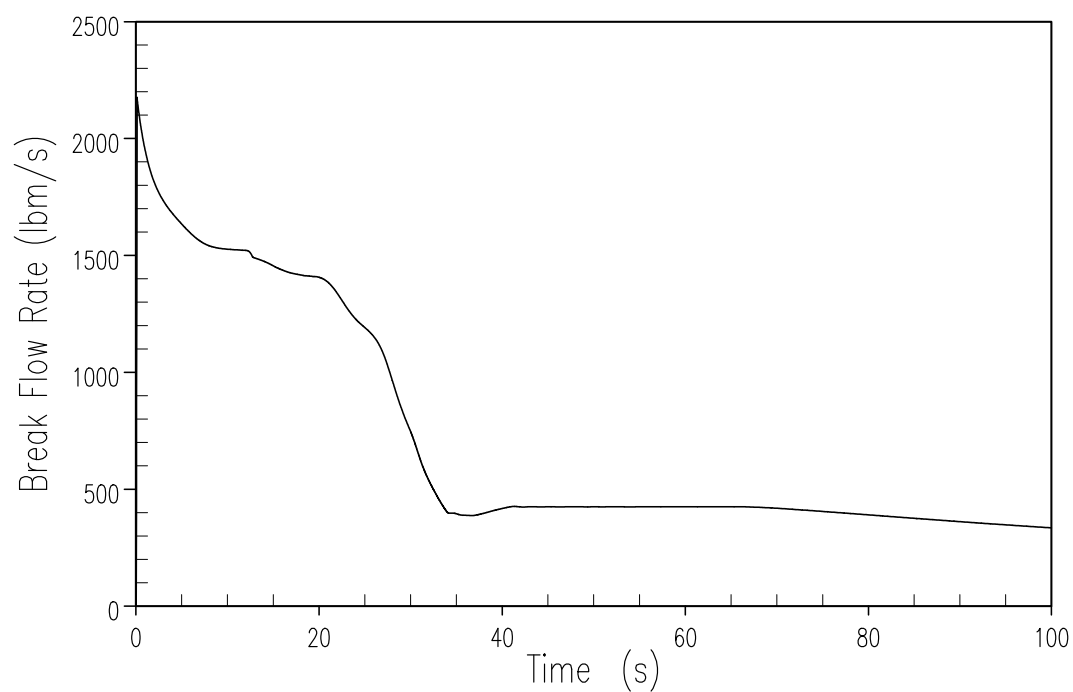
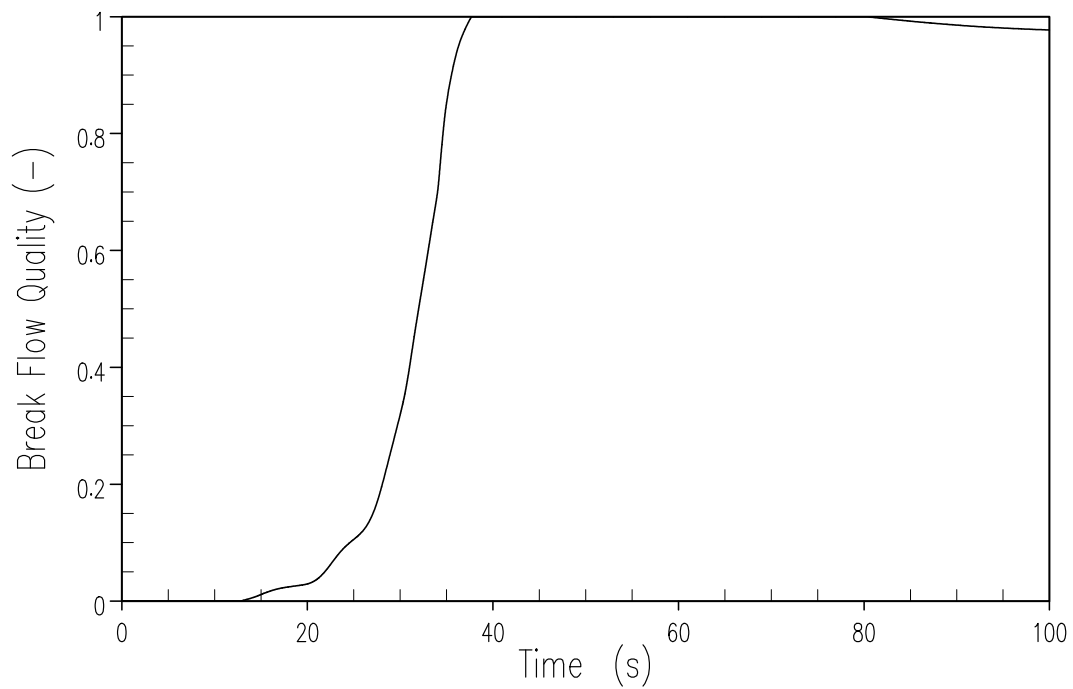


Figure 2.8.5.2.4-22
Feedwater Line Break DNB Case
Limiting Break Size = 0.20 ft²
Break Flow Quality



2.8.5.2.5 Asymmetric Steam Generator Transient

2.8.5.2.5.1 Regulatory Evaluation

NRC review standard RS-001 does not explicitly call out Standard Review Plans (SRP) or other guidance documentation for current or post-uprate license basis reviews pertaining to transients resulting from the malfunction of one steam generator. Florida Power and Light (FPL) postulates this event for St. Lucie Plant Unit 2 as an anticipated operational occurrence which could result in the reduction of the capacity of the secondary system to remove heat generated in the reactor coolant system (RCS). The asymmetric steam generator transient (ASGT) is analyzed to confirm that departure from nucleate boiling ratio (DNBR) and fuel centerline melt design limits are not exceeded.

The ASGT is characterized by events that result in unplanned decreases in heat removal by the secondary system (sudden reduction in steam flow), which consequently, result in pressurization events. Reactor protection and safety systems are actuated to mitigate the transient.

FPL'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.

Consistent with the NRC's acceptance criteria applied to other events involving decrease in heat removal by the secondary system, the acceptance criteria applied to this event are based on:

- General Design Criterion (GDC)-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that specified acceptable fuel design limits (SAFDLs) are not exceeded during normal operations, including anticipated operational occurrences (AOOs);
- 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 reactor coolant pressure boundary (RCPB) are not exceeded during any condition of normal operation; and
- 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.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

- GDC-10 is described in UFSAR Section 3.1.10 Criterion 10 - Reactor Design.

The reactor core and associated coolant, control and protection systems shall 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.

SAFDLs are discussed in UFSAR Section 4.4. Minimum margins to SAFDLs are prescribed in the technical specifications (limiting conditions for operations) which support UFSAR Chapters 4 and 15.

- GDC-15 is described in UFSAR Section 3.1.15 Criterion 15 - Reactor Coolant System Design Criterion.

The Reactor Coolant System and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.

The operating conditions for normal steady state and transient plant operations are established conservatively. Normal operating limits are selected so that an adequate margin exists between operating and design limits. The plant control systems are designed to ensure that plant variables are maintained well within the established operating limits. The plant transient response characteristics and pressure and temperature distributions during normal operations are considered in the design as well as the accuracy and response of the instruments and controls. These design techniques ensure that a satisfactory margin is maintained between the plant's normal operating conditions, including design transients, and the design limits for the RCPB.

The plant control systems function to minimize deviations from normal operating limits in the event of most anticipated operational occurrences. Where control systems response would be inadequate or fail upon demand, the RPS and the engineered safety features actuation system (ESFAS) function to mitigate the consequences of such events. The RPS and ESFAS function to mitigate the consequences of accidents such that the design limits for the reactor coolant pressure boundary are not exceeded.

- GDC-26 is described in UFSAR Section 3.1.26 Criterion 26 - Reactivity Control System Redundancy and Capability.

Two independent reactivity control systems of different design principles shall be provided. One of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margin for malfunctions such as stuck rods, specified acceptable fuel design limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure acceptable fuel design limits are not exceeded. One of the systems shall be capable of holding the reactor core subcritical under cold conditions.

Two independent reactivity control systems of different design principles are provided. The first system, using control element assemblies (CEAS), includes a positive means (gravity) for inserting CEAs and is capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. The CEAs can also be mechanically driven into the core. The appropriate margin for stuck rods is provided by assuming in the analyses of AOOs that the highest worth CEA does not fall into the core.

The second system, the chemical and volume control system (CVCS), using neutron absorbing soluble boron, is capable of reliably compensating for the rate of reactivity changes resulting from planned normal power changes (including xenon burnout) such that acceptable fuel design limits are not exceeded. This system is capable of holding the reactor subcritical under cold conditions. For a further description, see UFSAR Section 9.3.4.

Either system is capable of making the core subcritical from a hot operating condition. For further discussion, see UFSAR Sections 7.4 and 7.7.

UFSAR Section 15.2.9 describes the analyses pertaining to the ASGT.

NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plants, Units 1 and 2, dated September, 2003, defines the scope of license renewal. This specific transient analysis is not within the scope of License Renewal.

2.8.5.2.5.2 Technical Evaluation

2.8.5.2.5.2.1 Introduction

An ASGT event is described as a transient resulting from the malfunction of one steam generator. The four events which affect a single generator are identified below:

1. Loss of load to one steam generator (main steam isolation valve (MSIV) closure),
2. Excess load to one steam generator,
3. Loss of feedwater to one steam generator, and
4. Excess feedwater to one steam generator.

Of the four initiating events, the loss of load to one steam generator results in the most rapid temperature tilt across the reactor core due to the rapid rate of closure of an MSIV. The loss of load to one steam generator, therefore, represents the most limiting ASGT event presented in UFSAR Section 15.2.9, and therefore, is the only event presented herein. This transient is modeled as an inadvertent closure of the MSIV to one steam generator.

In the event of a large loss of load to a single steam generator, the main steam safety valve (MSSV) lift and the reactor is tripped by the high steam generator differential pressure (HSGDP) reactor trip function. This trip function is specifically designed to provide protection for an ASGT event. Upon the loss of load to a single steam generator, the affected steam generator pressure increases to the opening setpoint (including tolerances) of the MSSVs. A concurrent termination of feedwater flow to the affected steam generator is assumed in the analysis to conservatively bound any potential response of the feedwater system. Feedwater isolation to the affected steam generator will result in an increase in the vessel inlet temperature asymmetry during the transient, which is conservative with respect to demonstrating that the DNB design basis is satisfied. Once relief flow is established through the MSSVs, the pressure begins to decrease in the affected steam generator and settles to a value corresponding to the MSSV setpoint pressure.

The unaffected steam generator continues to supply steam to the turbine and attempts to replace the steam load previously supplied by the affected steam generator because the turbine demand is assumed to be maintained at its initial steam load. The increase in steam flow from the unaffected steam generator results in an overcooling of the cold legs associated with the unaffected loop. Additionally, the steam pressure in the unaffected steam generator decreases due to the increased steam flow in that loop. The increase in the core inlet temperature from the affected loops in combination with the decrease in core inlet temperature from the unaffected loops results in a large core temperature asymmetry. The asymmetric core temperature distributions result in an increase in the radial and axial peaking in the core, which may result in a challenge to the DNB design basis.

2.8.5.2.5.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The ASGT analysis is performed to demonstrate that the acceptance criteria described below are satisfied. This is accomplished by showing that the calculated minimum DNBR is greater than the safety analysis limit DNBR. With respect to the overpressure evaluation, the ASGT event is bounded by the Loss of Condenser Vacuum event (LR [Section 2.8.5.2.1](#)), and thus overpressure is not evaluated or presented herein. For the ASGT event, the pressurizer overfill criterion is satisfied by showing the maximum pressurizer water volume does not challenge the maximum pressurizer volume.

To produce conservative results during the transient, the following assumptions, which are consistent with the current analysis unless otherwise specified, were made in the ASGT analysis at the EPU conditions. See LR [Section 2.8.5.0](#), Accident and Transient Analyses, for additional inputs and assumptions.

1. The initial reactor power and RCS temperature are assumed to be at values consistent with 100 percent of rated thermal power, the initial RCS flow rate is assumed at a value consistent with the minimum measured flow rate and the initial RCS pressure is assumed at a value consistent with minimum value allowed by the plant technical specifications. Uncertainties in initial conditions are statistically included in the calculation of the DNBR limit as described in the Revised Thermal Design Procedures ([Reference 2](#)).
2. Two cases were analyzed: one assuming 0 percent of the steam generator U-tubes to be plugged and one assuming 10 percent of the steam generator U-tubes to be plugged. These cases will cover any asymmetry within these limits and are consistent with EPU conditions.
3. Examples of ASGT events are: loss of load to one steam generator (MSIV closure), excess load to one steam generator, loss of feedwater to one steam generator, or excess feedwater to one steam generator. Out of the four initiators, the loss of load to one steam generator results in the most rapid temperature tilt across the reactor core due to the rapid rate of closure of an MSIV and subsequently produces the most limiting event.
4. The ASGT event results in a loss of steam flow and associated main feedwater flow to the affected steam generator. This causes a heat up in the associated primary RCS loop. The turbine demand is assumed to be maintained at its initial steam load by the unaffected loop.

This causes a cool down to occur in the primary loop associated with the unaffected steam generator. The reactivity feedback is weighted to the unaffected loop since end-of-life reactivity feedback is assumed, which results in an increase in the core power due to the colder RCS temperature conditions.

5. The model assumes reactivity feedback coefficients that maximize the increase in nuclear power prior to reactor trip. These reactivity coefficients were weighted to the RCS loop associated with the unaffected steam generator to maximize the power increase. The effects associated with the asymmetric vessel inlet distribution caused by the transient were used to calculate conservative radial and axial peaking factors.
6. The cases are analyzed with the automatic pressurizer pressure control system assumed to be functional. Thus, full credit is taken for the effect of the pressurizer spray in limiting any primary coolant pressure increase above the initial pressure thereby, decreasing RCS pressure which results in a more limiting DNB value.
7. Trip setpoint uncertainties and delay times are discussed in LR [Section 2.8.5.0](#).

Acceptance Criteria

The ASGT event analyzed for the UFSAR is classified as an anticipated operational occurrence event.

The specific criteria for this accident are as follows:

- Pressures in the reactor coolant and main steam systems are maintained below 110 percent of their respective design pressures.
- Fuel cladding integrity is maintained by demonstrating that the minimum DNBR remains above the 95/95 DNBR limit for pressurized water reactors (PWRs).
- An incident of moderate frequency does not generate a more serious plant condition without other faults occurring independently. This criterion is satisfied by verifying that the pressurizer does not fill.

2.8.5.2.5.2.3 Description of Analysis and Evaluation

The ASGT event was conservatively analyzed with respect to the reactor core response. Key analysis assumptions were made to conservatively maximize the asymmetry in vessel inlet temperatures, so as to maximize the core power and peaking factors. Two cases were performed to assess both the minimum DNBR and peak rod power (kW/ft) for 0 percent SGTP and for 10 percent SGTP. The case with 10 percent SGTP was found to be the most limiting case. The DNB design basis limit is met for both cases analyzed.

The ASGT event was analyzed using the detailed digital computer code RETRAN ([Reference 1](#)). This code is NRC approved and simulates the neutron kinetics, reactor coolant pumps (RCPs), pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures,

pressures, and power level. The results from the RETRAN computer code are used to determine if the DNB SAFDL for the ASGT event is met.

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

As discussed above, the design transient analyses were determined to be outside the scope of License Renewal; therefore, with respect to the design basis accidents and transients, the EPU does not impact any License Renewal evaluations.

2.8.5.2.5.2.5 Results

The results of the analysis demonstrate that the ASGT event meets the applicable DNB acceptance criteria. With respect to the RCS and main steam system (MSS) overpressure criteria, LR [Table 2.8.5.2.5-4](#) illustrates that the RCS and MSS maximum pressures remain below the 110 percent design criteria. LR [Figures 2.8.5.2.5-3](#) and [2.8.5.2.5-11](#) illustrate that the pressurizer water volume remains below the maximum pressurizer volume of 1519 ft³ for both cases. LR [Table 2.8.5.2.5-1](#) summarizes the sequence of events and limiting conditions for the 0 percent steam generator tube plugging case and LR [Table 2.8.5.2.5-2](#) correspondingly summarizes the results of the 10 percent steam generator tube plugging case.

The transient response for the ASGT event are shown in LR [Figures 2.8.5.2.5-1](#) through [2.8.5.2.5-9](#) assuming 0 percent SGTP, maximum reactivity feedback conditions with automatic pressurizer pressure control (pressurizer spray). LR [Figures 2.8.5.2.5-10](#) through [2.8.5.2.5-16](#) are based on 10 percent SGTP, maximum reactivity feedback conditions, and automatic pressurizer pressure control (pressurizer spray). Following event initiation, the pressurizer pressure and average RCS temperature increase due to the rapidly reduced steam flow and heat removal capacity of the secondary side. The peak pressurizer pressure, water volume and RCS average temperature are reached shortly after the reactor is tripped on the HSGDP trip signal. The minimum DNBR remains well above the safety analysis limit value.

The overall transient response for the ASGT evaluated herein provides a similar system response as reported in the current analysis (LR [Tables 2.8.5.2.5-3](#) and [2.8.5.2.5-4](#)).

2.8.5.2.5.3 Conclusion

FPL has reviewed the ASGT event described above, and concludes that the analysis has adequately accounted for operation of the plant at the proposed power level and was performed using acceptable analytical models. FPL further concludes that the review 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 ASGT event. Based on this, FPL concludes that the plant will continue to meet the requirements of GDCs -10, -15, and -26 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to the events stated.

2.8.5.2.5.4 References

1. McFadden, J. H., et al., RETRAN-02 - A Program for Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, EPRI NP-1850-CCMA.
2. Friedland, A. J and Ray, S., Revised Thermal Design Procedure, WCAP-11397-P-A (Proprietary) and WCAP-11397-A (Non-Proprietary), April 1989.
3. WCAP-14882-P-A, RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, D. S. Huegel, et al., April 1999.

Table 2.8.5.2.5-1
Sequence of Events and Transient Results Asymmetric Steam Generator
Transient 0% Steam Generator Tube Plugging

Event	Time (seconds)⁽¹⁾
MSIV Closure (Affected Loop)	10.10
Feedwater Termination Assumed (Affected Loop)	10.10
HSGDP Setpoint Reached	13.60
Reactor Trip on HSGDP	14.93
Rod Motion Begins	15.67
Time of Minimum DNBR	0.00 ⁽²⁾
Results	
Minimum DNBR Value	2.229
DNBR Limit	1.42
1. The time sequence includes a ten second steady state, therefore subtract 10 seconds in order to obtain the transient time. 2. The DNBR value increases during the transient due to the large increasing RCS pressure, when compared to the small increase in power and core temperature, prior to reactor trip.	

Table 2.8.5.2.5-2
Sequence of Events and Transient Results Asymmetric Steam Generator
Transient 10% Steam Generator Tube Plugging

Event	Time (seconds)⁽¹⁾
MSIV Closure (Affected Loop)	10.14
Feedwater Termination Assumed (Affected Loop)	10.14
HSGDP Setpoint Reached	13.30
Reactor Trip on HSGDP	14.50
Rod Motion Begins	15.24
Time of Minimum DNBR	0.00 ⁽²⁾
Results	
Minimum DNBR Value	2.229
DNBR Limit	1.42
1. The time sequence includes a ten second steady state, therefore subtract 10 seconds in order to obtain the transient time. 2. The DNBR value increases during the transient due to the large increasing RCS pressure, when compared to the small increase in power and core temperature, prior to reactor trip.	

Table 2.8.5.2.5-3
Current ASGT Analysis Results

Parameter	Limit	Results
30% SGTP Case – DNBR	1.37	2.19
30% SGTP Maximum Primary Pressure – psia	2750	2289
30% SGTP Maximum Secondary Pressure – psia	1100	1076
30% SGTP Time of Trip – seconds	-	15.1
30% SGTP Maximum Power – Fraction of Nominal (FON)	-	1.039
30% SGTP Maximum Power Time - seconds	-	16.85
30% SGTP Maximum Heat Flux FON	-	1.012
30% SGTP Maximum Heat Flux Time - seconds	-	17.4
30% SGTP Cold Leg delta-T @ Trip deg. F	-	8.5
30% SGTP Cold Leg delta-T @ Max HF deg. F	-	24.2
0% SGTP Case - DNBR	1.37	2.21
0% SGTP Maximum Primary Pressure - psia	2750	2297
0% SGTP Maximum Secondary Pressure - psia	1100	1078

Table 2.8.5.2.5-4
ASGT EPU Analysis Results

Parameter	Limit	Results
10% SGTP Case - DNBR	1.42	2.229
10% SGTP Maximum Primary Pressure – psia ⁽¹⁾	2750	2392
10% SGTP Maximum Secondary Pressure - psia	1100	1080
10% SGTP Time of Trip – seconds	-	14.5
10% SGTP Maximum Power – FON	-	1.016
10% SGTP Maximum Power Time - seconds	-	15.35
10% SGTP Maximum Heat Flux FON	-	1.005
10% SGTP Maximum Heat Flux Time - seconds	-	15.1
10% SGTP Cold Leg delta-T @ Trip deg. F	-	4.4
10% SGTP Cold Leg delta-T @ Max HF deg. F	-	8.9
0% SGTP Case - DNBR	1.42	2.229
0% SGTP Maximum Primary Pressure – psia ⁽¹⁾	2750	2371
0% SGTP Maximum Secondary Pressure - psia	1100	1081
1. Primary pressure corresponds with the reactor vessel lower plenum pressure.		

Figure 2.8.5.2.5-1
Asymmetric Steam Generator Transient - 0% Tube Plugging
Nuclear Power

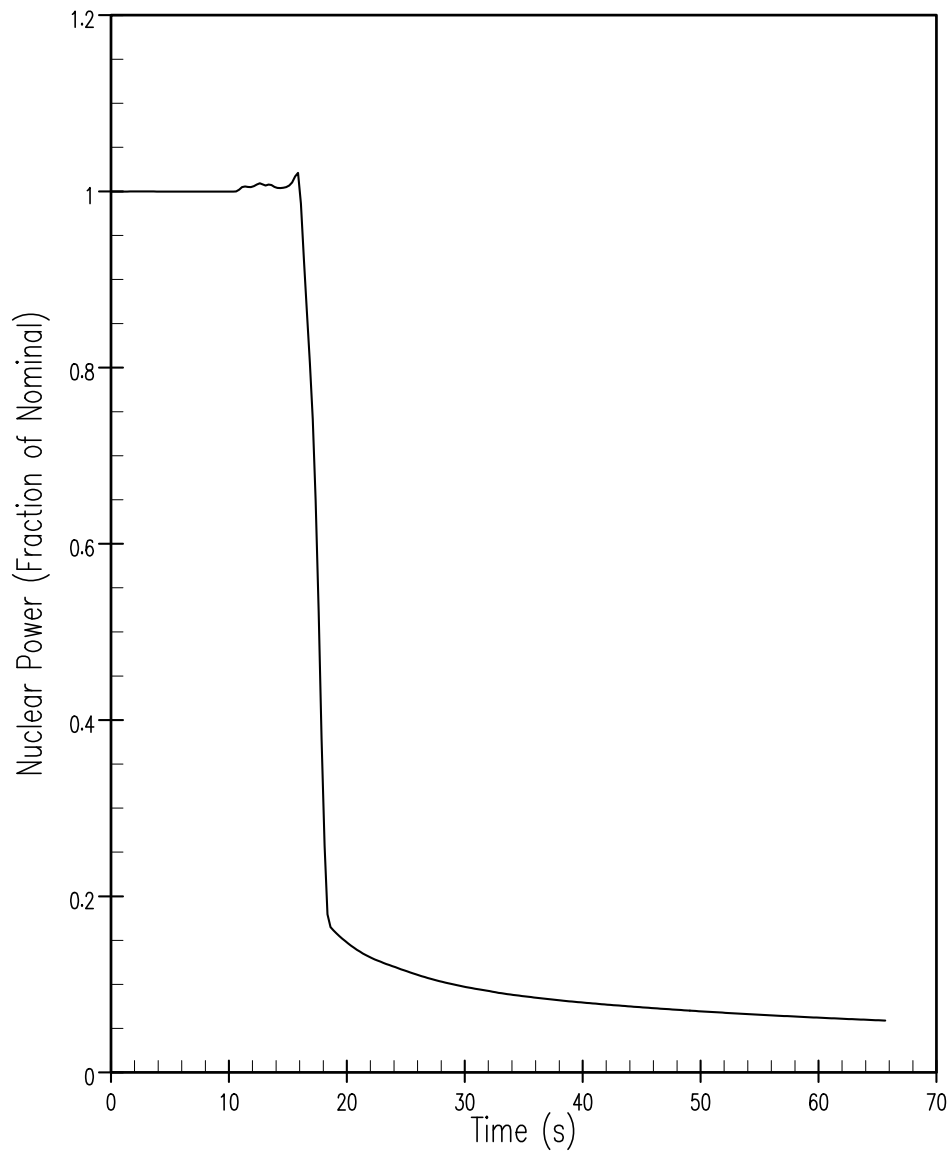


Figure 2.8.5.2.5-2
Asymmetric Steam Generator Transient - 0% Tube Plugging
RCS (Pressurizer) Pressure

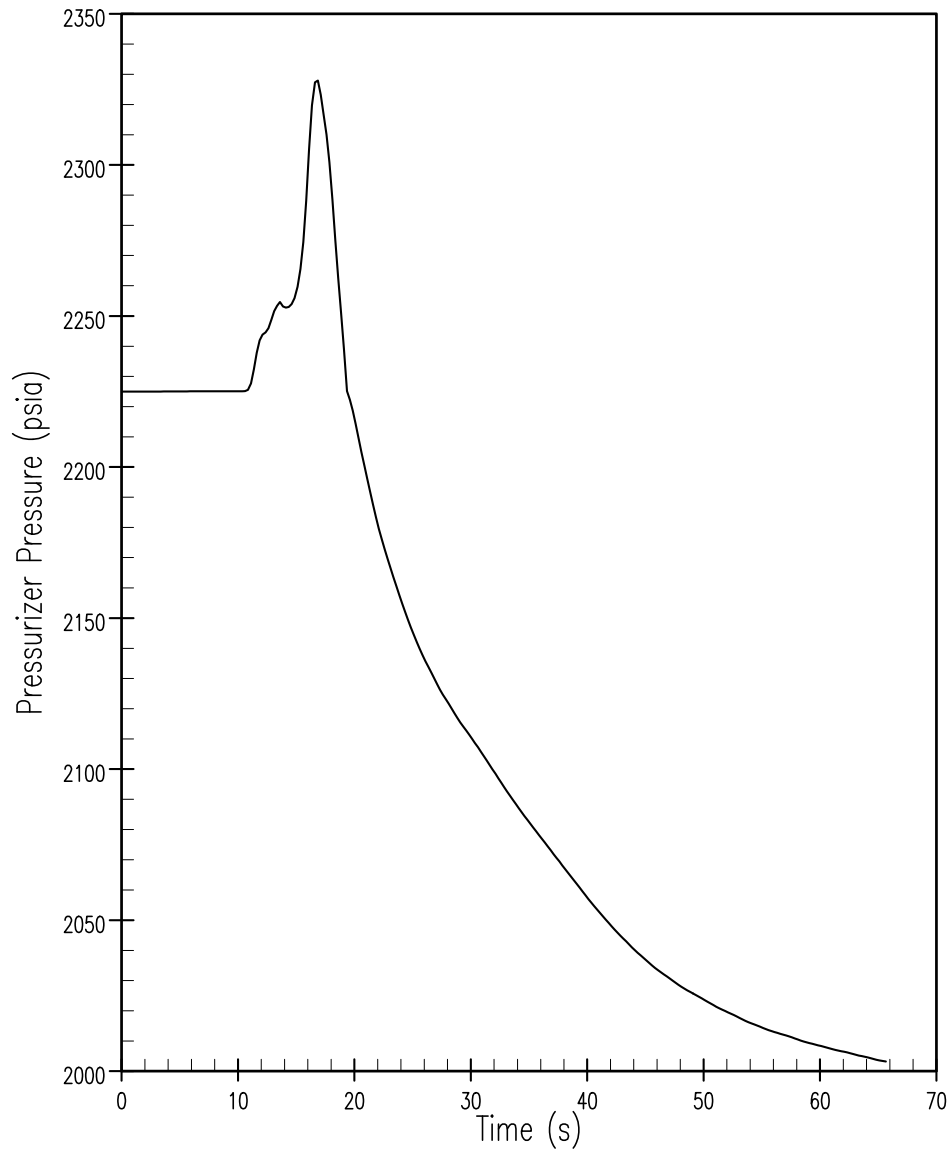


Figure 2.8.5.2.5-3
Asymmetric Steam Generator Transient - 0% Tube Plugging
Pressurizer Water Volume

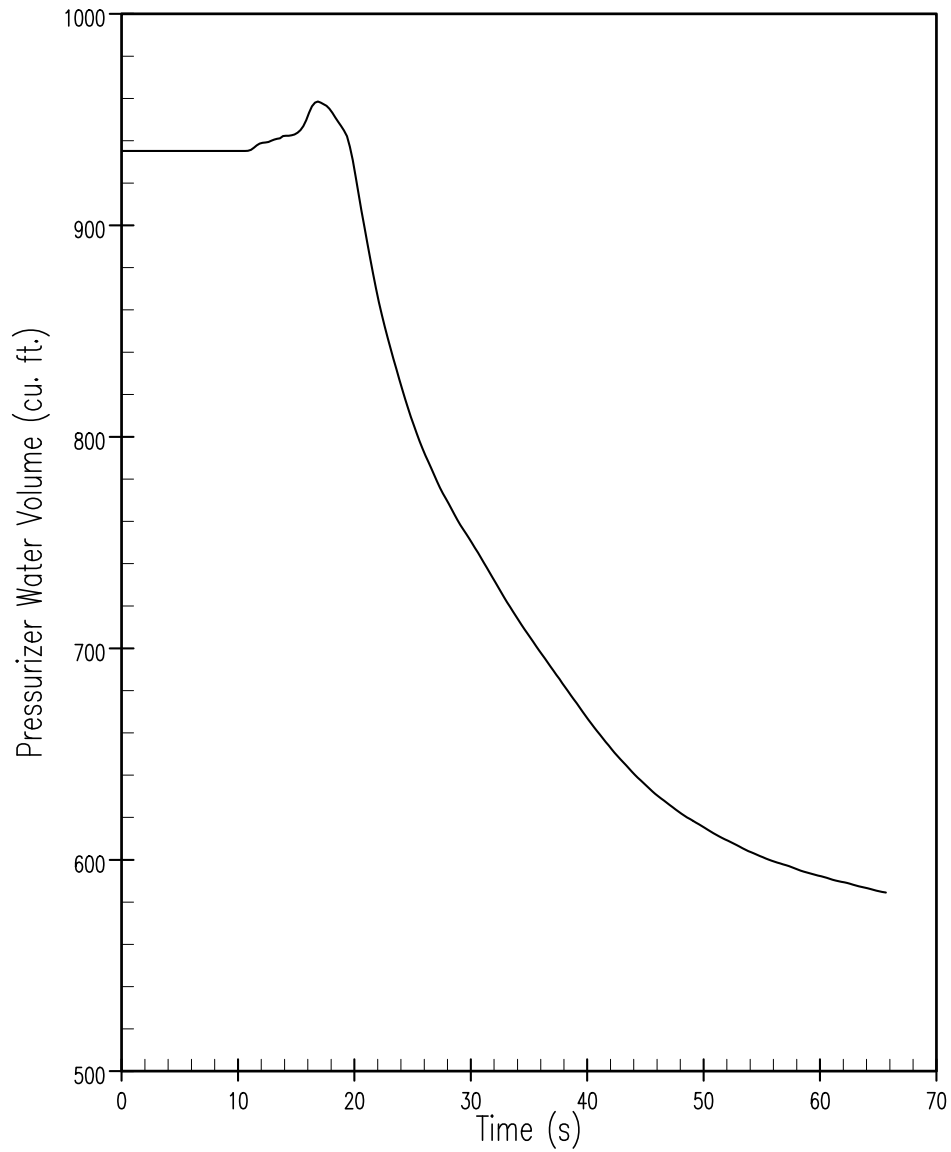


Figure 2.8.5.2.5-4
Asymmetric Steam Generator Transient - 0% Tube Plugging
Vessel Inlet Temperature

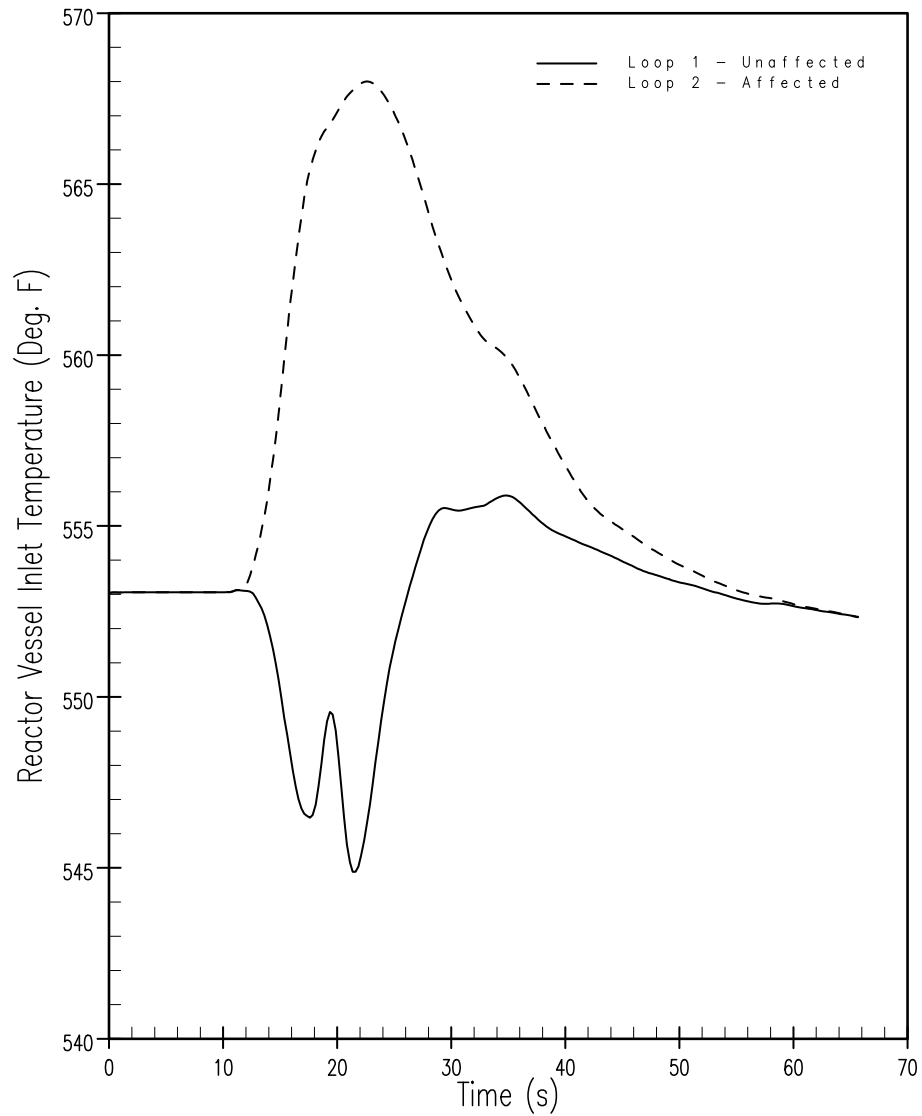


Figure 2.8.5.2.5-5
Asymmetric Steam Generator Transient - 0% Tube Plugging
Vessel Outlet Temperature

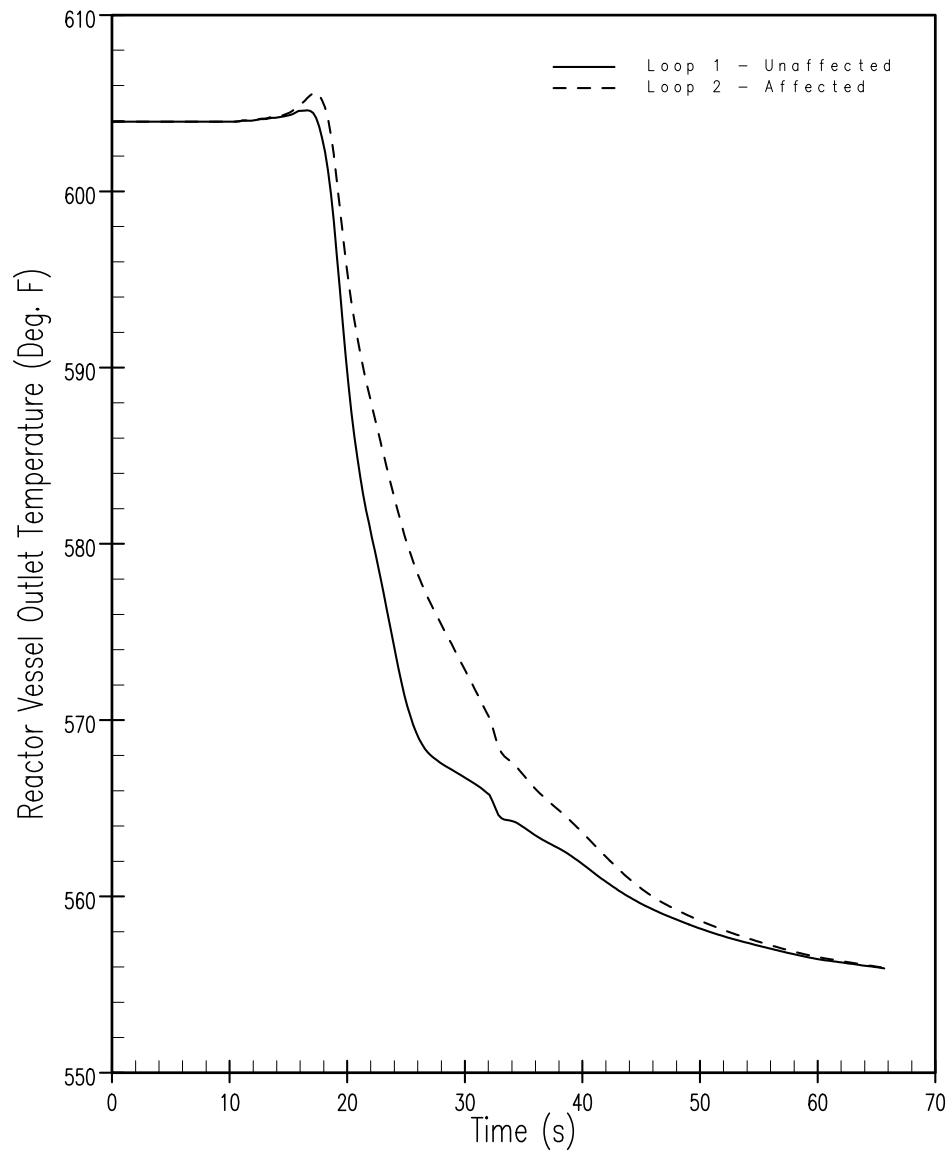


Figure 2.8.5.2.5-6
Asymmetric Steam Generator Transient - 0% Tube Plugging
Steam Generator Pressure

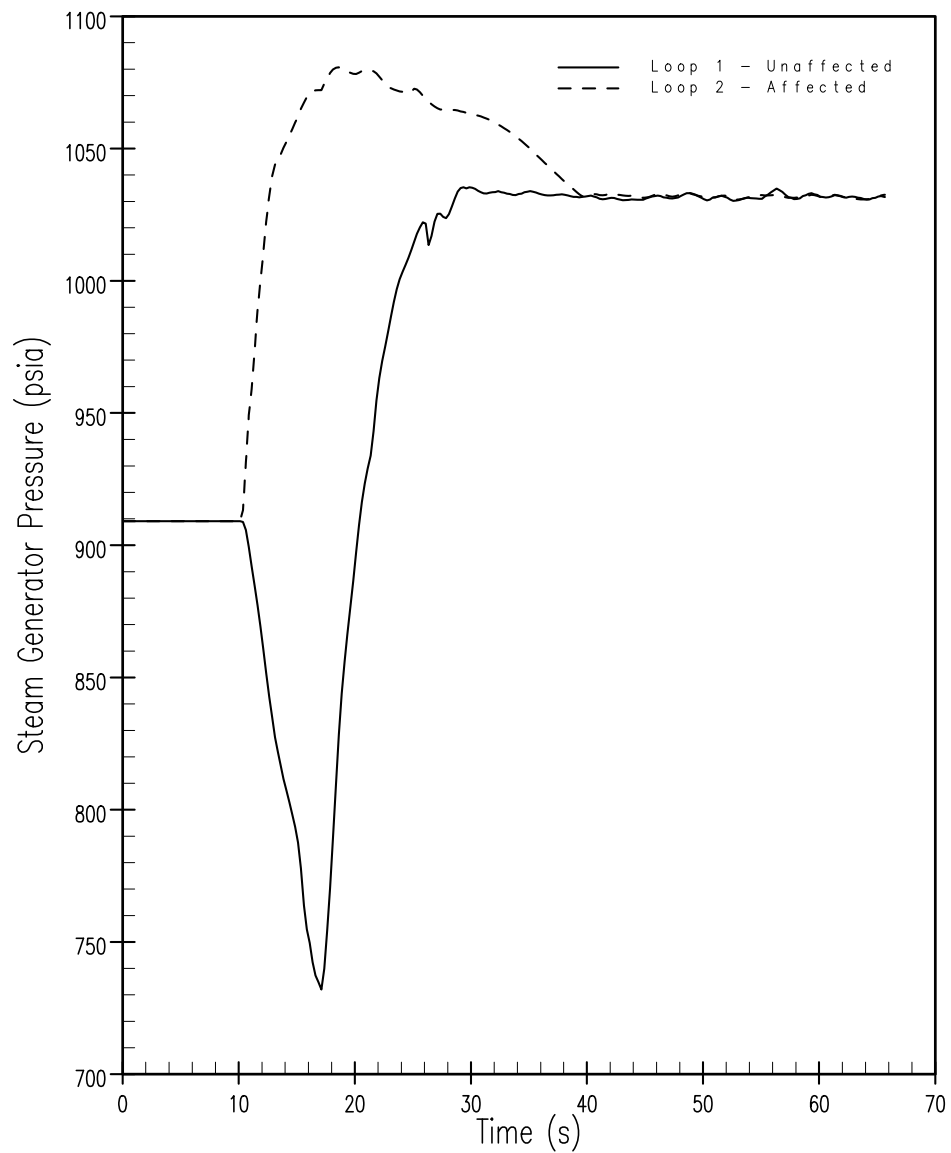


Figure 2.8.5.2.5-7
Asymmetric Steam Generator Transient - 0% Tube Plugging
Steam Flow

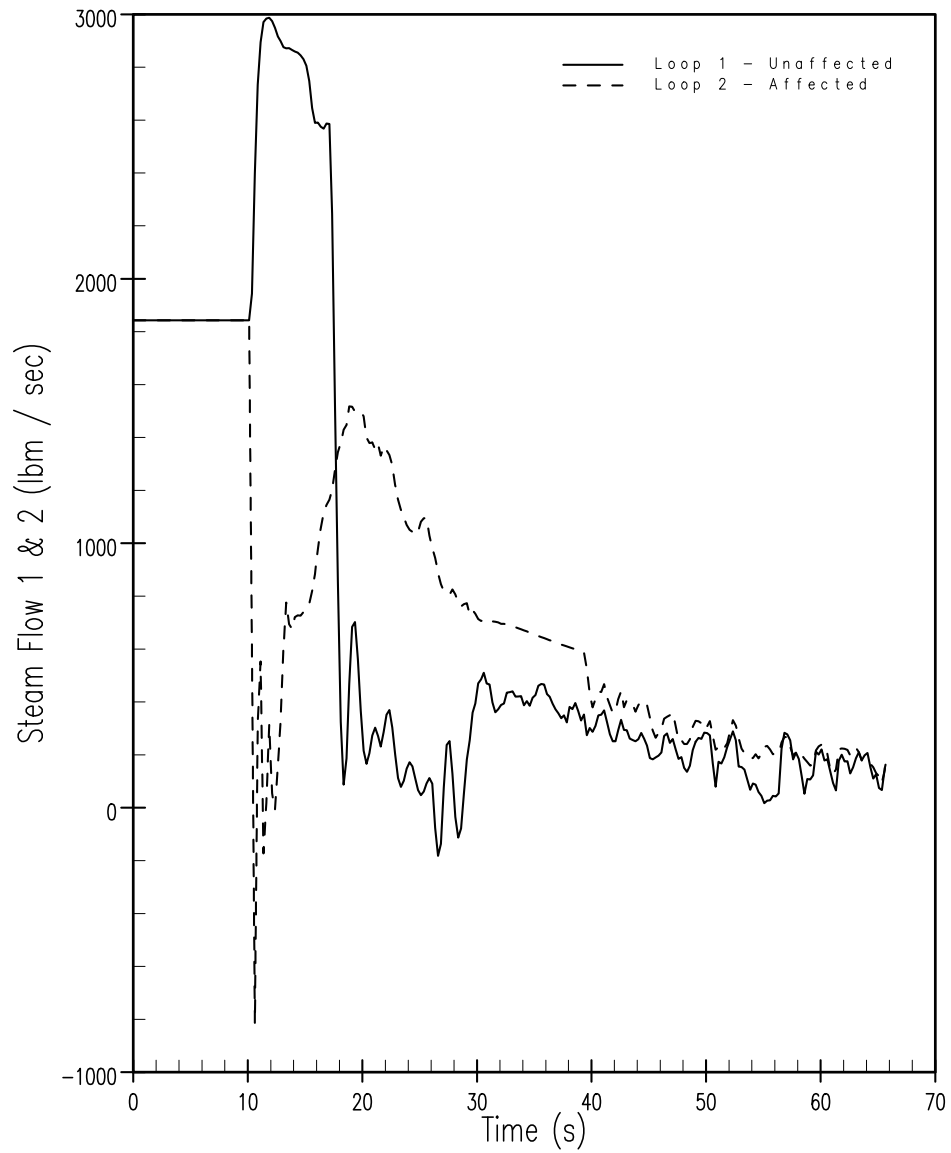


Figure 2.8.5.2.5-8
Asymmetric Steam Generator Transient - 0% Tube Plugging
Feedwater Flow

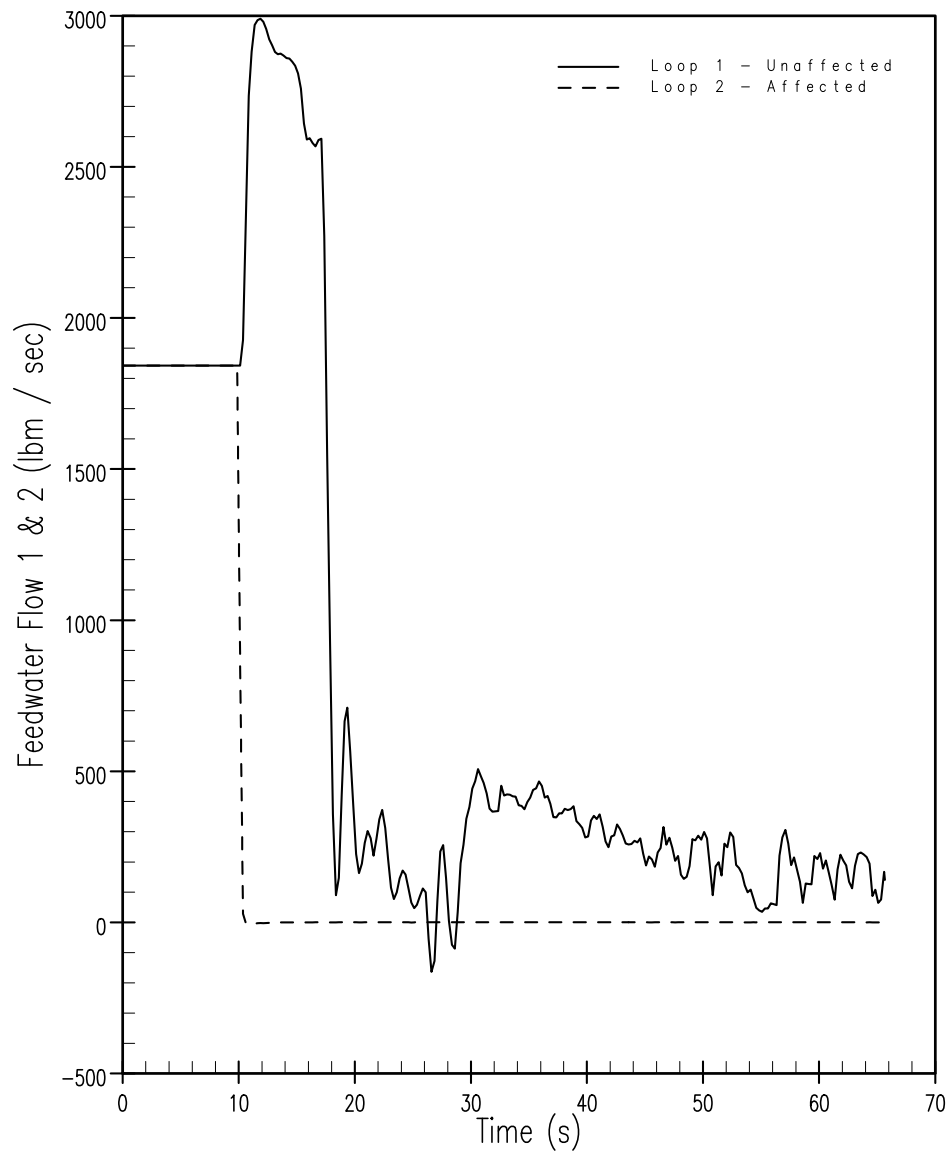


Figure 2.8.5.2.5-9
Asymmetric Steam Generator Transient - 10% Tube Plugging
Nuclear Power

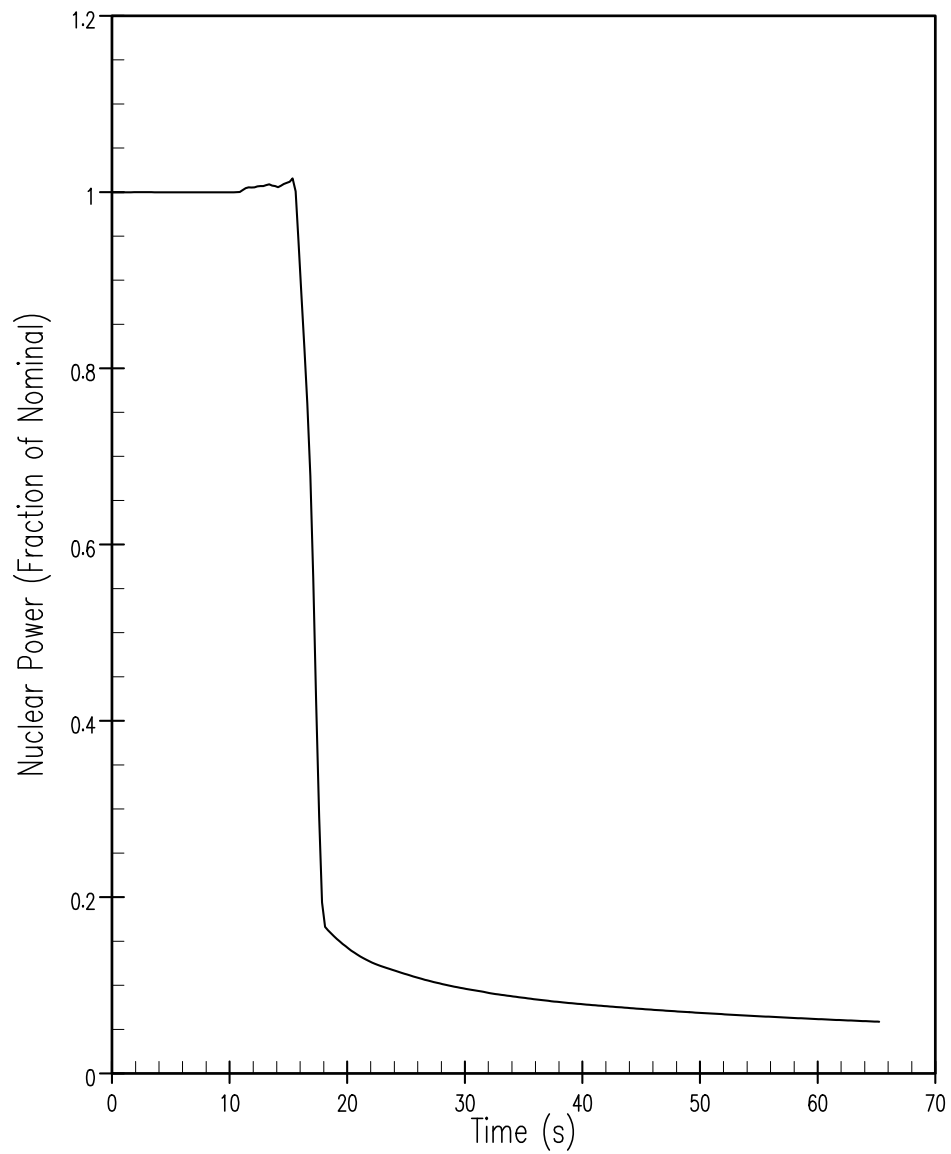


Figure 2.8.5.2.5-10
Asymmetric Steam Generator Transient - 10% Tube Plugging
RCS (Pressurizer) Pressure

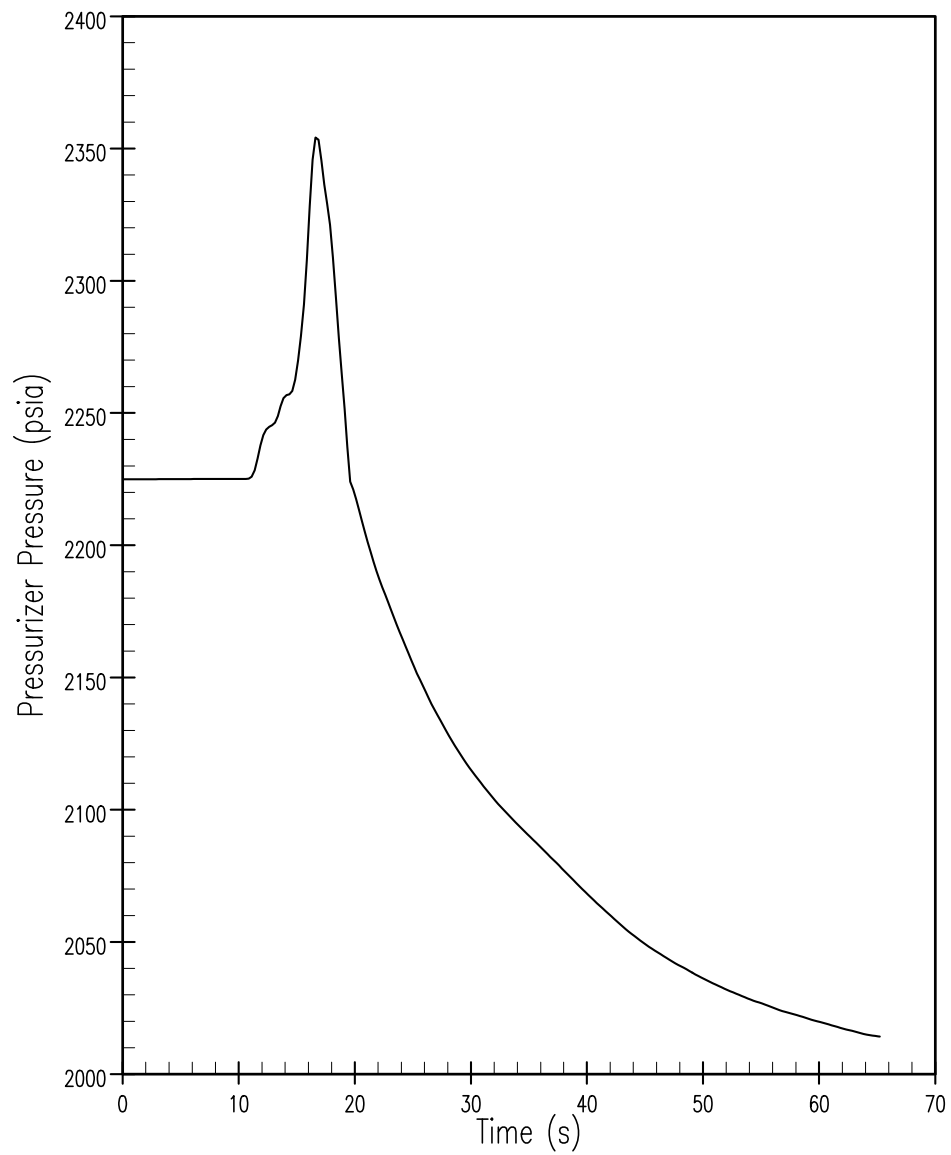


Figure 2.8.5.2.5-11
Asymmetric Steam Generator Transient - 10% Tube Plugging
Pressurizer Water Volume

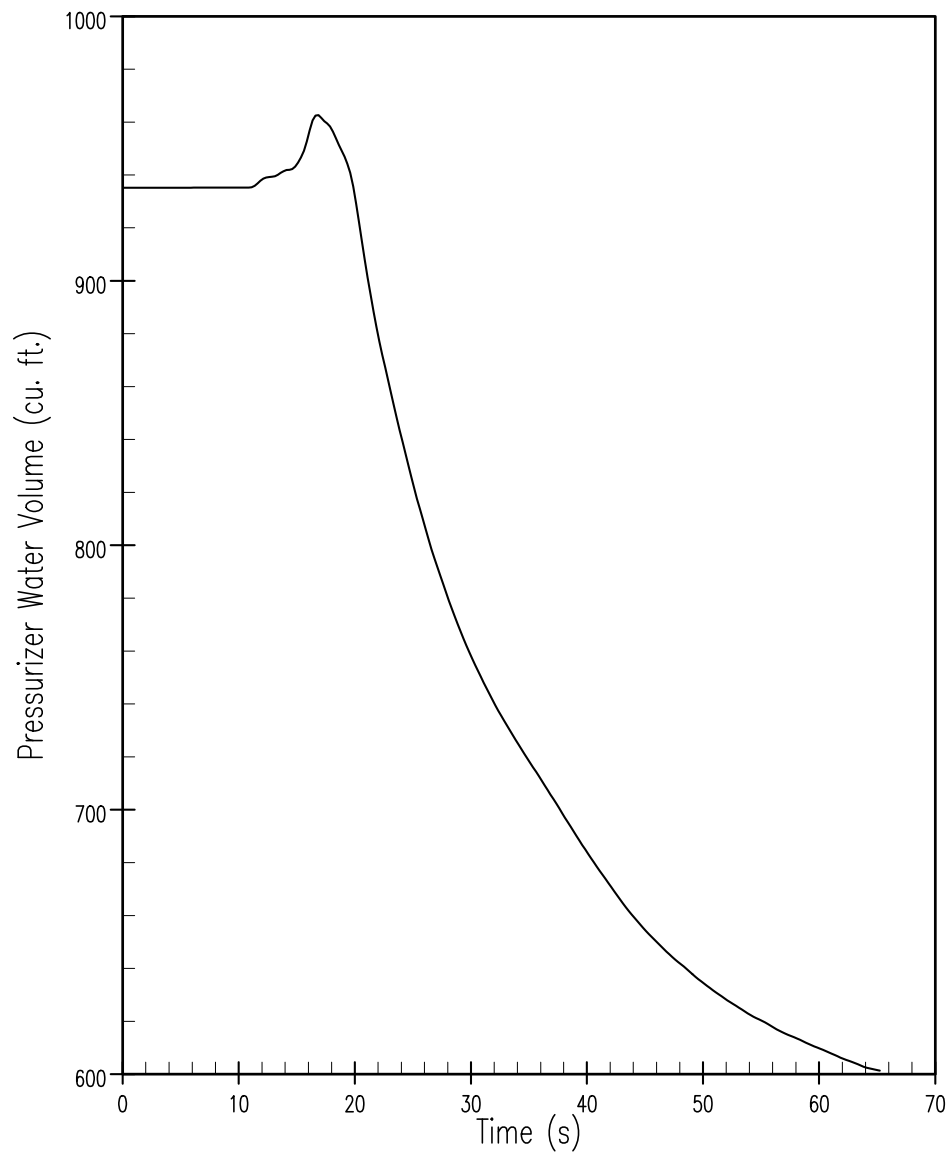


Figure 2.8.5.2.5-12
Asymmetric Steam Generator Transient - 10% Tube Plugging
Vessel Inlet Temperature

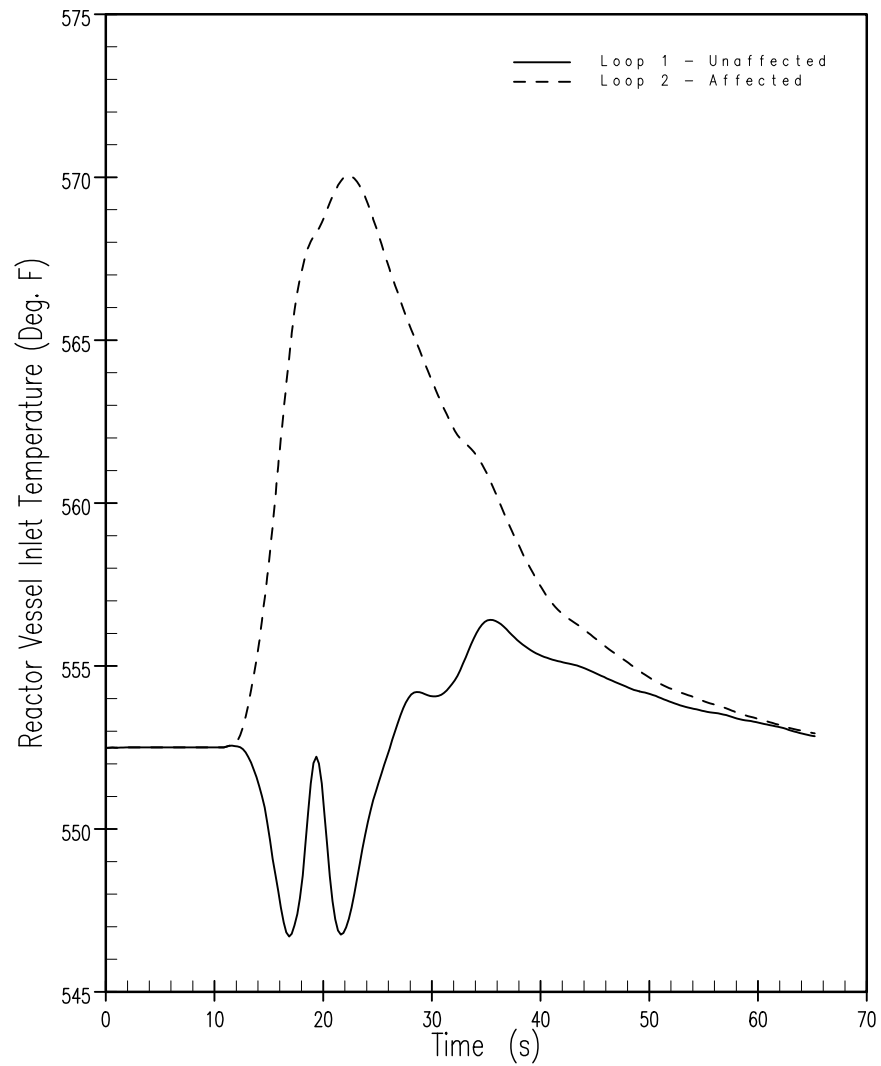


Figure 2.8.5.2.5-13
Asymmetric Steam Generator Transient - 10% Tube Plugging
Vessel Outlet Temperature

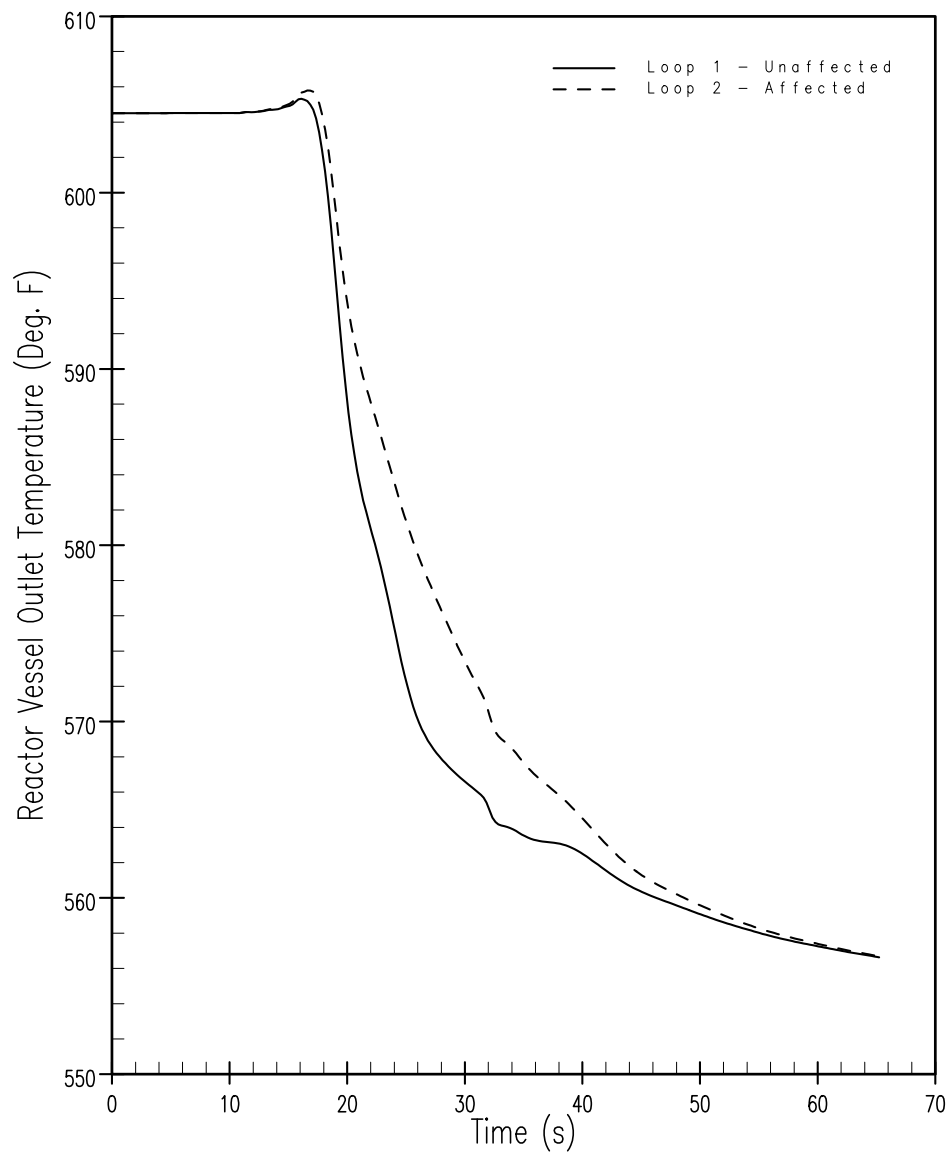


Figure 2.8.5.2.5-14
Asymmetric Steam Generator Transient - 10% Tube Plugging
Steam Generator Pressure

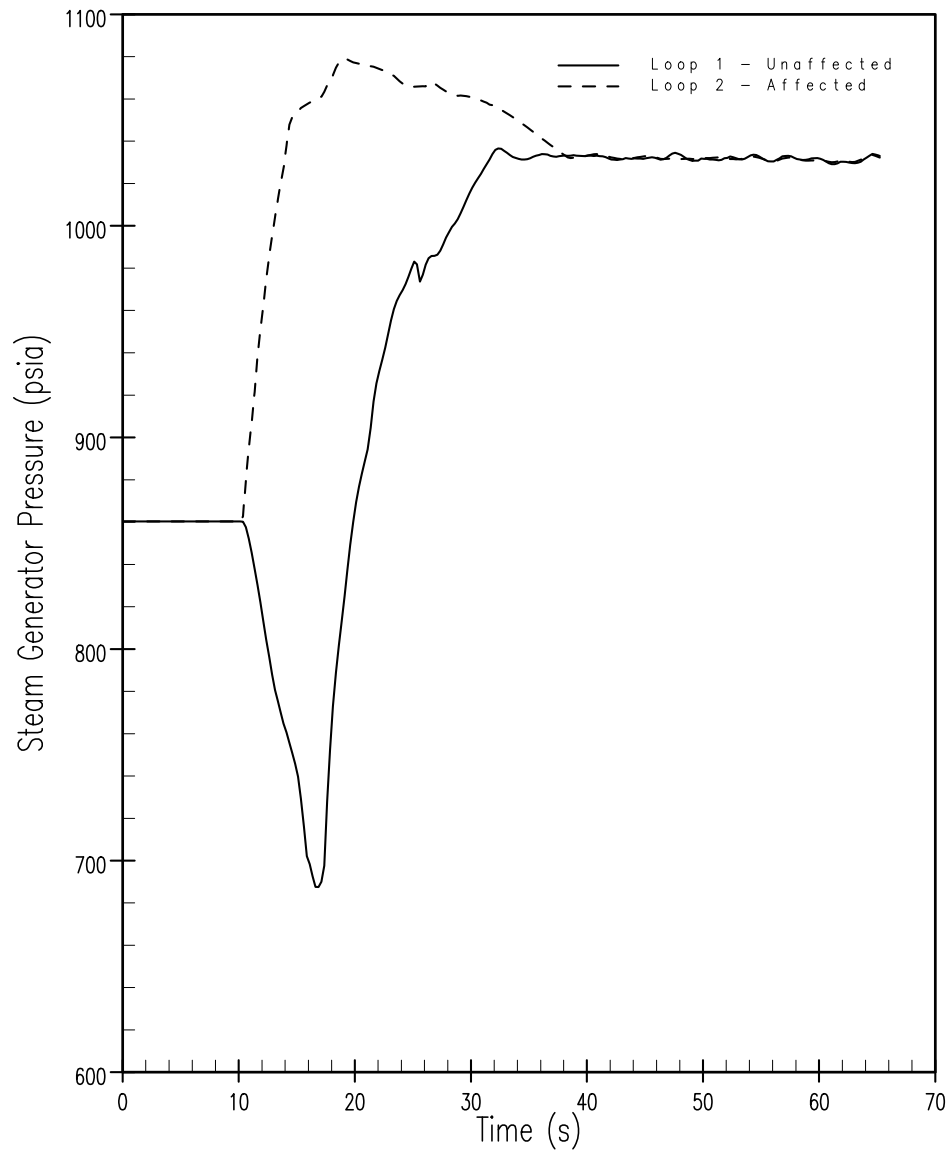


Figure 2.8.5.2.5-15
Asymmetric Steam Generator Transient - 10% Tube Plugging
Steam Flow

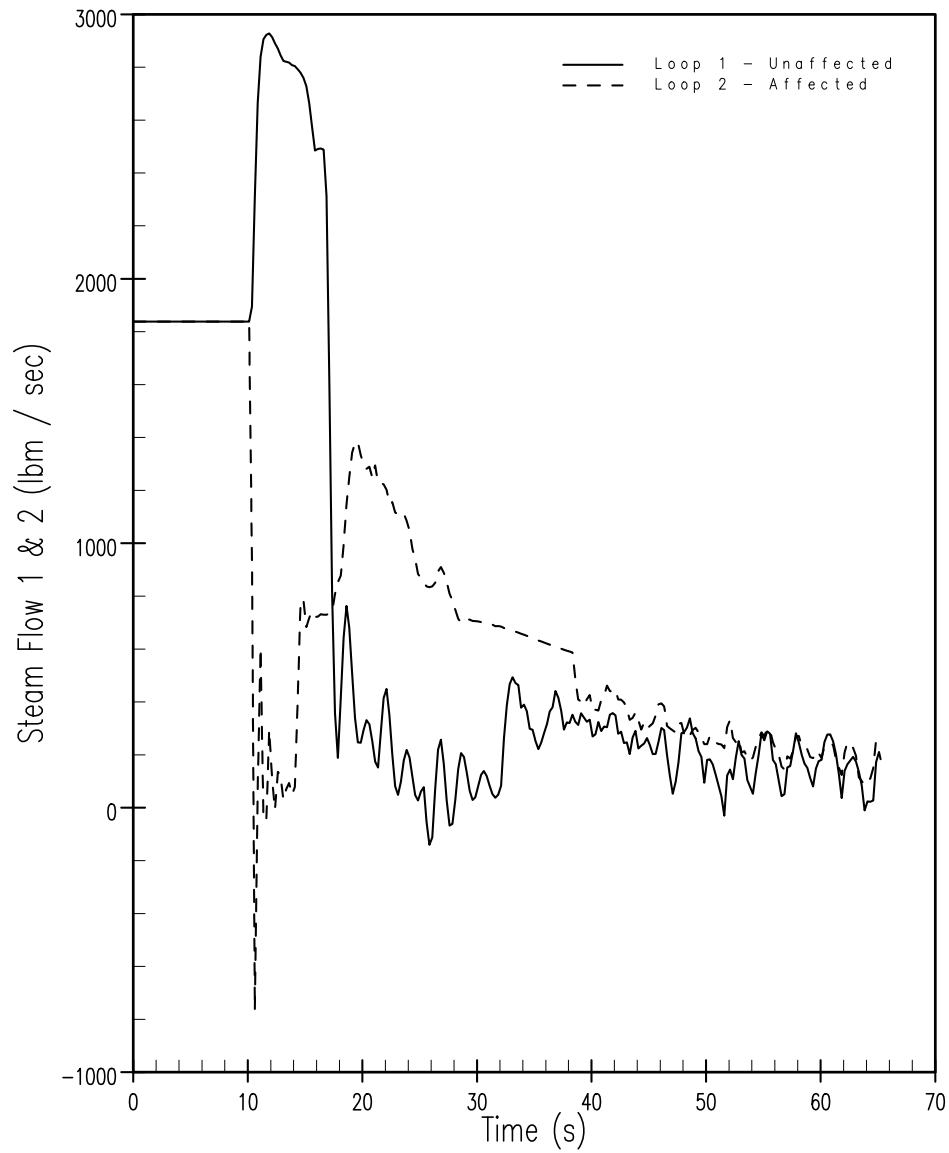
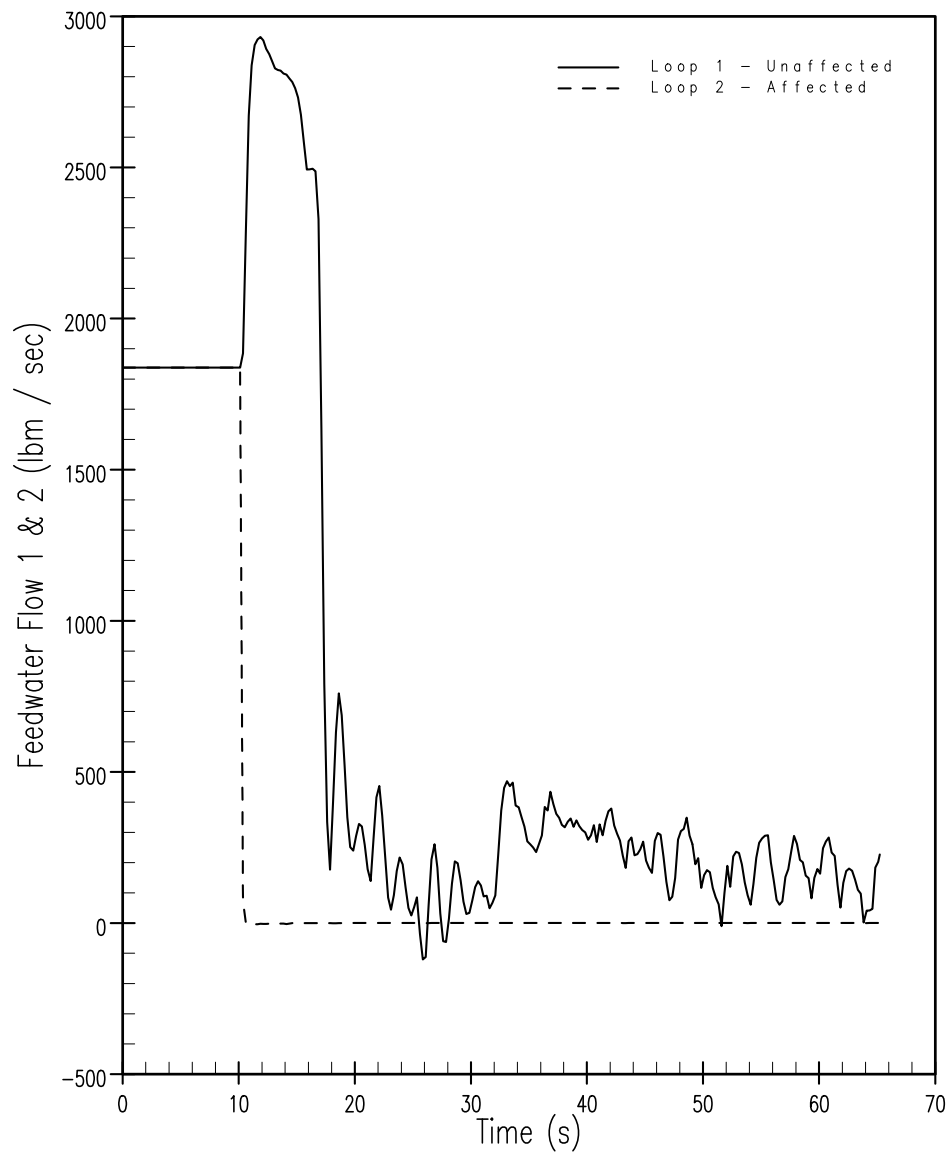


Figure 2.8.5.2.5-16
Asymmetric Steam Generator Transient - 10% Tube Plugging
Feedwater Flow



2.8.5.3 Decrease in Reactor Coolant System Flow

2.8.5.3.1 Loss of Forced Reactor Coolant Flow

2.8.5.3.1.1 Regulatory Evaluation

A decrease in reactor coolant flow occurring while the plant is at power could result in a degradation of core heat transfer. An increase in fuel temperature and accompanying fuel damage could then result if specified acceptable fuel design limits (SAFDLs) are exceeded during the transient. Reactor protection and safety systems are actuated to mitigate the transient.

The Florida Power and Light (FPL) review covered:

- The postulated initial core and reactor conditions,
- The methods of thermal and hydraulic analyses,
- The sequence of events,
- Assumed reactions of reactor systems components,
- The functional and operational characteristics of the reactor protection system,
- Operator actions, and
- The results of the transient analyses.

The NRC's acceptance criteria are based on:

- General Design Criterion (GDC) GDC-10, insofar as it requires that the reactor coolant system (RCS) be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including anticipated operational occurrences (AOOs);
- 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 reactor coolant pressure boundary (RCPB) are not exceeded during any condition of normal operation; and
- 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 Standard Review Plan (SRP) Section 15.3.1-2 and other guidance provided in Matrix 8 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in the Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC GDC for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDCs for the loss of forced reactor coolant flow are as follows:

- GDC-10 is described in UFSAR Section 3.1.10 Criterion 10 – Reactor Design.

The reactor core and associated coolant, control and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

SAFDLs are stated in UFSAR Section 4.3. Minimum margins to SAFDLs are prescribed in the Technical Specifications (Limiting Conditions for Operations) which support UFSAR Chapters 4 and 15.

- GDC-15 is described in UFSAR Section 3.1.15 Criterion 15 – Reactor Coolant System Design.

The reactor coolant system and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.

The operating conditions for normal steady state and transient plant operations are established conservatively. Normal operating limits are selected so that an adequate margin exists between operating and design limits. The plant control systems are designed to ensure that plant variables are maintained well within the established operating limits. The plant transient response characteristics and pressure and temperature distributions during normal operations are considered in the design as well as the accuracy and response of the instruments and controls. These design techniques ensure that a satisfactory margin is maintained between the plant's normal operating conditions, including design transients, and the design limits for the RCPB.

The plant control systems function to minimize deviations from normal operating limits in the event of most anticipated operational occurrences. Where control systems response would be inadequate or fail upon demand, the reactor protective system (RPS) and the engineered safety features actuation system (ESFAS) function to mitigate the consequences of such events.

The RPS and ESFAS function to mitigate the consequences of accidents such that the design limits for the RCPB are not exceeded.

- GDC-26 is described in UFSAR Section 3.1.26 Criterion 26 – Reactivity Control System Redundancy and Capability.

Two independent reactivity control systems of different design principles shall be provided. One of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margin for malfunctions such as stuck rods, specified acceptable fuel design limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure acceptable fuel design limits are not exceeded. One of the systems shall be capable of holding the reactor core subcritical under cold conditions.

Two independent reactivity control systems of different design principles are provided. The first system, using control element assemblies (CEAs) includes a positive means (gravity) for inserting CEAs and is capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including specified AOOs, SAFDLs are not exceeded. The CEAs can also be mechanically driven into the core. The appropriate margin for stuck rods is provided by assuming in the analyses of AOOs that the highest worth CEA does not fall into the core.

The second system, the chemical and volume control system (CVCS), using neutron absorbing soluble boron, is capable of reliably compensating for the rate of reactivity changes resulting from planned normal power changes (including xenon burnout) such that acceptable fuel design limits are not exceeded. This system is capable of holding the reactor subcritical under cold conditions. For a further description, see UFSAR Section 9.3.4.

Either system is capable of making the core subcritical from a hot operating condition. For further discussion, see UFSAR Sections 7.4 and 7.7.

The partial loss of forced reactor coolant system flow event is discussed in UFSAR Section 15.3.1. The core and system performance following a partial loss of forced reactor coolant flow would be no more adverse than those following a complete loss of forced reactor coolant flow which is discussed in UFSAR Section 15.3.2.

NUREG-1779 Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Power Plant Units 1 and 2 dated September 2003 defines the scope of License Renewal. Specific design transient analyses are not within the scope of License Renewal.

2.8.5.3.1.2 Technical Evaluation

2.8.5.3.1.2.1 Introduction

A loss of forced reactor coolant can result from a mechanical or electrical failure in one or more reactor coolant pumps (RCPs) or from a simultaneous loss of electrical supply to the RCPs. For a complete loss of forced flow, if the reactor is at power at the time of the accident, the immediate effect of loss of coolant flow is a rapid increase in the coolant temperature. This increase could result in departure from nucleate boiling (DNB) with subsequent fuel damage if the reactor is not promptly tripped.

Normal power for the RCPs is supplied through buses from a transformer connected to the generator and the offsite power system. Two diametrically opposed pumps are on a separate bus. When a generator trip occurs, the buses continue to be supplied from external power lines and the pumps continue to supply coolant flow to the core.

The reactor trip on low primary coolant flow is provided to protect against loss-of-flow conditions that affect one or more reactor coolant loops.

2.8.5.3.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

This event was analyzed using the revised thermal design procedure (RTDP) ([Reference 1](#)). Initial core power was assumed to be at its nominal EPU value consistent with steady-state, full-power operation. RCS pressure and RCS vessel average temperature were assumed to be

at their nominal values. Uncertainties in the initial conditions were included in the departure from nucleate boiling ratio (DNBR) limit value as described in the RTDP. See LR [Section 2.8.5.0](#), Accident and Transient Analyses, for additional inputs and assumptions.

A conservatively large absolute value of the Doppler-only power coefficient was used. The analysis also assumed a conservative moderator temperature coefficient (MTC) of 0 pcm/°F at hot full power (HFP) conditions. This resulted in the maximum core power and hot spot heat flux during the transient when the minimum DNBR is reached.

Engineered safety systems (e.g., safety injection) were not required to function. No single active failure in any system or component required for mitigation will adversely affect the consequences of this event.

The complete loss of forced reactor coolant flow event is analyzed to the AOO acceptance criteria. The immediate effect from a complete loss of forced reactor coolant flow is a rapid increase in the reactor coolant temperature and subsequent increase in RCS pressure. The specific acceptance criteria for the event are:

- Pressure in the RCS and main steam system should be maintained below 110 percent of the design values,
- Fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains above the limit value, and
- The event should not generate a more serious plant condition without other faults occurring independently.

With respect to the overpressure evaluation, the loss of flow events are bounded by the loss of condenser vacuum (LOCV) event (see LR [Section 2.8.5.2.1](#)). For the loss of flow events, turbine trip occurs simultaneously with reactor trip, whereas for the LOCV event, the initiating event is a complete loss of normal feedwater, and a loss of turbine load. Therefore, the primary to secondary power mismatch and resultant RCS and main stem system heat-up and pressurization transients are always more severe for the LOCV event. Therefore, the maximum RCS primary and secondary system pressures for this event are bounded by that of the LOCV event presented in LR [Section 2.8.5.2.1](#).

2.8.5.3.1.2.3 Description of Analyses and Evaluations

The complete loss of flow transient was analyzed with two computer codes to demonstrate that the reactor protection system functions and mitigates the consequences at the EPU conditions utilizing the currently approved methodology. First, the RETRAN computer code ([Reference 2](#)) was used to calculate the RCS loop and core flow during the transient, the time of reactor trip based on the calculated RCS flows, the nuclear power transient, and the primary-system pressure and temperature transients. The VIPRE computer code ([Reference 3](#)) was then used to calculate the heat flux and DNBR transients based on the nuclear power and RCS temperature (enthalpy), pressure, and core flow from RETRAN.

Note that two partial loss of flow cases were also considered. These cases consisted of a loss of power to a single RCP and another with a loss of power to two RCPs. However, since the most limiting point in the transient is the point where the power to flow ratio is the largest, the complete

loss of flow event always has a larger power to flow ratio than the partial loss of flow event, due to the lower flow. As a result, the complete loss of reactor coolant flow will be more limiting and bound the partial loss of reactor coolant flow cases. Note that the 3-out-of-4 RCP trip event was not analyzed since there is no credible failure that would result in this transient. During normal operation, power is provided to the RCPs through two electrical buses such that each bus supplies two diametrically opposed RCPs. Any failure which would result in loss of power to three pumps also would result in loss of power to the fourth pump.

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

As discussed above, the design transient analyses were determined to be outside the scope of License Renewal; therefore, with respect to the design basis accidents and transients, the EPU does not impact any License Renewal evaluations.

2.8.5.3.1.2.5 Results

The complete loss of flow case was assumed to trip on a low reactor coolant flow reactor trip. The VIPRE (Reference 3) analysis for this scenario confirmed that the minimum DNBR acceptance criterion was met. Fuel clad damage criteria were not challenged in the complete loss of forced reactor coolant flow case since the DNBR criterion was met.

Transient results for this case are presented in LR Figures 2.8.5.3.1-1 through 2.8.5.3.1-8. A sequence of events table is also provided in LR Table 2.8.5.3.1-1. Numerical results of the EPU analysis along with a comparison to the current analysis results are shown in LR Table 2.8.5.3.1-2, which shows the current analysis to be more limiting than the EPU analysis with respect to the DNBR acceptance criteria. This is because of the benefits gained from the increased RCS flow, and the reduction in peaking factor being implemented for the EPU as proposed in this EPU submittal.

The analysis performed for the EPU demonstrates that, for the aforementioned complete loss of flow cases, the DNBR did not decrease below the safety analysis limit value at any time during the transients; thus, no fuel or clad damage is predicted. The peak primary and secondary system pressures remained below their respective limits at all times and are bounded by the LOCV event.

2.8.5.3.1.3 Conclusion

FPL has reviewed the analyses of the decrease in reactor coolant flow event and concludes that the analyses adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. FPL further concludes that the analyses have 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 this event. Based on this, FPL concludes that the plant will continue to meet its licensing basis with respect to the requirements of GDCs -10, -15 and -26 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to the decrease in reactor coolant flow event.

2.8.5.3.1.4 References

1. WCAP-11397-P-A (Proprietary) and WCAP-11397-A (Non-Proprietary), Revised Thermal Design Procedure, Friedland, A. J. and Ray, S., April 1989.
2. WCAP-14882-P-A (Proprietary) and WCAP-15234-A (Non-Proprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, D. S. Huegel, et al., April 1999.
3. WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Non-Proprietary), VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, Sung, Y. X. et al., October 1999.

Table 2.8.5.3.1-1
Sequence of Events – Complete Loss of Reactor Coolant Flow

Complete Loss of Flow Event	Time (sec)⁽¹⁾
All Operating RCPs Lose Power and Coastdown Begins	10.01
Low Flow Reactor Trip Setpoint is Reached	10.92
Reactor Trip Signal occurs	11.82
Rods Begin to Drop	12.56
Minimum DNBR Occurs	14.00
1. 10 seconds of steady state execution is performed before the start of the transient. Subtracting 10 seconds from the above times will yield the transient timing.	

Table 2.8.5.3.1-2
Complete Loss of Reactor Coolant Flow
Comparison to Current Results

	EPU Analysis	Current Analysis	Limit
Minimum DNBR	1.445	1.41	1.42 ⁽¹⁾
Time of Minimum DNBR ⁽²⁾	4.00 seconds	3.75 seconds	-
Peak Primary Pressure	2399.0	2376.9	2750.0 psia
Peak Secondary Pressure	1039.5 psia	973.0	1100.0 psia
1. Generic margin retained in the calculation of the safety analysis DNB limit was allocated to offset the difference between the calculated DNBR value and the actual limit. 2. The times presented refer to the time from the beginning of the transient.			

Figure 2.8.5.3.1-1
Loss of Forced Reactor Coolant Flow
Total Core Inlet Flow vs. Time

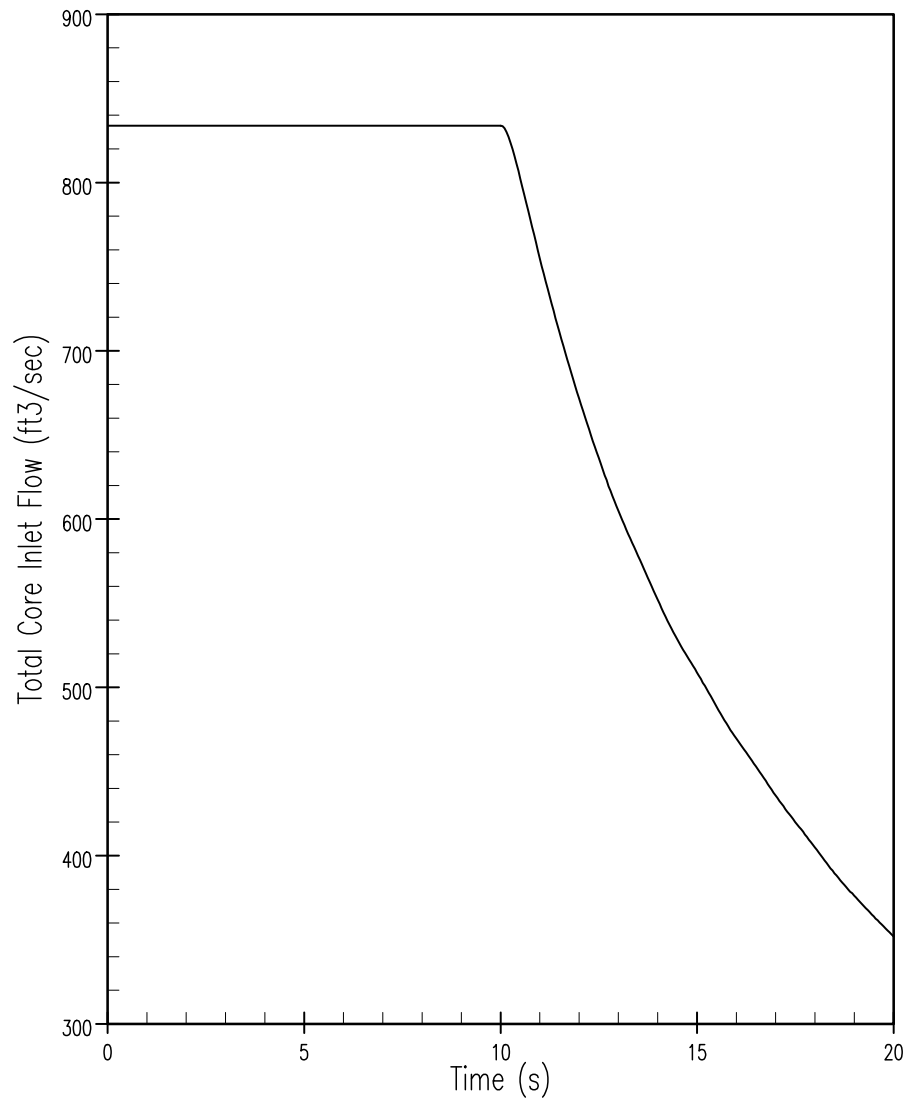


Figure 2.8.5.3.1-2
Loss of Forced Reactor Coolant Flow
RCS Loop Flow Fraction of Nominal (FON) vs. Time

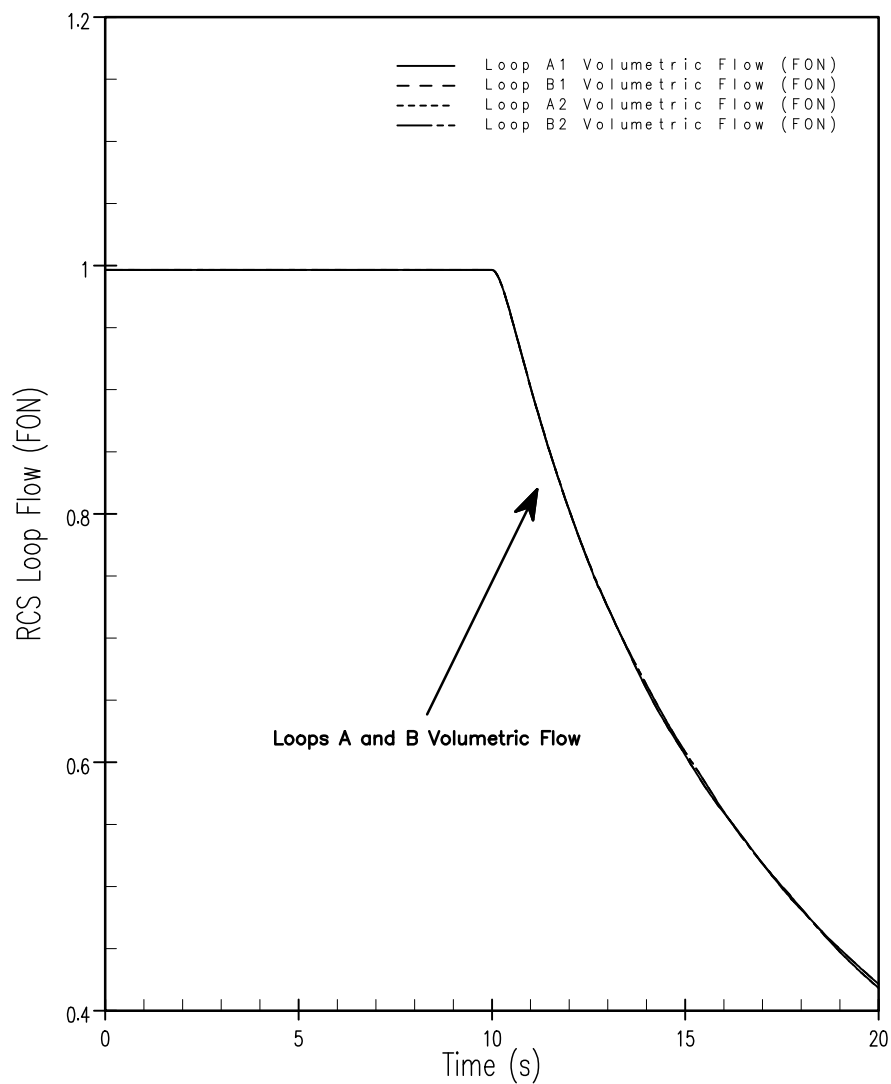


Figure 2.8.5.3.1-3
Loss of Forced Reactor Coolant Flow
Nuclear Power vs. Time

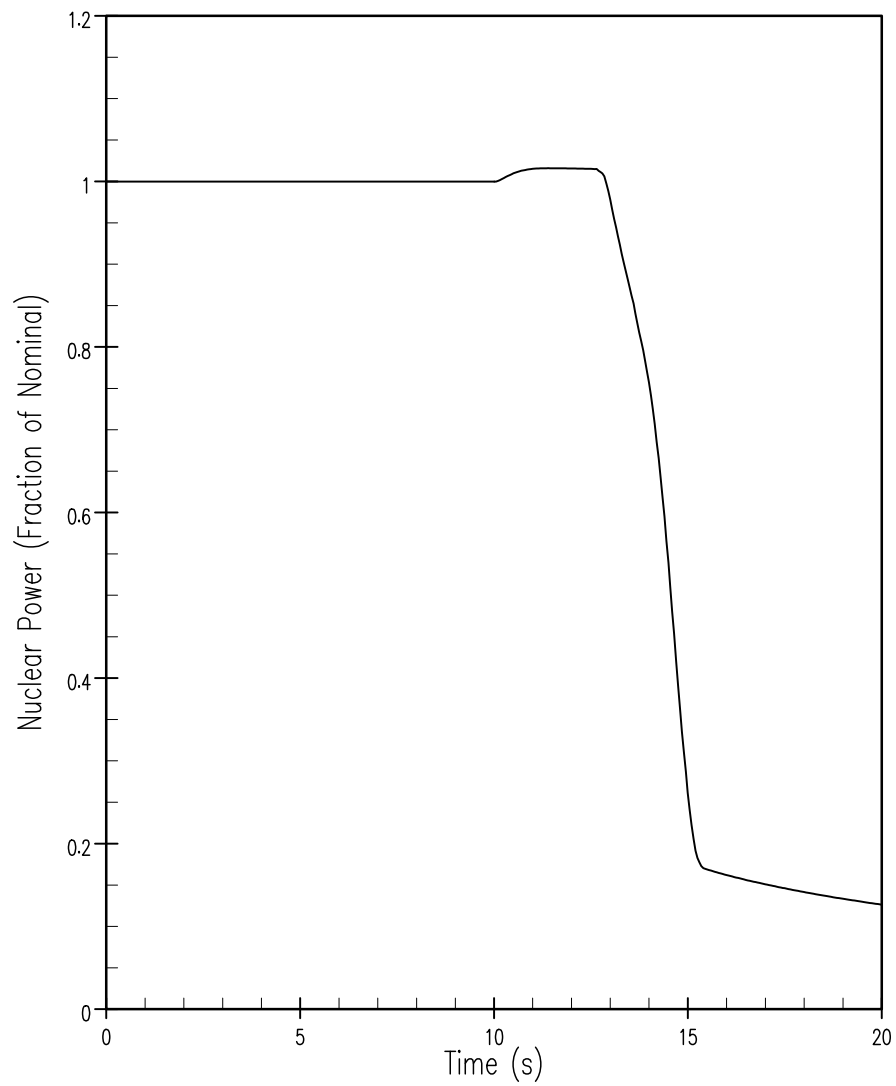


Figure 2.8.5.3.1-4
Loss of Forced Reactor Coolant Flow
Core Average Heat Flux vs. Time

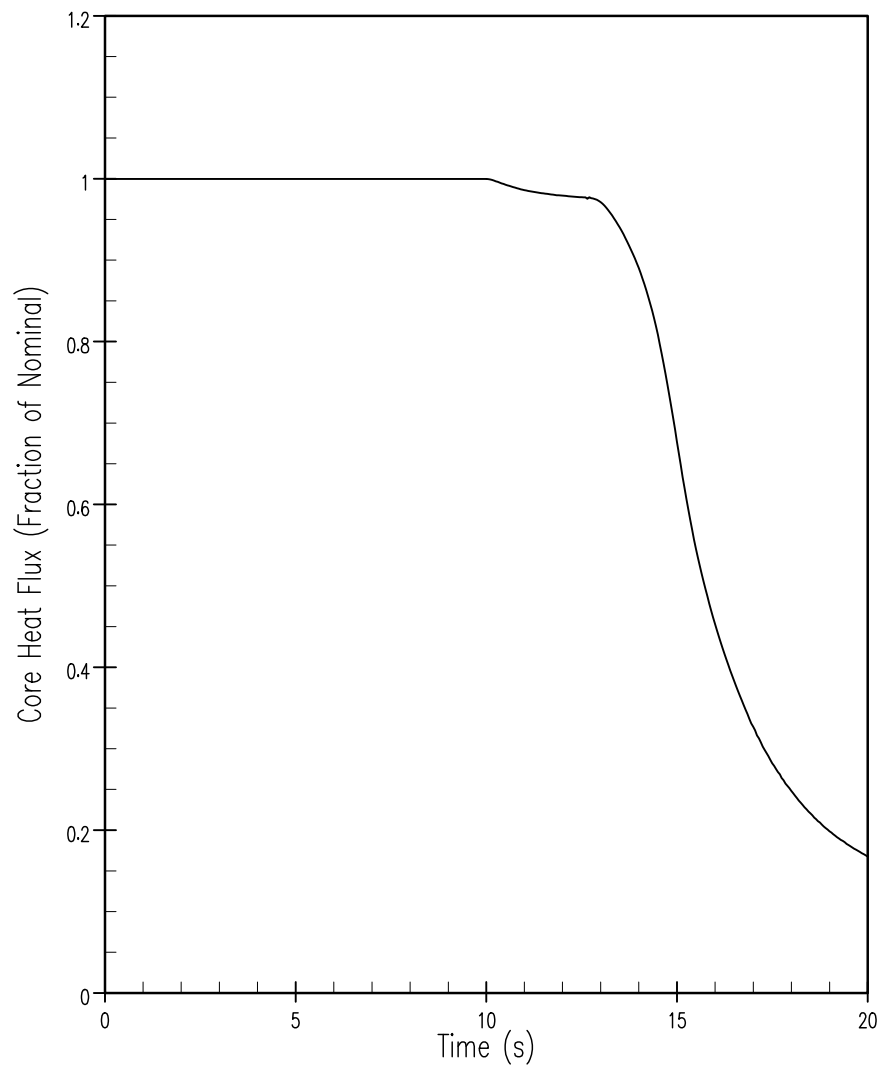


Figure 2.8.5.3.1-5
Loss of Forced Reactor Coolant Flow
Pressurizer Pressure vs. Time

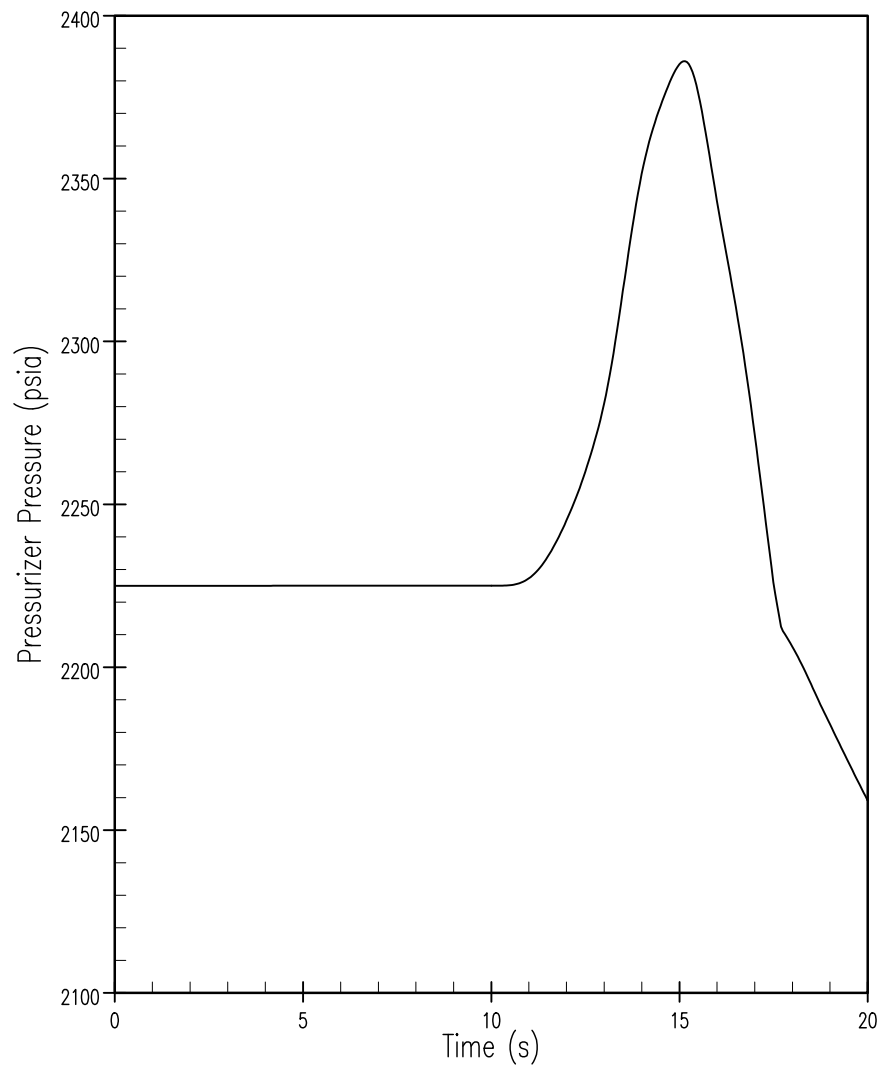


Figure 2.8.5.3.1-6
Loss of Forced Reactor Coolant Flow
RCS Loop Temperature vs. Time

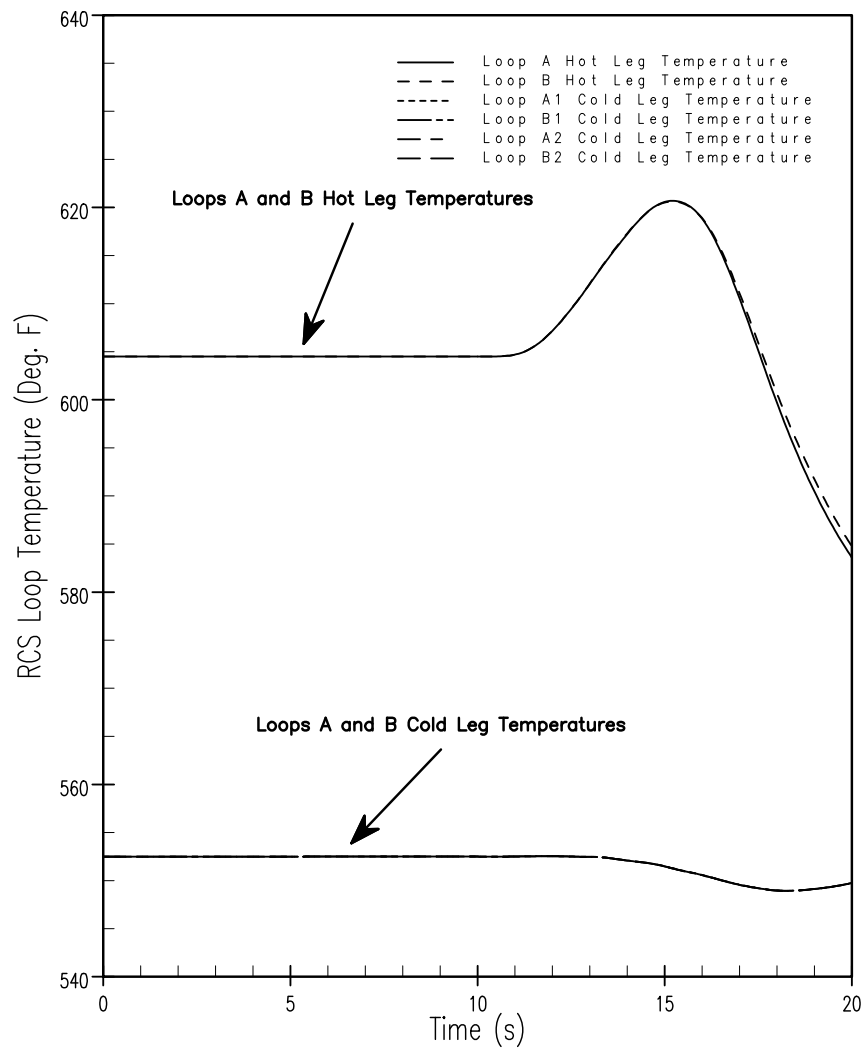


Figure 2.8.5.3.1-7
Loss of Forced Reactor Coolant Flow
Hot Channel Heat Flux Fraction of Initial (FOI) vs. Time

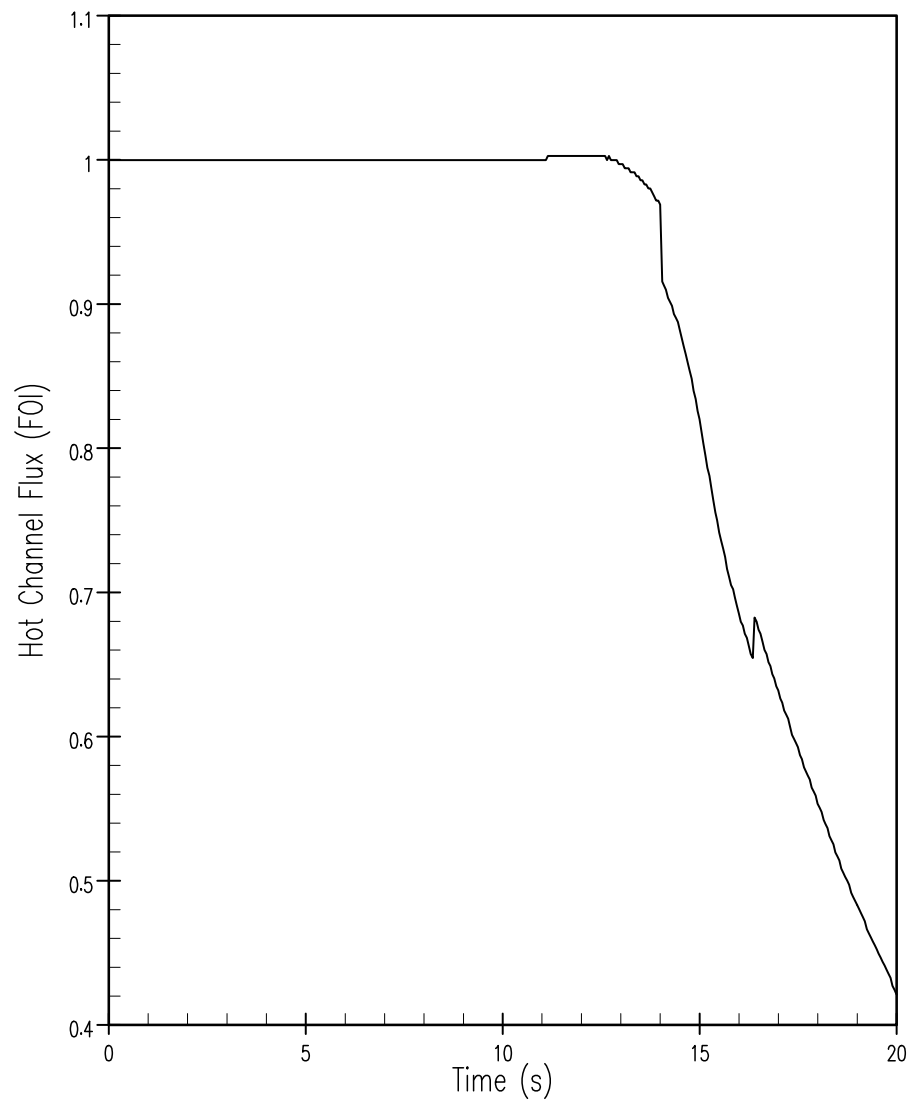
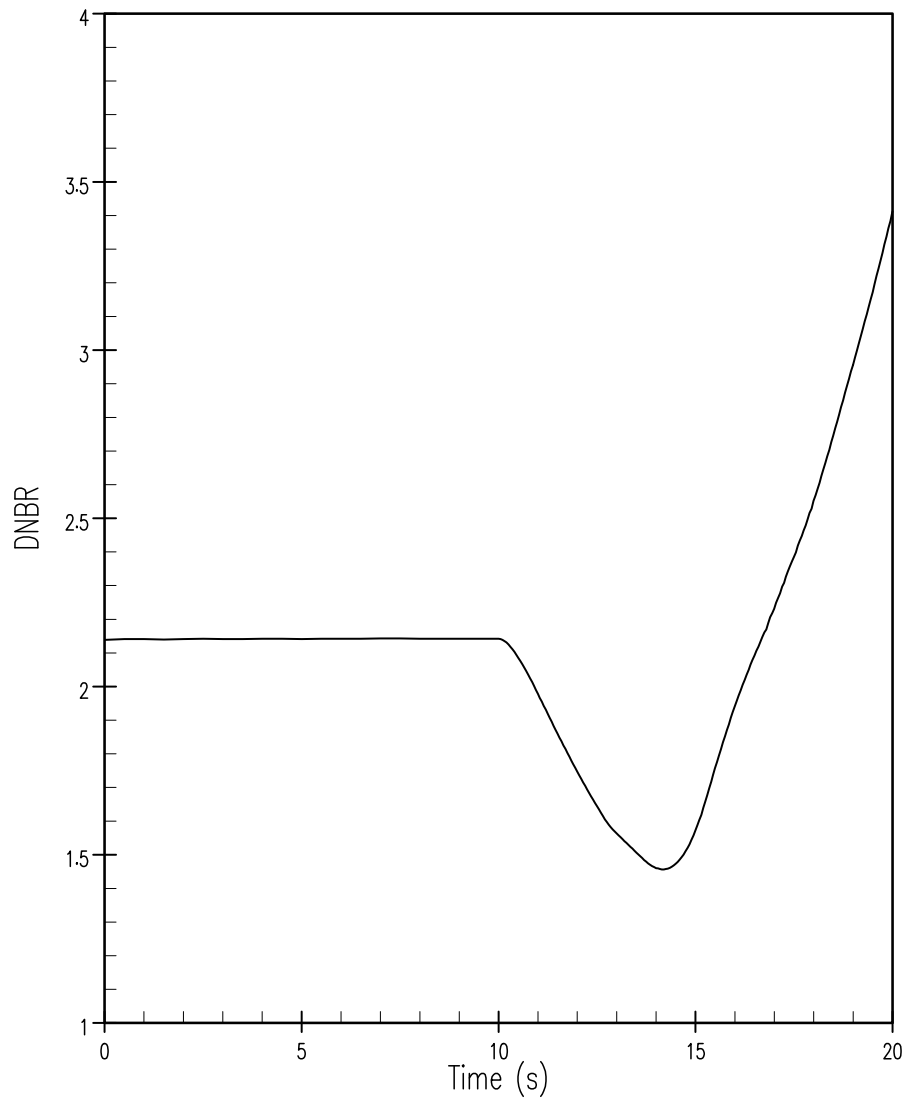


Figure 2.8.5.3.1-8
Loss of Forced Reactor Coolant Flow
DNBR vs. Time



2.8.5.3.2 Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break

2.8.5.3.2.1 Regulatory Evaluation

The events postulated are an instantaneous seizure of the rotor or break of the shaft of a reactor coolant pump (RCP). Flow through the affected loop is rapidly reduced, leading to a reactor and turbine trip. The sudden decrease in core coolant flow while the reactor is at power results in a degradation of core heat transfer, which could result in fuel damage. The initial rate of reduction of coolant flow is greater for the rotor seizure event. However, the shaft break event permits a greater reverse flow through the affected loop later during the transient and, therefore, results in a lower core flow rate at that time. In either case, reactor protection and safety systems are actuated to mitigate the transient.

The Florida Power and Light (FPL) review covered:

- the postulated initial and long-term core and reactor conditions,
- the methods of thermal and hydraulic analyses,
- the sequence of events,
- the assumed reactions of reactor system components,
- the functional and operational characteristics of the reactor protection system,
- operator actions, and
- the results of the transient analyses.

The NRC's acceptance criteria are based on:

- General Design Criterion (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 emergency core cooling systems (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 reactor coolant pressure boundary (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
- 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.

Specific review criteria are contained in Standard Review Plan (SRP) Section 15.3.3-4 and other guidance provided in Matrix 8 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Evaluation Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria as discussed in UFSAR Section 3.1.

The specific GDCs for the reactor coolant pump rotor seizure and reactor coolant pump shaft break (sheared shaft) are as follows:

- GDC-27 is described in UFSAR Section 3.1.27, Criterion 27 - Combined Reactivity Control Systems Capability.

The reactivity control systems shall be designed to have a combined capability, in conjunction with poison addition by the emergency core cooling system, of reliably controlling reactivity changes to assure that under postulated accident conditions and with appropriate margin for stuck rods the capability to cool the core is maintained.

The reactivity control systems that provide the means for making and holding the core sub-critical under postulated accident conditions are discussed in UFSAR Sections 9.3 and 4.3. Combined use of control element assemblies (CEAs) and chemical shim control by the chemical and volume control system (CVCS) provides the shutdown margin required for plant cooldown and long-term xenon decay, assuming the highest worth CEA is stuck out of the core.

During an accident, the safety injection system (SIS) functions to inject concentrated boric acid into the reactor coolant system (RCS) for short term and long term cooling and for reactivity control. Details of the system are given in UFSAR Section 6.3.

- GDC-28 is described in the UFSAR Section 3.1.28, Criterion 28 - Reactivity Limits.

The reactivity control systems shall be designed with appropriate limits on the potential amount and rate of reactivity increase to assure that the effects of postulated reactivity accidents can neither (1) result in damage to the Reactor Coolant Pressure Boundary (RCPB) greater than limited local yielding nor (2) sufficiently disturb the core, its support structures, or other reactor pressure vessel internals to impair significantly the capability to cool the core. These postulated reactivity accidents shall include consideration of rod ejection (unless prevented by positive means), rod dropout, steam line rupture, changes in reactor coolant temperature and pressure, and cold water addition.

The bases for CEA design include ensuring that the reactivity worth of any one CEA is not greater than a pre-selected maximum value. The CEAs are divided into two sets: a shutdown set and a regulating set. These sets are further subdivided into groups as necessary. Administrative procedures and control interlocks ensure that the amount and rate of reactivity increase is limited to predetermined values. The regulating groups are withdrawn only after the shutdown groups are fully withdrawn. The regulating groups are programmed to move in sequence and within limits which prevent the rate of reactivity addition and the worth of individual CEAs from exceeding limiting values (see UFSAR Sections 4.3 and 7.7).

The maximum rate of reactivity addition that may be produced by the CVCS is too low to induce any significant pressure forces that might rupture the RCPB or disturb the reactor vessel internals.

The RCPB (UFSAR Chapter 5) and the reactor internals (UFSAR Chapter 4) are designed to appropriate codes and accommodate the static and dynamic loads associated with an inadvertent, sudden release of energy, such as that resulting from a CEA ejection or a steam line break, without rupture and with limited deformation which will not impair the capability of cooling the core.

- GDC-31 is described in the UFSAR Section 3.1.31, Criterion 31 - Fracture Prevention of Reactor Coolant Pressure Boundary.

The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions (1) the boundary behaves in a non-brittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing, and postulated accident conditions and the uncertainties in determining (1) material properties, (2) the effects of irradiation on material properties, (3) residual, steady-state and transient stresses, and (4) size of flaws.

The RCPB components are designed and constructed in accordance with ASME Code Section III, and comply with the test and inspection requirements of this code. These test and inspection requirements assure that flaw sizes are limited so that the probability of failure by rapid propagation is extremely remote. Particular emphasis is placed on the quality control applied to the reactor vessel, on which tests and inspections exceeding ASME Code requirements are performed. The tests and inspections performed on the reactor vessel are summarized in UFSAR Sections 5.2 and 5.3.

UFSAR Sections 15.3.3 and 15.3.4 describe the analysis of the RCP shaft seizure (locked rotor) and RCP shaft break events, respectively.

NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September, 2003, defines the scope of license renewal. Specific transient analyses are not within the scope of License Renewal.

2.8.5.3.2.2 Technical Evaluation

2.8.5.3.2.2.1 Introduction

The postulated locked rotor event is an instantaneous seizure of an RCP rotor or break of the shaft of the RCP. Flow through the affected reactor coolant loop is rapidly reduced, leading to an initiation of a reactor trip on a low flow signal. The consequences of a postulated pump shaft break accident are similar to the locked rotor event. With a sheared shaft, the impeller is free to spin, as opposed to it being fixed in position during the locked rotor event. Therefore, the initial rate of reduction in core flow is greater during a locked rotor event than in a sheared shaft event because the fixed shaft causes greater resistance than a free spinning impeller early in the transient, when flow through the affected loop is in the positive direction. As the transient

continues, the flow direction through the affected loop is reversed. If the impeller is able to spin freely, the flow to the core will be less than that available with a fixed shaft during periods of reverse flow in the affected loop. Because peak pressure, cladding temperature, and departure from nucleate boiling (DNB) occur very early in the transient, the reduction in core flow during the period of forward flow in the affected loop dominates the severity of the results. Consequently, the results for the locked rotor transients bound the results of the RCP shaft break transient.

Protection for the locked rotor accident is provided by the low reactor coolant system flow reactor trip function.

2.8.5.3.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

To produce conservative results in calculating the peak pressure and peak clad temperature response, and in calculating the rods-in-DNB value, the following assumptions were made in the EPU analysis and are consistent with the current analysis (See LR [Section 2.8.5.0](#), Accident and Transient Analyses, for additional inputs and assumptions):

- The case analyzed to determine the maximum RCS pressure and peak cladding temperature employ the standard thermal design procedure (STDP). Therefore, the plant is assumed to be in operation under the most adverse steady state operating conditions; that is, a steady state thermal power of 100 percent of rated thermal power plus uncertainty, maximum steady state pressure plus uncertainty, maximum steady state coolant average temperature plus uncertainty, and the use of thermal design flow.
- The case analyzed to determine the rods-in-DNB utilizes the revised thermal design procedure (RTDP) methodology ([Reference 3](#)). Initial reactor power is 100 percent of rated thermal power, and the associated pressurizer pressure and RCS temperature are assumed to be at the top of the corresponding technical specifications windows, without uncertainty. Minimum measured flow is assumed for the rods-in-DNB analysis. All the uncertainties are covered in the departure from nucleate boiling ratio (DNBR) limit.
- This evaluation models a failure of the fast bus transfer system coincident with the reactor trip, consistent with the current analysis of record. The assumed single failure is a failure of one train of the reactor protection system.
- A maximum, uniform, steam generator tube plugging level of 10 percent was assumed in the RETRAN analysis. The effect of a flow asymmetry resulting from asymmetric tube plugging is addressed in the DNB analysis of the locked rotor statepoints.
- A conservatively large absolute value of the Doppler-only power coefficient is used, along with the most positive moderator temperature coefficient (MTC) limit for full-power operation. These assumptions maximize the core power during the initial part of the transient when the peak RCS pressures and hot spot results are reached.
- A conservatively low trip reactivity value is used to minimize the effect of rod insertion following reactor trip and maximize the heat flux statepoint used in the DNBR evaluation for this event. This value is based on the assumption that the highest worth CEA is stuck in its fully withdrawn position. A conservative trip reactivity worth versus rod position was modeled in addition to accounting for the rod drop holding coil delay time.

- The locked rotor event is of a sufficiently short duration (less than ten seconds) such that steam generator tube uncover does not impact the results. Additionally, no operator actions are credited for the locked rotor event.

The following items summarize the acceptance criteria associated with this event:

The locked rotor event is analyzed to the following criteria:

- Rods in DNB is below the limit used in the radiological consequences analysis.
- Due to the low probability of this event, the locked rotor supports 120 percent of design pressure as an acceptance criteria. However, for this event, the primary system pressure (maximum in the loop) remains below 110 percent of the RCS design pressure.

Coolable core geometry is ensured by showing that the peak cladding temperature and maximum oxidation level for the hot spot are below 2375°F and 16.0 percent by weight, respectively.

The radiological consequences analysis acceptance criteria for the locked rotor/sheared shaft (LR/SS) event are discussed in LR [Section 2.9.2](#), Radiological Consequences Analysis Using Alternative Source Terms (AST).

With respect to secondary over-pressurization, the results of the locked rotor event were bounded by the results of the loss of condenser vacuum (LOCV) event described in LR [Section 2.8.5.2.1](#). For the LR/SS event, turbine trip occurs simultaneously with reactor trip, whereas for the LOCV event, the initiating event is a complete loss of normal feedwater and a loss of turbine load. Therefore, the primary to secondary power mismatch and resultant main steam system heatup and pressurization transients are always more severe for the LOCV event.

2.8.5.3.2.2.3 Description of Analyses and Evaluation

The locked rotor transient was evaluated to demonstrate that the reactor protection system functions and mitigates the consequences at the EPU conditions utilizing the currently approved methodology.

The locked rotor transient is analyzed with two computer codes. First, the RETRAN computer code ([Reference 1](#)) is used to calculate the loop and core flow during the transient. The time of reactor trip based on the calculated flows, the nuclear power transient, and the primary system pressure and temperature transients. The VIPRE computer code ([Reference 2](#)) is then used to calculate the thermal behavior of the fuel located at the core hot spot including the rods-in-DNB using the nuclear power and RCS temperature (enthalpy), pressure, and flow from RETRAN. Both RETRAN and VIPRE are NRC approved and part of the St. Lucie Unit 2 current licensing basis.

For this accident, an evaluation of the consequences with respect to the fuel rod thermal transient is performed. The evaluation incorporates the assumption of rods going into DNB as a conservative initial condition to determine the cladding temperature and zirconium water reaction resulting from the locked rotor. Results obtained from the analysis of this hot spot condition represent the upper limit with respect to cladding temperature and zirconium water reaction. In

the evaluation, the rod power at the hot spot is assumed to be 2.5 times the average rod power at the initial core power level.

Film Boiling Coefficient

The film boiling coefficient is calculated in the VIPRE code ([Reference 2](#)) using the Bishop-Sandberg-Tong film boiling correlation. The fluid properties are evaluated at film temperature. The program calculates the film coefficient at every time step based upon the actual heat transfer conditions at the time. The nuclear power, system pressure, bulk density, and RCS flow rate as a function of time are based on the RETRAN results.

Fuel Cladding Gap Coefficient

The magnitude and time dependence of the heat transfer coefficient between fuel and cladding (gap coefficient) has a pronounced influence on the thermal results. The larger the value of the gap coefficient, the more heat is transferred between the pellet and cladding. Based on investigations on the effect of the gap coefficient upon the maximum cladding temperature during the transient, the gap coefficient was assumed to increase from a steady-state value consistent with initial fuel temperature to 10,000 BTU/hr ft² °F at the initiation of the transient. Therefore, the large amount of energy stored in the fuel because of the small initial value is released to the cladding at the initiation of the transient.

Zirconium Steam Reaction

The zirconium-steam reaction can become significant above 1800°F (cladding temperature). The Baker-Just parabolic rate equation is used to define the rate of zirconium-steam reaction. The effect of the zirconium-steam reaction is included in the calculation of the hot spot cladding temperature transient.

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

As discussed above, the design transient analyses were determined to be outside the scope of License Renewal; therefore, with respect to the design basis accidents and transients, the EPU does not impact any License Renewal evaluations.

2.8.5.3.2.2.5 Results

With respect to the peak RCS pressure, peak clad temperature, zirconium-steam reaction, and rods-in-DNB, the analysis demonstrated that all applicable acceptance criteria were met. The calculated sequence of events is presented in LR [Table 2.8.5.3.2-1](#) for the locked rotor event. The results of the calculations (peak primary pressure, peak clad temperature, zirconium steam reaction, rods-in-DNB and minimum DNBR) are summarized in LR [Table 2.8.5.3.2-2](#) along with a comparison to the results from the current analysis. The peak primary pressure and peak clad temperature of the primary overpressure and peak clad temperature (OP/PCT) case improved (lower values) slightly in comparison to the current analysis due to the increased heat transfer of the replacement steam generators. The transient results for the OP/PCT case are provided in LR [Figures 2.8.5.3.2-1](#) through [2.8.5.3.2-9](#). The hot channel DNBR results for the rods-in-DNB case is provided in LR Figure [Figure 2.8.5.3.2-10](#).

The analysis performed for the EPU demonstrated that, for the locked rotor event, the peak clad surface temperature calculated for the hot spot during the worst transient remained less than 2375°F, and the amount of zirconium water reaction was much less than 16 percent. Under such conditions, the core remained in place and intact with no loss of core cooling capability and thus, the ability to insert control rods into the core is maintained.

The analysis also confirmed that the peak RCS pressure reached during the transient remained below 110 percent of the design pressure, therefore demonstrating that the 120 percent of the design pressure criterion was met. With respect to secondary over-pressurization, the results of the locked rotor event are bounded by the results of the LOCV event described in LR

Section 2.8.5.2.1.

Additionally, this analysis determined that the fuel rods in DNB during the transient is less than the rods-in-DNB assumption used in the radiological dose analysis, as presented in LR

Section 2.9.2, Radiological Consequences Analysis Using Alternative Source Terms (AST).

2.8.5.3.2.3 Conclusion

FPL has reviewed the sudden decrease in core coolant flow events 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. FPL further concludes 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, FPL concludes that the plant will continue to meet the requirements of GDCs -27, -28, and -31 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to the sudden decrease in core coolant flow events.

2.8.5.3.2.4 References

1. WCAP-14882-P-A (Proprietary) and WCAP-15234-A (Non-Proprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, D. S. Huegel, et al., April 1999.
2. WCAP-14565-P-A (Proprietary) and WCAP 15306-NP-A (Non-Proprietary), VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non LOCA Thermal-Hydraulic Safety Analysis, Sung, Y. X. et al., October 1999.
3. WCAP-11397-P-A (Proprietary) and WCAP-11397-A (Non-Proprietary), Revised Thermal Design Procedure, A. J. Friedland and S. Ray, April 1989.

Table 2.8.5.3.2-1
Sequence of Events – Reactor Coolant Pump Locked Rotor

Event	Time (seconds) ⁽¹⁾	
	Rods-in-DNB Case	Peak Clad Temp Case
Rotor on one pump locks	10.000	10.000
Low flow reactor trip setpoint reached	10.012	10.012
Reactor trip occurs	10.919	10.950
Failure of fast bus transfer (two RCPs coastdown)	10.929	10.960
Rod motion begins (0.74 seconds after breakers open)	11.659	11.690
Maximum cladding temperature occurs	N/A	13.70
Minimum DNBR	12.900	N/A
Maximum RCS pressure occurs	13.900	13.450
Remaining active pump begins to coastdown	13.929	13.960
1. Note that the times provided include a 10 second steady state period prior to the initiation of the event.		

Table 2.8.5.3.2-2
Results – Reactor Coolant Pump Locked Rotor

Case	UFSAR Limit	Current Analysis ⁽¹⁾	EPU Analysis ⁽¹⁾
Peak clad temperature	2375 °F ⁽³⁾	1703.6 °F at 13.70 sec	1589.8 °F ⁽⁴⁾ at 13.70 sec
Max reacted Zirconium	16%	0.3% at 18.30 sec	0.3% at 19.95 sec
Peak primary pressure	2750 psia	2660 psia at 16.65 sec	2650.03 psia ⁽⁴⁾ at 13.45 sec
Rods-in-DNB	2.5% (10% for EPU ⁽²⁾)	< 0.6% at 13.20 sec	< 1.0% ⁽⁶⁾ at 12.9 sec
Minimum DNBR	1.42	>1.35 ⁽⁵⁾	1.38 ⁽⁶⁾ at 12.9 sec
- Note that the times provided include a 10 second steady state period prior to the initiation of the event. - The Rods-in-DNB limit as assumed in the radiological consequences analysis is 19.7 percent (LR Section 2.9.2, “Radiological Consequences Analysis Using Alternative Source Terms (AST)”). A limit of 10 percent, set here for EPU, conservatively meets the dose analysis limit. - The acceptance criterion for peak clad temperature has been revised from 2700°F to 2375°F to cover both ZIRLO™ and Optimized ZIRLO™ - The peak pressure and peak clad temperature results for the OP/PCT EPU case improved slightly (decreased) due to the increased heat transfer of the RSGs. - Note that for the AOR analysis the SAL DNB was relaxed to account for a reduction in the discretionary margin applied to the design DNB correlation limit. - Although the EPU analysis minimum DNBR is below the analysis DNBR limit, it remains above the design DNBR limit for fuel failures. A value of <1.0 percent for Rods-in-DNB is conservatively reported for EPU analysis.			

Figure 2.8.5.3.2-1
Locked Rotor / Sheared Shaft (OP/PCT Case)
Nuclear Power

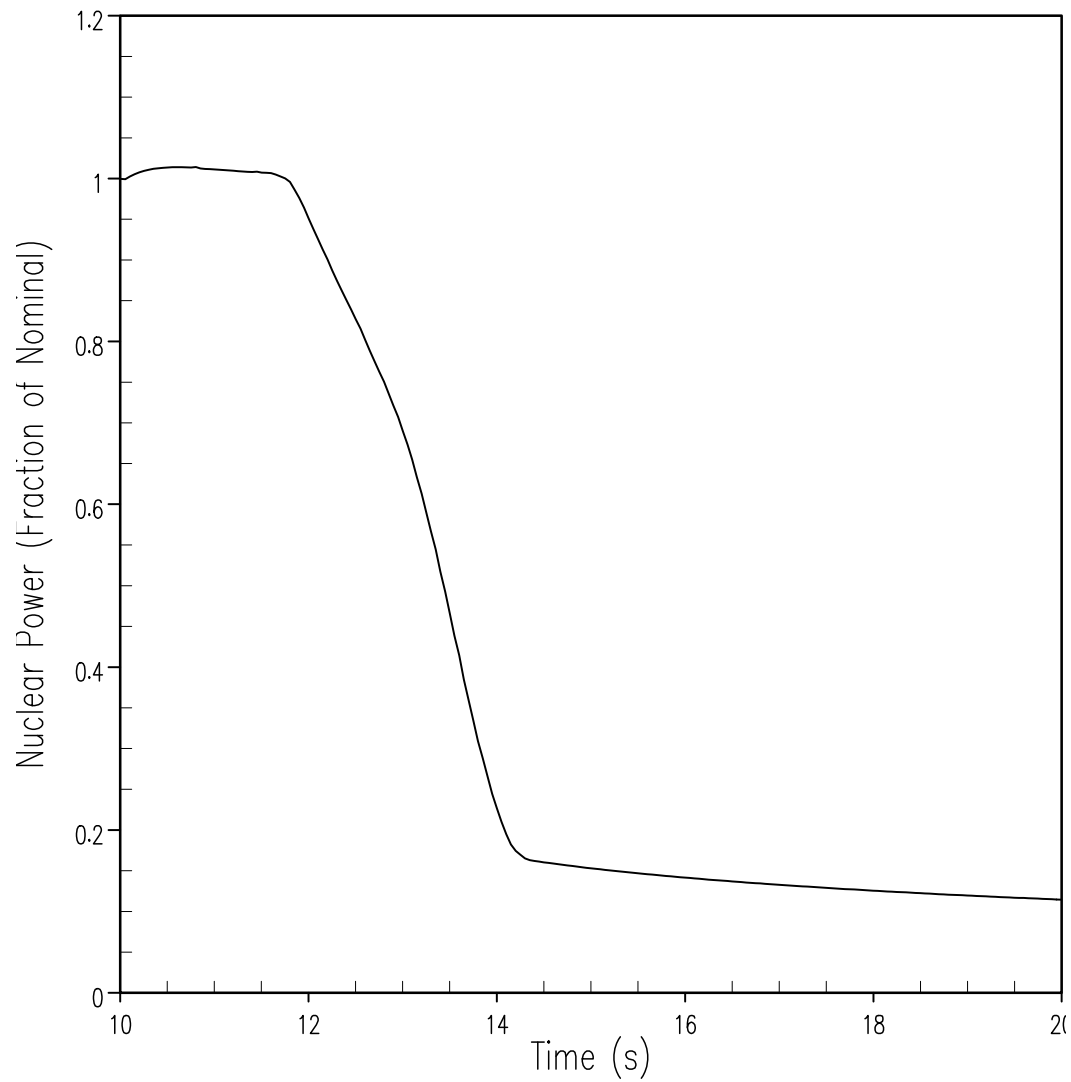


Figure 2.8.5.3.2-2
Locked Rotor / Sheared Shaft (OP/PCT Case)
RCS Pressure (Pressurizer Pressure)

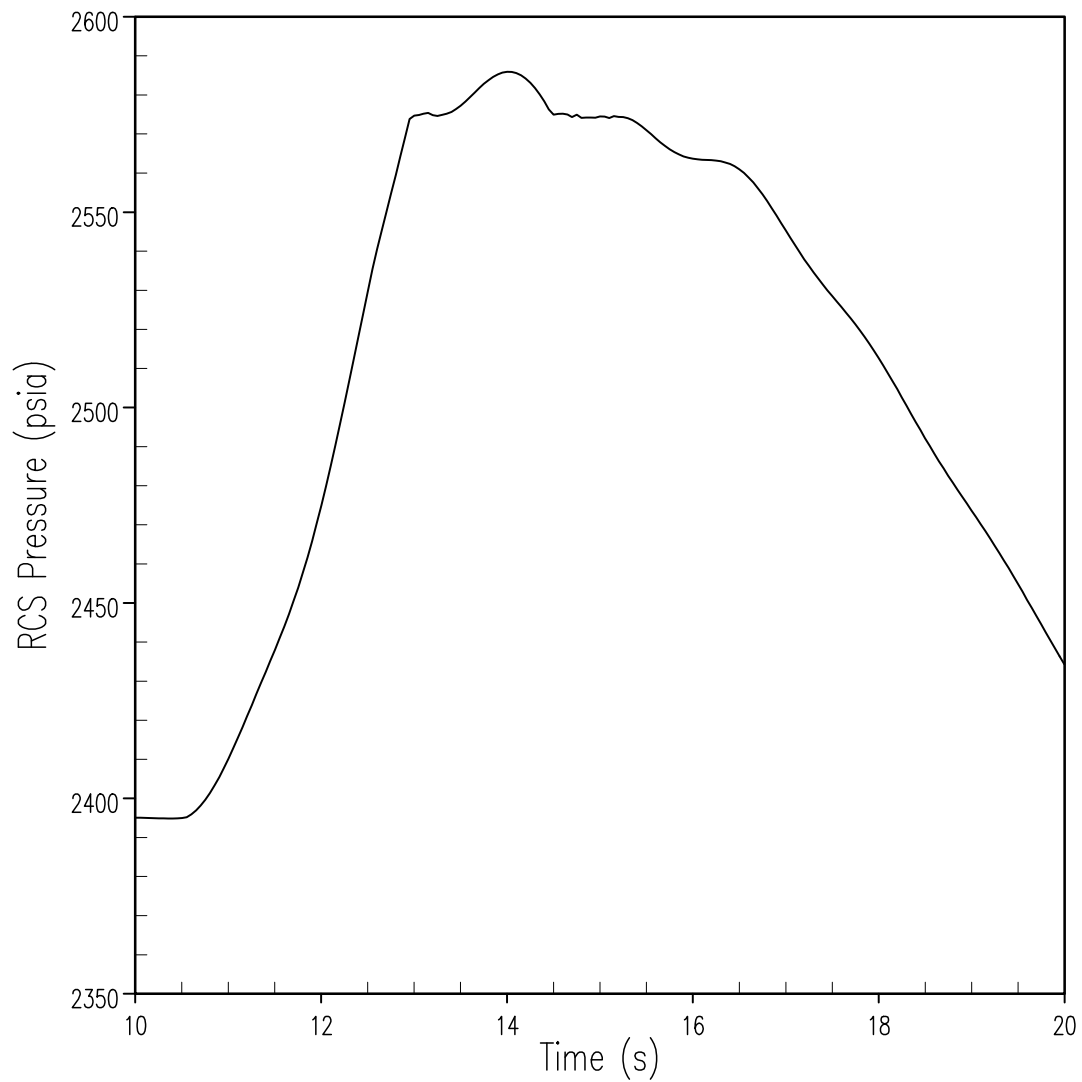


Figure 2.8.5.3.2-3
Locked Rotor / Sheared Shaft (OP/PCT Case)
RCS Pressure (Lower Plenum Pressure)

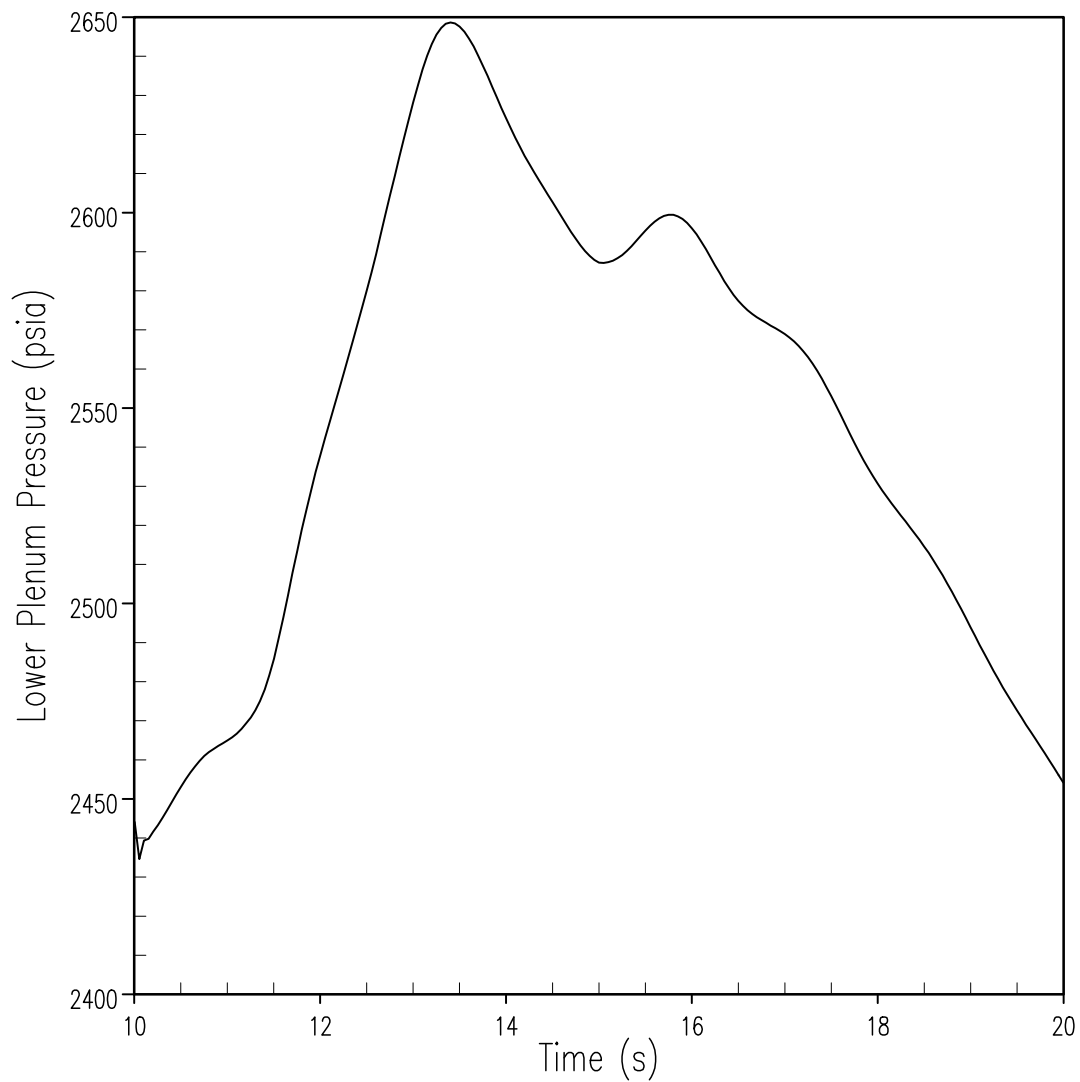


Figure 2.8.5.3.2-4
Locked Rotor / Sheared Shaft (OP/PCT Case)
Core Average Heat Flux

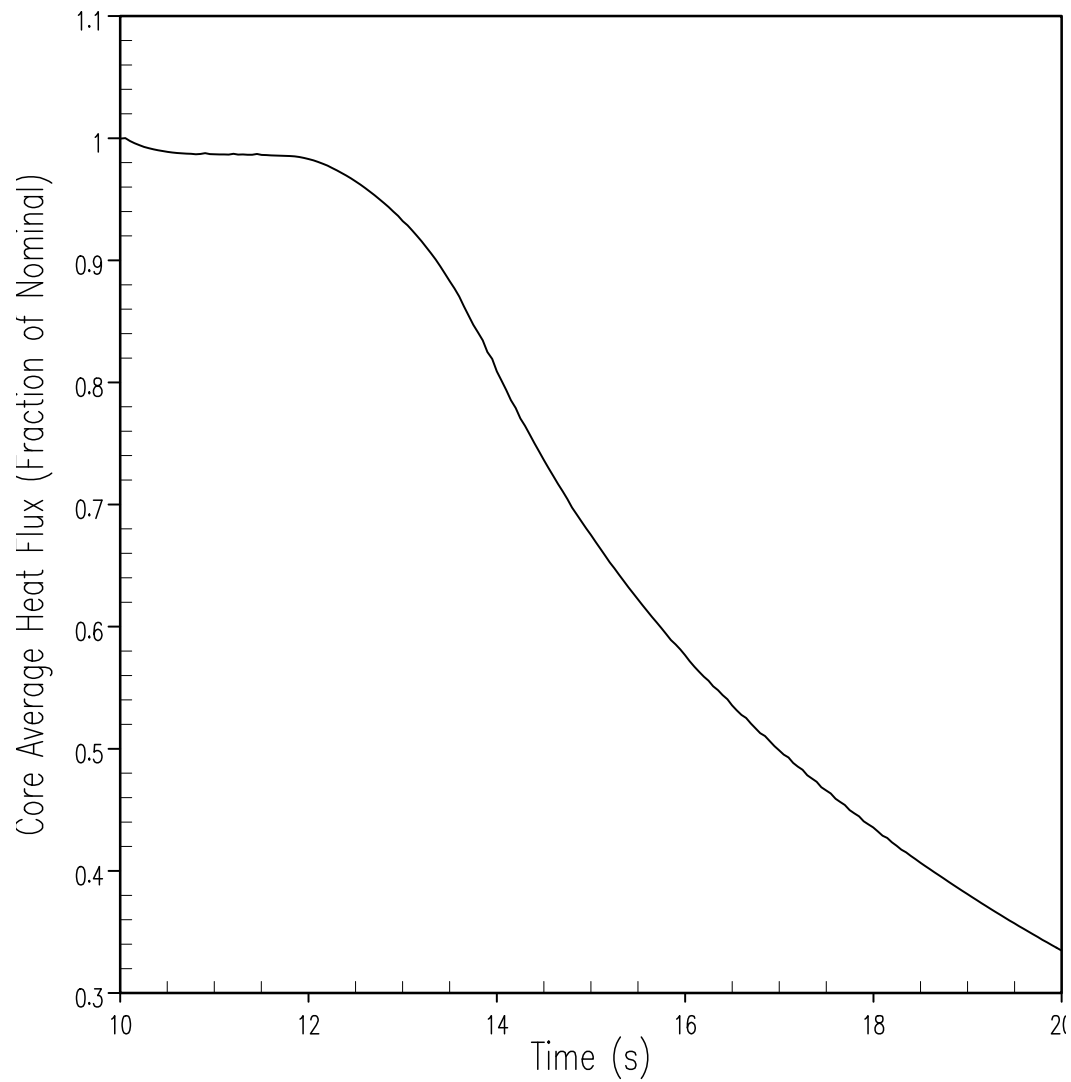


Figure 2.8.5.3.2-5
Locked Rotor/Sheared Shaft (OP/PCT Case)
RCS Volumetric Flow Rate

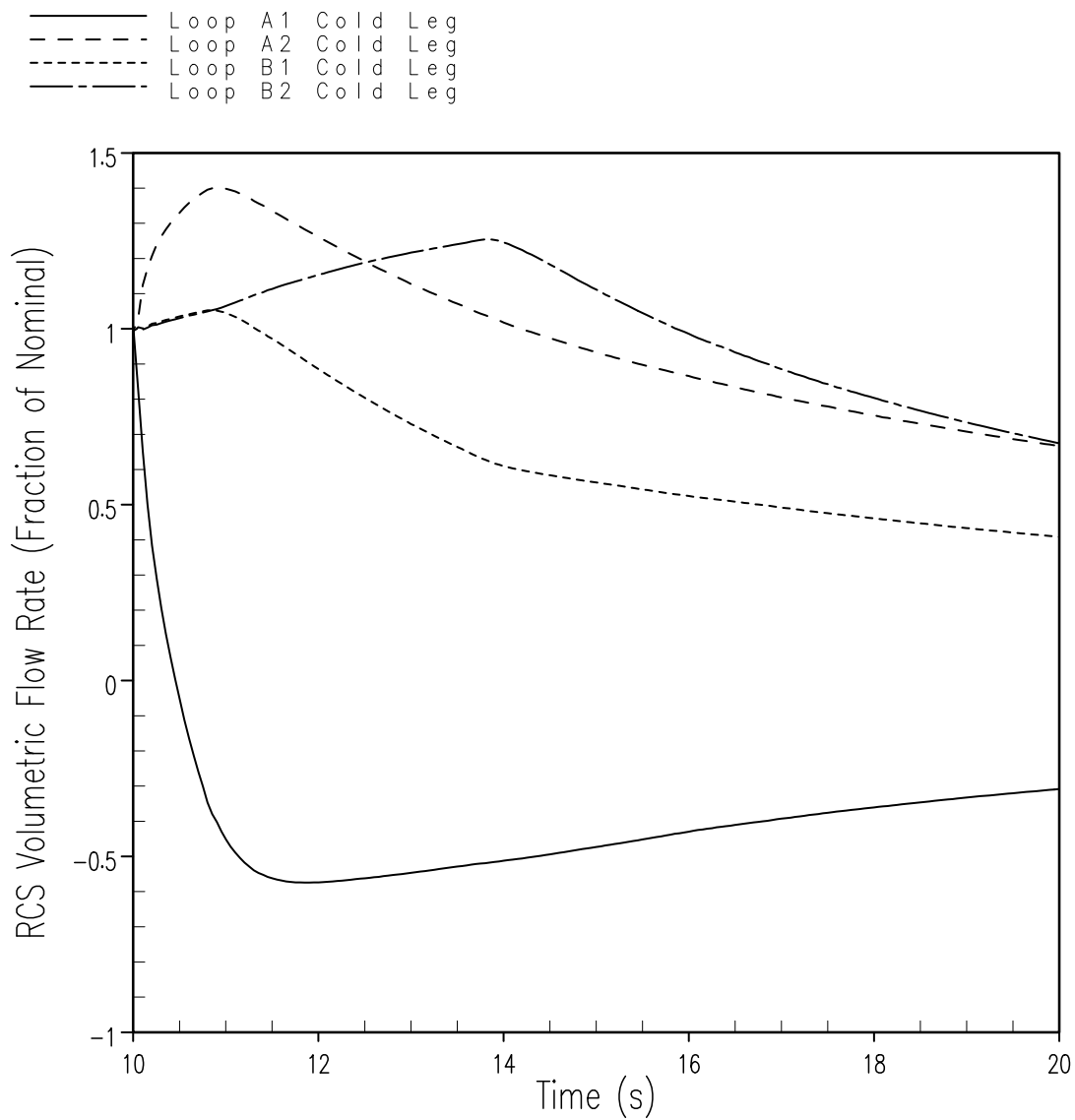


Figure 2.8.5.3.2-6
Locked Rotor / Sheared Shaft (OP/PCT Case)
Core Volumetric Flow Rate

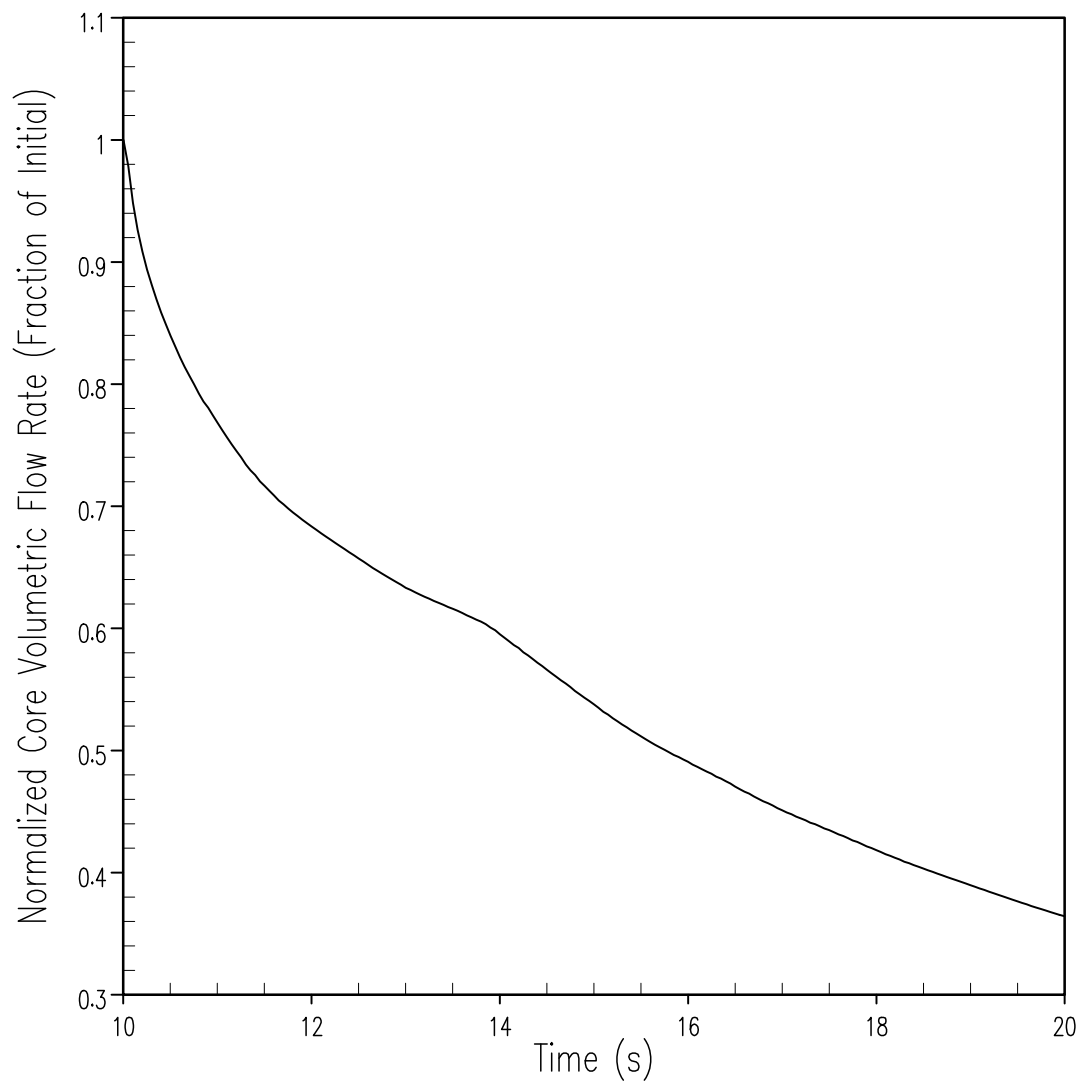


Figure 2.8.5.3.2-7
Locked Rotor / Sheared Shaft (OP/PCT Case)
RCS Loop Temperature

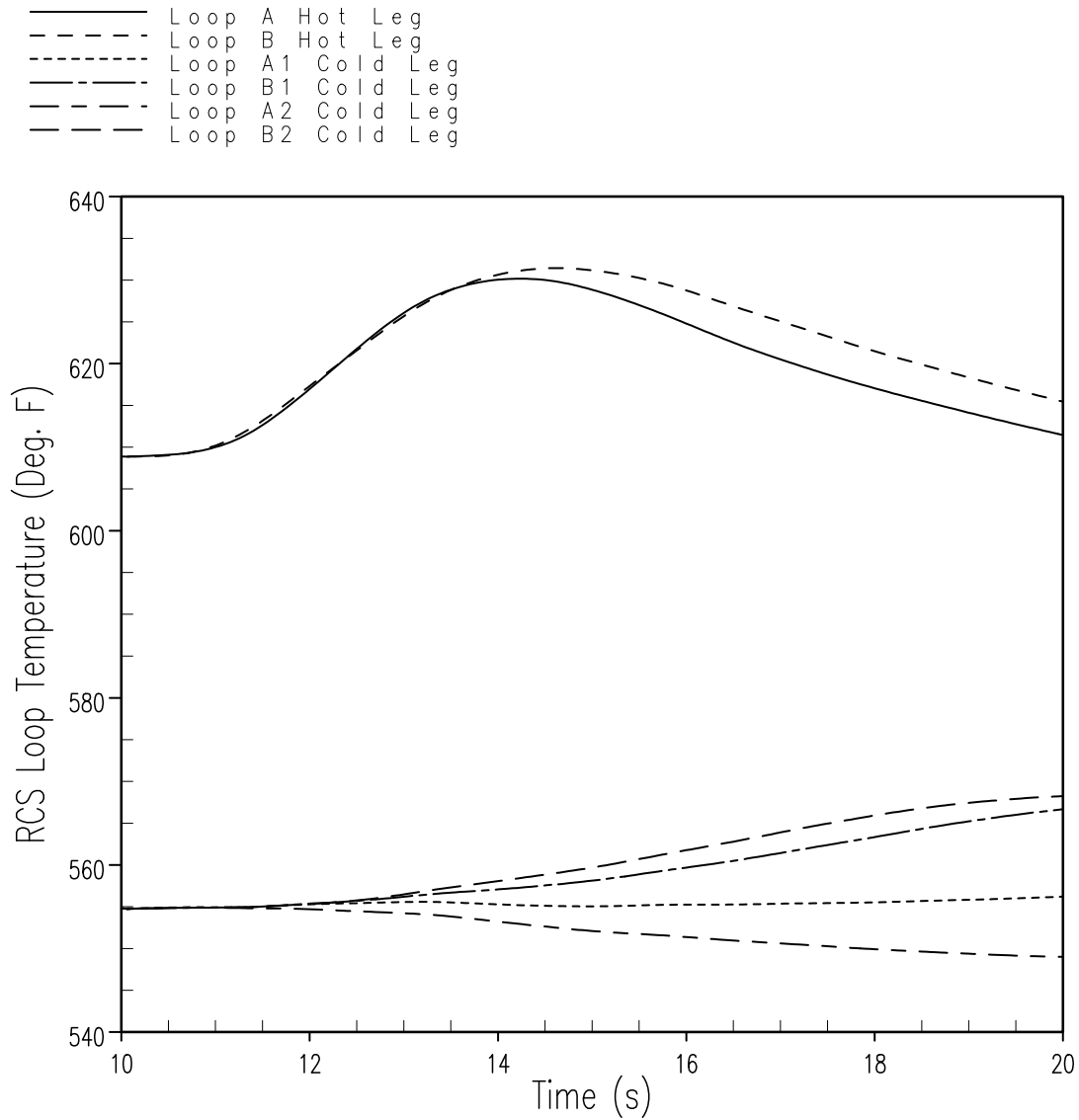


Figure 2.8.5.3.2-8
Locked Rotor / Sheared Shaft (OP/PCT Case)
Hot-Spot Clad Inner Temperature

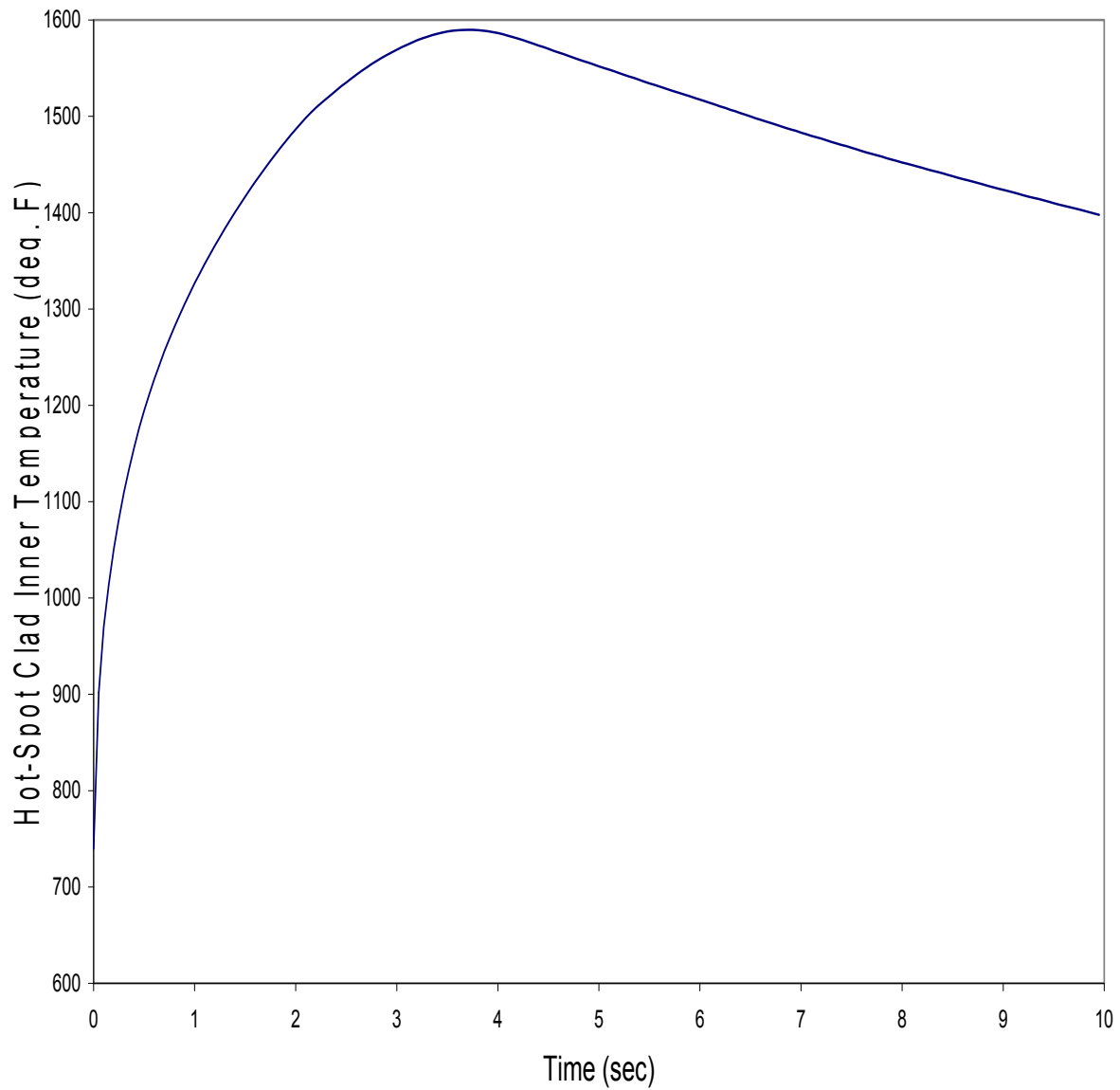


Figure 2.8.5.3.2-9
Locked Rotor / Sheared Shaft (OP/PCT Case)
Hot Channel Heat Flux

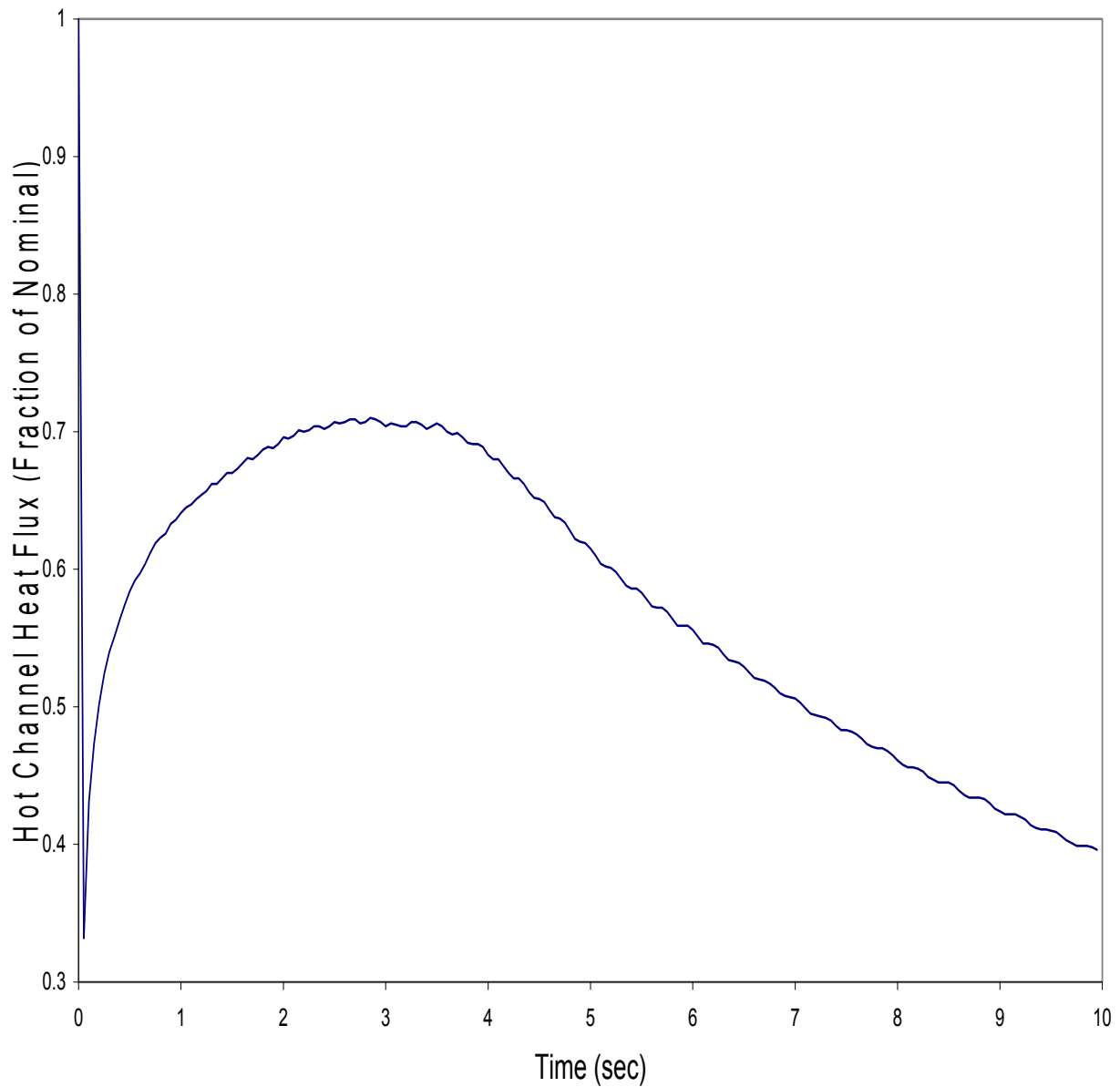
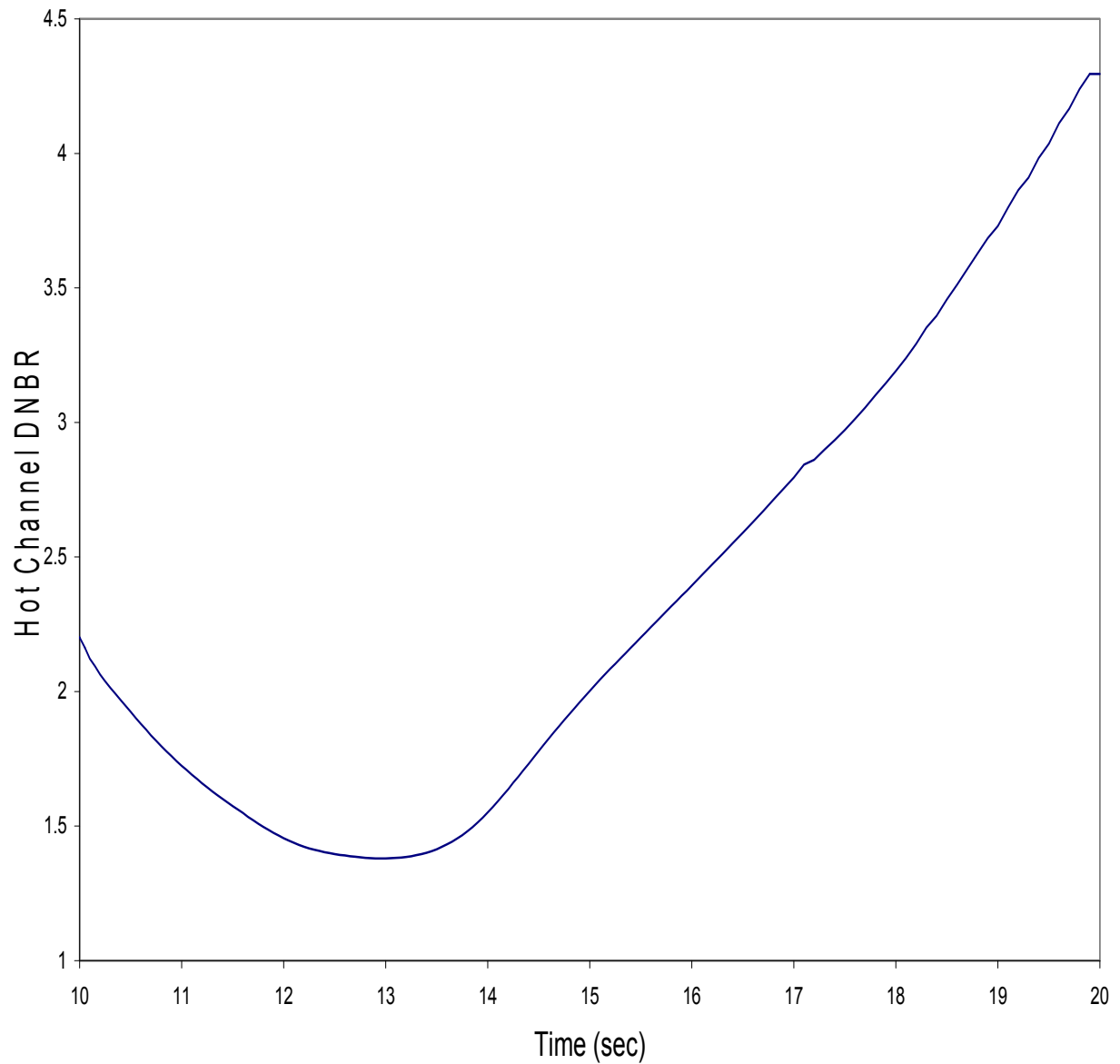


Figure 2.8.5.3.2-10
Locked Rotor / Sheared Shaft (Rods-in-DNB Case)
Hot Channel Minimum DNBR



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

2.8.5.4.1.1 Regulatory Evaluation

An uncontrolled control rod assembly withdrawal from subcritical or low power startup conditions may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion.

The Florida Power and Light (FPL) review covered:

- the description of the causes of the transient and the transient itself,
- the initial conditions,
- the values of reactor parameters used in the analysis,
- the analytical methods and computer codes used, and
- the results of the transient analyses.

The NRC's acceptance criteria are based on:

- GDC-10, insofar as it requires that the reactor coolant system (RCS) be designed with appropriate margin to ensure that specified acceptable fuel design limits (SAFDLs) are not exceeded during normal operations, including anticipated operational occurrences (AOOs).
- GDC-20, insofar as it requires that the reactor protection system (RPS) 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.
- 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.

Specific review criteria are contained in Standard Review Procedure (SRP) Section 15.4.1 and other guidance provided in Matrix 8 of RS-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in the Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria (GDC) as discussed in UFSAR Section 3.1.

The specific GDC's for this positive reactivity addition event are as follows:

- GDC-10 is described in UFSAR Section 3.1.10 Criterion 10 – Reactor Design.

The reactor core and associated coolant, control and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not

exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

SAFDLs are stated in UFSAR Section 4.3. Minimum margins to the SAFDLs are specified in the technical specifications (limiting conditions for operations) which support UFSAR Chapters 4 and 15.

- GDC-20 is described in UFSAR Section 3.1.20 Criterion 20 - Protection System Functions.

The protection system shall be designed (1) to initiate automatically the operation of appropriate systems including the reactivity control systems, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and to initiate the operation of systems and components important to safety.

The RPS monitors reactor operating conditions and automatically initiates a reactor trip when the monitored variable or combination of variables exceeds a prescribed operating range. The reactor trip setpoints are selected to ensure that AOO do not cause the SAFDLs to be violated. Specific reactor trips are described in UFSAR Section 7.2.

The engineered safety features actuation system (ESFAS) monitors potential accident conditions and automatically initiates engineered safety features and their supporting systems when the monitored variables reach prescribed setpoints. The parameters which automatically actuate engineered safety features are described in UFSAR Section 7.3. Manual actuation is provided to the operator.

- GDC-25 is described in UFSAR Section 3.1.25 Criterion 25 - Protection System Requirements for Reactivity Control Malfunctions.

The protection system shall be designed to assure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of control rods.

Reactor shutdown with control element assemblies (CEAs) is accomplished completely independent of the control functions since the trip breakers interrupt power to the control element drive mechanisms (CEDMs) regardless of existing control signals. The design is such that the system can withstand accidental withdrawal of controlling groups without exceeding acceptable fuel design limits. Analysis of possible reactivity control malfunctions is given in UFSAR Section 15.4. The RPS will prevent SAFDLs from being exceeded for any AOO.

UFSAR Section 15.4.1 describes the analysis pertaining to the CEA withdrawal from a subcritical or low power start-up condition event.

NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September, 2003, defines the scope of license renewal. Specific transient analyses are not within the scope of License Renewal.

2.8.5.4.1.2 Technical Evaluation

2.8.5.4.1.2.1 Introduction

CEA withdrawal accident is defined as an uncontrolled addition of reactivity to the reactor core caused by withdrawal of CEA banks resulting in a power excursion. While the occurrence of a transient of this type is unlikely, such a transient could be caused by a malfunction of the reactor control or the control element drive system. This could occur with the reactor either subcritical, at hot zero power (HZP), or at power. The “at power” case is discussed in LR [Section 2.8.5.4.2](#), Uncontrolled Control Rod Assembly Withdrawal at Power.

Withdrawal of a CEA bank adds reactivity at a prescribed and controlled rate to bring the reactor from a subcritical condition to a low-power level during startup. A CEA bank movement can cause much faster changes in reactivity than can be made by changing boron concentration.

The neutron flux response to a continuous reactivity insertion is characterized by a very fast flux increase terminated by the reactivity feedback effect of the negative Doppler coefficient. This self-limitation of the power burst is of primary importance since it limits the power to a tolerable level during the delay time for protective action. Should a continuous CEA withdrawal event occur, the following automatic features of the reactor protection will terminate the transient:

- Variable power level – high trip, and
- Rate-of-change of power trip.

2.8.5.4.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

In order to give conservative results for the analysis of the uncontrolled CEA bank withdrawal from subcritical event, the following assumptions, which are consistent with those made for the current analysis, are made (See LR [Section 2.8.5.0](#), Accident and Transient Analyses, for additional inputs and assumptions):

1. Since the magnitude of the power peak reached during the initial part of the transient for any given rate of reactivity insertion is strongly dependent on the Doppler power defect, a conservatively low (absolute magnitude) value is used.
2. The contribution of the moderator reactivity coefficient is negligible during the initial part of the transient because the heat transfer time constant between the fuel and the moderator is much longer than the neutron flux response time constant. However, after the initial neutron flux peak, the moderator temperature coefficient (MTC) can affect the succeeding rate of power increase. The effect of moderator temperature changes on the rate of nuclear power increase is conservatively calculated in TWINKLE based on temperature dependant moderator cross sections.
3. The analysis assumes the reactor to be at HZP nominal temperature. This assumption is more conservative than that of a lower initial system temperature (that is, shutdown conditions). The higher initial system temperature yields a larger fuel-to-water heat transfer coefficient, a larger specific heat of the water and fuel, and a less negative (smaller absolute

magnitude) Doppler power coefficient (DPC). The less negative DPC reduces the Doppler feedback effect, thereby increasing the neutron flux peak. The high neutron flux peak combined with a high fuel-specific heat and larger heat transfer coefficient yields a larger peak heat flux.

4. The analysis assumes the initial effective multiplication factor (k_{eff}) to be 1.0 since this results in the maximum neutron flux peak.
5. The reactor is conservatively tripped on variable power level – high trip at a conservative analysis value of 35 percent. This increase from the nominal setpoint of 15 percent accounts for uncertainties. LR [Figure 2.8.5.4.1-1](#) shows that the rise in nuclear flux is so rapid that the effect of any variation in the trip setpoint on the actual time at which the rods are released is negligible. The variable power level – high trip is conservatively assumed in order to maximize the pre-trip power level; which is conservative for departure from nucleate boiling (DNBR). The total reactor trip reactivity is based on the assumption that the highest worth CEA is stuck in its fully withdrawn position. Further, the delays for trip signal actuation and CEA release are accounted for in the analysis.
6. A conservative maximum positive reactivity insertion rate of 53 pcm/sec was assumed, which is greater than that for the simultaneous withdrawal of the two sequential CEA banks having the greatest combined worth at the maximum speed.
7. The departure from nucleate boiling (DNB) analysis assumes the most-limiting axial and radial power shapes possible during the fuel cycle associated with having the two highest combined worth banks in their high worth position.
8. The analysis assumes the initial power level to be below the power level expected for any shutdown condition. The combination of highest reactivity insertion rate and low initial power produces the highest peak heat flux.
9. The accident analysis employs the standard thermal design procedure (STDP) methodology. Use of the STDP stipulates that the RCS flow rate will be based on the thermal design flow (TDF) and that the RCS pressure is the nominal pressure minus the uncertainty. Since the event is analyzed from HZP, the steady-state STDP uncertainties on core power and RCS average temperature are not used in defining the initial conditions.
10. The fuel rod heat transfer calculations performed to determine the maximum fuel temperature during this event assume a total peaking factor or hot channel factor that is a function of the axial and radial power distributions. The conservatively high value used in this analysis is presented in LR [Table 2.8.5.4.1-2](#).
11. Both UO_2 -only fuel and fuel with up to 8 weight-percent (w/o) gadolinia content were considered in the transient analysis.

The uncontrolled control rod assembly bank withdrawal from subcritical event is considered an AOO, and is analyzed to show that the core and the reactor coolant system parameters continue

to meet the design basis limits. This is demonstrated by showing that the DNB design basis is not violated and consequently that there is little likelihood of core damage. It must also be shown that the peak hot spot fuel centerline temperature remains within the acceptable limit.

The specific acceptance criteria applied for this event were as follows:

- The DNBR should remain above the 95/95 DNBR limit at all times during the transient. Demonstrating that the DNBR limit is met meets the current licensing basis requirements with respect to GDC-10.
- Per GDC-20, the protection system should be designed to automatically initiate the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of an AOO, and to sense accident conditions and initiate the operation of important-to-safety systems and components. For this event, protection is provided via the Variable power level – high trip.
- GDC-25 requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of control rods. Demonstrating that the fuel design limits (i.e., DNBR) are met satisfies the current licensing basis requirements with respect to GDC-25.

2.8.5.4.1.2.3 Description of Analyses and Evaluations

The analysis of the uncontrolled CEA bank withdrawal from subcritical accident is performed in three stages to demonstrate that the reactor protections system functions and mitigates the consequences at the Extended Power Uprate (EPU) conditions utilizing currently approved methodology. First, the spatial neutron kinetics computer code TWINKLE ([Reference 1](#)) is used to calculate the core average nuclear power transient including the various core feedback effects; that is, Doppler and moderator reactivity. FACTRAN ([Reference 2](#)) then uses the average nuclear power calculated by TWINKLE and performs a fuel rod transient heat transfer calculation to determine the core-average heat flux and hot spot fuel temperature transients. Finally, the peak core-average heat flux calculated by FACTRAN is used in the VIPRE computer code ([Reference 3](#)) for transient DNBR calculations. TWINKLE, FACTRAN, and VIPRE are NRC approved modeling codes and are used in the current plant licensing basis.

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

As discussed above, the design transient analyses were determined to be outside the scope of License Renewal; therefore, with respect to the design basis accidents and transients, the EPU does not impact any License Renewal evaluations.

2.8.5.4.1.2.5 Results

The analysis demonstrates that all applicable acceptance criteria are met. The minimum DNBR remains above the limit value and the peak fuel centerline temperature is well below the minimum temperature where fuel melting is expected.

LR [Figure 2.8.5.4.1-1](#) shows the neutron flux transient. The neutron flux overshoots the full-power nominal value for a very short period of time. Therefore, the energy release and fuel temperature increase are relatively small. The heat flux response of interest for the DNB considerations is shown in LR [Figure 2.8.5.4.1-2](#). The beneficial effect of the inherent thermal lag in the fuel is evidenced by a peak heat flux of much less than the nominal full power value. LR [Figure 2.8.5.4.1-3](#) shows the transient response of the hot-spot fuel centerline, fuel average, and cladding average temperatures.

LR [Table 2.8.5.4.1-1](#) presents the time sequence of events. Refer to LR [Table 2.8.5.4.1-2](#) for a summary of assumptions with the numerical results of the analysis. LR [Table 2.8.5.4.1-3](#) provides a comparison to the current licensing basis.

2.8.5.4.1.3 Conclusion

FPL has reviewed the uncontrolled control rod assembly withdrawal from a subcritical or low power startup condition and concludes that the analyses have adequately accounted for the changes in core design necessary for operation of the plant at the proposed power level. FPL also concludes that the analyses were performed using acceptable analytical models. FPL further concludes that the reactor protection and safety systems will continue to ensure the SAFDLs are not exceeded. Based on this, FPL concludes that the plant will continue to meet its licensing basis with respect to the requirements of GDCs -10, -20, and -25 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to the uncontrolled control rod assembly withdrawal from a subcritical or low power startup condition.

2.8.5.4.1.4 References

1. WCAP-7979-P-A, January 1975 (Proprietary) and WCAP-8028-A, January 1975 (Nonproprietary), TWINKLE, a Multi-dimensional Neutron Kinetics Computer Code, Barry, R. F., Jr. and Risher, D. H.
2. WCAP-7908, FACTRAN – A FORTRAN-IV Code for Thermal Transients in a UO₂ Fuel Rod, Hargrove, H. G., December 1989.
3. WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Nonproprietary), VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, Sung, Y. X. et al., October 1999.

Table 2.8.5.4.1-1
Time Sequence of Events – Uncontrolled CEA
Withdrawal from a Subcritical Condition

Event	Time (seconds)
Initiation of Uncontrolled CEA Bank Withdrawal	0
Variable Power Level - High Trip Setpoint (Lower Limit Setting) is Reached	13.4
Peak Nuclear Power Occurs	13.7
Reactor Trip Breaker Opens	13.8
Rod Motion Begins	14.6
Peak Heat Flux Occurs	15.1
Minimum DNBR Occurs	15.1
Peak Cladding Temperature Occurs	15.3
Peak Fuel Centerline Temperature Occurs	16.7

Table 2.8.5.4.1-2
Assumptions and Results – Uncontrolled CEA Withdrawal
from a Subcritical Condition

Initial Power Level, %	0	
Reactivity Insertion Rate, pcm/sec	53	
Delayed Neutron Fraction	0.0070	
Doppler Power Defect, pcm	900	
Trip Reactivity, % Δk	2.0	
Hot Channel Factor	7.82	
Number of RCPs Operating	4	
Results		
	Calculated Value	Limit
Peak Fuel Centerline Temperature, °F	3432	4717
Minimum DNBR (small thimble cell)	1.28	1.26
Minimum DNBR (large thimble cell)	1.29	1.26
Minimum DNBR (typical cell)	1.42	1.26

Table 2.8.5.4.1-3
Uncontrolled CEA Withdrawal from a Subcritical Condition
Comparison to Previous Results

	Time of Minimum DNBR	Minimum DNBR	Limit
Current Analysis	15.0 seconds	1.36	1.29
EPU Analysis	15.1 seconds	1.28	1.26 ⁽¹⁾
1. The DNBR limit was relaxed to account for a reduction in the discretionary margin applied to the DNB correlation limit.			

Figure 2.8.5.4.1-1
Uncontrolled CEA Withdrawal from Subcritical Condition
Reactor Power versus Time

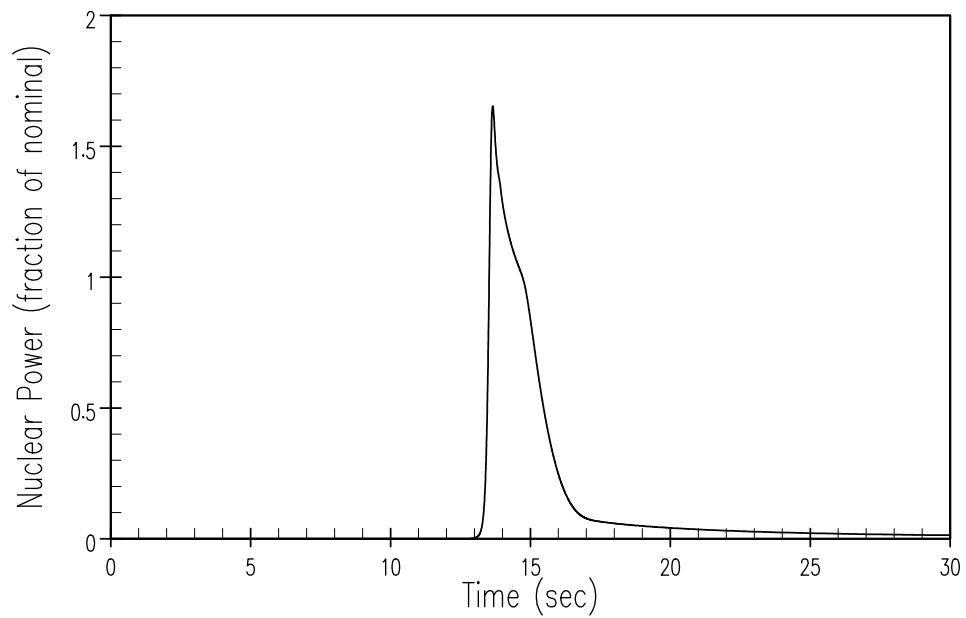


Figure 2.8.5.4.1-2
Uncontrolled CEA Withdrawal from Subcritical Condition
Heat Flux versus Time

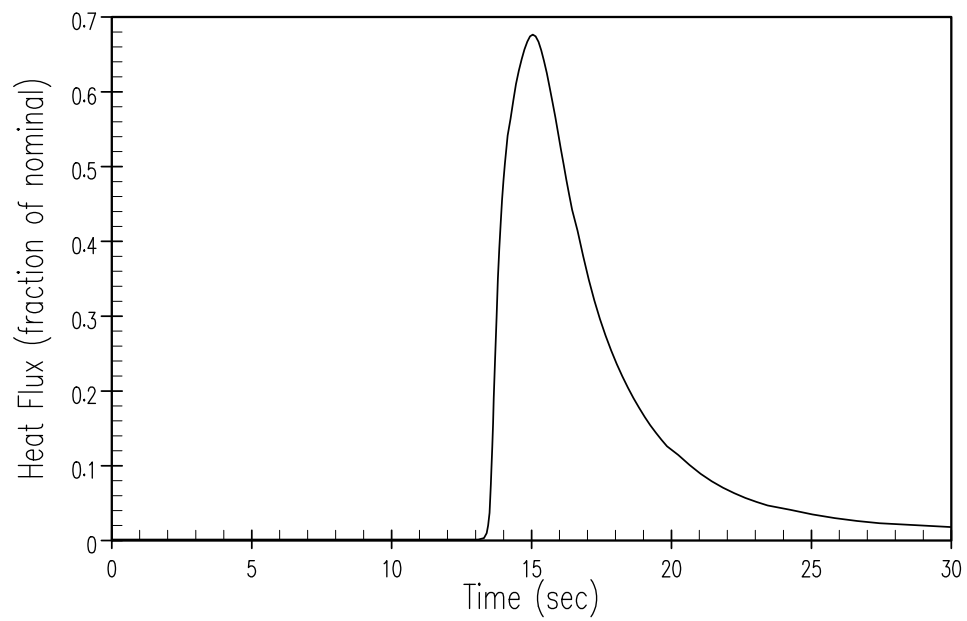
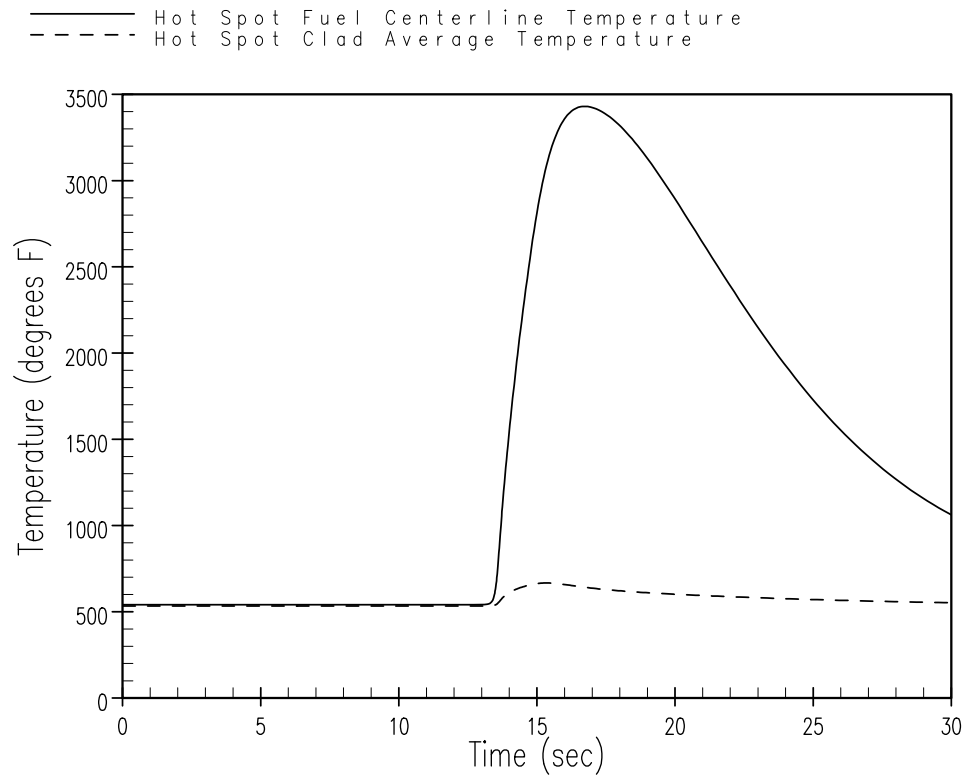


Figure 2.8.5.4.1-3
Uncontrolled CEA Withdrawal from Subcritical Condition
Hot Spot Temperatures versus Time



2.8.5.4.2 Uncontrolled Control Rod Assembly Withdrawal at Power

2.8.5.4.2.1 Regulatory Evaluation

An uncontrolled control element assembly withdrawal at power (CEAWAP) may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion.

The Florida Power and Light (FPL) review covered:

- The description of the causes of the anticipated operational occurrence (AOO) and the description of the event itself,
- The initial conditions,
- The values of reactor parameters used in the analysis,
- The analytical methods and computer codes used, and
- The results of the associated analyses.

The NRC's acceptance criteria are based on:

- General Design Criterion (GDC)-10, insofar as it requires that the reactor coolant system (RCS) be designed with appropriate margin to ensure that specified acceptable fuel design limits (SAFDLs) are not exceeded during normal operations, including AOOs;
- GDC-20, insofar as it requires that the reactor protection system (RPS) 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
- 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.

Specific review criteria are contained in Standard Review Plan (SRP) Section 15.4.2 and other guidance provided in Matrix 8 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDCs for the CEAWAP event are as follows:

- GDC-10 is described in UFSAR Section 3.1.10 Criterion 10 – Reactor Design.

The reactor core and associated coolant, control, and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

SAFDLs are stated in UFSAR Section 4.3. Minimum margins to SAFDLs are prescribed in the technical specifications (limiting conditions for operations) which support UFSAR Chapters 4 and 15.

- GDC-20 is described in UFSAR Section 3.1.20 Criterion 20 – Protection System Functions.

The protection system shall be designed (1) to initiate automatically the operation of appropriate systems including the reactivity control systems, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and to initiate the operation of systems and components important to safety.

The RPS monitors reactor operating conditions and automatically initiates a reactor trip when the monitored variable or combination of variables exceeds a prescribed operating range. The reactor trip setpoints are selected to ensure that AOOs do not cause SAFDLs to be violated. Specific reactor trips are described in UFSAR Section 7.2.

Reactor trip is accomplished by de-energizing the control element drive mechanism (CEDM) bolting latch coils through the interruption of the CEDM power supply. The control element assemblies (CEAs) are thus released to drop into the core reducing reactor power.

The engineered safety features actuation system (ESFAS) monitors potential accident conditions and automatically initiates engineered safety features and their supporting systems when the monitored variables reach prescribed setpoints. The parameters which automatically actuate engineered safety features are described in UFSAR Section 7.3.

- GDC-25 is described in UFSAR Section 3.1.25 Criterion 25 – Protection System Requirements for Reactivity Control Malfunctions.

The protection system shall be designed to assure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of control rods.

Reactor shutdown with CEAs is accomplished completely independent of the control functions since the trip breakers interrupt power to the CEDMs regardless of existing control signals. The design is such that the system can withstand accidental withdrawal of controlling groups without exceeding acceptable fuel design limits. Analysis of possible reactivity control malfunctions is given in UFSAR Section 15.4. The RPS will prevent SAFDLs from being exceeded for an AOO.

UFSAR Section 15.4.2 describes the analysis of the uncontrolled CEAWAP event.

NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Power Plant Units 1 and 2, dated September 2003, defines the scope of license renewal. Specific design transient analyses are not within the scope of license renewal.

2.8.5.4.2.2 Technical Evaluations

2.8.5.4.2.2.1 Introduction

A continuous CEAWAP will result in an increase in the core heat flux due to the positive reactivity insertion. Immediately after the initiation of the CEAWAP event, steam generator heat removal

rates will lag behind the core power generation rate, steam pressure will increase until the steam generator pressure reaches the safety valve setpoint. This power mismatch will cause increases in RCS pressure and T_{avg} , and pressurizer water level and pressure. The rate of the power increase depends upon the reactivity insertion rate. Unless this accident is terminated by manual or automatic action, the power mismatch and resultant coolant temperature rise will eventually result in departure from nucleate boiling (DNB) and/or fuel centerline melt.

The uncontrolled CEAWAP event is analyzed for Mode 1 (power operation). The uncontrolled CEA bank withdrawal from a subcritical or low-power condition is considered as an independent event discussed in LR [Section 2.8.5.4.1](#), Uncontrolled Control Rod Assembly Withdrawal from a Subcritical or Low Power Startup Condition.

To avert the core damage that would result from this event, the RPS is designed to automatically terminate any such event before the departure from nucleate boiling ratio (DNBR) falls below the limit value, the peak linear heat rate limit is reached, or the peak primary pressure exceeds the overpressure limit. Depending on the initial power level and the reactivity insertion rate, the reactor will be tripped and the CEAWAP terminated by any of the following trip signals:

- Variable high power trip (VHPT),
- High pressurizer pressure,
- Thermal margin/low pressure (TM/LP), and
- High local power density.

2.8.5.4.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

A number of cases were analyzed assuming a range of reactivity insertion rates for both minimum and maximum reactivity feedback conditions at various power levels. The cases presented below are representative for this event.

To obtain conservative values for minimum DNBR and ensure that the peak linear heat rate limits are met, the following analysis assumptions are made. See LR [Section 2.8.5.0](#), Accident and Transient Analyses, for additional inputs and assumptions.

1. Cases analyzed to assess the acceptability with respect to DNBR limits are analyzed with the revised thermal design procedure (RTDP) methodology (Reference WCAP-11397-P-A (Proprietary) and WCAP-11397-A (Non-Proprietary), Revised Thermal Design Procedure, Friedland, A. J. and Ray, S., April 1989.). Therefore, the initial reactor power, RCS pressure, RCS flow, and RCS temperatures are assumed to be at their nominal values. Uncertainties in these initial conditions are included in the DNBR limit. Minimum measured flow is modeled.
2. Reactivity coefficients – two feedback conditions are analyzed:
 - a. Minimum reactivity feedback – A zero moderator temperature coefficient (MTC) of reactivity is assumed at full power. For power levels less than or equal to 70 percent power, a positive MTC is conservatively assumed, corresponding to the beginning of core

life. A conservatively small (in absolute magnitude) Doppler power coefficient is used in the analysis.

- b. Maximum reactivity feedback – A negative MTC of reactivity is assumed. A conservatively large positive moderator density coefficient and a large (in absolute magnitude) negative Doppler power coefficient are assumed.

- 3. Power levels of 20, 50, 65, and 100 percent of full power are considered.

To obtain conservative values for peak RCS pressure, the following analysis assumptions are made:

- 1. Cases analyzed to assess the acceptability with respect to peak RCS pressure limits are analyzed with the standard thermal design procedure (STDP) methodology. Uncertainties are applied to the nominal values for the initial conditions on reactor power, RCS temperature, and pressurizer pressure. Specifically, the appropriate uncertainties are added to the reactor power and RCS temperature. Both positive and negative pressure uncertainties are considered, as defined in Assumption 3 below. Thermal design flow is modeled.
- 2. Minimum reactivity feedback conditions are assumed.
- 3. A spectrum of cases considered two initial pressure conditions corresponding to the application of positive and negative pressure uncertainty. Initial pressurizer pressures of 2180 psia and 2395 psia were assumed.
- 4. Power Levels of 25, 50, 75, 85, 90, 95, and 100 percent of full power with an initial pressurizer pressure of 2395 psia were considered for the analysis of peak RCS pressure.

The following conservative assumptions were applied to both the DNBR and RCS overpressurization cases:

- 1. The VHPT ceiling is calculated based on the technical specifications' ceiling of 107% of rated thermal power (RTP) plus appropriate uncertainties.
- 2. The VHPT offset, for part power cases, is calculated based on the Technical Specifications nominal value of 9.61% plus appropriate uncertainties.
- 3. The TM/LP trip is modeled without taking credit for any reduction in the calculated trip setpoint pressure associated with any skewed axial shape index (ASI).
- 4. The high pressurizer pressure reactor trip setpoint assumed in the safety analysis is 2415 psia.
- 5. The CEA trip insertion characteristics were based on the assumption that the highest worth assembly is stuck in its fully withdrawn position.

6. A range of reactivity insertion rates was examined. The maximum positive reactivity insertion rate is greater than that which would be obtained from the simultaneous withdrawal of the two control rod banks having the maximum combined differential rod worth at a conservative speed. The maximum bounding reactivity insertion rate that is required for consideration is 53 pcm/sec. A minimum withdrawal rate of 1 pcm/sec is considered as well.
7. The analysis assumed 10% steam generator tube plugging (SGTP) in both steam generators.
8. The 100% of rated power, primary overpressurization case considered more limiting, conservative, de-calibration factors compared to those utilized for the part-power primary overpressurization cases. An additional 100% case was re-analyzed with the same de-calibration factors used for the part-power cases to provide an accurate trend comparison.

The CEAWAP accident is considered an AOO. The following items summarize the main acceptance criteria associated with this event:

- The critical heat flux will not be exceeded. This is met by demonstrating that the minimum DNBR does not go below the safety analysis limit value at any time during the transient.
- Fuel centerline temperatures will not exceed the melting point of the fuel. This is met by demonstrating that the peak linear heat rate criterion is not exceeded.
- Pressure in the primary RCS will be maintained below 110 percent of the design pressures.
- The event will not generate a more serious plant condition without other faults occurring independently. This is met by demonstrating that the pressurizer does not reach a water-solid condition.

The protection features presented in LR [Section 2.8.5.4.2.2.1](#) provide mitigation of the CEAWAP transient such that the above criteria are satisfied.

2.8.5.4.2.2.3 Description of Analyses and Evaluations

The CEAWAP analysis is performed to demonstrate that the reactor protection system functions and mitigates the consequences at the extended power uprate (EPU) conditions utilizing currently approved methodology. The CEAWAP transient is analyzed with the RETRAN (Reference WCAP-14882-P-A (Proprietary) and WCAP-15234-A (Non-Proprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, Huegel, D. S., et. al., April 1999.) and ANC (Reference WCAP-10965-P-A, ANC: A Westinghouse Advanced Nodal Computer Code, Liu Y. S., et al., September 1986.) computer programs. RETRAN simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generators, and steam generator relief and safety valves. The program computes pertinent plant variables including temperatures, pressures, and power level. ANC is then used to calculate the peak linear heat rate based on the nuclear power and RCS temperature (enthalpy), and core flow from RETRAN. Both ANC and RETRAN are NRC approved computer codes.

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

As discussed above, the design transient analyses were determined to be outside the scope of License Renewal; therefore, with respect to the design basis accidents and transients, the EPU does not impact any License Renewal evaluations.

2.8.5.4.2.2.5 Results

The sequence of events for two selected cases are reported in LR [Table 2.8.5.4.2-1](#) for the CEAWAP transients analyzed to support the EPU. The limiting results are summarized in LR [Table 2.8.5.4.2-2](#).

LR [Table 2.8.5.4.2-4](#) compares the results of the EPU analysis against the results of the current analysis. The current analysis modeled the VHPT very conservatively with a large fixed offset, the EPU analysis directly models both the power measurement and process uncertainties to account for excore de-calibration. Therefore, this analysis directly considers excore de-calibration resulting from the CEA withdrawal. The end result shows that the EPU is an improvement when compared to DNBR. However, the EPU attains a higher peak heat flux and a higher peak pressure in the RCS when compared to the current analysis.

LR [Table 2.8.5.4.2-3](#) compares the results of the part power cases analyzed for RCS overpressurization. The RCS overpressurization cases demonstrate that the maximum RCS pressure remains below the safety analysis limit of 2750 psia. LR [Figure 2.8.5.4.2-13](#) illustrates that the maximum pressurizer pressure remains below the safety analysis limit of 2750 psia. This confirms that the peak pressure criterion is met for the CEAWAP event.

The results of the relaxation of constant axial offset control (RAOC) (Reference WCAP-10216-P-A (Proprietary), Relaxation of Constant Axial Offset Control; FQ Surveillance Technical Specification, Miller, R. W., et al., June 1983.) analysis, using the ANC computer code, demonstrates that the peak linear heat rate calculated for the limiting statepoint, 100% power, maximum feedback, and 53 pcm/sec case, is below the safety analysis design limit. This demonstrates that the peak linear heat rate criterion is met for the CEAWAP event. Due to the core power increase associated with the EPU, the peak heat flux for the event increased from the current analysis value of 117% to 125%. This peak heat flux value was confirmed to result in a peak linear heat rate value that would not exceed the limit of 22.0 kW/ft and is therefore acceptable to meet the fuel centerline melting acceptance criteria.

LR [Figures 2.8.5.4.2-1](#) through [2.8.5.4.2-4](#) show the response of nuclear power, pressurizer pressure, RCS vessel T_{avg} , and DNBR for a rapid (53 pcm/sec) CEA withdrawal incident starting from full power with maximum reactivity feedback conditions. Reactor trip on the variable high power function occurs shortly after the start of the accident. Since this case results in a rapid increase in nuclear power with core heat flux lagging behind because of the thermal time constants of the plant, small changes in the reactor core T_{avg} and pressurizer pressure result. Therefore, a large margin to the safety analysis limit DNBR is maintained.

The response of nuclear power, pressurizer pressure, RCS vessel T_{avg} , and DNBR for a slow (2 pcm/sec) CEA withdrawal from 100% power with maximum reactivity feedback conditions are

shown in **Figures 2.8.5.4.2-5** through **2.8.5.4.2-8**. Reactor trip on TM/LP occurs after a longer period of time compared to the rapid CEA withdrawal mentioned above and thus, the rise in temperature is consequently larger. Again, the minimum DNBR is greater than the safety analysis limit value.

LR **Figures 2.8.5.4.2-9** through **2.8.5.4.2-12** show the minimum predicted DNBR as a function of the reactivity insertion rate for the four initial power levels analyzed (100%, 65%, 50% and 20%) for both minimum and maximum reactivity feedback conditions. It is shown that the combination of reactor trip functions modeled provides protection over the entire range of reactivity insertion rates because the minimum DNBR is never less than the safety analysis limit value. In the references figures, the shape of the curves of minimum DNBR versus reactivity insertion rate is a function of both the reactor core and coolant system transient response and the reactor trips assumed to provide protection for this event.

It has been shown that for all power levels considered, pressurizer filling is precluded for the CEAWAP event. Therefore, the CEAWAP event will not generate a more serious plant condition without other faults occurring independently.

Based on the above, it is concluded that all acceptance criteria associated with uncontrolled CEAWAP event have been met for at the EPU conditions.

2.8.5.4.2.3 Conclusion

FPL has reviewed the analyses of the uncontrolled CEAWAP event and concludes that the analyses have adequately accounted for the changes in core design required for operation of the plant at the proposed power level. FPL also concludes that the analyses were performed using acceptable analytical models. FPL further concludes that the analyses have demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs are not exceeded. Based on this, FPL concludes that the plant will continue to meet the requirements of GDCs -10, -20 and -25 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to the uncontrolled control rod assembly withdrawal at power.

2.8.5.4.2.4 References

1. WCAP-11397-P-A (Proprietary) and WCAP-11397-A (Non-Proprietary), Revised Thermal Design Procedure, Friedland, A. J. and Ray, S., April 1989.
2. WCAP-14882-P-A (Proprietary) and WCAP-15234-A (Non-Proprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, Huegel, D. S., et. al., April 1999.
3. WCAP-10965-P-A, ANC: A Westinghouse Advanced Nodal Computer Code, Liu Y. S., et al., September 1986.
4. WCAP-10216-P-A (Proprietary), Relaxation of Constant Axial Offset Control; FQ Surveillance Technical Specification, Miller, R. W., et al., June 1983.

**Table 2.8.5.4.2-1
Time Sequence of Events for Uncontrolled CEA Withdrawal at Power
(100% Initial Power & Maximum Reactivity Feedback)**

Event	Time (Seconds)⁽¹⁾
Case A (53 pcm/sec):	
Initiation of Uncontrolled CEA Withdrawal at Full Power with Maximum Reactivity Feedback	0.0
Pressurizer power-operated relief valve (PORV) opens	9.20 ⁽²⁾
High pressurizer pressure trip (HPPT) setpoint reached	11.14
Reactor trip on high pressurizer pressure	13.29
Rods begin to fall into core	14.03
Minimum DNBR occurs	14.10
First main steam safety valve (MSSV) opens	18.34
Case B (2 pcm/sec):	
Initiation of Uncontrolled CEA Withdrawal at Full Power with Maximum Reactivity Feedback	0.0
First MSSV opens	713.16
TM/LP setpoint reached	765.18
Reactor trip on TM/LP	766.10
Rods begin to fall into core	766.84
Minimum DNBR occurs	765.00
Notes:	
1. The times are from the beginning of the transient.	
2. It is conservative for the PORV to open prior to obtaining the HPPT reactor trip for the evaluation of DNB due to the lower RCS pressure obtained.	

Table 2.8.5.4.2-2
Limiting Results for Uncontrolled CEA Withdrawal at Power

Criterion	Limiting Analysis Value	Analysis Limit	Case
DNBR	1.74	1.42	100% power, maximum feedback, 53 pcm/sec
Core heat flux fraction of nominal (FON)	1.246	1.27	100% power, maximum feedback, 53 pcm/sec
Peak linear heat rate (kW/ft)	14.9	22.0	100% power, maximum feedback, 53 pcm/sec
RCS pressure (psia)	2485.2	2750.0	100% power, 2395 psia initial pressure, minimum feedback, 53 pcm/sec
Pressurizer overfill (ft ³)	1483.4	1519	100% power, maximum feedback, 1 pcm/sec

Table 2.8.5.4.2-3
Summary of Part Power RCS Overpressurization Results

Power Level (%) ⁽¹⁾	Initial Core Power (MWth)	Maximum RCS Pressure (psia)	Maximum Pressurizer Volume (ft³)
100	3030	2485.2 ⁽²⁾ 2483.90	958.74 ⁽²⁾ 945.85
95	2880	2483.00	945.37
90	2730	2481.51	944.89
85	2575	2481.25	944.40
75	2250	2479.69	923.07
50	1500	2476.66	753.21
25	750	2473.24	592.61
Notes: 1. Approximate power level in percent. The initial power level includes the power measurement uncertainty. 2. The 100% power primary overpressurization case documented in LR Tables 2.8.5.4.2-2 and 2.8.5.4.2-4 uses more conservative de-calibration factors than the case runs considered for the part-power overpressurization examination. As such, an additional 100% power case was run with the same de-calibration factors used for the remaining lower power cases to provide an accurate comparison.			

Table 2.8.5.4.2-4
Results and Comparison to Current Analysis

	EPU Analysis	Current Analysis	Limit
Minimum DNBR	1.74	1.49	1.42
Peak primary system pressure (psia)	2485.2	2483.3	2750.0
Maximum core heat flux (FON)	1.246	1.172	1.27 ⁽¹⁾
Notes: 1. A maximum heat flux of 1.27 FON yields a peak linear heat rate below the acceptance criteria.			

Figure 2.8.5.4.2-1
Uncontrolled CEAWAP 100% Power, 53 pcm/sec
Reactivity Insertion Rate & Maximum Feedback
Nuclear Power vs. Time

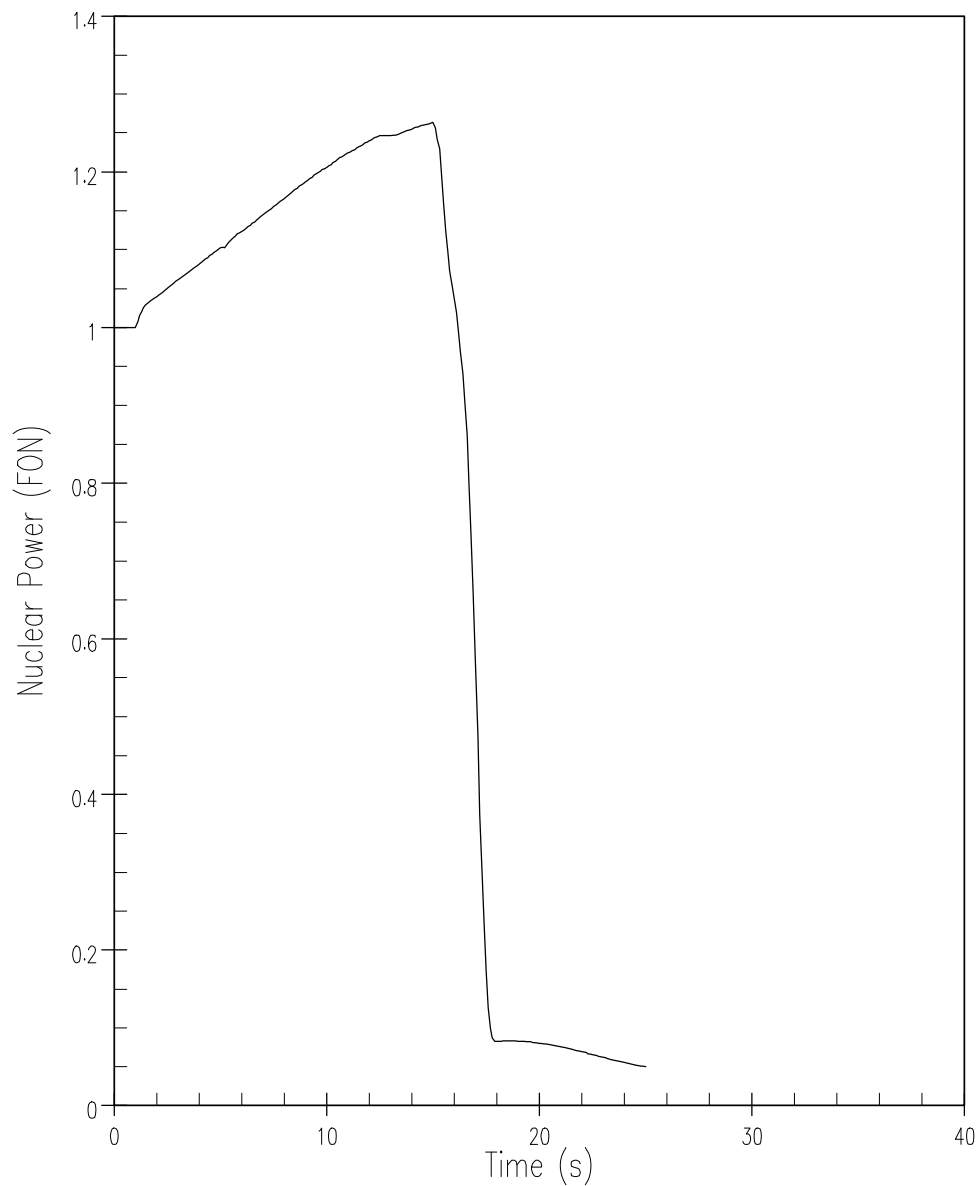


Figure 2.8.5.4.2-2
Uncontrolled CEAWAP 100% Power, 53 pcm/sec
Reactivity Insertion Rate & Maximum Feedback
Pressurizer Pressure vs. Time

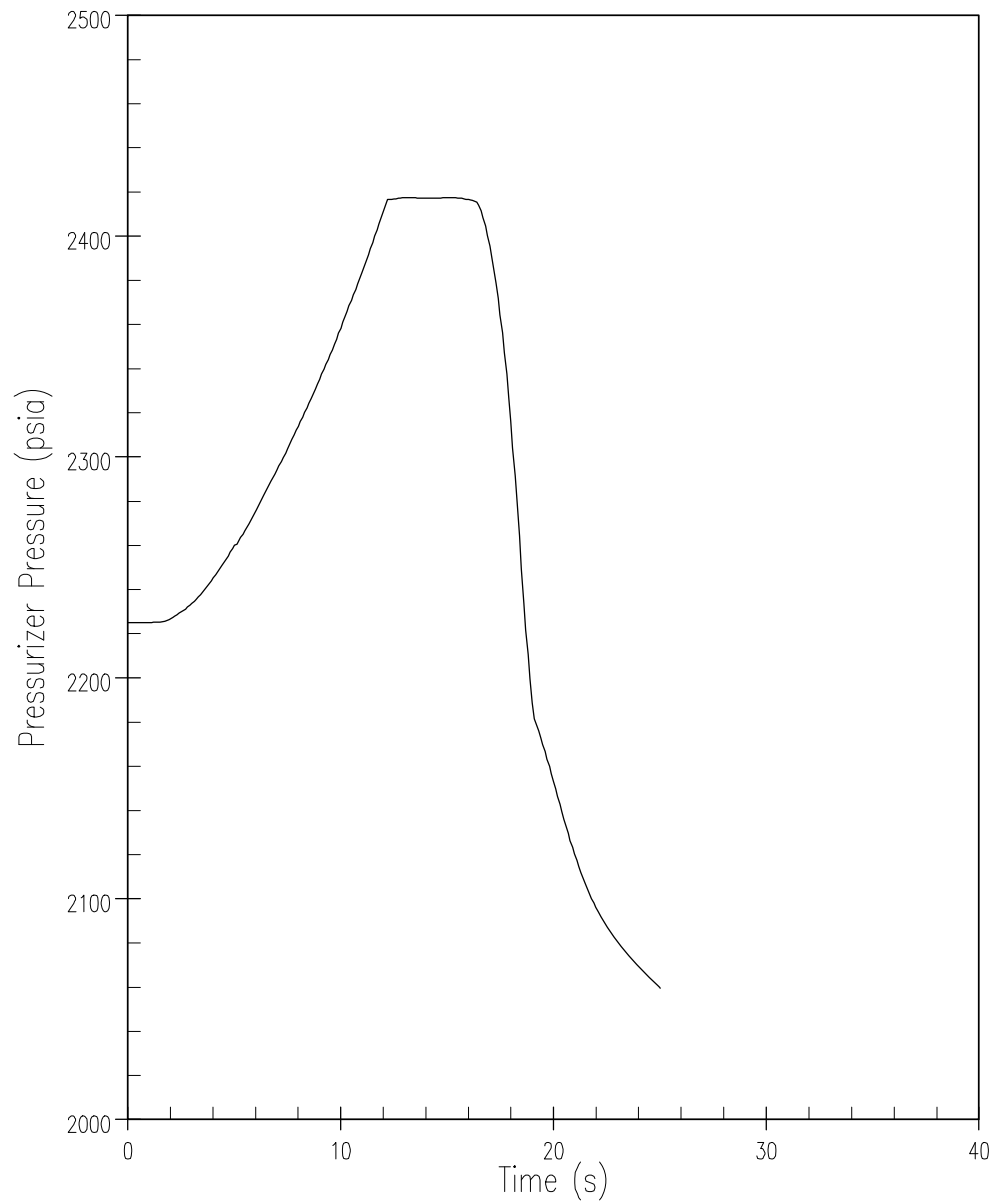


Figure 2.8.5.4.2-3
Uncontrolled CEAWAP 100% Power, 53 pcm/sec
Reactivity Insertion Rate & Maximum Feedback
Vessel T_{avg} vs. Time

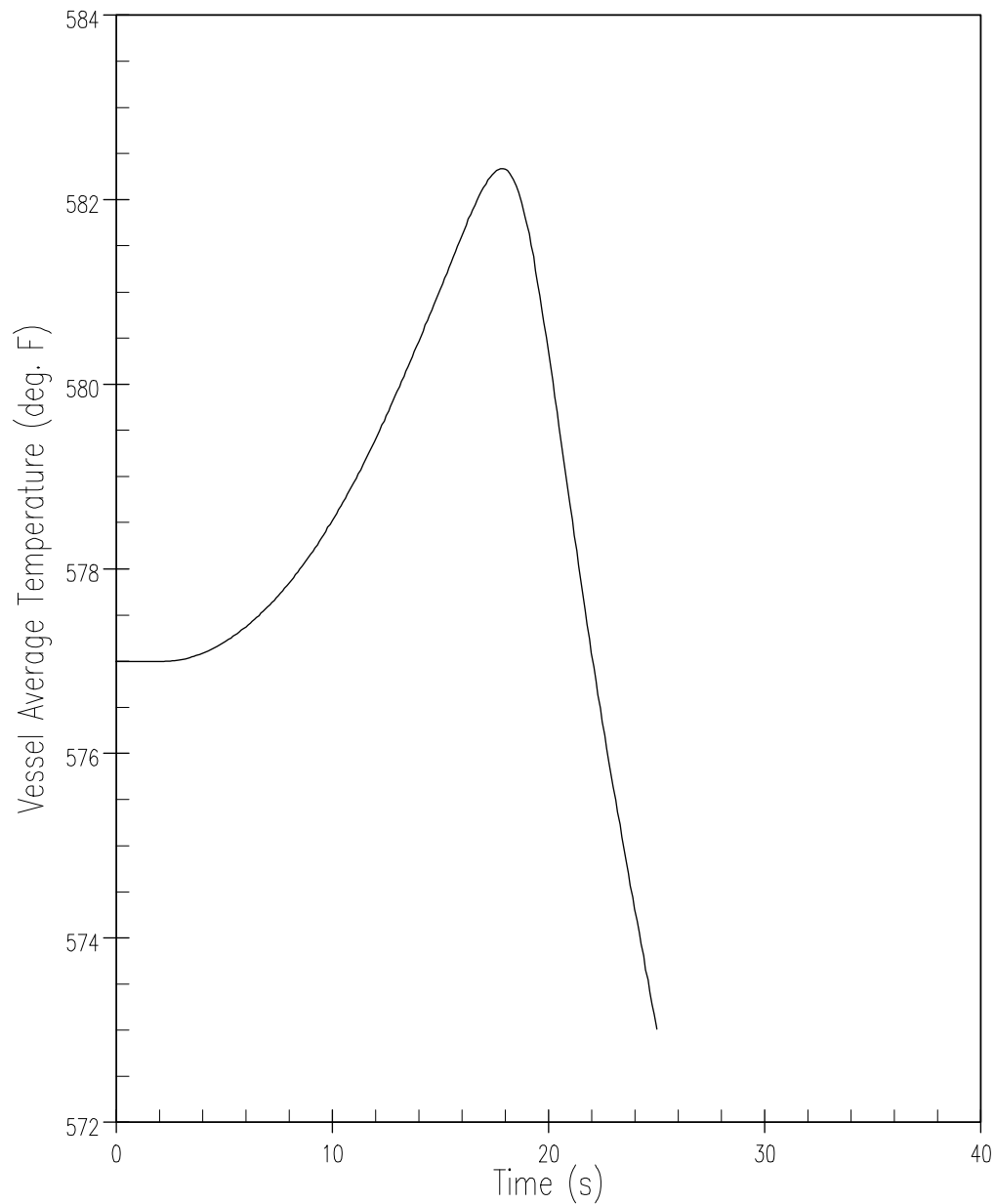


Figure 2.8.5.4.2-4
Uncontrolled CEAWAP 100% Power, 53 pcm/sec
Reactivity Insertion Rate & Maximum Feedback
DNBR vs. Time

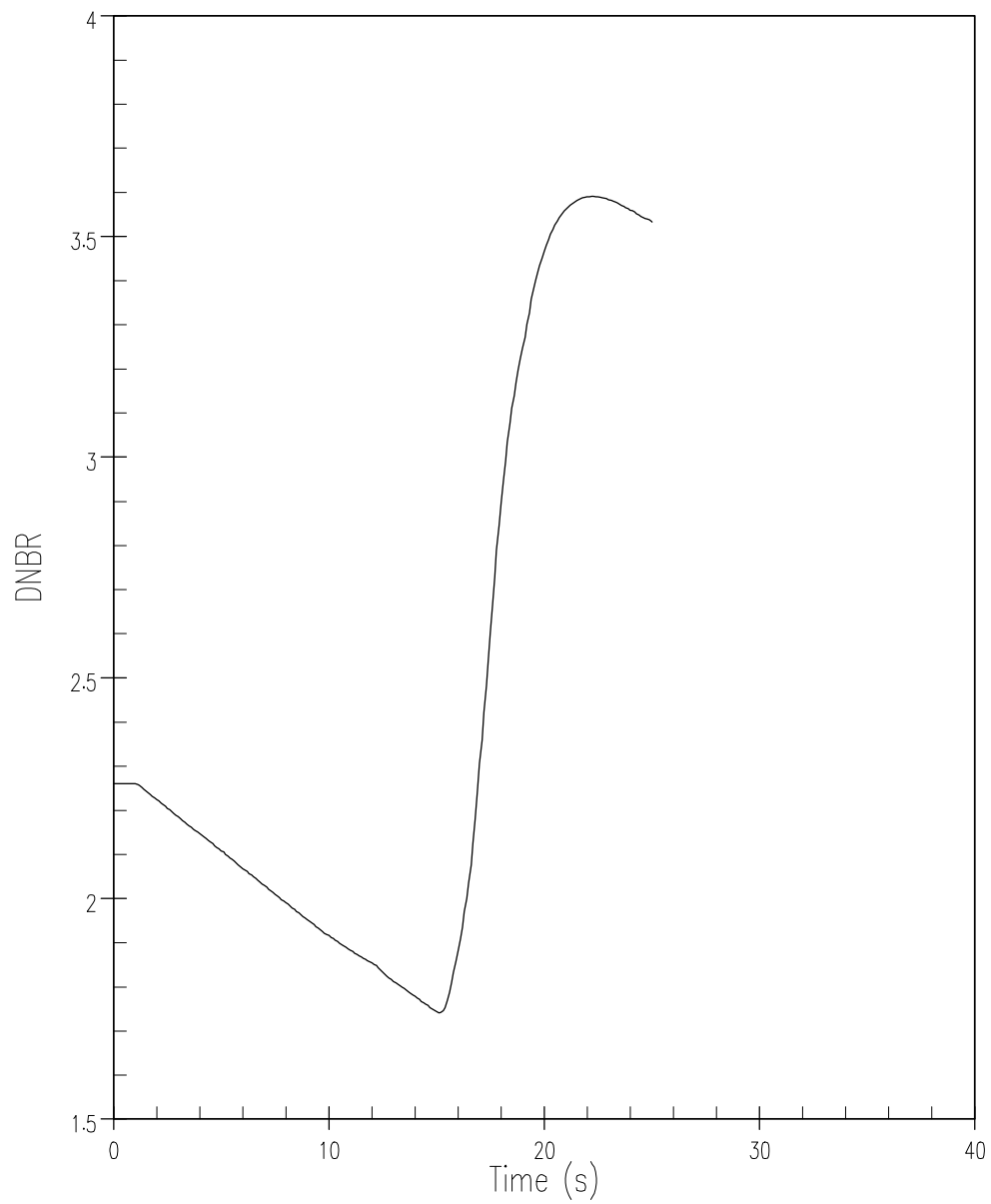


Figure 2.8.5.4.2-5
Uncontrolled CEAWAP 100% Power, 2 pcm/sec
Reactivity Insertion Rate & Maximum Feedback
Nuclear Power vs. Time

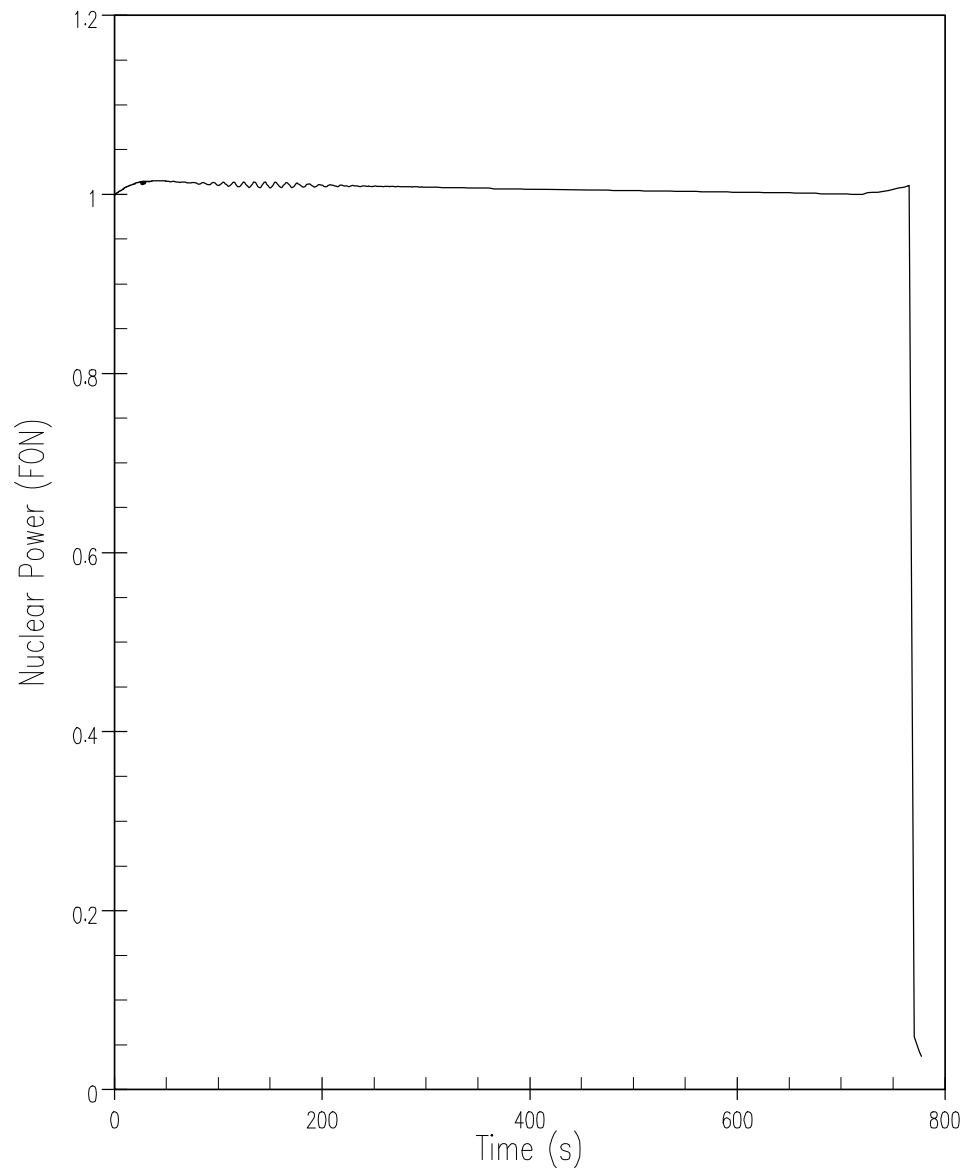


Figure 2.8.5.4.2-6
Uncontrolled CEAWAP 100% Power, 2 pcm/sec
Reactivity Insertion Rate & Maximum Feedback
Pressurizer Pressure vs. Time

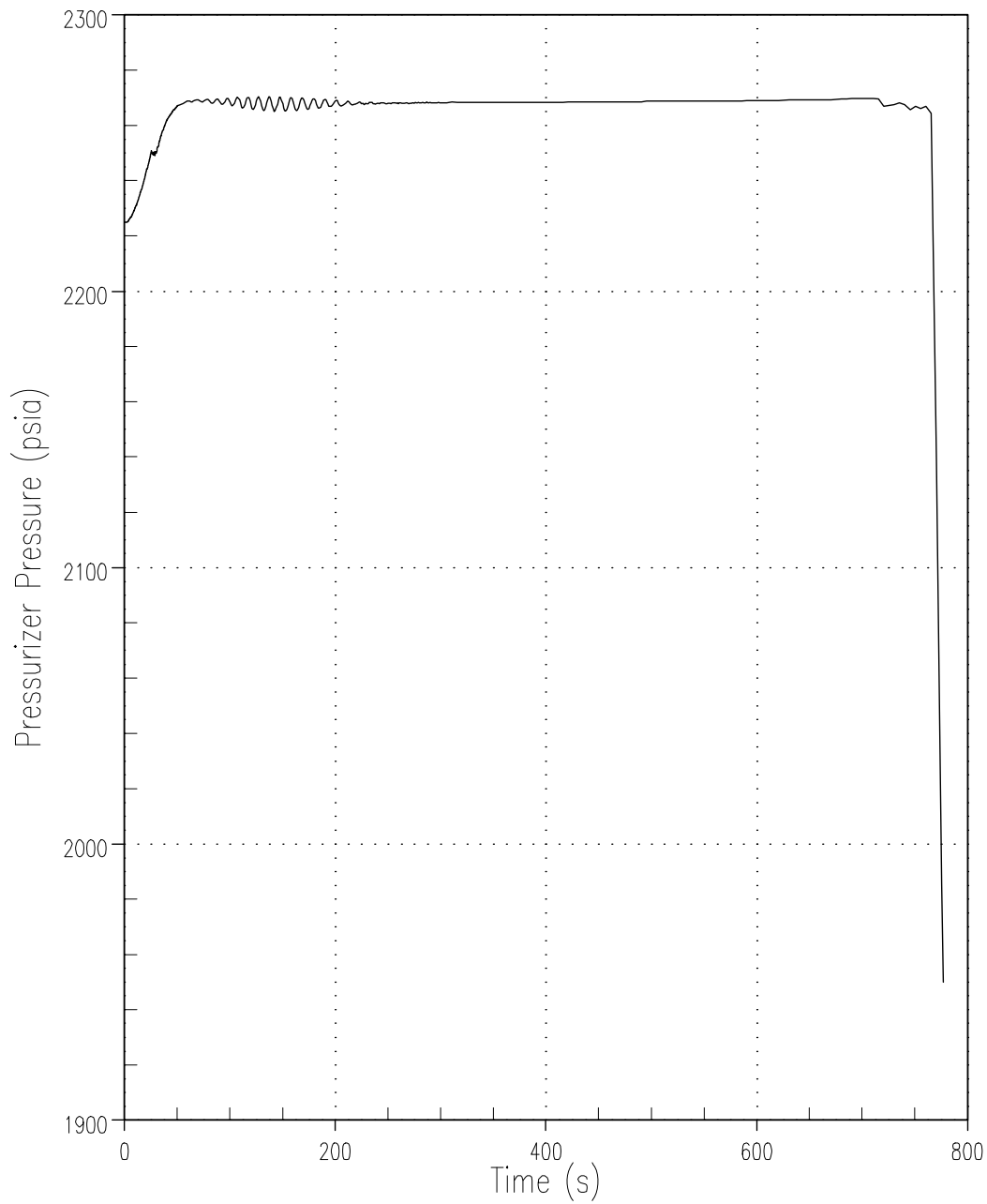


Figure 2.8.5.4.2-7
Uncontrolled CEAWAP 100% Power, 2 pcm/sec
Reactivity Insertion Rate & Maximum Feedback
Vessel T_{avg} vs. Time

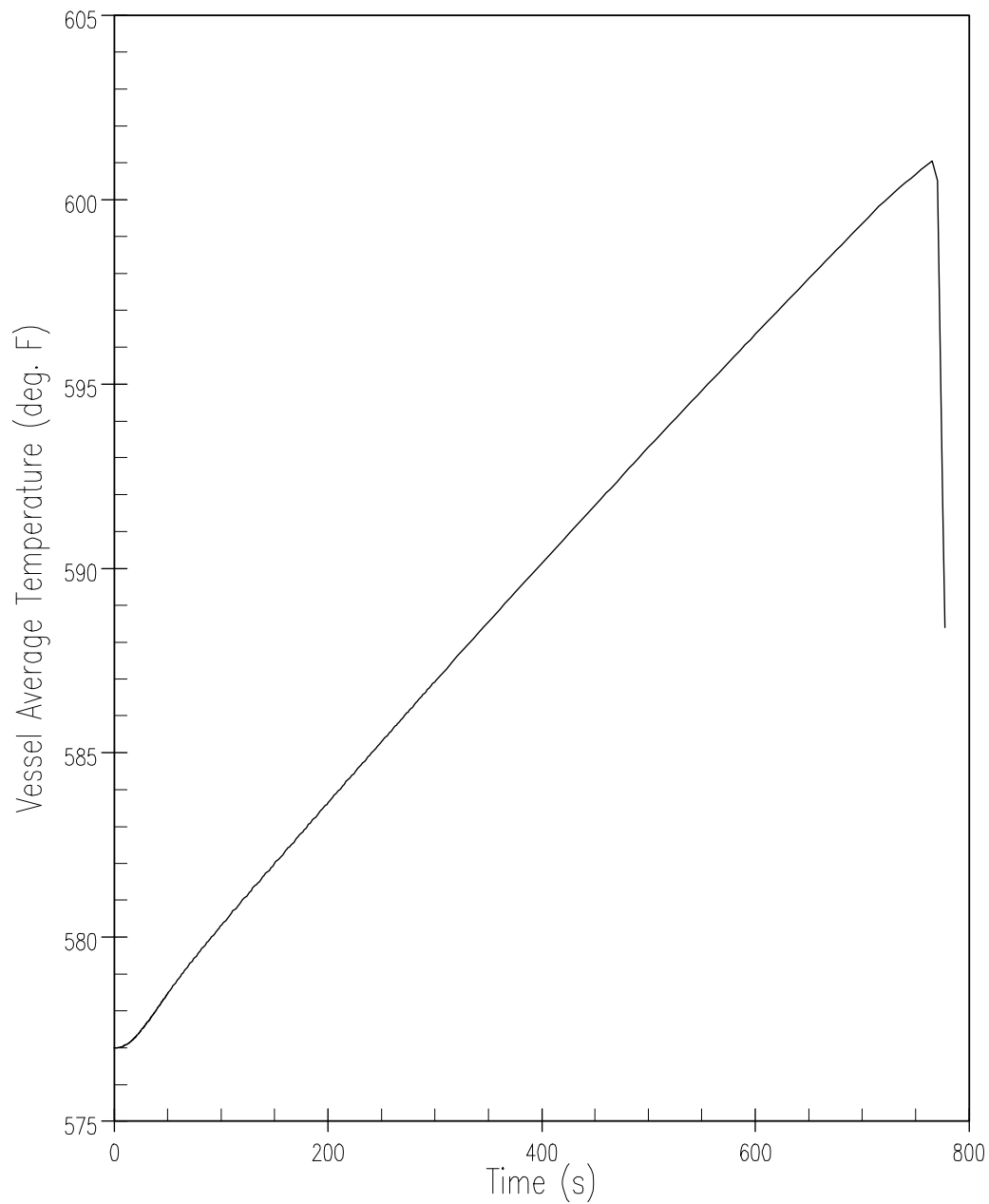


Figure 2.8.5.4.2-8
Uncontrolled CEAWAP 100% Power, 2 pcm/sec
Reactivity Insertion Rate & Maximum Feedback
DNBR vs. Time

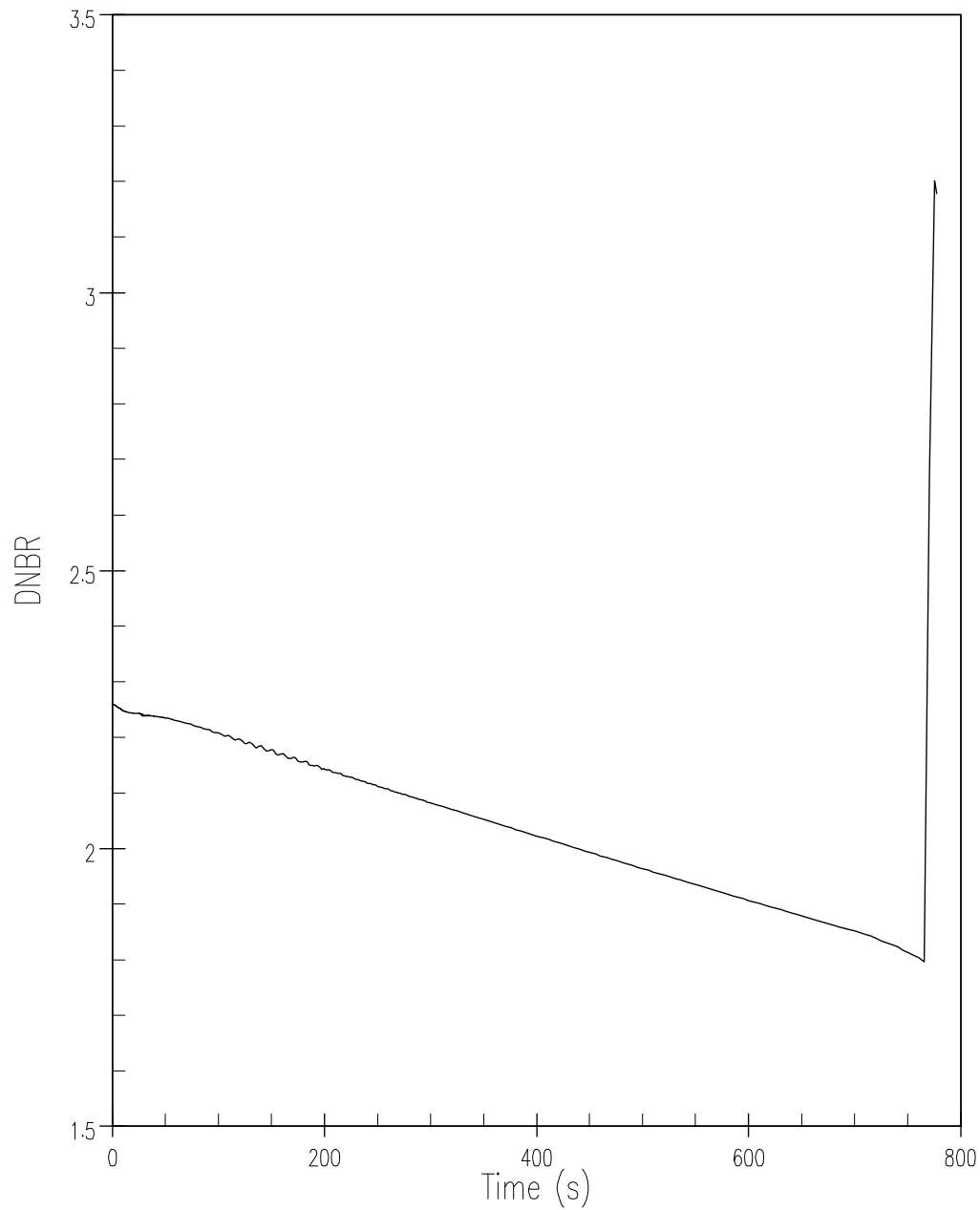


Figure 2.8.5.4.2-9
Uncontrolled CEAWAP 100% Power
DNBR vs. Reactivity Insertion Rate

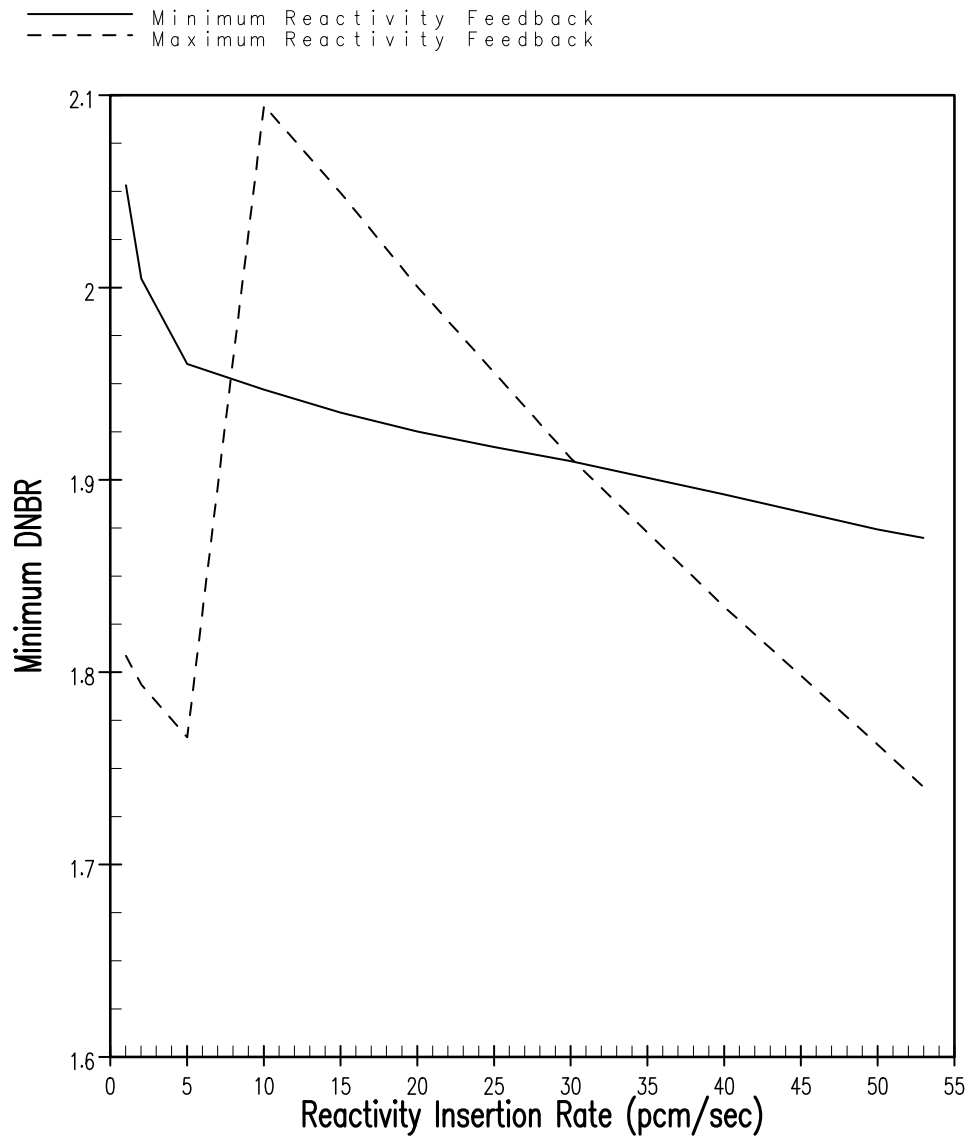


Figure 2.8.5.4.2-10
Uncontrolled CEAWAP 65% Power
DNBR vs. Reactivity Insertion Rate

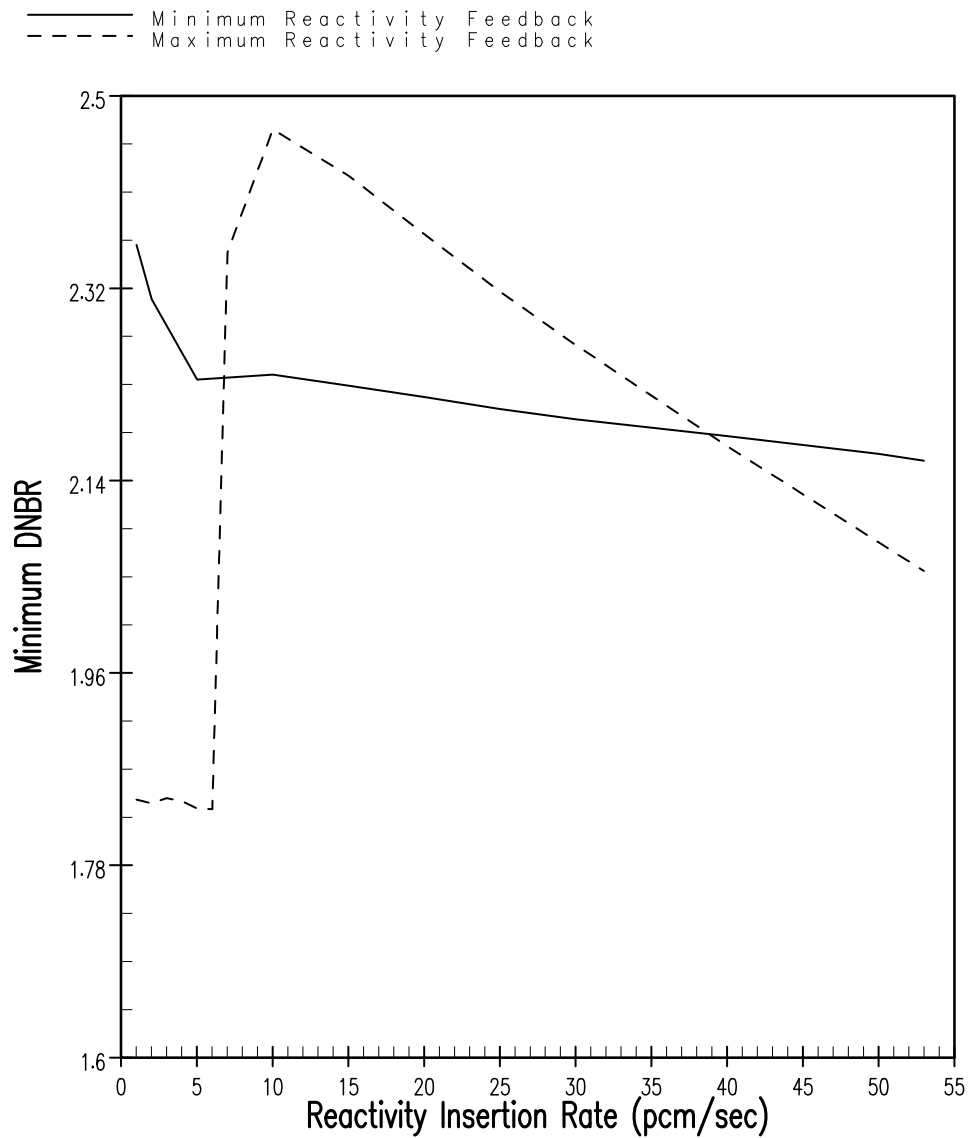


Figure 2.8.5.4.2-11
Uncontrolled CEAWAP 50% Power
DNBR vs. Reactivity Insertion Rate

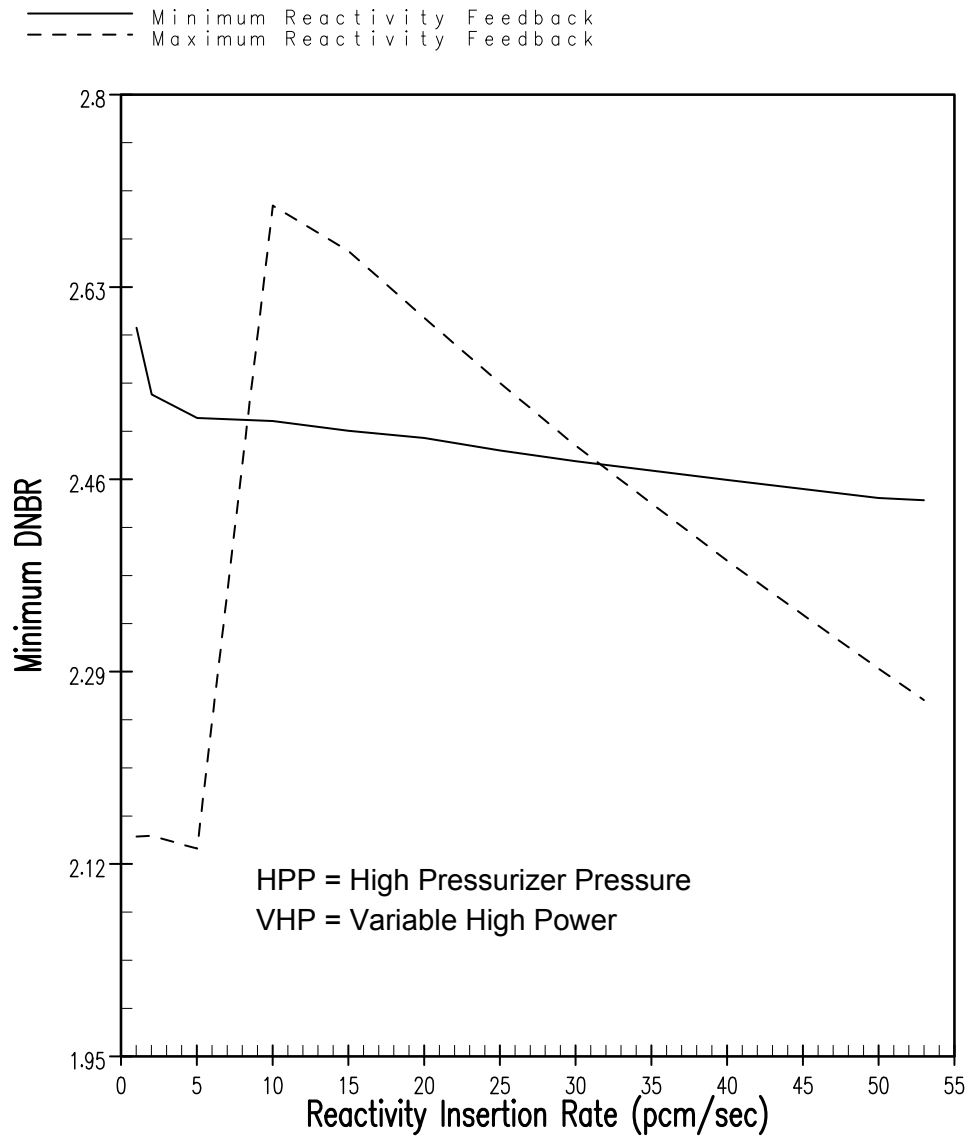


Figure 2.8.5.4.2-12
Uncontrolled CEAWAP 20% Power
DNBR vs. Reactivity Insertion Rate

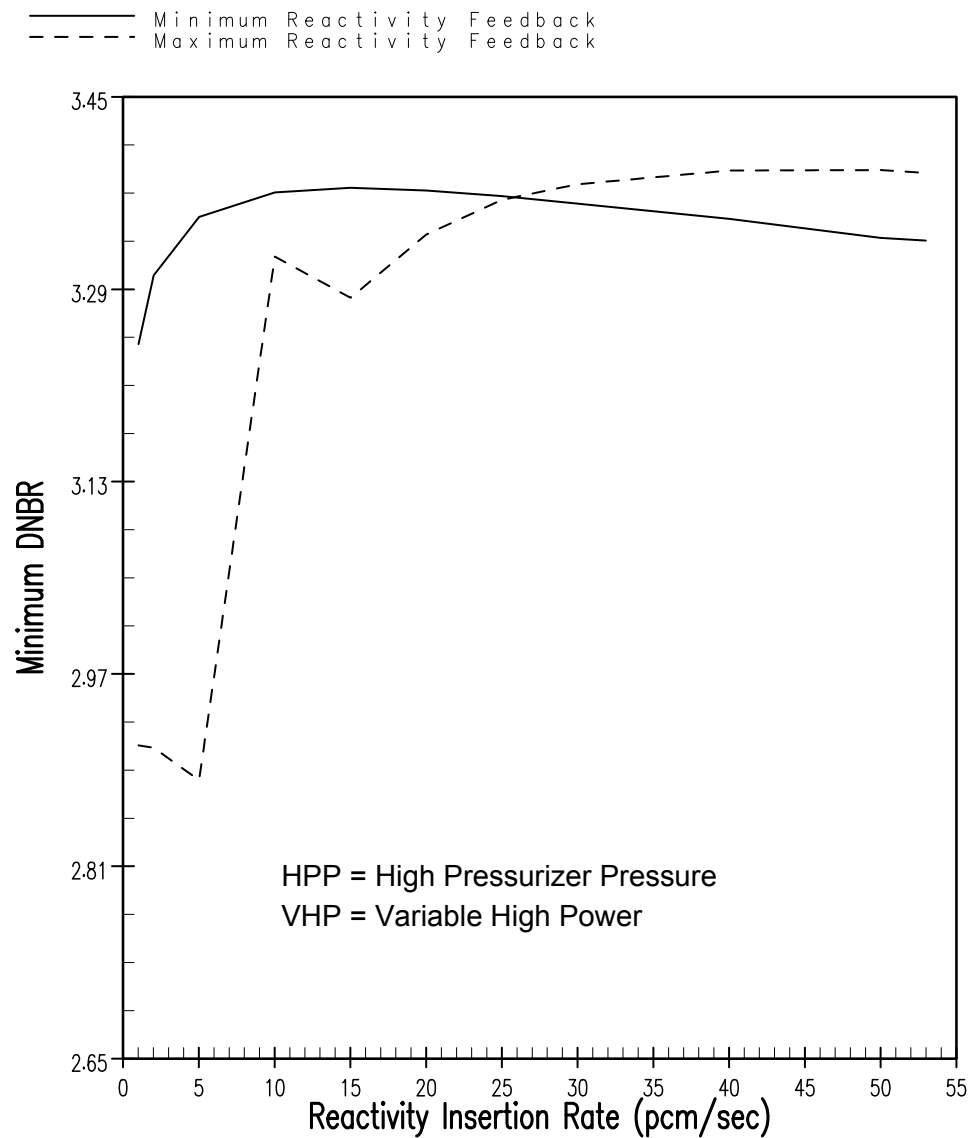
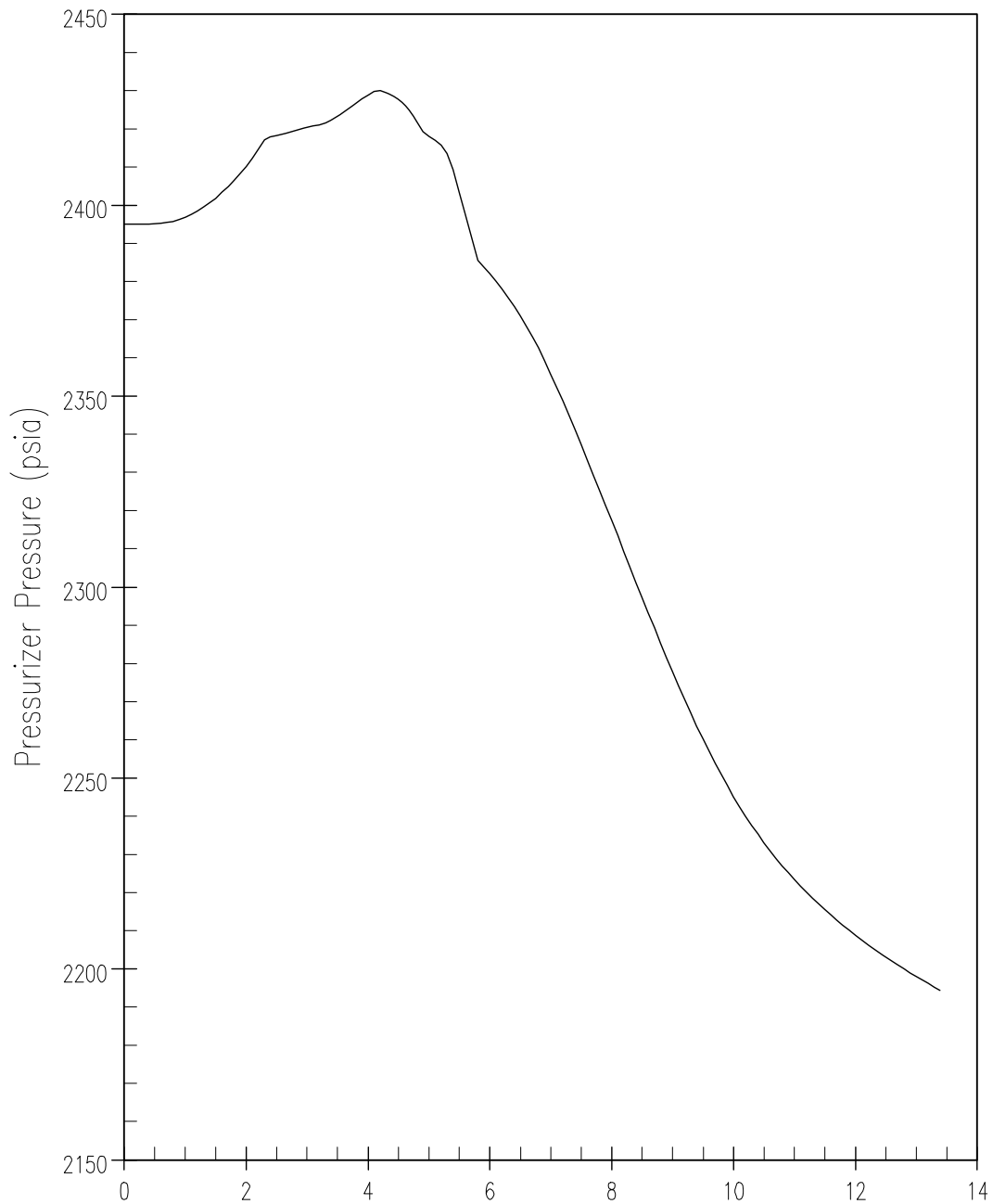


Figure 2.8.5.4.2-13
Uncontrolled CEAWAP 100% Power
RCS Overpressurization
Pressurizer Pressure vs. Time



2.8.5.4.3 Control Rod Misoperation

2.8.5.4.3.1 Regulatory Evaluation

Florida Power and Light (FPL) utilizes the “control element assembly” (CEA) nomenclature whereas RS-001 uses “control rod.” It is FPL’s intention to use CEA where applicable throughout this LR section. The FPL review covered the types of CEA misoperations that are assumed to occur, including those caused by a system malfunction or operator error.

The review covered:

- Descriptions of CEA position, flux, pressure, and temperature indication systems, and those actions initiated by these systems (e.g., turbine runback, CEA withdrawal prohibit, CEA block) which can mitigate the effects or prevent the occurrence of various misoperations;
- The sequence of events;
- The analytical model used for analyses;
- Important inputs to the calculations; and
- The results of the analyses.

The NRC’s acceptance criteria are based on:

- General Design Criterion (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 (AOOs);
- 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
- 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.

Specific review criteria are contained in Standard Review Plan (SRP) Section 15.4.3 and other guidance provided in Matrix 8 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in the Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

Specific GDCs for the CEA misoperation are as follows:

- GDC-10 is described in UFSAR Section 3.1.10 Criterion 10 – Reactor Design.

The reactor core and associated coolant, control and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

SAFDLs are stated in UFSAR Section 4.3. Minimum margins to SAFDLs are prescribed in the technical specifications (limiting conditions for operations) which support UFSAR Chapters 4 and 15.

- GDC-20 is described in UFSAR Section 3.1.20 Criterion 20 – Protection System Functions.

The protection system shall be designed (1) to initiate automatically the operation of appropriate systems including the reactivity control systems, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and to initiate the operation of systems and components important to safety.

The reactor protection system (RPS) monitors reactor operating conditions and automatically initiates a reactor trip when the monitored variable or combination of variables exceeds a prescribed operating range. The reactor trip setpoints are selected to ensure that AOOs do not cause SAFDLs to be violated. Specific reactor trips are described in UFSAR Section 7.2.

The engineered safety features actuation system (ESFAS) monitors potential accident conditions and automatically initiates engineered safety features and their supporting systems when the monitored variables reach prescribed setpoints. The parameters which automatically actuate engineered safety features are described in UFSAR Section 7.3. Manual actuation capability is provided to the operator.

- GDC -25 is described in UFSAR Section 3.1.25 Criterion 25 – Protection System Requirements for Reactivity Control Malfunctions.

The protection system shall be designed to assure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of CEAs.

Reactor shutdown with CEAs is accomplished completely independent of the control functions since the trip breakers interrupt power to the control element drive mechanism (CEDM) regardless of existing control signals. The design is such that the system can withstand accidental withdrawal of controlling groups without exceeding acceptable fuel design limits. Analysis of possible reactivity control malfunctions is given in UFSAR Section 15.4. The RPS will prevent SAFDLs from being exceeded for any event of moderate frequency.

UFSAR Section 15.4.3 describes the analysis pertaining to the CEA misoperation event.

NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Power Plant Units 1 and 2, dated September 2003, defines the scope of license renewal. Specific design transient analyses are not within the scope of license renewal.

2.8.5.4.3.2 Technical Evaluation

2.8.5.4.3.2.1 Introduction

A CEA misoperation event is initiated by a single electrical or mechanical failure which causes any number and combination of rods from a CEA subgroup to drop to the bottom of the core. The resulting negative reactivity insertion causes nuclear power to rapidly decrease. The skewed power distribution representative of a control rod misoperation configuration causes an increase in the hot channel factor. For this event, it must be shown that the departure from nucleate boiling (DNB) design basis is met for the combination of power, hot channel factor, and other system conditions which exist following a dropped rod.

The CEA misoperation event accident includes:

- Full-length CEA drop, and
- Full-length CEA subgroup drop.

Automatic rod withdrawal capabilities have been eliminated at St. Lucie Unit 2. Furthermore, the automatic withdrawal prohibit remains functional at the plant and activates via rod bottom contacts. Consequently, it is not possible for the rods to automatically withdraw in response to a power mismatch as a result of a dropped CEA. Therefore, with a decrease in reactor power, the turbine load is not reduced and will remain the same as prior to the dropped CEA. This results in a power mismatch between the primary and secondary system, which leads to a cooldown of the reactor coolant system (RCS). In cases where the reactivity feedback is large enough to offset the worth of the dropped rod, the core power is able to return to the approximate initial full power condition while the RCS temperature and pressure decreases to a lower (than initial) equilibrium condition. In cases where the reactivity feedback is not sufficient enough to offset the worth of the dropped rod, there is a reduction in the core power while a continuous cooldown causes the RCS temperature and pressure to drop until either the thermal margin / low pressure (TM/LP) reactor trip (floor) or low steam generator pressure reactor trip is reached.

2.8.5.4.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The CEA misoperation event is analyzed at EPU conditions. The purpose of the analysis is to generate bounding transient statepoints that will be verified on a plant-specific, cycle-specific basis for future reload cycles. The initial conditions for these events were analyzed using the revised thermal design procedure (RTDP) ([Reference 1](#)). See LR [Section 2.8.5.0](#), Accident and Transient Analyses Introduction, for additional inputs and assumptions. Note that uncertainties in the initial conditions described below were addressed in the determination of the safety analysis departure from nucleate boiling ratio (DNBR) limit as described in [Reference 1](#).

1. The initial reactor power is assumed to be a value consistent with 100 percent of rated thermal power plus nominal reactor coolant pump heat.
2. The core inlet temperature is assumed to be at the nominal full power inlet temperature of 551 °F with no additional uncertainty.

3. Minimum measured flow (MMF) with a value of 195,000 gpm/hot leg is used.
4. Design core bypass flow is supported for this analysis.
5. A steam generator tube plugging level of 0 percent is analyzed as it maximizes the cooldown of the event.

The transient statepoint conditions cover a range of reactivity parameters and dropped rod conditions expected to occur during the core life. These include a range of moderator temperature coefficients (MTCs), which would bound the values from beginning of life to end of life conditions. Dropped rod worths from 100 pcm to 1000 pcm (in 100 pcm intervals) are analyzed to bound both single and subgroup CEA drops.

The CEA misoperation event is classified as an AOO. For an AOO, it must be demonstrated that the SAFDLs are not exceeded; in particular that the minimum DNBR remains above the DNBR limit and that the peak linear heat generation rate (expressed in kW/ft) does not exceed a value which would cause fuel centerline melt. Additional criteria such as peak RCS pressure and peak steam generator pressure conditions are not challenged (non-limiting) during the CEA misoperation event.

2.8.5.4.3.2.3 Description of Analyses and Evaluations

The CEA misoperation event is analyzed to demonstrate that the acceptance criteria for this event are met at the extended power uprate (EPU) conditions utilizing the currently approved methodology. The RETRAN-02W ([Reference 2](#)) computer code is a digital computer code, developed to simulate transient behavior in light water reactor systems. The code computes pertinent plant variables including temperatures, pressures, and power levels. Since RETRAN employs a point kinetics model, a CEA drop is modeled as a negative reactivity insertion corresponding to the reactivity worth of the dropped CEA regardless of the configurations of the CEA(s) that drop. The system transient is calculated by assuming a constant turbine load demand at the initial value (no turbine runback) and no bank withdrawal (as the automatic CEA withdrawal capability has been disabled making it non-functional).

The transient conditions calculated are then analyzed with nuclear models to obtain a hot channel factor consistent with the primary system conditions and reactor power. By using the statepoints generated from the transient and the hot channel factor from the nuclear analysis, the DNB and fuel centerline melt criteria are shown to be met using the VIPRE ([Reference 3](#)) computer code. The VIPRE code iterates on the hot channel factor until the DNB SAFDL is obtained. These hot channel factors are then compared against the design hot channel factor, used in reload cycle designs, to verify that the transient meets safety analysis limits. Both RETRAN and VIPRE are NRC approved modeling codes and are used in the current licensing basis.

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

As discussed above, the design transient analyses were determined to be outside the scope of License Renewal; therefore, with respect to the design basis accidents and transients, the EPU does not impact any License Renewal evaluations.

2.8.5.4.3.2.5 Results

The CEA misoperation transient statepoints analyzed through RETRAN and confirmed through VIPRE showed that the DNB design basis and peak linear heat generation rate criteria are satisfied at the EPU conditions.

LR [Table 2.8.5.4.3-1](#) displays the sequence of events for the 0 pcm/°F MTC case while LR [Table 2.8.5.4.3-2](#) displays the sequence of events for the -25 pcm/°F MTC case. LR [Table 2.8.5.4.3-3](#) tabulates a comparison of results and assumptions to the current analysis.

Following a CEA drop event, power is reestablished by reactivity feedback. In cases where reactivity feedback does not offset the worth of the dropped CEA, a cooldown condition exists until a reactor trip is reached on a TM/LP (floor) or a low steam generator pressure reactor trip signal. LR [Figures 2.8.5.4.3-1](#) through [2.8.5.4.3-4](#) show typical transient responses for a dropped CEA of 500 PCM worth at an MTC of 0 pcm/°F. LR [Figures 2.8.5.4.3-5](#) through [2.8.5.4.3-8](#) show typical transient responses of a dropped CEA of 500 pcm worth at a moderator temperature coefficient of -25 pcm/°F. In cases where reactivity is large enough to offset the worth of the dropped CEA, reactor power is reestablished at the original power level at a reduced RCS temperature and pressure condition. In all cases, the minimum DNBR remained greater than the safety limit value.

2.8.5.4.3.3 Conclusion

FPL has analyzed CEA misoperation events and concludes that the analyses have adequately accounted for the changes in core design required for operation of the plant at the proposed power level. FPL also concludes that the analyses were performed using acceptable analytical models. FPL further concludes that the analyses have demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs will not be exceeded during normal or anticipated operational transients. Based on this, FPL concludes that St. Lucie Unit 2 will continue to meet the requirements of GDCs -10, -20 and -25 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to CEA misoperation events.

2.8.5.4.3.4 References

1. WCAP-11397-P-A (Proprietary) and WCAP-11397-A (Non-Proprietary), Revised Thermal Design Procedure, Friedland, A. J. and Ray, S., April 1989.

2. WCAP-14882-P-A (Proprietary) and WCAP-15234-A (Non-Proprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, D. S. Huegel, et al., April 1999.
3. WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Non-Proprietary), VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, Sung, Y. X. et al., October 1999.

Table 2.8.5.4.3-1
Sequence of Events – Dropped CEA with Reactor Trip
500 pcm Drop Rod Worth, 0 pcm/°F MTC Case

Event	Time (seconds)
Initiation of the event	20.00
Dropped CEA falls to bottom of core	20.01
TM/LP reactor trip setpoint reached	59.42
Reactor trip on TM/LP	60.62
Rod begin to fall	61.36
Maximum post-trip core heat flux occurs (0.6971 frac. of nominal)	61.36

Table 2.8.5.4.3-2
Sequence of Events – Dropped CEA without Reactor Trip
500 pcm Drop Rod Worth, -25 pcm/°F MTC Case

Events	Time (seconds)
Initiation of the event	20.00
Dropped CEA falls to bottom of core	20.01
Return to (near) initial power conditions (1.0090 frac. of nominal)	130.00

Table 2.8.5.4.3-3
Comparison of Assumptions and Results to Current Analysis

Parameter	EPU Assumption	Current Assumption
Initial Core Power, MWt	3020	2700
RTDP Statistical Peaking Factor (F_r)	1.60	1.70
Pressurizer level, %	63.0	63.0
RCS Flowrate, gpm	390,000	341,400
Dropped CEA Reactivity Worth, pcm	100 to 1000	100 to 1000
MTC, pcm/°F	0 to -35	0 to -35
Criteria	Value	Limit
Minimum DNBR	>1.42	>1.42
Maximum Peak Linear Heat Generation Rate	< 22.0 kW/ft	<22.0 kW/ft
Hot Channel Factor (@ 500 pcm)	2.18	2.24

Figure 2.8.5.4.3-1
CEA Drop Event
CEA Drop Worth of 500 PCM at a MTC of 0 pcm/°F
Nuclear Power, Fraction of Nominal (FON) vs. Time

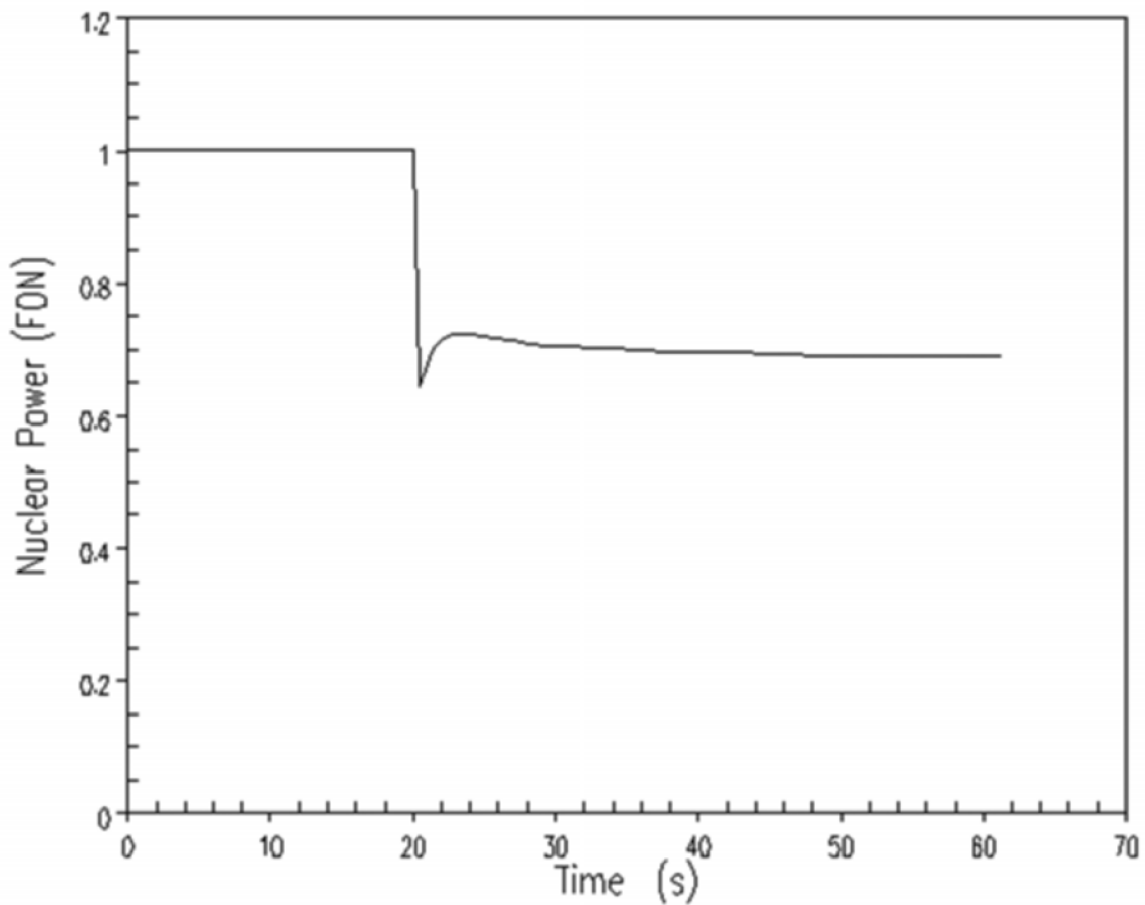


Figure 2.8.5.4.3-2
CEA Drop Event
CEA Drop Worth of 500 PCM at a MTC of 0 pcm/°F
Core Heat Flux vs. Time

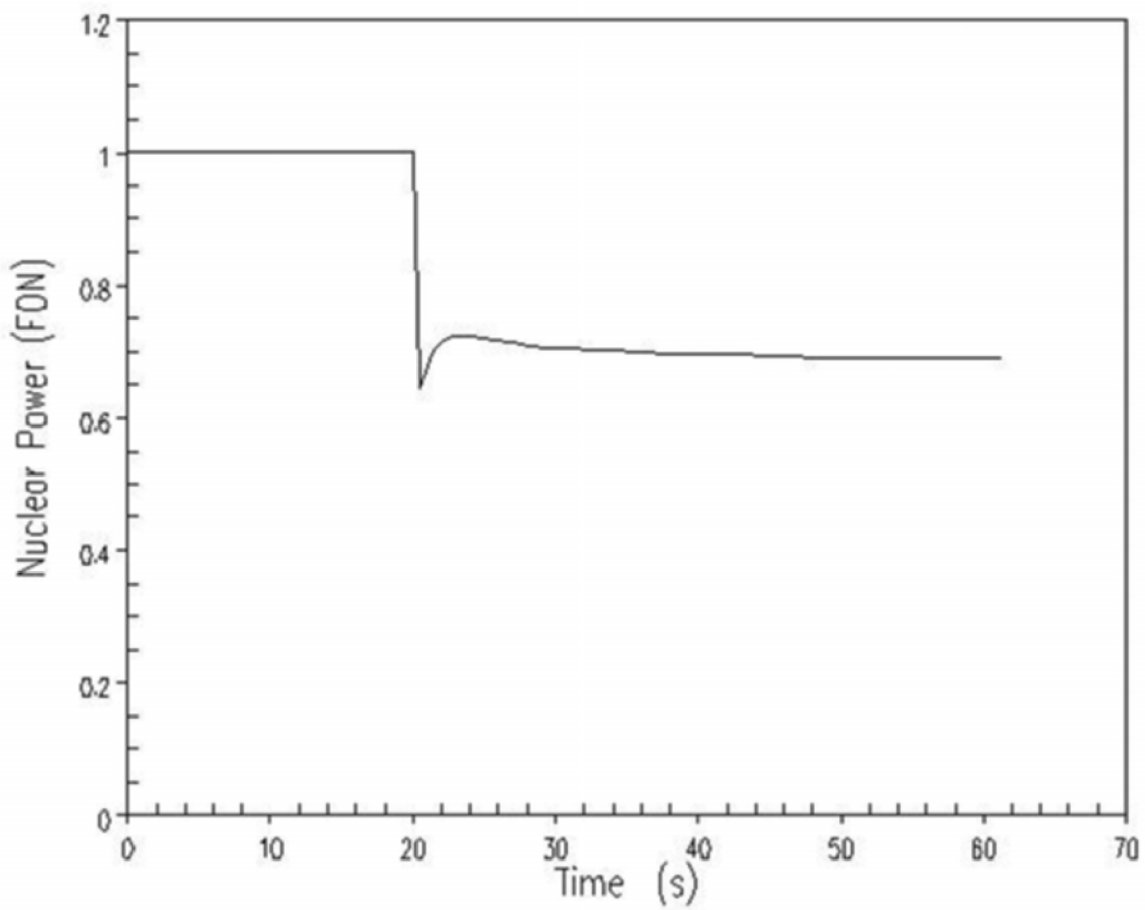


Figure 2.8.5.4.3-3
CEA Drop Event
CEA Drop Worth of 500 PCM at a MTC of 0 pcm/°F
Pressurizer Pressure vs. Time

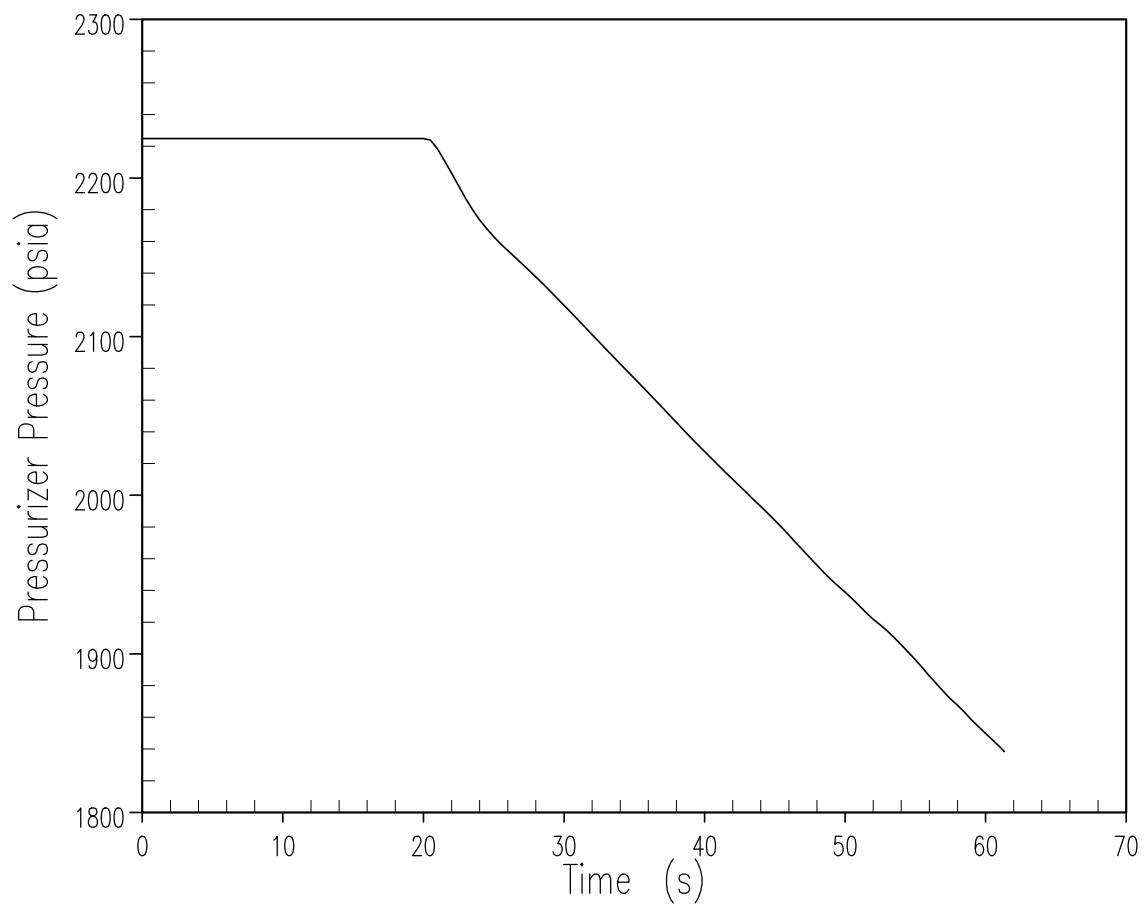


Figure 2.8.5.4.3-4
CEA Drop Event
CEA Drop Worth of 500 PCM at a MTC of 0 pcm/°F
Vessel Average Temperature vs. Time

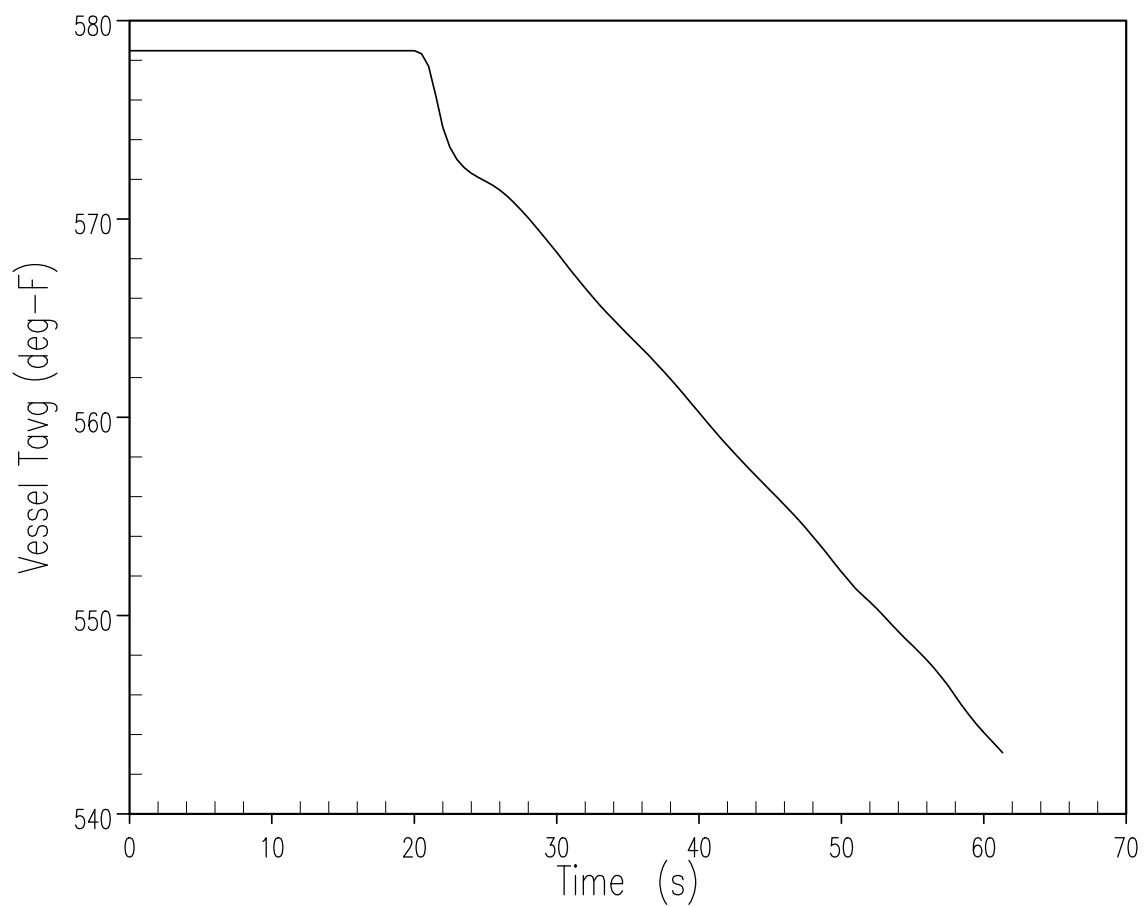


Figure 2.8.5.4.3-5
CEA Drop Event
CEA Drop Worth of 500 PCM at a MTC of -25 pcm/°F
Nuclear Power vs. Time

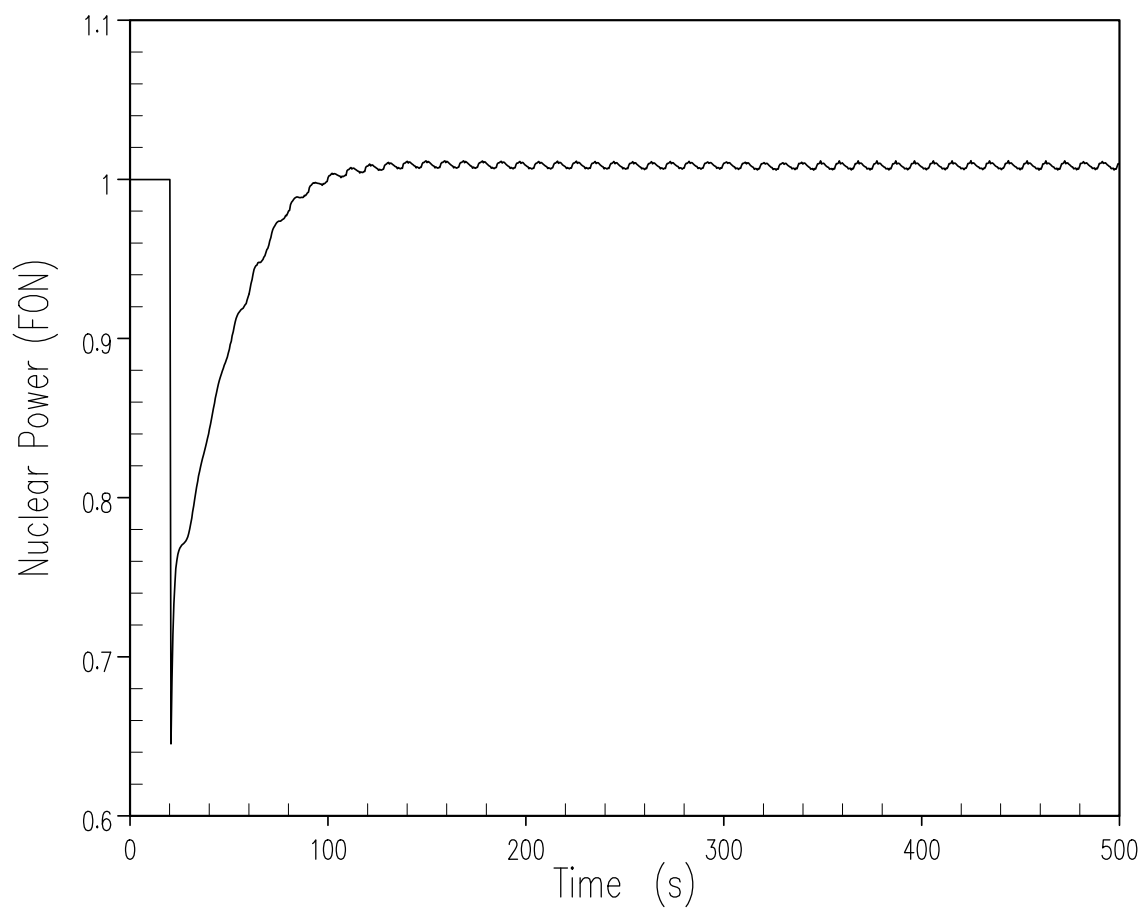


Figure 2.8.5.4.3-6
CEA Drop Event
CEA Drop Worth of 500 PCM at a MTC of -25 pcm/°F
Core Heat Flux vs. Time

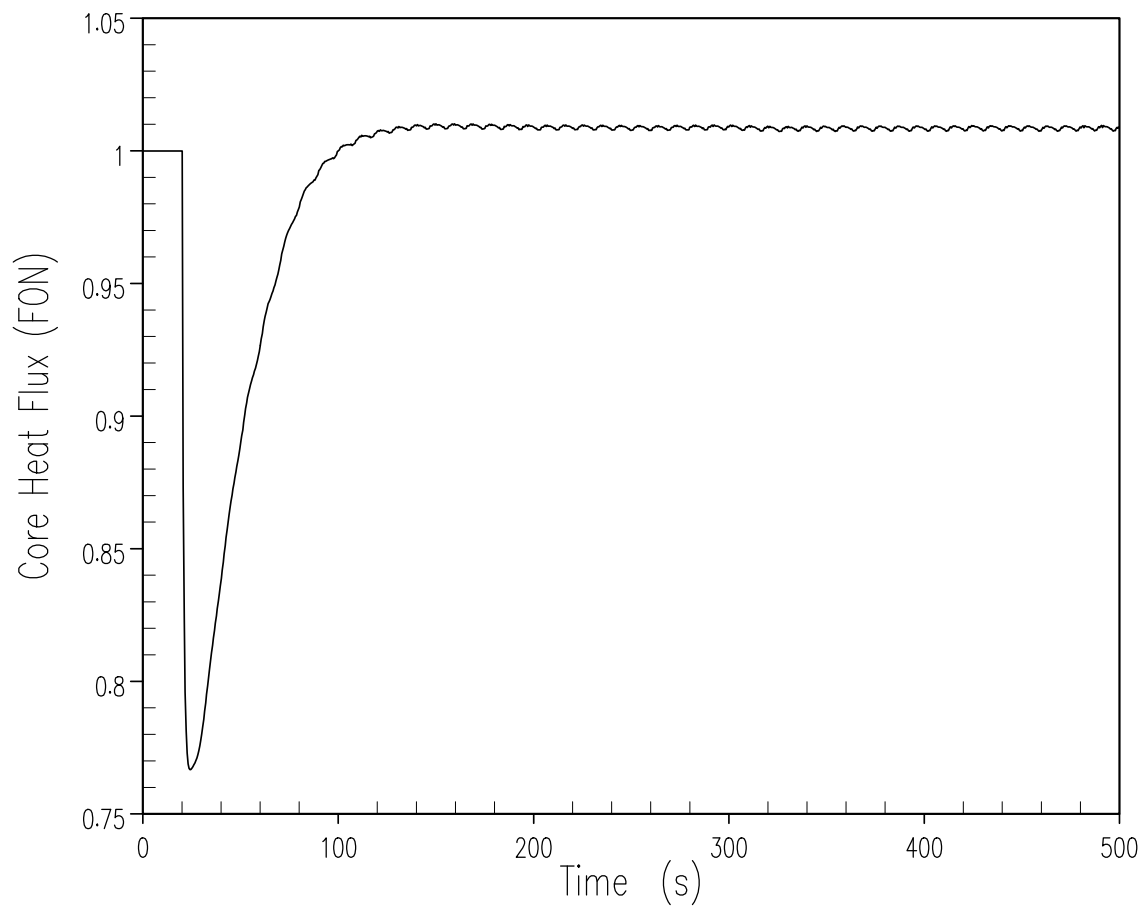


Figure 2.8.5.4.3-7
CEA Drop Event
CEA Drop Worth of 500 PCM at a MTC of -25 pcm/°F
Pressurizer Pressure vs. Time

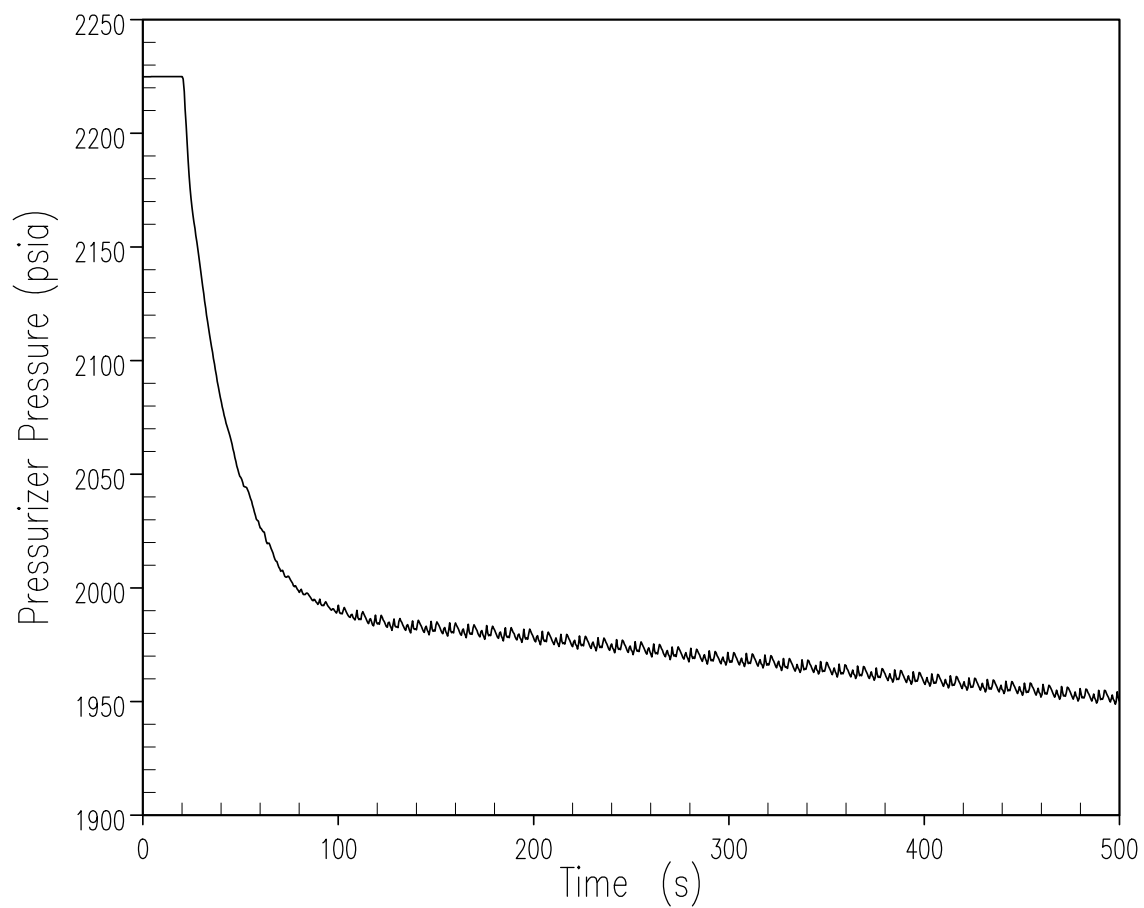
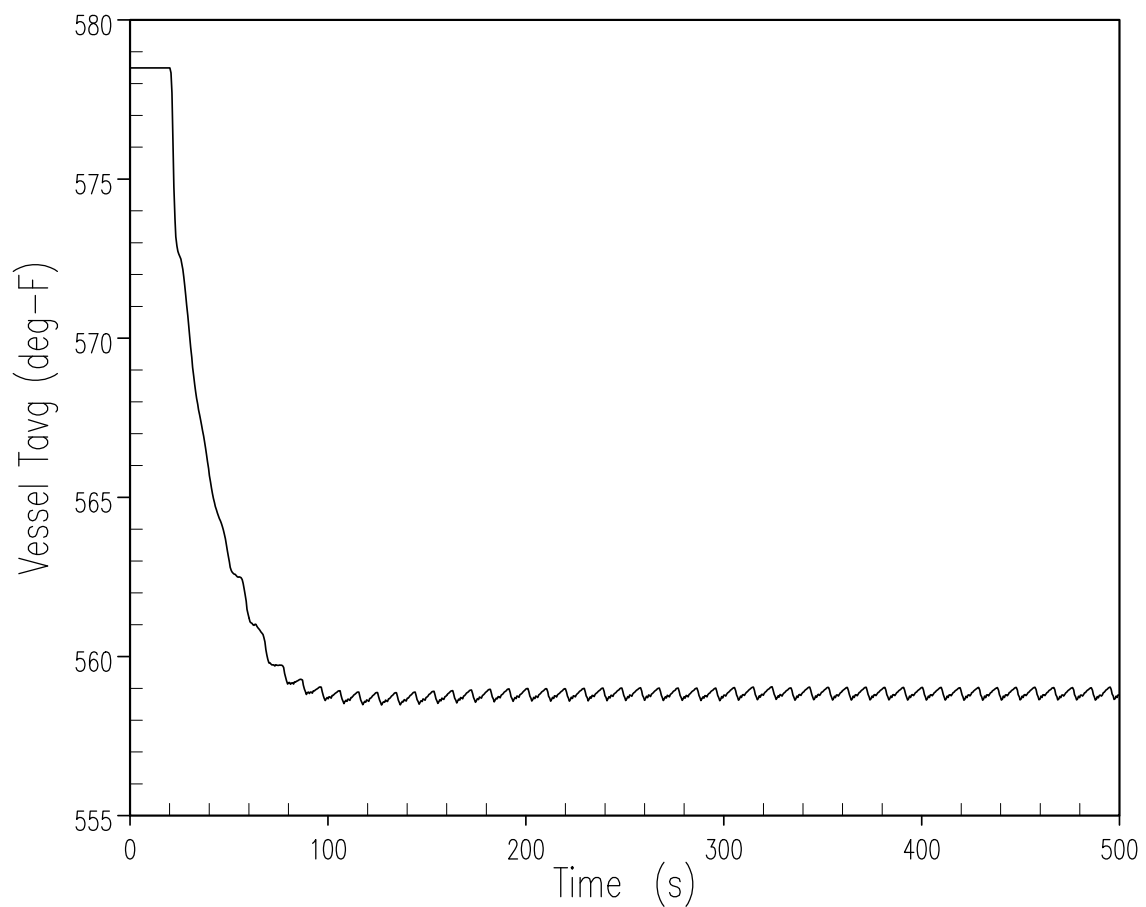


Figure 2.8.5.4.3-8
CEA Drop Event
CEA Drop Worth of 500 PCM at a MTC of -25 pcm/°F
Vessel Average Temperature vs. Time



2.8.5.4.4 Startup of an Inactive Loop at an Incorrect Temperature

Technical Specification 3.4.1.1 does not allow the reactor to go critical without both reactor coolant loops and both reactor coolant pumps in each loop in operation. Thus, this event is precluded by Technical Specifications. Therefore, Florida Power and Light determined an analysis of this event was not necessary for EPU. The discussion presented in Updated Final Safety Analysis Report Section 15.4.4 supports that no analysis is necessary.

2.8.5.4.5 Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant

2.8.5.4.5.1 Regulatory Evaluation

Unborated water can be added to the reactor coolant system (RCS), via the chemical and volume control system (CVCS). This may happen inadvertently because of operator error or CVCS malfunction, and cause an unwanted increase in reactivity and a decrease in shutdown margin. The operator should stop this unplanned dilution before the shutdown margin is eliminated.

The Florida Power and Light (FPL) review covered:

- Conditions at the time of the unplanned dilution,
- Causes,
- Initiating events,
- The sequence of events,
- The analytical model used for analyses,
- The values of parameters used in the analytical model, and
- Results of the analyses.

The Nuclear Regulatory Commission's (NRC) acceptance criteria are based on:

- 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 specified acceptable fuel design limits (SAFDLs) are not exceeded during any condition of normal operation, including anticipated operational occurrences (AOOs);
- 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 reactor coolant pressure boundary (RCPB) are not exceeded during any condition of normal operation, including AOOs;
- 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 Standard Review Plan (SRP) Section 15.4.6 and other guidance provided in Matrix 8 of RS-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

- GDC-10 is described in UFSAR Section 3.1.10, Criterion 10 - Reactor Design.

The reactor core and associated coolant, control and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

SAFDLs are stated in UFSAR Section 4.3. Minimum margins to SAFDLs are prescribed in the technical specifications (limiting conditions for operations) which support UFSAR Chapters 4 and 15.

- GDC-15 is described in the UFSAR Section 3.1.15, Criterion 15 - Reactor Coolant System Design.

The Reactor Coolant System and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.

The design criteria and bases for the RCPB are described in the response to GDC-14.

The operating conditions for normal steady state and transient plant operations are established conservatively. Normal operating limits are selected so that an adequate margin exists between operating and design limits. The plant control systems are designed to ensure that plant variables are maintained well within the established operating limits. The plant transient response characteristics and pressure and temperature distributions during normal operations are considered in the design as well as the accuracy and response of the instruments and controls. These design techniques ensure that a satisfactory margin is maintained between the plant's normal operating conditions, including design transients, and the design limits for the RCPB.

The plant control systems function to minimize deviations from normal operating limits in the event of most AOOs. Where control systems response would be inadequate or fail upon demand, the RPS and the engineered safety features actuation system (ESFAS) function to mitigate the consequences of such events.

The RPS and ESFAS function to mitigate the consequences of accidents such that the design limits for the RCPB are not exceeded.

- GDC-26 is described in the UFSAR Section 3.1.26, Criterion 26 - Reactivity Control System Redundancy and Capability.

Two independent reactivity control systems of different design principles shall be provided. One of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margin for malfunctions such as stuck rods, specified acceptable fuel design limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure acceptable fuel design limits are not exceeded. One of the systems shall be capable of holding the reactor core subcritical under cold conditions.

Two independent reactivity control systems of different design principles are provided. The first system, using control element assemblies (CEAs), includes a positive means (gravity) for inserting CEAs and is capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including specified AOOs, SAFDLs are not exceeded. The CEAs can also be mechanically driven into the core. The appropriate margin for stuck rods is provided by assuming in the analyses of AOOs that the highest worth CEA does not fall into the core.

The second system, the CVCS, using neutron absorbing soluble boron, is capable of reliably compensating for the rate of reactivity changes resulting from planned normal power changes (including xenon burnout) such that acceptable fuel design limits are not exceeded. This system is capable of holding the reactor subcritical under cold conditions. For a further description, see UFSAR Section 9.3.4.

Either system is capable of making the core subcritical from a hot operating condition. For further discussion, see UFSAR Sections 7.4 and 7.7.

UFSAR Section 15.4.6 describes the analysis pertaining to the CVCS malfunction event. Boron dilutions during all six modes of operation (refueling, cold shutdown, hot shutdown, hot standby, startup, and power operation) are considered in the analysis.

NUREG-1779, "Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2," dated September, 2003, defines the scope of license renewal. Specific transient analyses are not within the scope of License Renewal.

2.8.5.4.5.2 Technical Evaluation

2.8.5.4.5.2.1 Introduction

An uncontrolled boron dilution event is defined as any event caused by a malfunction or an inadvertent operation of the CVCS that results in a dilution of the active portion of the RCS. Reactivity can be added to the core by adding primary grade water into the RCS via the reactor makeup portion of the CVCS. As discussed below, the CVCS is designed to limit, even under various postulated failure modes, the potential rate of dilution to a value that, after indication through alarms and instrumentation, provides the operator sufficient time to correct the situation in a safe and orderly manner.

The Boron Dilution Alarm Signal (BDAS) utilizes the start-up channel nuclear instrumentation signals to detect a possible inadvertent Boron dilution event while in Modes 3, 4, 5 & 6. There are two redundant and independent channels in the BDAS to ensure detection and alarming of the event.

Detection of a boron dilution transient while in Mode 2 is provided by the occurrence of a high power trip or a high rate of change of power trip.

Detection of a boron dilution transient while in Mode 1 is provided by the occurrence of a thermal margin/low pressure (TM/LP) trip, a variable high power trip (VHPT), or a high pressurizer pressure (HPP) trip. The specific reactor trip reached depends on the reactivity insertion rate occurring during the transient.

2.8.5.4.5.2.2 Input Parameters, Assumptions, and Acceptance Criteria

A CVCS malfunction is classified as an AOO. These events, at worst result in a reactor trip with the plant capable of complete recovery and resumption of plant operation within the requirements of the technical specifications. The criteria are met if analyses results demonstrate that:

- minimum DNBR is greater than or equal to the design limit,
- fuel centerline temperature is less than 4700°F, and
- maximum reactor coolant system pressure is less than or equal to 110 percent of design pressure.

These specific criteria satisfy the relevant requirements of 10 CFR Part 50, Appendix A, GDC-10 and -15 and Section III, Article NB-7000 of the ASME Boiler and Pressure Vessel Code. The analysis assumptions satisfy the requirements of 10 CFR Part 50, Appendix A, GDC 26 by assuring that appropriate margin for malfunctions, such as stuck rods, are addressed. See LR [Section 2.8.5.0](#), Non-LOCA Analyses Introduction for additional inputs and assumptions.

Calculations are performed to identify the amount of time available for operator mitigation of the boron dilution event prior to the complete loss of plant shutdown margin. As long as the calculated time is sufficient for operator action, it can be assumed that the automatic or manual actions will effectively prevent the complete loss of minimum allowable shutdown margin. Because shutdown margin is not lost, the condition of the plant at any point in the transient is within the bounds of those calculated for other UFSAR AOOs. If the above criteria are shown to be met for the balance of the UFSAR AOO transients and the calculated amount of time is accepted as sufficient for the successful mitigation of the dilution event, it can be concluded that the above criteria are met for the UFSAR Boron dilution accident.

The calculated time, from the time an alarm (while in Modes 3, 4, 5, or 6) or a reactor trip (while in Modes 1 or 2) alerts the operator to a dilution to the complete loss of shutdown margin, must be greater than or equal to the following (see UFSAR Table 15.4.6-1):

Refueling (Mode 6)	30 minutes
Cold shutdown (Mode 5)	15 minutes
Hot shutdown (Mode 4)	15 minutes
Hot standby (Mode 3)	15 minutes
Start-up (Mode 2)	15 minutes
Power (Mode 1)	15 minutes

Additional mode specific assumptions are identified below.

2.8.5.4.5.2.3 Description of Analyses and Evaluation

The boron dilution analyses assume complete mixing in the RCS. The method used to generate the time to dilute to criticality is described in UFSAR Section 15.4.6.2.

Dilution during Refueling (Mode 6)

In Mode 6, when the head bolts are being tensioned or detensioned for the replacement or removal of the vessel head, the water level in the vessel is maintained at the centerline of the reactor vessel nozzles (or hot leg). The primary coolant forced flow is provided by the shutdown cooling system (SDC). Cases with 1, 2, and 3 charging pumps operating are analyzed for this mode.

The following conditions are assumed for the limiting Mode 6 analysis with the RCS drained to the hot leg centerline:

- Dilution flow is the maximum capacity of 1, 2, or 3 charging pumps; 49, 98, or 147 gpm, respectively;
- A minimum RCS water volume of 3410 ft³ is assumed, which is more conservative (that is, smaller) than the volume necessary to fill the reactor vessel up to the mid-plane of the nozzles plus the volume of one SDC train;
- The minimum Boron concentration during refueling ($k_{\text{eff}} < 0.95$) and minimum change in Boron concentration from initial to critical conditions are cycle-specific values that are determined and verified every cycle as part of the reload process;
- A BDAS setpoint of 0.5 Volts is used in the analysis, which corresponds to a flux multiplication of greater than 2.0. This setpoint is then adjusted for appropriate uncertainties. In addition, the inverse count rate ratio curve used to predict the time when the alarm setpoint is reached is St. Lucie Unit 2 specific. Therefore, NRC Information Notice 93-32 (Reference 1) does not apply to the St. Lucie Unit 2 Mode 6 analysis.

These conditions are consistent with those assumed in the current Mode 6 analysis.

Dilution during Cold Shutdown (Mode 5)

In Mode 5, the water level can be dropped to the mid-plane of the hot leg for maintenance work that requires the steam generators to be drained. The limiting scenario for Mode 5 is typically the case where the vessel is drained and the reactor is shut down by Boron to the Technical Specifications requirement. Cases with 1, 2, and 3 charging pumps operating are analyzed for the case with the water level at (or above) the hot leg centerline, and with 1 charging pump for the case with the water level at the bottom of the hot leg.

The Boron dilution event is analyzed assuming the following conditions:

- Dilution flow is the maximum capacity of 1, 2, or 3 charging pumps; 49, 98, or 147 gpm, respectively;
- Minimum RCS water volumes of 3410 ft³ corresponding to the active RCS volume (not including the pressurizer volume) for the case with the water level at the hot leg centerline, and 2655 ft³ corresponding to the active RCS volume for the case with the water level at the bottom of the hot leg are assumed;
- The maximum critical Boron concentration and minimum change in Boron concentration from initial to critical conditions are cycle-specific values that are determined and verified every cycle as part of the reload verification process;

- A BDAS setpoint of 0.5 Volts is used in the analysis, which corresponds to a flux multiplication of greater than 2.0. This setpoint is then adjusted for appropriate uncertainties. In addition, the inverse count rate ratio curve used to predict the time when the alarm setpoint is reached is St. Lucie Unit 2 specific. Therefore, NRC Information Notice 93-32 (Reference 1) does not apply to the St. Lucie Unit 2 Mode 5 analysis.

These conditions are consistent with those assumed in the current Mode 5 analysis.

Dilution during Hot Shutdown (Mode 4)

In Mode 4, the primary coolant forced flow can be provided by either the SDC or a reactor coolant pump (RCP), depending on the system pressure. Cases with 1, 2, and 3 charging pumps operating are analyzed for this Mode.

The boron dilution event in Mode 4 is analyzed assuming the following conditions:

- Dilution flow is the maximum capacity of 1, 2, or 3 charging pumps; 49, 98, or 147 gpm, respectively;
- A minimum RCS water volume of 3711 ft³ corresponding to the active RCS volume (not including the pressurizer volume) is assumed for the case with the plant on shutdown cooling system with no RCPs running. A minimum RCS water volume of 8332 ft³ (not including the pressurizer volume and including the effects of 10 percent steam generator tube plugging (SGTP)) is assumed for the case with the plant operating with at least one RCP running.
- The maximum critical Boron concentration and minimum change in Boron concentration from initial to critical conditions are cycle-specific values that are determined and verified every cycle as part of the reload verification process.
- A BDAS setpoint of 0.5 Volts is used in the analysis, which corresponds to a flux multiplication of greater than 2.0. This setpoint is then adjusted for appropriate uncertainties. In addition, the inverse count rate ratio curve used to predict the time when the alarm setpoint is reached is St. Lucie Unit 2 specific. Therefore, NRC Information Notice 93-32 (Reference 1) does not apply to the St. Lucie Unit 2 Mode 4 analysis.

These conditions are consistent with those assumed in the current Mode 4 analysis.

Dilution during Hot Standby (Mode 3)

In Mode 3, all RCPs may not be in operation. If the control rods are withdrawn to the hot zero power (HZIP) insertion limits, the inadvertent dilution scenario is similar to the Mode 2 analysis. Cases with 1, 2, and 3 charging pumps operating are analyzed for this Mode.

Conditions assumed for the analysis are:

- Dilution flow is the maximum capacity of 1, 2, or 3 charging pumps; 49, 98, or 147 gpm, respectively;
- A minimum RCS water volume of 8332 ft³ corresponding to the active RCS volume (not including the pressurizer volume and including the effects of 10 percent SGTP) with at least one RCP running is assumed;

- The maximum critical boron concentration and minimum change in boron concentration from initial to critical conditions are cycle-specific values that are determined and verified every cycle as part of the reload verification process;
- A BDAS setpoint of 0.5 Volts is used in the analysis, which corresponds to a flux multiplication of greater than 2.0. This setpoint is then adjusted for appropriate uncertainties. In addition, the inverse count rate ratio curve used to predict the time when the alarm setpoint is reached is St. Lucie Unit 2 specific. Therefore, NRC Information Notice 93-32 (Reference 1) does not apply to the St. Lucie Unit 2 Mode 3 analysis.

These conditions are consistent with those assumed in the current Mode 3 analysis.

Dilution during Startup (Mode 2)

In this mode, the plant is being taken from one long-term mode of operation, hot standby (Mode 3), to another, power operation (Mode 1). All normal actions required to change power level require operator actions. Conditions assumed for the analysis are:

- Dilution flow is the maximum capacity of all three charging pumps, 147 gpm;
- A minimum RCS water volume of 8332 ft³ corresponding to the active RCS volume (not including the pressurizer and including the effects of 10 percent SGTP) is assumed;
- The maximum critical boron concentration and minimum change in boron concentration from initial to critical conditions during startup are cycle-specific values that are confirmed to be valid every cycle as part of the reload verification process.

These conditions are consistent with those assumed in the current Mode 2 analysis.

This mode of operation is a transitory operational mode. During this mode, the plant is in manual rod control with the operator required to maintain a high level of awareness of the plant status. For a normal approach to criticality, the operator manually initiates a limited dilution and then withdraws the control rods. Alternately, the operator may withdraw the rods to a predetermined critical rod position and then dilute to criticality. This process takes several hours. The technical specifications require that the reactor does not go critical with the control rods below the insertion limits. For inadvertent Boron dilution with slow reactivity additions, the reactivity excursion is bounded by the CEA withdrawal event. For fast reactivity additions, the reactivity excursion is protected by the high rate of change of power reactor trip.

Once dilution has been identified subsequent to the reactor trip, the operator terminates the flow of non-borated water. This action terminates the transient.

Dilution at Power (Mode 1)

For Mode 1, the analysis is performed assuming three charging pumps are in operation.

Conditions assumed for this Mode are:

- Dilution flow is the maximum capacity of all three charging pumps, 147 gpm;
- A minimum RCS water volume of 8332 ft³ at 581.5°F is assumed. This is a conservative estimate of the active RCS volume (not including the pressurizer and including the effects of 10 percent SGTP).

- The maximum critical Boron concentration (corresponding to the rods inserted to the insertion limits) and the minimum change in Boron concentration from this initial condition to an HZP critical condition with all rods inserted are cycle-specific values that are confirmed to be valid every cycle as part of the reload verification process. Full rod insertion, minus the most reactive stuck rod, is assumed to occur due to reactor trip.

These conditions are consistent with those assumed in the current Mode 1 analysis.

If the dilution is not secured, the reactor will be shut down by either the TM/LP reactor trip, the HPP reactor trip or the VHPT. The specific reactor trip reached depends on the reactivity insertion rate occurring during the transient.

Once dilution has been identified subsequent to the reactor trip, the operator terminates the flow of non-borated water. This action terminates the transient.

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

As discussed above, the design transient analyses were determined to be outside the scope of License Renewal; therefore, with respect to the design basis accidents and transients, the EPU does not impact any License Renewal evaluations.

2.8.5.4.5.2.5 Results

If an unintentional boron dilution in the RCS does occur, numerous alarms and indications are available to alert the operator to the condition. The maximum reactivity addition due to the dilution is slow enough to allow the operator sufficient time to determine the cause of the addition and take corrective action before shutdown margin is lost.

The boron dilution analysis demonstrated that all applicable acceptance criteria are met at EPU conditions. This means that operator action to terminate the dilution flow within 15 minutes from the time of an alarm (or reactor trip) for Modes 1, 2, 3, 4, and 5 and within 30 minutes from the time of an alarm for Mode 6 precludes a return to criticality. The results of the Boron dilution analysis are provided in LR [Table 2.8.5.4.5-1](#). A comparison to the current analyses of record results is also provided. Additional results are provided in LR [Tables 2.8.5.4.5-2](#) through [2.8.5.4.5-5](#). The EPU results are determined to be reasonable as compared to the current analysis.

Should the automatic Boron dilution alarm be unavailable, UFSAR Section 13.7.2.4 contains backup requirements for the maximum frequency of RCS chemistry sampling. These sampling frequencies, implemented by administrative controls, ensure that the specified criteria are met to ensure sufficient time is available to the operators, from the detection of dilution until criticality is achieved to mitigate the consequences of this event. The revised conservative backup Boron dilution detection monitoring frequencies for Modes 3, 4, 5, and 6 are provided in LR [Table 2.8.5.4.5-6](#). A comparison to the current analysis of record results is also provided. The EPU monitoring frequencies are comparable to those of the current analysis.

Meeting the acceptance criteria for the operator action times confirms that fuel design limits for the DNB and fuel melt will be met. Additionally, this event is not limiting with respect to RCS pressure and thus will not challenge the limit of 110 percent of the design pressure.

2.8.5.4.5.3 Conclusion

FPL has reviewed the analyses of the decrease in boron concentration in the reactor coolant due to a CVCS malfunction and concluded that the analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. FPL further concludes 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 this event. Based on this, FPL concludes that the plant will continue to meet the requirements of GDCs -10, -15, and -26 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to the decrease in boron concentration in the reactor coolant due to a CVCS malfunction.

2.8.5.4.5.4 References

1. NRC Information Notice 93-32, "Nonconservative Inputs for Boron Dilution Event Analysis," April 21, 1993.

**Table 2.8.5.4.5-1
Uncontrolled Boron Dilution Sequence of Events**

Mode		Event	Time (minutes)	
			EPU	Current
Refueling (Mode 6)		Dilution begins	0	0
		Time from initiation of boron dilution to alarm annunciation	>75	>75
		• 1 charging pump		
		• 2 charging pumps	>40	>50
		• 3 charging pumps	>30	>35
		Time from alarm annunciation to criticality	>30	>30
Cold Shutdown (Mode 5)	Filled to hot leg centerline	Dilution begins	0	0
		Time from initiation of boron dilution to alarm annunciation	>30	>30
		• 1 charging pump		
		• 2 charging pumps	>30	>30
		• 3 charging pumps	>30	>30
		Time from alarm annunciation to criticality	>15	>15
	Drained to bottom of hot leg	Dilution begins	0	0
		Time from initiation of boron dilution to alarm annunciation (1 charging pump)	>30	>30
		Time from alarm annunciation to criticality	>15	>15

Table 2.8.5.4.5-1 (Continued)
Uncontrolled Boron Dilution Sequence of Events

Mode		Event	Time (minutes)	
			EPU	Current
Hot Shutdown (Mode 4)	At least one RCP operating	Dilution begins	0	0
		Time from initiation of boron dilution to alarm annunciation	>130	>130
		• 1 charging pump		
		• 2 charging pumps	>50	>50
		• 3 charging pumps	>30	>30
		Time from alarm annunciation to criticality	>15	>15
	Shutdown Cooling System (SDC)	Dilution begins	0	0
		Time from initiation of boron dilution to alarm annunciation	>75	>95
		• 1 charging pump		
		• 2 charging pumps	>35	>35
		• 3 charging pumps	>30	>30
		Time from alarm annunciation to criticality	>15	>15
Hot Standby (Mode 3)		Dilution begins	0	0
		Time from initiation of boron dilution to alarm annunciation	>150	>150
		• 1 charging pump		
		• 2 charging pumps	>50	>50
		• 3 charging pumps	>40	>40
		Time from alarm annunciation to criticality	>15	>15
Startup (Mode 2)		Dilution begins	0	0
		Time from reactor trip to criticality (loss of shutdown margin)	>15	>15
At Power (Mode 1)		Dilution begins	0	0
		Time of reactor trip to loss of shutdown margin (dilution continues after trip)	>15	>15

Table 2.8.5.4.5-2
Boron Dilution Parameters

1.0	Boron Dilution at Power (Mode 1) (No Xenon)	
a.	Maximum critical C_b , Hot Zero Power (HZIP), most-reactive burnup, N-1 rods inserted, ppm	1100
b.	Minimum change in C_b from a. above to Hot Full Power (HFP), rods to insertion limits, ppm	400
2.0	Boron Dilution at Startup (Mode 2) (HZIP, No Xenon)	
a.	Maximum critical C_b , HZIP, most-reactive burnup, N-1 rods inserted, ppm	1100
b.	Minimum change in C_b from a. above to HZIP, rods to insertion limits, ppm	400
3.0	Boron Dilution at Hot Standby (Mode 3) (No Xenon, $325^{\circ}\text{F} < T_{\text{avg}} \leq T_{\text{HZIP}}$)	
a.	Maximum critical C_b , most reactive burnup, N-1 rods inserted, ppm	1450
b.	Minimum change in C_b from a. above to N-1 rods inserted, <u>3.6%</u> $\Delta\rho$ Shutdown Margin (SDM), ppm	350
4.0	Boron Dilution at Hot Shutdown (Mode 4) (No Xenon, $200^{\circ}\text{F} < T_{\text{avg}} \leq 325^{\circ}\text{F}$)	
a.	Maximum critical C_b , HZIP, most reactive burnup, N-1 rods inserted, ppm	1500 (Note 1)
b.	Minimum change in C_b from a. above to N-1 rods inserted, <u>3.6%</u> $\Delta\rho$ SDM, ppm	300 (Note 1)
5.0	Boron Dilution at Cold Shutdown (Mode 5) (No Xenon, $T_{\text{avg}} \leq 200^{\circ}\text{F}$)	
a.	Maximum critical C_b , most reactive burnup, N-1 rods inserted, ppm	Table 2.8.5.4.5-4
b.	Minimum change in C_b from a. above to N-1 rods inserted, <u>3.0%</u> $\Delta\rho$ SDM, ppm	Table 2.8.5.4.5-4

Table 2.8.5.4.5-2 (Continued)
Boron Dilution Parameters

6.0 Boron Dilution during Refueling (Mode 6)

(No Xenon, $T_{avg} \leq 140^{\circ}\text{F}$)

a. Maximum critical C_b , ppm

Table 2.8.5.4.5-5

b. Minimum C_b at $k_{eff} < 0.95$, ppm

Table 2.8.5.4.5-5

Note:

1. The limits for Mode 4 on the Shutdown Cooling System with 2 and 3 charging pumps are given in Table 2.8.5.4.5-3.

**Table 2.8.5.4.5-3
Mode 4 on SDC Boron Concentrations**

Minimum Initial C_b (ppm)	Maximum Critical C_b (ppm)	
	2 Charging Pumps in Operation	3 Charging Pumps in Operation
1200	974	858
1220	987	872
1240	1003	886
1260	1018	900
1280	1034	914
1300	1049	928
1320	1064	942
1340	1080	957
1360	1095	973
1380	1111	988
1400	1126	1004
1420	1142	1020
1440	1157	1035
1460	1173	1051
1480	1188	1066
1500	1204	1082
1520	1219	1097
1540	1235	1113
1560	1250	1129
1580	1266	1145
1600	1281	1161
1620	1297	1177
1640	1312	1193
1660	1328	1209
1680	1344	1225
1700	1359	1241
1720	1375	1257
1740	1391	1273
1760	1407	1290
1780	1423	1306

Table 2.8.5.4.5-3 (Continued)
Mode 4 on SDC Boron Concentrations

Minimum Initial C_b (ppm)	Maximum Critical C_b (ppm)	
	2 Charging Pumps in Operation	3 Charging Pumps in Operation
1800	1438	1322
1820	1454	1338
1840	1470	1354
1860	1486	1371
1880	1502	1388
1900	1518	1404
1920	1535	1421
1940	1552	1437
1960	1569	1455
1980	1586	1472
2000	1603	1489
2020	1620	1507
2040	1637	1524
2060	1654	1542
2080	1671	1559
2100	1687	1576
2120	1704	1594
2140	1721	1611
2160	1738	1628
2180	1755	1646
2200	1772	1664
2220	1789	1681
2240	1806	1699
2260	1823	1717
2280	1841	1734
2300	1858	1752

**Table 2.8.5.4.5-4
Mode 5
Boron Concentrations**

Minimum Initial C_b (ppm)	Maximum Critical C_b (ppm)		
	1 Charging Pump in Operation	2 Charging Pumps in Operation	3 Charging Pumps in Operation
1200	1059	966	851
1220	1077	982	865
1240	1094	997	879
1260	1112	1012	893
1280	1129	1028	907
1300	1146	1043	921
1320	1162	1059	936
1340	1179	1074	952
1360	1196	1089	967
1380	1213	1105	983
1400	1230	1120	998
1420	1248	1135	1014
1440	1265	1151	1029
1460	1282	1166	1045
1480	1299	1182	1060
1500	1317	1197	1076
1520	1334	1212	1091
1540	1351	1228	1107
1560	1368	1243	1123
1580	1386	1259	1139
1600	1403	1274	1155
1620	1420	1290	1171
1640	1437	1305	1187
1660	1453	1321	1203
1680	1470	1337	1219
1700	1486	1352	1235
1720	1502	1368	1251
1740	1519	1384	1267

Table 2.8.5.4.5-4 (Continued)
Mode 5
Boron Concentrations

Minimum Initial C_b (ppm)	Maximum Critical C_b (ppm)		
	1 Charging Pump in Operation	2 Charging Pumps in Operation	3 Charging Pumps in Operation
1760	1535	1399	1283
1780	1552	1415	1299
1800	1566	1431	1315
1820	1583	1447	1332
1840	1600	1462	1348
1860	1617	1479	1365
1880	1634	1496	1382
1900	1651	1512	1398
1920	1668	1529	1415
1940	1684	1546	1432
1960	1701	1563	1450
1980	1718	1580	1467
2000	1735	1597	1484
2020	1752	1614	1502
2040	1769	1630	1519
2060	1786	1647	1536
2080	1803	1664	1554
2100	1820	1681	1571

**Table 2.8.5.4.5-5
Mode 6 Boron Concentrations**

Minimum Initial C_b (ppm)	Maximum Critical C_b (ppm)		
	1 Charging Pump In Operation	2 Charging Pumps in Operation	3 Charging Pumps in Operation
1720	1377	1186	1102
1730	1385	1194	1110
1740	1393	1203	1118
1750	1401	1211	1127
1760	1409	1220	1135
1770	1417	1228	1143
1780	1425	1237	1152
1790	1433	1245	1160
1800	1441	1254	1168
1810	1449	1262	1176
1820	1456	1271	1185
1830	1464	1279	1193
1840	1472	1288	1201
1850	1480	1296	1210
1860	1488	1305	1218
1870	1496	1313	1226
1880	1504	1322	1234
1890	1512	1330	1243
1900	1520	1339	1251
1910	1529	1347	1259
1920	1537	1356	1267
1930	1545	1364	1276
1940	1554	1373	1284
1950	1562	1381	1292
1960	1571	1390	1301
1970	1579	1398	1309
1980	1588	1407	1317
1990	1596	1415	1325
2000	1605	1424	1334

Table 2.8.5.4.5-5 (Continued)
Mode 6 Boron Concentrations

Minimum Initial C_b (ppm)	Maximum Critical C_b (ppm)		
	1 Charging Pump In Operation	2 Charging Pumps in Operation	3 Charging Pumps in Operation
2010	1613	1433	1342
2020	1622	1442	1350
2030	1630	1451	1358
2040	1639	1459	1367
2050	1647	1468	1375
2060	1656	1477	1383
2070	1664	1486	1391
2080	1672	1495	1400
2090	1681	1504	1408
2100	1689	1513	1416
2110	1698	1522	1424
2120	1706	1531	1432
2130	1715	1540	1440
2140	1723	1549	1448
2150	1732	1558	1457
2160	1740	1567	1465
2170	1749	1576	1473
2180	1757	1585	1481
2190	1766	1594	1489
2200	1774	1603	1497
2210	1783	1612	1505
2220	1791	1621	1513
2230	1800	1630	1521
2240	1808	1639	1529
2250	1817	1648	1537
2260	1825	1657	1545
2270	1834	1667	1553
2280	1843	1677	1561
2290	1851	1686	1569

Table 2.8.5.4.5-5 (Continued)
Mode 6 Boron Concentrations

Minimum Initial C_b (ppm)	Maximum Critical C_b (ppm)		
	1 Charging Pump In Operation	2 Charging Pumps in Operation	3 Charging Pumps in Operation
2300	1860	1695	1577
2310	1869	1703	1585
2320	1877	1712	1593
2330	1886	1721	1601
2340	1895	1730	1609
2350	1903	1739	1616
2360	1912	1747	1624
2370	1921	1756	1632
2380	1929	1765	1640
2390	1938	1774	1648
2400	1947	1783	1656

**Table 2.8.5.4.5-6
Backup Monitoring Frequencies**

MODE	NUMBER OF OPERABLE CHARGING PUMPS							
	0		1		2		3	
	EPU	Current	EPU	Current	EPU	Current	EPU	Current
3	12 hr	12 hr	100 min	100 min	40 min	40 min	25 min	25 min
4 (At least 1 RCP)	12 hr	12 hr	130 min	130 min	50 min	50 min	30 min	30 min
4 (No RCPs)	12 hr	12 hr	75 min ⁽¹⁾	95 min	35 min	35 min	30 min	30 min
5	8 hr	8 hr	30 min	30 min	30 min	30 min	30 min	30 min
5 (RCS Level below hot leg centerline)	8 hr	8 hr	30 min	30 min	Operation not allowed		Operation not allowed	
6	24 hr	24 hr	75 min	75 min	40 min ⁽²⁾	50 min	30 min ⁽²⁾	35 min
1. A decrease in the monitoring frequency was needed to cover a conservative higher value of critical Boron concentration corresponding to EPU conditions.								
2. A decrease in the monitoring frequency was needed to cover a wider range of initial Boron concentrations to conservatively bound EPU conditions.								

2.8.5.4.6 Spectrum of Rod Ejection Accidents

2.8.5.4.6.1 Regulatory Evaluation

Control rod ejection accidents cause a rapid positive reactivity insertion together with an adverse core power distribution, which could lead to localized fuel rod damage. Florida Power and Light (FPL) evaluated the consequences of a control rod ejection accident to determine the potential damage caused to the reactor coolant pressure boundary (RCPB) and to determine whether the fuel damage resulting from such an accident could impair cooling water flow.

FPL'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 which affect the peak reactor pressure or the probability of fuel rod failure, and the results of the transient analyses.

The Nuclear Regulatory Commission's (NRC) 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 reactor vessel internals so as to impair significantly the capability to cool the core.

Specific review criteria are contained in Standard Review Plan (SRP) Section 15.4.8 and other guidance provided in Matrix 8 of RS-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDC's relevant to the spectrum of rod ejection accidents are as follows:

- GDC-28 is described in UFSAR 3.1.28 Criterion 28 - Reactivity Limits.

The reactivity control systems shall be designed with appropriate limits on the potential amount and rate of reactivity increase to assure that the effects of postulated reactivity accidents can neither (1) result in damage to the [Reactor Coolant Pressure Boundary] RCPB greater than limited local yielding nor (2) sufficiently disturb the core, its support structures, or other reactor pressure vessel internals to impair significantly the capability to cool the core. These postulated reactivity accidents shall include consideration of rod ejection (unless prevented by positive means), rod dropout, steam line rupture, changes in reactor coolant temperature and pressure, and cold water addition.

The bases for control element assembly (CEA) design include ensuring that the reactivity worth of any one CEA is not greater than a preselected maximum value. The CEAs are divided into two sets: a shutdown set and a regulating set. These sets are further subdivided into groups as necessary. Administrative procedures and control interlocks ensure that the amount and rate of reactivity increase is limited to predetermined values. The regulating groups are withdrawn only

after the shutdown groups are fully withdrawn. The regulating groups are programmed to move in sequence and within limits which prevent the rate of reactivity addition and the worth of individual CEAs from exceeding limiting values (see UFSAR Sections 4.3 and 7.7).

The maximum rate of reactivity addition that may be produced by the chemical and volume control systems (CVCS) is too low to induce any significant pressure forces that might rupture the RCPB or disturb the reactor vessel internals. The design basis of the CVCS is described in UFSAR Section 9.3.4.

The RCPB (UFSAR Chapter 5) and the reactor internals (UFSAR Chapter 4) are designed to appropriate codes and accommodate the static and dynamic loads associated with an inadvertent, sudden release of energy, such as that resulting from a CEA ejection or a steam line break, without rupture and with limited deformation which will not impair the capability of cooling the core. Discussion of the CEA ejection event is provided in UFSAR Section 15.4.8.1.

NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Power Plant Units 1 and 2, dated September 2003, defines the scope of license renewal. Specific design transient analyses are not within the scope of license renewal.

2.8.5.4.6.2 Technical Evaluation

2.8.5.4.6.2.1 Introduction

A CEA ejection is the result of the postulated mechanical failure of a CEDM pressure housing such that the reactor coolant system (RCS) pressure would eject the CEA and drive shaft. The consequences of this mechanical failure, in addition to being a minor loss-of-coolant accident (LOCA), will also cause a rapid reactivity insertion together with an adverse core power distribution, possibly leading to localized fuel rod damage.

Rapid ejection of a CEA from the core would require a complete circumferential break of the CEDM housing or the CEDM nozzle on the reactor vessel head. The CEDM housing and CEDM nozzle are an extension of the RCPB. They are designed and manufactured to Section III of the American Society of Mechanical Engineer (ASME) Boiler and Pressure Vessel Code.

If a CEA ejection accident were to occur, a fuel rod thermal transient would occur that could potentially result in DNB and limited fuel damage. The amount of fuel damage that results from such an accident is governed by the worth of the ejected CEA and the power distribution attained with the remaining control element pattern. The transient is limited by the Doppler reactivity effects of the increase in fuel temperature and is terminated by reactor trip actuated by the high-power level trip. The transient is terminated before conditions are reached that will result in damage to the RCPB, or significant disturbances in the core, its support structures or other reactor pressure vessel internals that would impair the capability to cool the core.

The neutron flux response to a continuous reactivity insertion is characterized by a very fast flux increase terminated by the reactivity feedback effect of the negative Doppler Power Coefficient (DPC). This self limitation of the power burst is of primary importance since it limits the power to a tolerable level during the delay time for protective action. Should a CEA ejection accident

occur, the following automatic features of the reactor protection system are available to terminate the transient:

- Variable power level trip – high (VHP), and
- Rate-of-change of power trip - high.

2.8.5.4.6.2.2 Input Parameters, Assumptions, and Acceptance Criteria

In calculating the nuclear power and hot-spot fuel rod transients following CEA ejection, the following conservative assumptions are made (See LR [Section 2.8.5.0](#), Accident and Transient Analyses, for additional inputs and assumptions):

1. The standard thermal design procedure (STDP) (maximum uncertainties in initial conditions) is employed. The analysis assumes uncertainties in nominal vessel T_{AVG} and nominal pressurizer pressure.
2. A minimum value for the delayed neutron fraction for beginning of cycle (BOC) and end of cycle (EOC) conditions is assumed, which increases the rate at which the nuclear power increases following CEA ejection.
3. A minimum value of Doppler power defect is assumed, which conservatively results in the maximum amount of energy deposited in the fuel following CEA ejection. A minimum value of the moderator feedback is also assumed. A positive moderator temperature coefficient (MTC) is assumed for the BOC, zero-power case.
4. Maximum value of ejected CEA worth and post-ejection total hot-channel factors are assumed for all cases considered. These parameters are calculated using standard nuclear design codes for the maximum allowed bank insertion at a given power level as determined by the rod insertion limits. No credit is taken for the flux flattening effects of reactivity feedback.
5. The total time for CEA ejection is assumed to be 0.05 seconds.
6. For the hot zero power (HZIP) cases, the reactor is assumed to be tripped by the nuclear power signal of the VHP trip at the lower limit (floor) setpoint. For the hot full power (HFP) cases, the reactor trip is assumed to occur on the variable power level function of the Variable High Power (VHP) trip at a conservative setpoint. The reactor does not trip on high Rate-of-Change because it is conservative to assume a trip on VHP. Appropriate error allowances are added to the Technical Specification setpoints to determine the analysis trip point. A trip time delay of 0.4 seconds for reactor trip breaker opening is used, with the control rods assumed to start moving 0.74 seconds after breaker opening.
7. The analysis conservatively assumes the trip rods are inserted starting from the fully withdrawn position, using a conservative rod position versus time curve. Also, the total trip

reactivity is based on the conservative assumption that the highest worth adjacent CEA is stuck in its fully withdrawn position in addition to the ejected rod.

8. Both UO₂-only fuel and 8 weight percent (w/o) gadolinium-doped fuel were modeled in the analysis.

The CEA ejection event is classified as a postulated accident (PA). The physical limits of this accident are that any consequential damage to either the core or the RCS must not prevent long term cooling and that the radiological consequences must conform to the applicable regulatory dose limits. More specific criteria are applied to ensure that fuel dispersal in the coolant, gross lattice distortion, or severe shock waves will not occur. These criteria per SRP 15.4.8 are:

1. Fuel failure due to DNB failures and fuel centerline melt should be limited so as not to impair the capability to cool the core. Additionally, the fuel failures should be within the limits of the fuel failures used in the radiological analysis,
2. Peak RCS pressure must remain below that which would cause the stresses in the RCS to exceed the faulted condition stress limits, and
3. Maximum average fuel pellet enthalpy at the hot spot must remain below 200 cal/g (360 Btu/lbm).

The radiological dose consequence analyses for this event are provided in LR [Section 2.9.2](#), Radiological Consequences Analyses Using Alternative Source Term.

2.8.5.4.6.2.3 Description of Analyses and Evaluations

The calculation of the CEA ejection transient is performed in two stages, using a core neutron kinetic analysis and a hot-spot fuel heat transfer analysis, to demonstrate that the reactor protection system functions and mitigates the consequences at the extended power uprate (EPU) conditions utilizing the currently approved methodology. The spatial neutron kinetics code TWINKLE ([Reference 1](#)) is used in a 1-D axial kinetics model to calculate the core nuclear power including the various total core feedback effects; that is, Doppler reactivity and moderator reactivity. The average core nuclear power is multiplied by the post-ejection hot channel factor, and the fuel enthalpy and temperature transients at the hot spot are calculated with the detailed fuel and cladding transient heat transfer computer code, FACTRAN ([Reference 2](#)). The power distribution calculated without feedback is conservatively assumed to persist throughout the transient. Both TWINKLE and FACTRAN are NRC approved modeling codes and are used in the current licensing basis.

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

As discussed above, the design transient analyses were determined to be outside the scope of License Renewal; therefore, with respect to the design basis accidents and transients, the EPU does not impact any License Renewal evaluations.

2.8.5.4.6.2.5 Results

LR Figures 2.8.5.4.6-1 through 2.8.5.4.6-8 present the nuclear power and hot spot fuel rod thermal transients for the CEA ejection cases analyzed. The assumptions of the analysis are summarized in LR Table 2.8.5.4.6-1. A time sequence of events is provided in LR Table 2.8.5.4.6-2.

LR Table 2.8.5.4.6-3 provides a comparison of results to the current analysis. For the hot zero power (HZIP) cases, power suppression was not credited for either the current analysis or EPU cases. As such, the EPU results were shown to be more limiting because of an increase in core average heat flux. The EPU HFP cases did credit power suppression which offsets the increase in core average heat flux and this produced similar results to the current analysis, which did not credit power suppression.

Based on the generic assessment in WCAP-7588, Revision 1-A (Reference 3), the peak reactor coolant pressure will be less than that which would cause stresses to exceed the faulted conditions stress limits. The ejected rod worths that support the EPU are bounded by the values used in the WCAP-7588, Revision 1-A (Reference 3) overpressure study. Therefore, the overpressure results of WCAP-7588 remain valid at the EPU conditions.

This analysis determined that there are no fuel failures due to rods-in-DNB. The maximum number of fuel rods to experience DNB during the transient is thus less than the limit used as an input to the radiological consequences analysis presented in LR Section 2.9.2, Radiological Consequences Using Alternative Source Term (AST).

For all cases, the maximum fuel pellet enthalpy remained below 200 cal/g. The peak hot-spot fuel centerline temperature remained below the fuel melting temperature (4900°F at BOC and 4800°F at EOC for UO₂-only; 4816°F at BOC and 4717°F at EOC for 8 w/o gad-doped fuel) for all cases. Thus, there are no fuel failures due to fuel melt. Gad-doped UO₂ fuel was found to be more limiting for all cases. The maximum clad average temperature remained below 3000°F and the maximum reacted zirconium percent remained below 16 percent. Power suppression was credited in both the HFP cases and not credited for the HZIP cases.

Therefore, based on the above, it is concluded that all acceptance criteria associated with CEA ejection event have been met at the EPU conditions.

2.8.5.4.6.3 Conclusion

FPL has reviewed the analyses of the rod ejection accident 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. FPL further concludes that the appropriate reactor protection 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, FPL concludes that St. Lucie Unit 2 will continue to meet the requirements of GDC-28 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to the rod ejection accident.

2.8.5.4.6.4 References

1. WCAP-7979-P-A (Proprietary) and WCAP-8028-A (Non-Proprietary), Twinkle – A Multi-Dimensional Neutron Kinetics Compute Code, Risher, D.H., Jr. and Barry, R. F., January 1975.
2. WCAP-7908-A, FACTRAN – A FORTRAN IV Code for Thermal Transients in a UO₂ Fuel Rod, Hargrove, H.G., December 1989.
3. WCAP-7588, Revision 1-A, An Evaluation of the Rod Ejection Accident in Westinghouse Pressurized Water Reactors Using Spatial Kinetics Methods, Risher, D. H., January 1975.

Table 2.8.5.4.6-1
Assumptions – CEA Ejection

Beginning of Cycle	Full Power	Zero Power
Initial Power Level, %	100	0
Ejected CEA Worth, % Δk	0.25	0.60
Delayed Neutron Fraction	0.0050	0.0050
Doppler Power Defect, % Δk	-0.900	-0.900
Feedback Reactivity Weighting	1.262	2.633
Trip Reactivity, % Δk	3.0	2.0
F_Q Before Ejection	2.415	N/A
F_Q After Ejection	5.25	15.0
Number of Reactor Coolant Pumps (RCP) Operating	4	4
End of Cycle	Full Power	Zero Power
Initial Power Level, %	100	0
Ejected CEA Worth, % Δk	0.25	0.60
Delayed Neutron Fraction	0.0044	0.0044
Doppler Power Defect, % Δk	-0.900	-0.900
Feedback Reactivity Weighting	1.262	3.802
Trip Reactivity, % Δk	3.0	2.0
F_Q Before Ejection	2.415	N/A
F_Q After Ejection	5.25	26.25
Number of RCPs Operating	4	4

Table 2.8.5.4.6-2
Sequence of Events – CEA Ejection

BOC - HZP	Time (seconds)
CEA Ejection Occurs	0.00
VHP Trip Setpoint (Lower Limit Setting) is Reached	0.49
Peak Nuclear Power Occurs	0.56
Reactor Trip	0.89
Rods Begin to Fall Into the Core	1.63
Peak Cladding Average Temperature Occurs	2.3
Peak Fuel Average Temperature Occurs	2.6
BOC - HFP	Time (seconds)
CEA Ejection Occurs	0.00
VHP Trip Setpoint is Reached	0.03
Peak Nuclear Power Occurs	0.09
Reactor Trip	0.43
Rods Begin to Fall Into the Core	1.17
Peak Fuel Average Temperature Occurs	2.4
Peak Cladding Average Temperature Occurs	2.4
EOC - HZP	Time (seconds)
CEA Ejection Occurs	0.00
VHP Trip Setpoint (Lower Limit Setting) is Reached	0.31
Peak Nuclear Power Occurs	0.36
Reactor Trip	0.71
Rods Begin to Fall Into the Core	1.45
Peak Cladding Average Temperature Occurs	1.8
Peak Fuel Average Temperature Occurs	2.0
EOC - HFP	Time (seconds)
CEA Ejection Occurs	0.00
VHP Trip Setpoint is Reached	0.03
Peak Nuclear Power Occurs	0.09
Reactor Trip	0.43
Rods Begin to Fall Into the Core	1.17
Peak Fuel Average Temperature Occurs	2.4
Peak Cladding Average Temperature Occurs	2.4

**Table 2.8.5.4.6-3
Comparison to Current Licensing Basis Results**

Beginning of Cycle Cases					
	HFP Current	HFP EPU	HZP Current	HZP EPU	Limit
Max. Fuel Pellet Enthalpy, (cal/g)	151.4	151.4	70.8	78.2	200.0
Max. Clad Average Temperature (°F)	1946.0	1941.0	1307.0	1373.0	3000.0
Max. Reacted Zirc (%)	0.33	0.33	0.08	0.09	16.0
Max. Rods-in-DNB, %	< 9.5	< 9.5	< 9.5	< 9.5	9.5
Maximum Fuel Melted, %	< 0.5	< 0.5	< 0.5	< 0.5	0.5
End of Cycle Cases					
	HFP Current	HFP EPU	HZP Current	HZP EPU	Limit
Max. Fuel Pellet Enthalpy, (cal/g)	141.7	141.3	77.4	88.7	200.0
Max. Clad Average Temperature (°F)	1841.0	1832.0	1403.0	1509.0	3000.0
Max. Reacted Zirc (%)	0.24	0.24	0.09	0.09	16.0
Max. Rods-in-DNB, %	< 9.5	< 9.5	< 9.5	< 9.5	9.5
Maximum Fuel Melted, %	< 0.5	< 0.5	< 0.5	< 0.5	0.5

Figure 2.8.5.4.6-1
CEA Ejection – HFP, BOC
Reactor Power v. Time

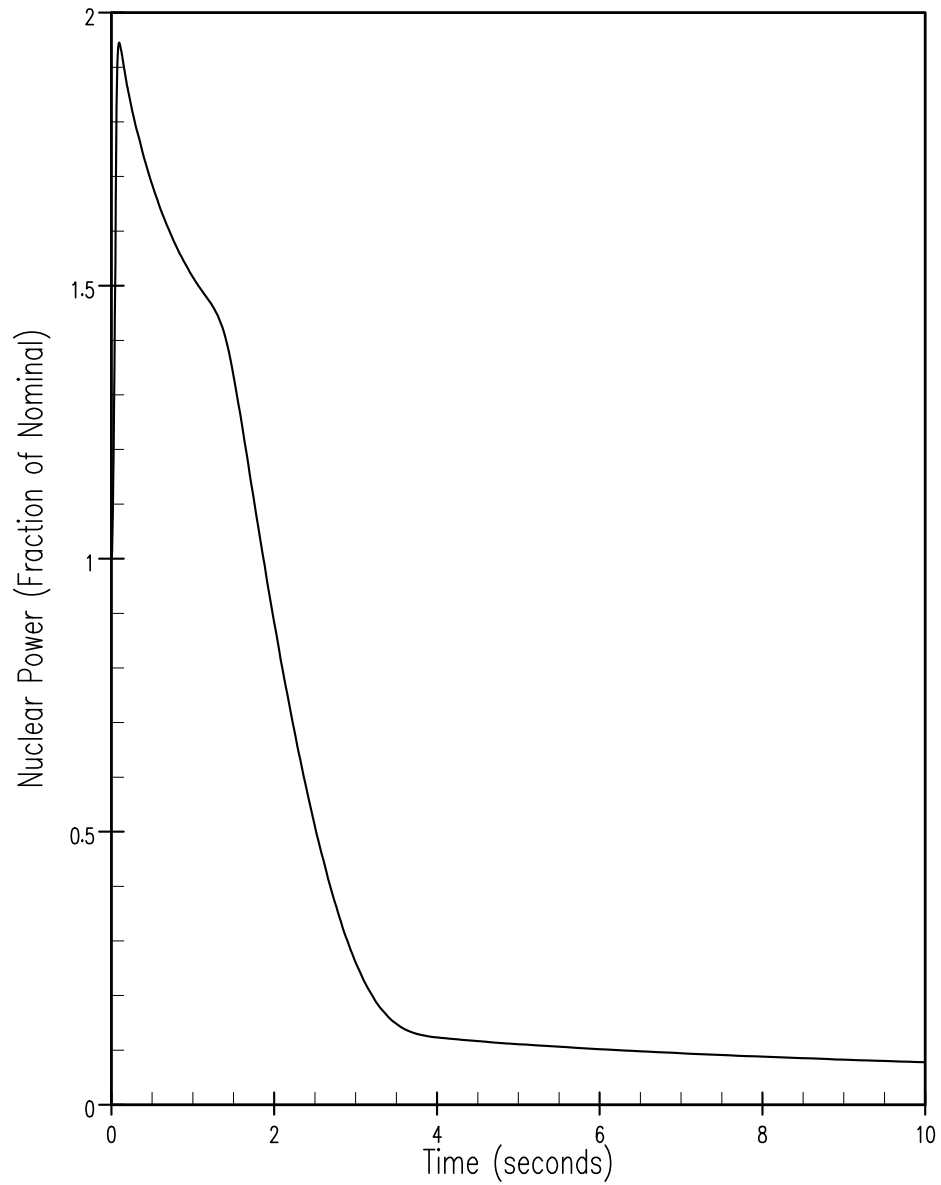


Figure 2.8.5.4.6-2
CEA Ejection – HFP, BOC
Fuel and Cladding Temperature v. Time

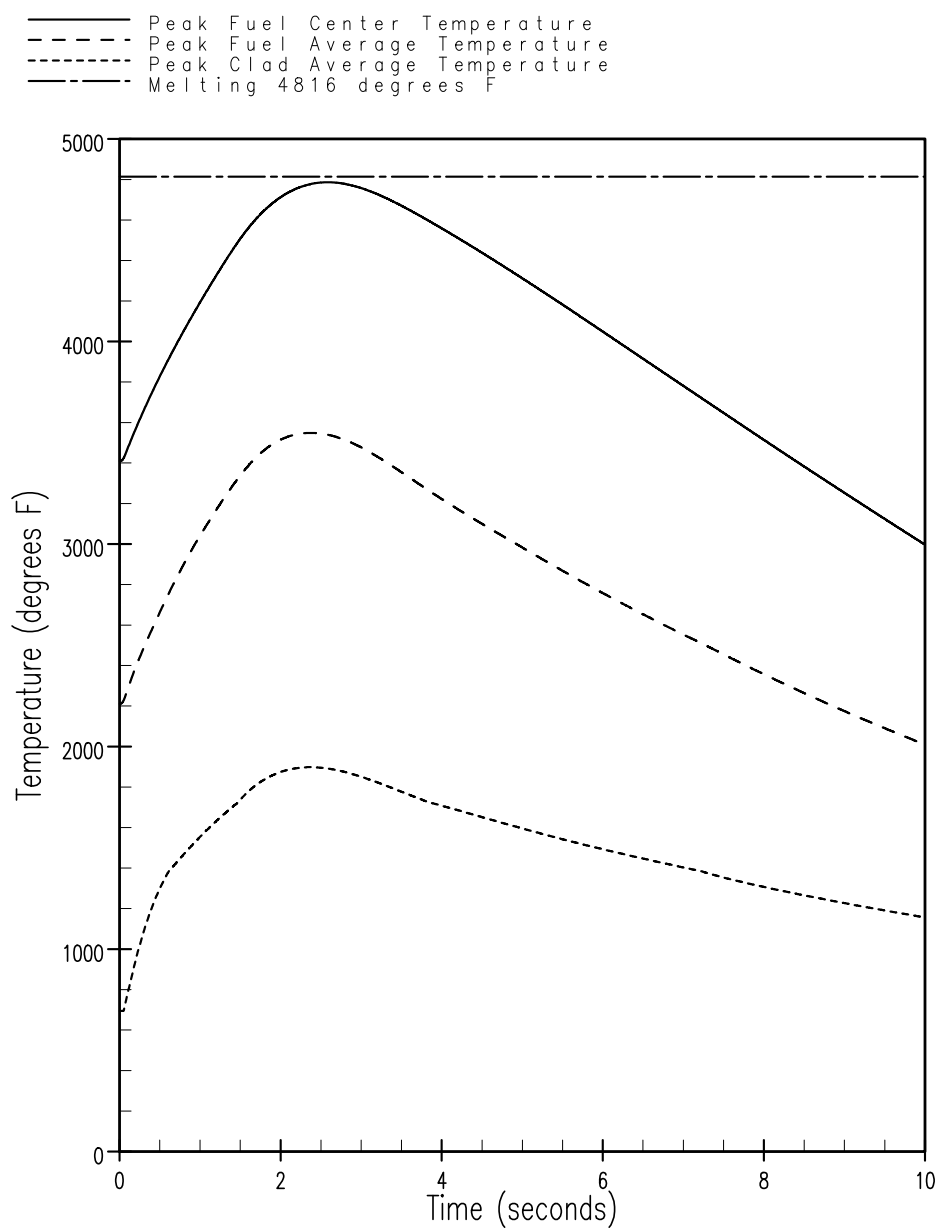


Figure 2.8.5.4.6-3
CEA Ejection – HZP, BOC
Reactor Power v. Time

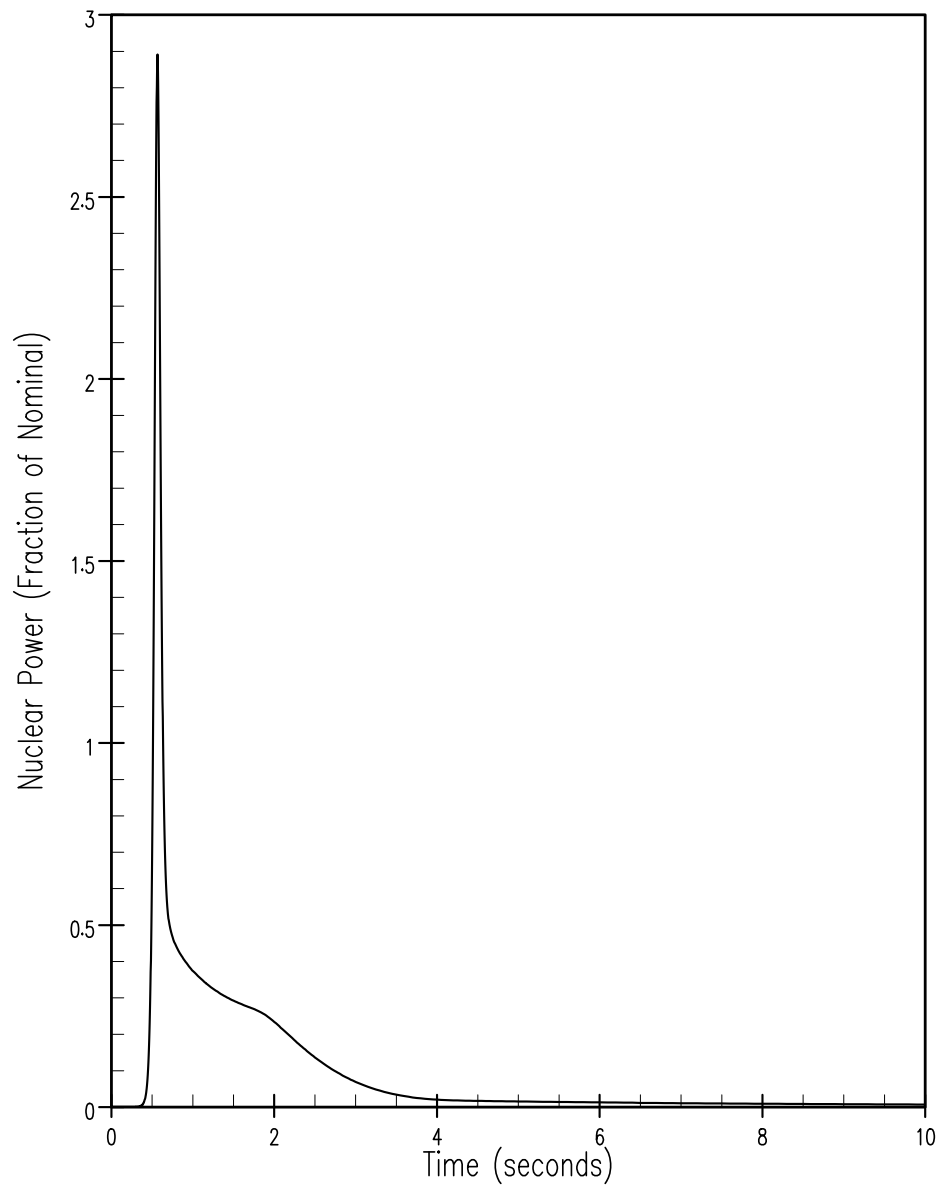


Figure 2.8.5.4.6-4
CEA Ejection – HZP, BOC
Fuel and Cladding Temperatures v. Time

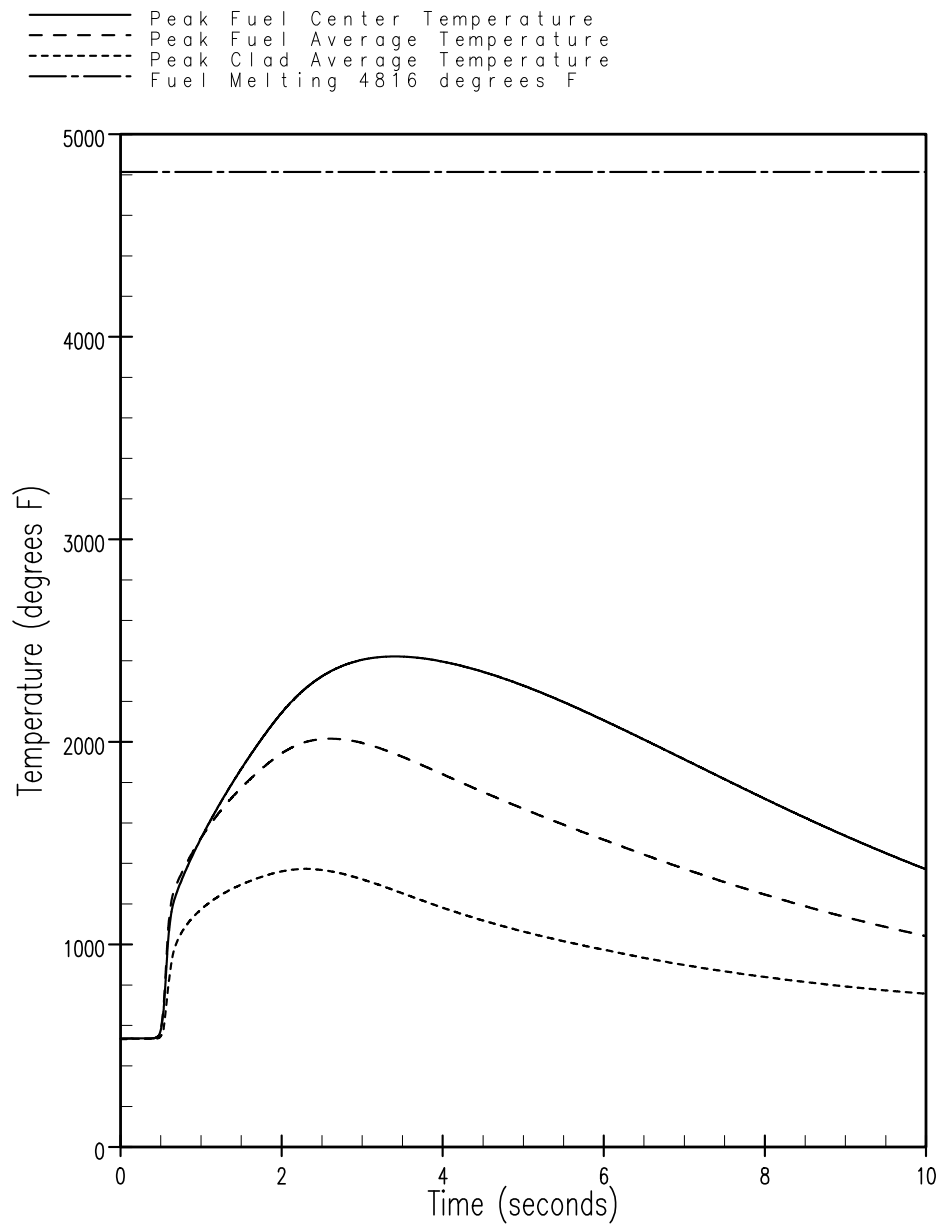


Figure 2.8.5.4.6-5
CEA Ejection – HFP, EOC
Reactor Power v. Time

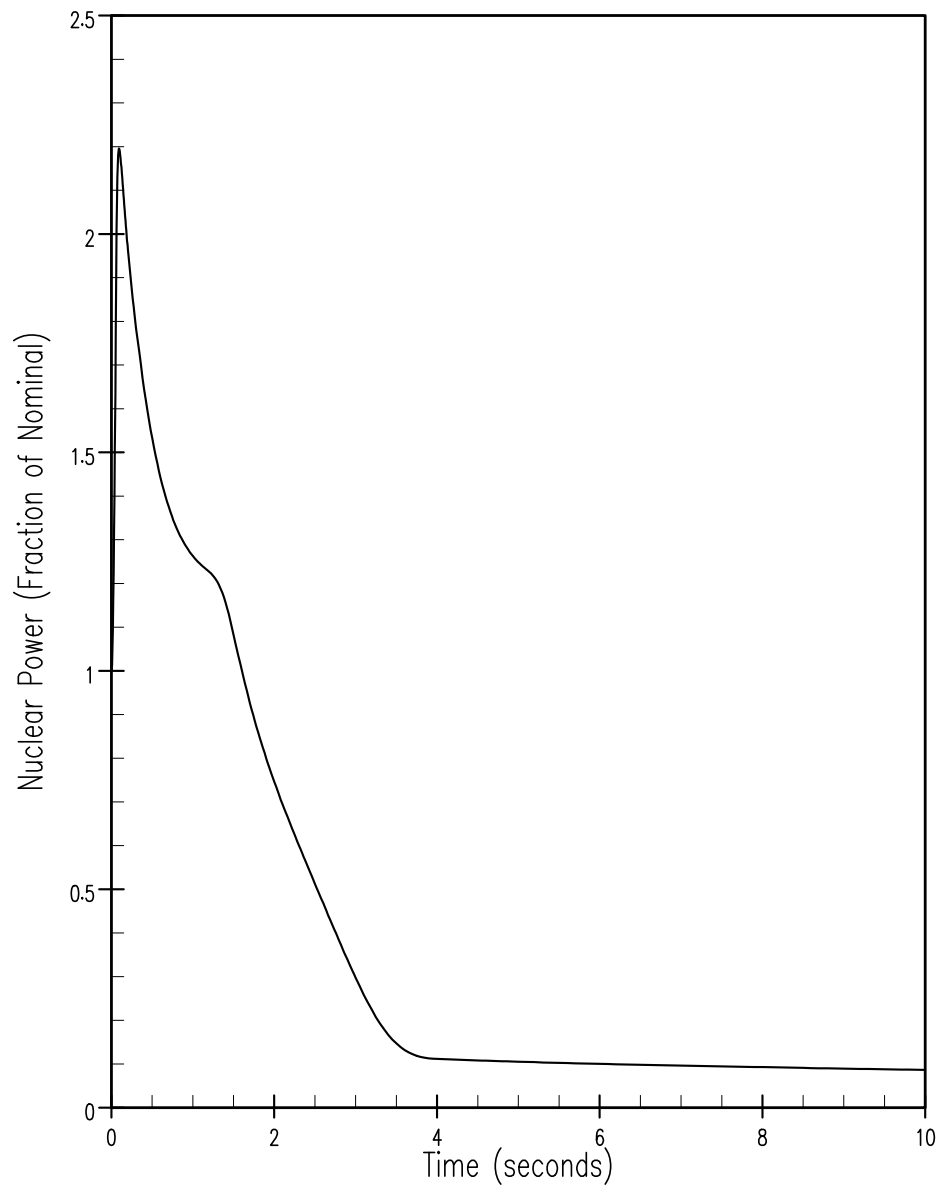


Figure 2.8.5.4.6-6
CEA Ejection – HFP, EOC
Fuel and Cladding Temperatures v. Time

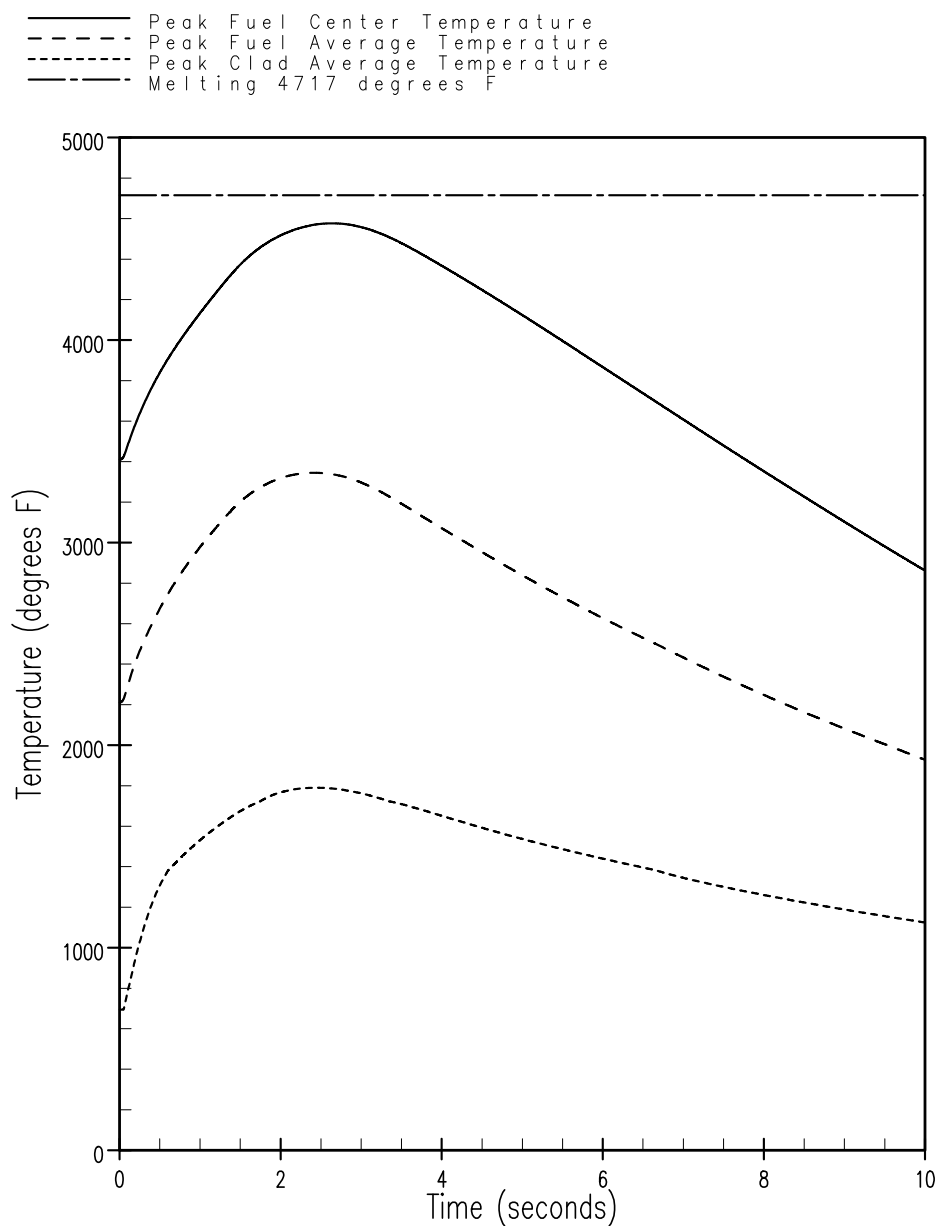


Figure 2.8.5.4.6-7
CEA Ejection – HZP, EOC
Reactor Power v. Time

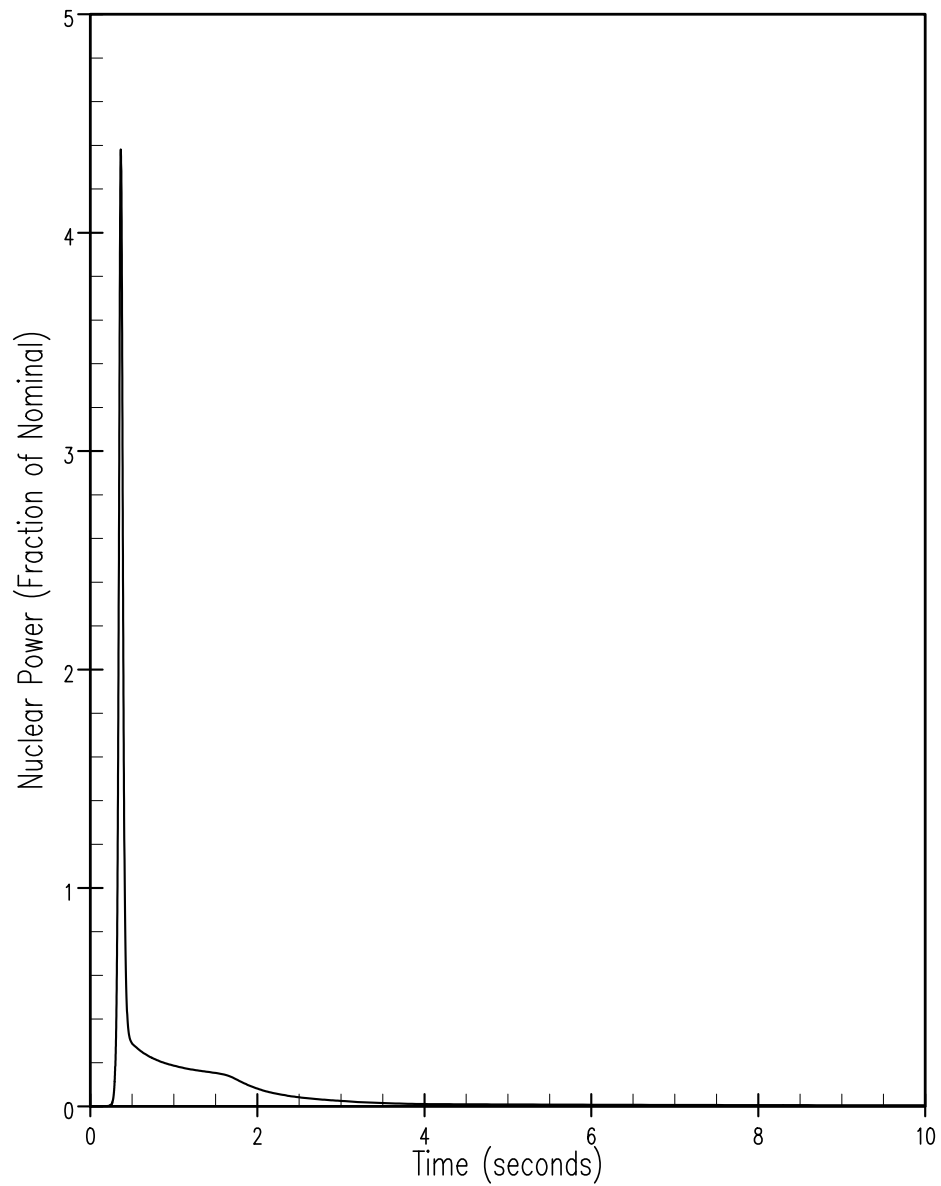
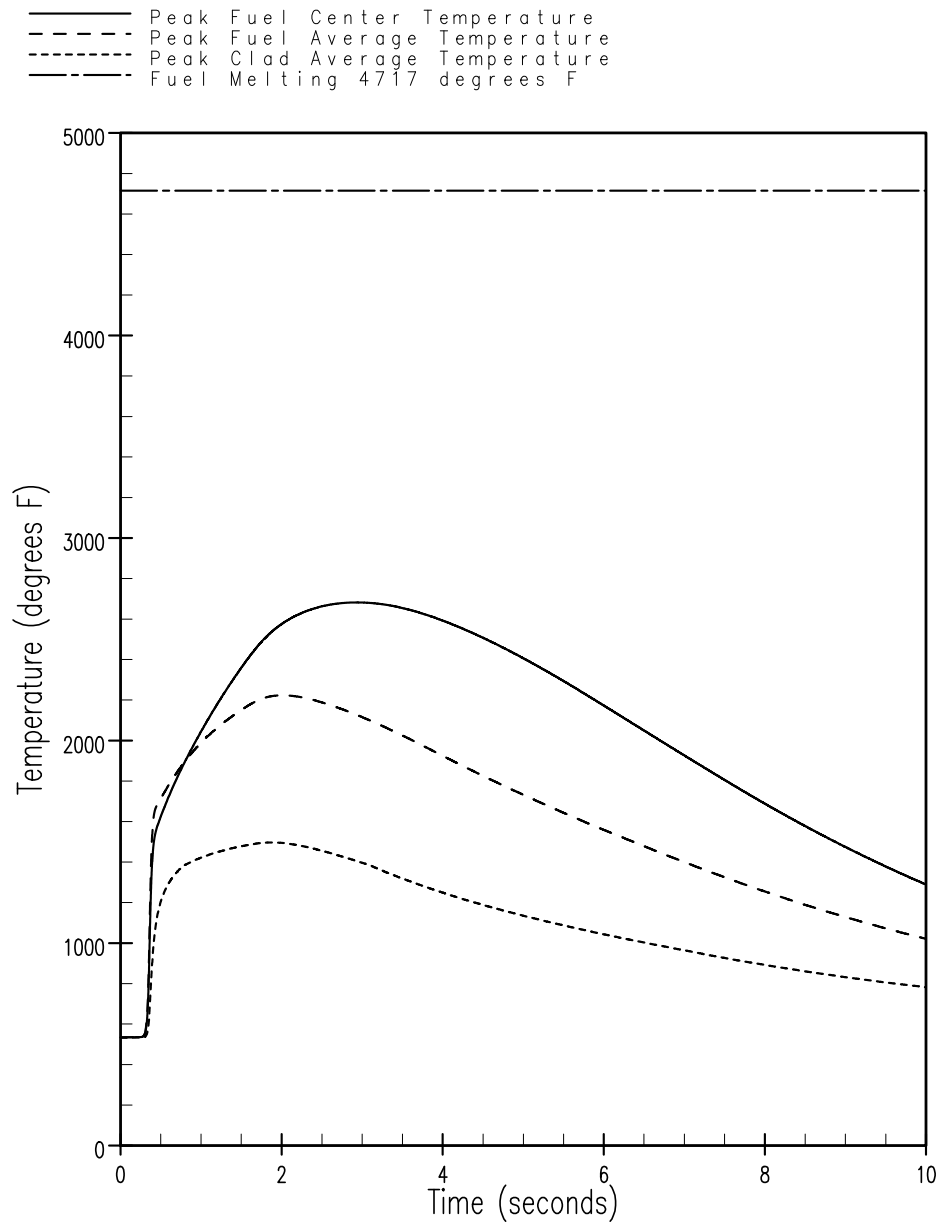


Figure 2.8.5.4.6-8
CEA Ejection – HZP, EOC
Fuel and Cladding Temperatures v. Time



2.8.5.5 Inadvertent Operation of Emergency Core Cooling System (ECCS) and Chemical and Volume Control System (CVCS) Malfunction that Increases Reactor Coolant Inventory

2.8.5.5.1 Regulatory Evaluation

Equipment malfunctions, operator errors, and abnormal occurrences could cause unplanned increases in reactor coolant inventory. Depending on the boron concentration and temperature of the injected water and the response of the automatic control systems, a power level increase may result and, without adequate controls, could lead to fuel damage or overpressurization of the reactor coolant system (RCS). Alternatively, a power level decrease and depressurization may result. Reactor protection and safety systems are actuated to mitigate these events.

FPL's review covered:

- The sequence of events,
- The analytical model used for analyses,
- The values of parameters used in the analytical model, and
- The results of the transient analyses.

The NRC's acceptance criteria are based on:

- General Design Criterion (GDC)-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that Specified Acceptable Fuel Design Limits (SAFDL) are not exceeded during normal operations, including anticipated operational occurrences (AOOs);
- 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 reactor coolant pressure boundary (RCPB) are not exceeded during AOOs; and
- 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 Standard Review Plan (SRP) Section 15.5.1-2 and other guidance provided in Matrix 8 of RS-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDCs for the inadvertent operation of ECCS and CVCS malfunction that increases reactor coolant inventory are as follows:

- GDC-10 is described in UFSAR Section 3.1.10 Criterion 10 – Reactor Design.

The reactor core and associated coolant, control and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

SAFDLs are stated in UFSAR Section 4.3. Minimum margins to SAFDLs are prescribed in the Technical Specifications (Limiting Conditions for Operations) which support UFSAR Chapters 4 and 15.

- GDC-15 is described in UFSAR Section 3.1.15 Criterion 15 – Reactor Coolant System Design.

The reactor coolant system and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences.

The operating conditions for normal steady state and transient plant operations are established conservatively. Normal operating limits are selected so that an adequate margin exists between operating and design limits. The plant control systems are designed to ensure that plant variables are maintained well within the established operating limits. The plant transient response characteristics and pressure and temperature distributions during normal operations are considered in the design as well as the accuracy and response of the instruments and controls. These design techniques ensure that a satisfactory margin is maintained between the plant's normal operating conditions, including design transients, and the design limits for the reactor coolant pressure boundary.

The plant control systems function to minimize deviations from normal operating limits in the event of most AOOs. Where control systems response would be inadequate or fail upon demand, the RPS and the engineered safety features actuation system (ESFAS) function to mitigate the consequences of such events.

The RPS and ESFAS function to mitigate the consequences of accidents such that the design limits for the RCPB are not exceeded.

- GDC-26 is described in UFSAR Section 3.1.26 Criterion 26 – Reactivity Control System Redundancy and Capability.

Two independent reactivity control systems of different design principles shall be provided. One of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margin for malfunctions such as stuck rods, specified acceptable fuel design limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure acceptable fuel design limits are not exceeded. One of the systems shall be capable of holding the reactor core subcritical under cold conditions.

Two independent reactivity control systems of different design principles are provided. The first system, using control element assemblies (CEAs), includes a positive means (gravity) for inserting CEAs and is capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. The CEAs can also be mechanically driven into the core. The appropriate margin for stuck rods is provided by assuming in the analyses of AOOs that the highest worth CEA does not fall into the core.

The second system, the chemical and volume control system (CVCS), using neutron absorbing soluble boron, is capable of reliably compensating for the rate of reactivity changes resulting from planned normal power changes (including xenon burnout) such that SAFDLs are not exceeded. This system is capable of holding the reactor subcritical under cold conditions. For a further description, see UFSAR Section 9.3.4.

Either system is capable of making the core subcritical from a hot operating condition.

For further discussion, see UFSAR Sections 7.4 and 7.7.

As discussed in UFSAR Section 15.5.1, the inadvertent operation of the ECCS during power operation (Mode 1) is not analyzed since the shutoff head of the injection pumps is much less than the RCS pressure in Mode 1.

UFSAR Section 15.5.2 describes the analysis pertaining to a CVCS malfunction event that produces an unplanned increase in RCS inventory.

The CVCS malfunction that decreases the primary coolant boron concentration is discussed in LR [Section 2.8.5.4.5](#), Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the Reactor Coolant.

NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, published September 2003 defines the scope of license renewal. Specific design transient analyses are not within the scope of License Renewal.

2.8.5.5.2 Technical Evaluation

2.8.5.5.2.1 Introduction

A CVCS malfunction event that produces an unplanned increase in reactor coolant system inventory may be caused by operator error or a failure in the pressurizer level transmitter which causes an erroneous low-low level signal. The generated signal will be transmitted to the controller which responds by actuating a second charging pump and closing the letdown flow control valve to its minimum flow position. The CVCS malfunction is assumed to occur without increasing or diluting the primary coolant initial boron concentration. With the mismatch between letdown and charging flow, the pressurizer mixture level and pressure increase. The pressurizer sprays mitigate the pressure increase. The operators are alerted to the event either by a high pressurizer pressure trip (HPPT) or by the pressurizer high level alarm (PHLA). Twenty (20) minutes after either HPPT or the PHLA occurs, it is assumed that the operators mitigate the event by reducing charging flow and/or restoring letdown flow.

UFSAR Section 15.5.1 states that inadvertent operation of the ECCS, through high pressure safety injection (HPSI), during power operation (Mode 1) is not analyzed since the shutoff head

of the injection pumps is much less than the RCS pressure in Mode 1. The HPSI delivery curves start at or below 1450 psia, which is well below the nominal pressure at power.

2.8.5.5.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The analysis of the CVCS malfunction event has been performed to demonstrate that operators have a sufficient amount of time to preclude the pressurizer from going water solid following a high pressurizer level alarm. To maximize the peak pressurizer mixture volume, the following assumptions are made. Note that the event does not reach the HPPT setpoint, and as such, the PHLA serves to alert the operator of the event.

1. An initial core power of 3030 MWt based on a rated core power of 3020 MWt, with 0.3 percent uncertainty. (20 MWt pump heat is added to the core power.)
2. A maximum steam generator tube plugging level of 10 percent.
3. Initial values of pressurizer pressure corresponding to the low end of the allowable range (2225 psia) minus the 45 psia pressure uncertainty.
4. The vessel average temperature (T_{avg}) is set to the nominal high T_{avg} plus the T_{avg} measurement uncertainty.
5. The initial pressurizer level is conservatively set to 60 percent, based on the nominal level minus the level uncertainty.
6. Maximum charging flow is 49 gpm per pump for a total of 98 gpm for two charging pumps. This is reduced by 4 gpm for the reactor coolant pump bleedoff flow and results in a total charging flow assumption of 94 gpm.
7. The initiating event is an erroneous low-low level signal that actuates a second charging pump and closes the letdown flow control valve to the minimum position.
8. The assumed single failure is the complete closure of the letdown flow control valve that occurs concurrently with the start of the second charging pump.
9. The charging flow boron concentration is assumed to be equal to the initial RCS boron concentration.
10. The pressurizer high level alarm setpoint is assumed to be 70 percent of tap span, which includes level uncertainty.
11. The pressurizer safety valves are assumed to have a -3 percent tolerance that corresponds to a minimum opening setpoint of 2425 psia. The PORVs are assumed to be inoperable or in manual and are not credited.
12. Operator action is assumed to occur at 20 minutes after the PHLA actuates.

13. Maximum reactivity feedback conditions are assumed.

14. Pressurizer sprays and heaters are assumed in the automatic mode.

The CVCS Malfunction is an AOO event and is analyzed to show that the limits for an AOO (specifically, generation of a more serious plant condition, pressurizer fill) are not exceeded. The applicable acceptance criteria are discussed as follows.

With respect to peak RCS and main steam system pressures, the CVCS malfunction at-power event is bounded by the loss of condenser vacuum event described in LR [Section 2.8.5.2.1](#), which is analyzed with assumptions that are made to conservatively calculate the RCS and main steam system pressure transients.

With respect to the fuel damage acceptance criterion, the CVCS malfunction at-power event is bounded by the CEA bank withdrawal at-power event described in LR [Section 2.8.5.4.2](#). During the CVCS malfunction there are very small increases in core power and RCS temperatures, and a very small change in RCS mass flow. The RCS pressure increase is limited by the pressurizer sprays and offsets any negative effects due to the minimal changes in other departure from nucleate boiling (DNB) related parameters.

With respect to the acceptance criterion of not generating a more serious plant condition, this is satisfied by demonstrating that the pressurizer safety valves (PSVs) do not discharge water. Due to the mismatch between charging and letdown flows, the pressurizer water volume increases during the CVCS malfunction at-power event. Operator action is required to preclude water discharge through the PSVs.

With respect to the fission product barrier failure criterion, this is met by demonstrating that the DNB design basis is satisfied. Thus, there is no loss of function of any fission product barrier for the CVCS malfunction at-power event.

2.8.5.5.2.3 Description of Analyses and Evaluations

The CVCS malfunction at power transient is analyzed by employing the detailed digital computer code RETRAN ([Reference 1](#)). The code simulates the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

The thermal hydraulic response of the NSSS to the CVCS malfunction was modelled following the current methodology as outlined in UFSAR Section 15.5.2 and the thermal-hydraulic response of the transient was simulated using the RETRAN computer code.

The CVCS malfunctions event's initial conditions are listed in LR [Table 2.8.5.0-2](#) of LR [Section 2.8.5.0](#), Accident and Transient Analyses, and in LR [Section 2.8.5.5.2.2](#) above.

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

As discussed above, the design transient analyses were determined to be outside the scope of License Renewal; therefore, with respect to the design basis accidents and transients, the EPU does not impact any License Renewal evaluations.

2.8.5.5.2.5 Results

LR [Table 2.8.5.5.1-1](#) lists the Sequence of Events. LR [Figures 2.8.5.5.1-1 to 2.8.5.5.1-5](#) show the key transient parameters response during the event.

The transient is assumed to start at 10 seconds, and the pressurizer high level alarm alerts the operators at 374.4 seconds. At 1574.4 seconds (20 minutes later), the pressurizer mixture volume is 1512.3 ft³, which corresponds to 6.7 ft³ of margin to filling the pressurizer water solid.

The maximum pressurizer pressure is 2229.7 psia at 956 seconds. This is well below the pressurizer safety valves opening setpoint of 2425 psia. In addition, although the PORVs are not credited in the analysis, the analysis demonstrated that the PORV opening setpoint is not reached.

Note that as discussed in LR [Section 2.8.5.5.2.2](#), DNB in the CVCS malfunction event is bounded by the CEA withdrawal at power event, as shown in LR [Section 2.8.5.4.2](#). This is further supported by LR [Figures 2.8.5.5.1-1 through 2.8.5.5.1-3](#). Reactor power and RCS temperatures remain constant throughout the transient, and pressurizer pressure increases. These conditions indicate that DNB does not decrease during the event, and thus is not challenged.

The results demonstrate that the pressurizer volume does not become water solid prior to 20 minutes after the PHLA is actuated. The CVCS malfunction at-power event is assumed to be mitigated by operator action prior to the pressurizer filling and no water is discharged through the PSVs. Thus, it is concluded that this transient does not generate a more serious plant condition and is acceptable for the EPU.

2.8.5.5.3 Conclusion

FPL has reviewed the evaluation of the inadvertent operation of ECCS event and the analysis of the malfunction of the CVCS event and concludes that the evaluation/analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. FPL further concludes that the evaluation/analyses have 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 this event. Based on this, FPL concludes that the plant will continue to meet its licensing basis with respect to the requirements of GDCs -10, -15, and -26 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to the inadvertent operation of ECCS event and malfunction of the CVCS event.

2.8.5.5.4 References

1. WCAP-14882-P-A (Proprietary) and WCAP-15234-A (Non-Proprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, D. S. Huegel, et al., April 1999.

Table 2.8.5.5.1-1
Sequence of Events for the CVCS Malfunction Event

Time, sec		Event	Setpoint or Limit		Value	
EPU	Current		EPU	Current	EPU	Current
10.0	10.0	Erroneous low-low level pressurizer level control system signal, Second charging pump starts, Letdown flow is isolated	---	---	---	---
374.4 *	337.7 *	Pressurizer High Level Alarm occurs	70% of tap span	70% of tap span	70.0	70.0
956 *	967.5 *	Maximum pressurizer pressure	2750.0 psia	2750.0 psia	2229.7 psia	2222.1 psia
1574.4 *	1537.7 *	Operator action occurs to mitigate the event	1200 seconds after PHLA	1200 seconds after PHLA	---	---
1574.4 *	1537.7 *	Maximum Pressurizer Volume occurs	1519.0 ft ³	1519.0 ft ³	1512.3 ft ³	1508.3 ft ³
* These values include the 10 seconds steady state time.						

Figure 2.8.5.5.1-1
CVCS Malfunction at Power
Nuclear Power

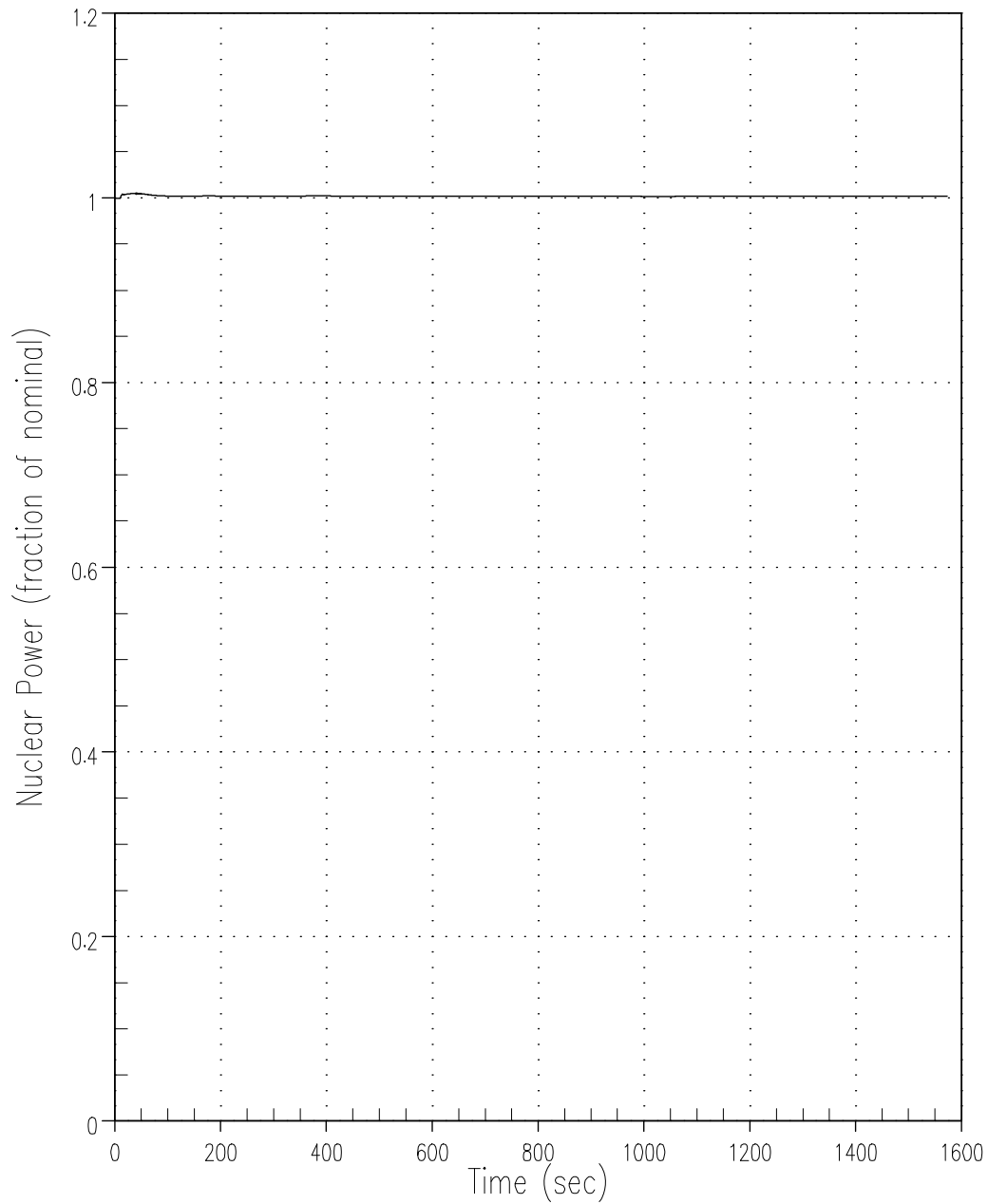


**Figure 2.8.5.5.1-2
CVCS Malfunction at Power
Pressurizer Pressure**

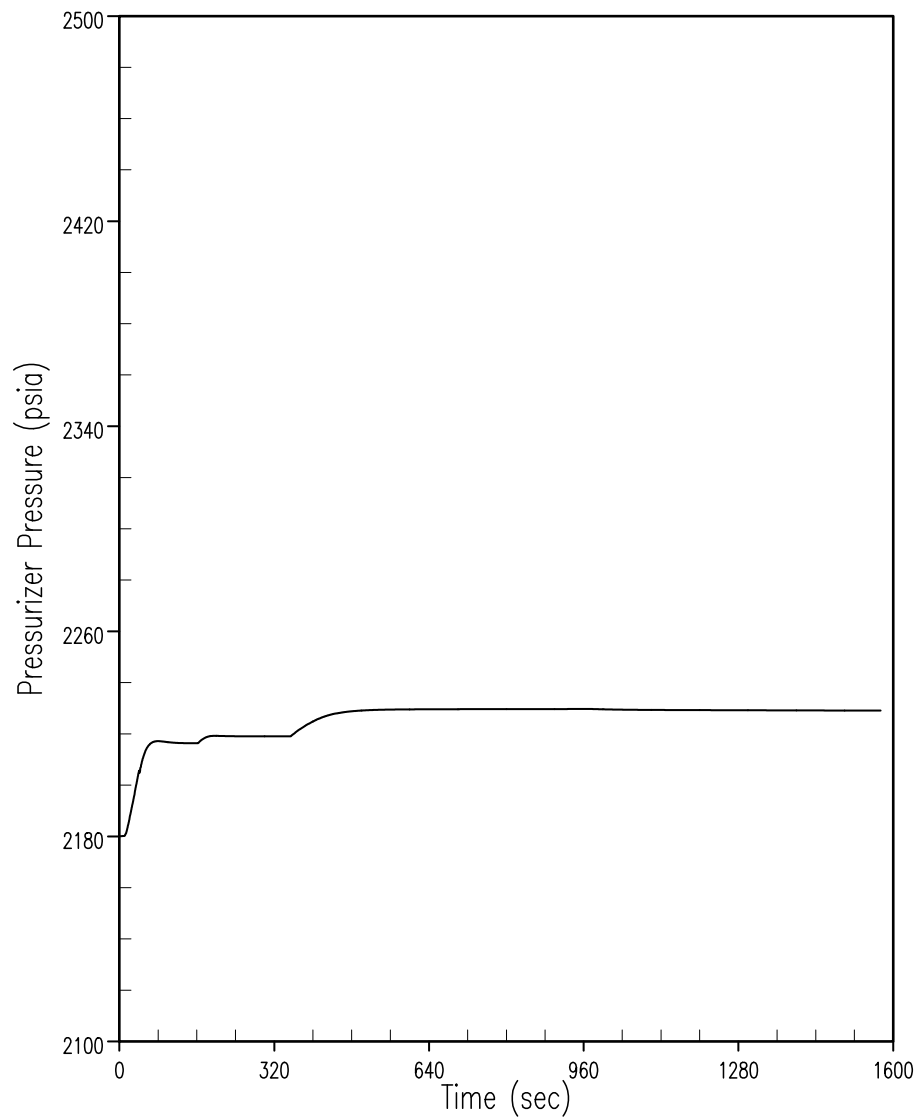


**Figure 2.8.5.5.1-3
CVCS Malfunction at Power
Vessel Average Temperature**

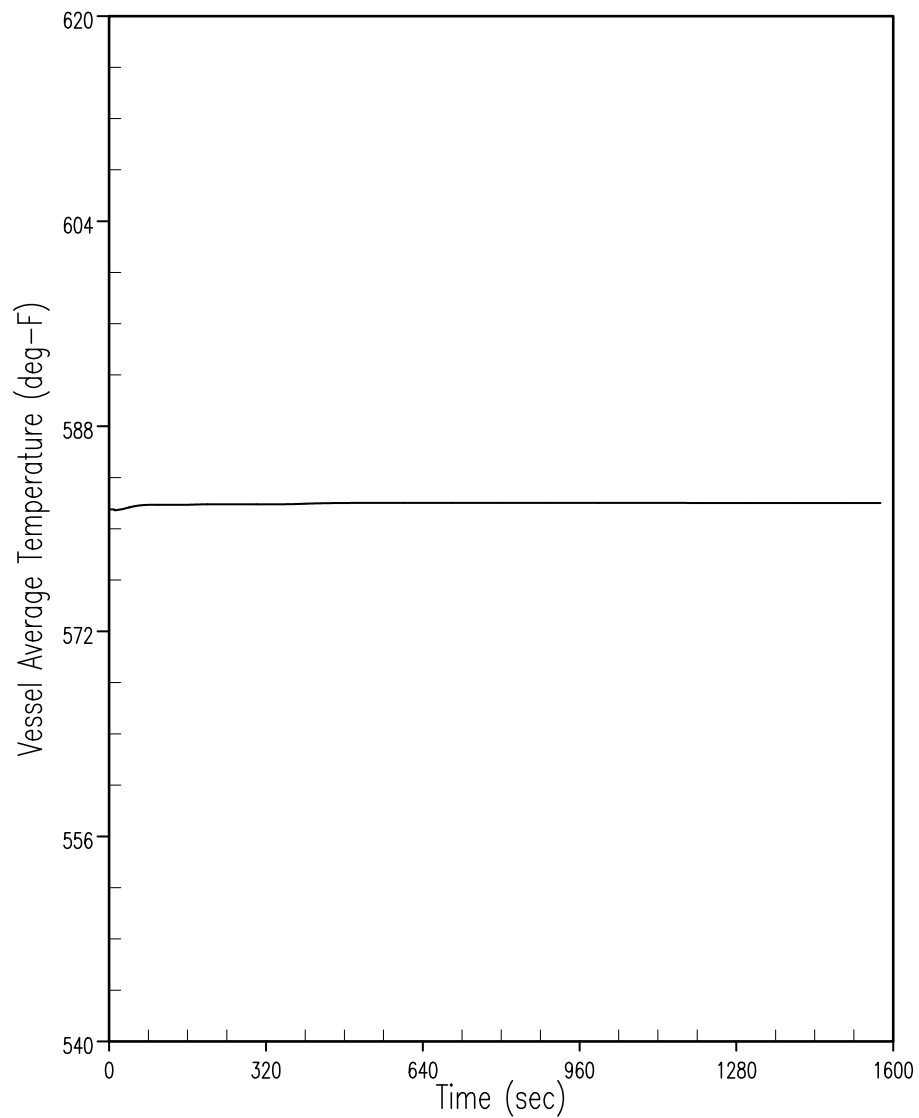


Figure 2.8.5.5.1-4
CVCS Malfunction at Power
Pressurizer Water Volume

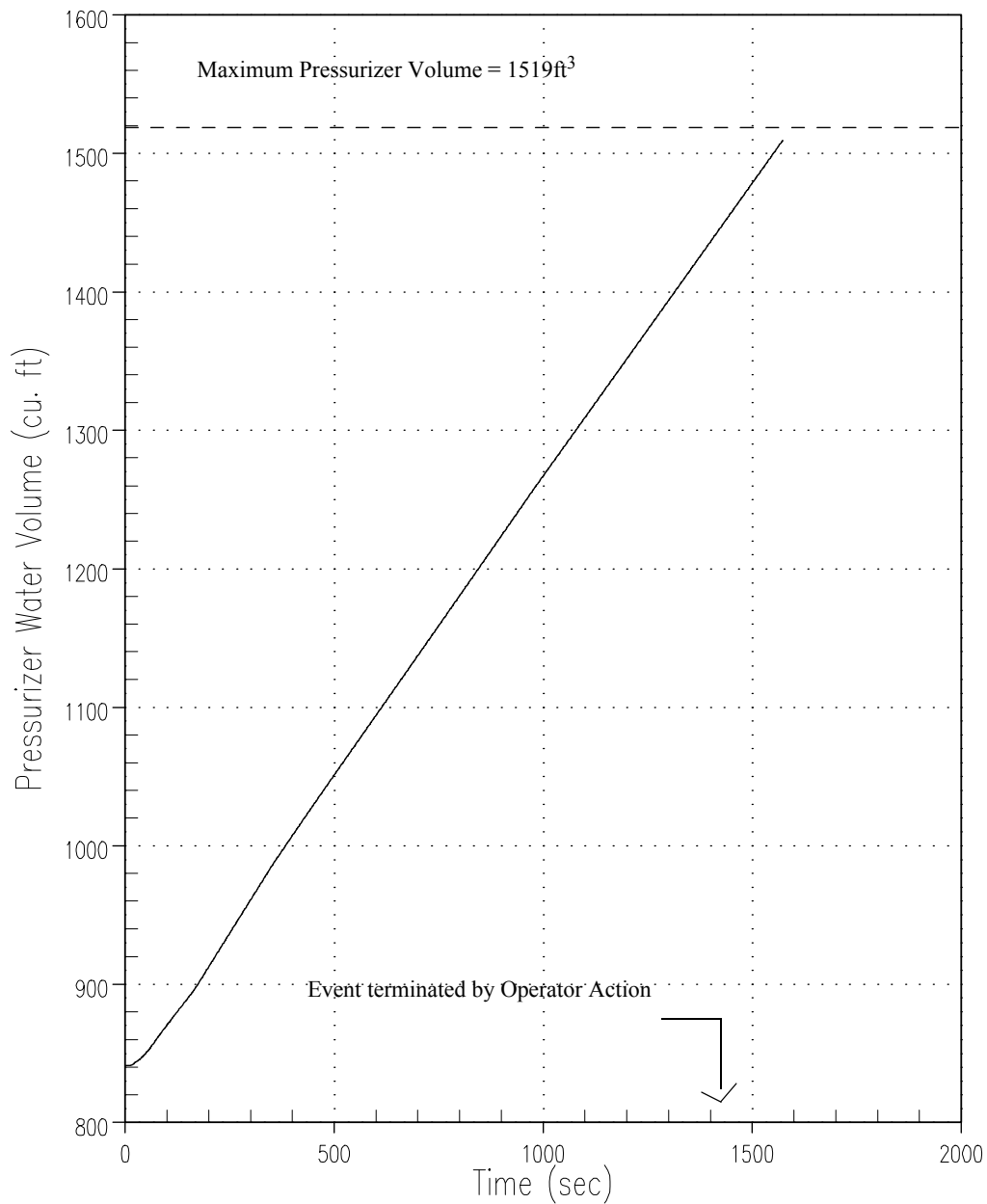
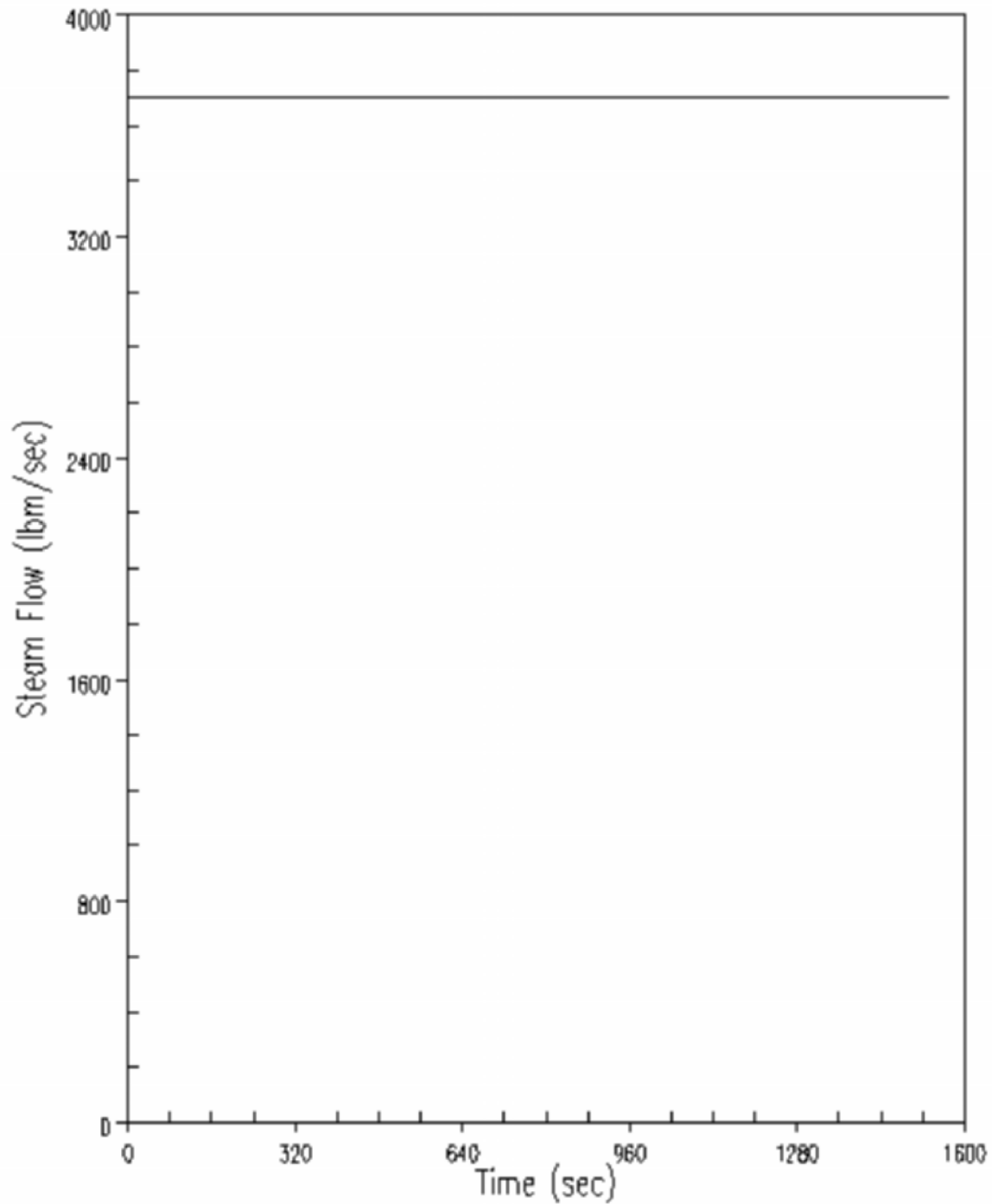


**Figure 2.8.5.5.1-5
CVCS Malfunction at Power
Steam Flow**



2.8.5.6 Decrease in Reactor Coolant Inventory

2.8.5.6.1 Inadvertent Opening of Pressurizer Pressure Relief Valve

2.8.5.6.1.1 Regulatory Evaluation

The inadvertent opening of a pressure relief valve results in a reactor coolant inventory decrease and a decrease in reactor coolant system (RCS) pressure. A reactor trip normally occurs due to low RCS pressure.

The Florida Power and Light (FPL) review covered:

- The sequence of events,
- The analytical model used for analyses,
- The values of parameters used in the analytical model, and
- The results of the transient analyses.

The NRC's acceptance criteria for this review are based on:

- General Design Criterion (GDC)-10 insofar as it requires that the RCS be designed with appropriate margin to ensure that specified acceptable fuel design limits (SAFDLs) are not exceeded during normal operations, including anticipated operational occurrences (AOOs);
- 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 reactor coolant pressure boundary (RCPB) are not exceeded during any condition of normal operation, including AOOs; and
- 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 Standard Review Plan (SRP) Section 15.6.1 and other guidance provided in Matrix 8 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

Specific GDCs associated with the inadvertent opening of a pressurizer pressure relief valve are as follows:

- GDC-10 compliance is described in UFSAR Section 3.1.10 Criterion 10 – Reactor Design.

The reactor core and associated coolant, control and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not

exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

SAFDLs are stated in UFSAR Section 4.3. Minimum margins to SAFDLs are specified in the technical specifications (limiting conditions for operations) which support UFSAR Chapters 4 and 15.

- GDC-15 compliance is described in UFSAR Section 3.1.15 Criterion 15 – Reactor Coolant System Design.

The RCS and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including AOOs.

The operating conditions for normal steady state and transient plant operations are established conservatively. Normal operating limits are selected so that an adequate margin exists between operating and design limits. The plant control systems are designed to ensure that plant variables are maintained well within the established operating limits. The plant transient response characteristics and pressure and temperature distributions during normal operations are considered in the design as well as the accuracy and response of the instruments and controls. These design techniques ensure that a satisfactory margin is maintained between the plant's normal operating conditions, including design transients, and the design limits for the RCPB.

The plant control systems function to minimize deviations from normal operating limits in the event of most anticipated operational occurrences. Where control systems response would be inadequate or fail upon demand, the RPS and the engineered safety features actuation system (ESFAS) function to mitigate the consequences of such events.

The RPS and ESFAS function to mitigate the consequences of accidents such that the design limits for the RCPB are not exceeded.

- GDC-26 compliance is described In UFSAR Section 3.1.26, Criterion 26 – Reactivity Control System Redundancy and Capability.

Two independent reactivity control systems of different design principles shall be provided. One of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margin for malfunctions such as stuck rods, specified acceptable fuel design limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including Xenon burnout) to assure acceptable fuel design limits are not exceeded. One of the systems shall be capable of holding the reactor core subcritical under cold conditions.

Two independent reactivity control systems of different design principles are provided. The first system, using control element assemblies (CEAs) includes a positive means (gravity) for inserting CEAs and is capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including specified AOOs, SAFDL are not exceeded. The CEAs can also be mechanically driven into the core. The appropriate margin for stuck rods is provided by assuming in the analyses of AOOs that the highest worth CEA does not fall into the core.

The second system, the chemical and volume control system (CVCS), using neutron absorbing soluble boron, is capable of reliably compensating for the rate of reactivity changes resulting from planned normal power changes (including xenon burnout) such that acceptable fuel design limits are not exceeded. This system is capable of holding the reactor subcritical under cold conditions. For a further description, see UFSAR Section 9.3.4.

Either system is capable of making the core subcritical from a hot operating condition. For further discussion, see UFSAR Sections 7.4 and 7.7.

UFSAR Section 15.6.1 describes the analysis pertaining to the inadvertent opening of a pressurizer pressure relief valve. As discussed in UFSAR Section 15.6.1, an accidental depressurization of the RCS could occur as a result of one of the following: an inadvertent opening of both of the pressurizer power operated relief valves (PORVs), an inadvertent opening of a single pressurizer safety valve (PSV), or a malfunction of the pressurizer spray system. Since a PSV is sized to relieve approximately half the steam flow rate of a PORV, and the pressurizer spray system, even if fully open, cannot depressurize the RCS at the rate of two open PORVs, the most severe core conditions are associated with an inadvertent opening of both of the PORVs.

NUREG-1779 Safety Evaluation Report related to the License Renewal of St. Lucie Nuclear Power Plant Units 1 and 2 dated September, 2003, defines the scope of License Renewal. Specific design transient analyses are not within the scope of License Renewal.

2.8.5.6.1.2 Technical Evaluation

2.8.5.6.1.2.1 Introduction

An accidental depressurization of the RCS could occur as a result of one of the following: an inadvertent opening of both of the PORVs, an inadvertent opening of a single PSV, or a malfunction of the pressurizer spray system. Since a PSV is sized to relieve approximately half the steam flow rate of a PORV, and the pressurizer spray system, even if fully open, cannot depressurize the RCS at the rate of two open PORVs, the most severe core conditions are associated with an inadvertent opening of both of the PORVs. It is assumed that a mechanical failure, spurious actuation signal, or unanticipated operator action will cause the opening of both PORVs. Initially, the event results in a rapidly decreasing RCS pressure which could reach the hot-leg saturation pressure if a reactor trip did not occur. The pressure continues to decrease throughout the transient. The effect of the pressure decrease is to decrease power via the moderator density feedback. Pressurizer level increases initially due to expansion caused by depressurization and then decreases following reactor trip.

The reactor core is protected against fuel damage by the thermal margin/low pressure (TM/LP) reactor trip function.

2.8.5.6.1.2.2 Input Parameters, Assumptions and Acceptance Criteria

To produce conservative results in calculating the departure from nucleate boiling ratio (DNBR) during the transient, the following assumptions were made in the RCS depressurization analysis

at the EPU conditions (See LR [Section 2.8.5.0](#), Accident and Transient Analyses, for additional inputs and assumptions):

- The initial reactor power and RCS temperature are assumed to be at their nominal values consistent with 100 percent power, the initial RCS flow rate is assumed at a value consistent with the minimum measured flow rate, and the initial RCS pressure is assumed at a value consistent with minimum value allowed by the plant technical specifications. Uncertainties in initial conditions are statistically included in the calculation of the DNBR limit, using revised thermal design procedure (RTDP) as described in [Reference 1](#).
- The analysis also assumed a conservative moderator temperature coefficient (MTC) of 0 pcm/°F at hot full power (HFP) conditions. The spatial effect of voiding due to local or subcooled boiling is conservatively not considered in the analysis with respect to reactivity feedback or core power shape.
- A least negative Doppler power coefficient is assumed such that the resultant amount of negative feedback is conservatively low in order to maximize any power increase due to moderator reactivity feedback.

The accidental depressurization of the RCS is considered an AOO event. The following items summarize the acceptance criteria associated with this event:

- Fuel cladding integrity shall be maintained by ensuring that the minimum DNBR remains above the 95/95 DNBR limit for pressurized water reactors (PWRs) based on acceptable correlations,
- Pressure in the RCS and main steam systems should be maintained below 110 percent of the design pressure. Note that since this event is a depressurization event, these limits are not challenged. Both primary and secondary pressure decrease for the entire duration of the event,
- The event should not generate a more serious plant condition without other faults occurring independently, and
- The event, in combination with any single active component failure or single operator error, shall be considered and it is an event for which an estimate of the number of potential fuel failures will be provided for radiological dose calculations. For such accidents, fuel failure must be assumed for all rods for which the DNBR falls below those values cited above for cladding integrity unless it can be shown, based on an acceptable fuel damage model (see SRP Section 4.2) that fewer failures occur. There shall be no loss of function of any fission product barrier other than the fuel cladding.

2.8.5.6.1.2.3 Description of Analyses and Evaluations

The purpose of this analysis is to demonstrate that the reactor protection system (RPS) functions and mitigates the consequences of an RCS depressurization event at the EPU conditions utilizing the currently approved methodology.

The accidental depressurization transient is analyzed by employing the detailed digital computer code RETRAN ([Reference 2](#)). The code is NRC approved and simulates the neutron kinetics,

RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, steam generator, and steam generator safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level.

This accident is analyzed for departure from nucleate boiling (DNB) using RTDP as described in [Reference 1](#).

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

As discussed above, the design transient analyses were determined to be outside the scope of License Renewal; therefore, with respect to the design basis accidents and transients, the EPU does not impact any License Renewal evaluations.

2.8.5.6.1.2.5 Results

The system response to an inadvertent opening of both PORVs is shown in LR [Figures 2.8.5.6.1-1](#) through [2.8.5.6.1-4](#). LR [Figure 2.8.5.6.1-1](#) illustrates the nuclear power transient following the depressurization. Nuclear power is stable until the reactor trip occurs on TM/LP, and then sharply declines. The pressurizer pressure transient is illustrated in LR [Figure 2.8.5.6.1-2](#). Pressure decreases continuously throughout the transient; however, pressure decreases more rapidly after core heat generation is reduced via the reactor trip. If the saturation temperature is reached in the hot leg, the pressure decrease slows down. Illustrated in LR [Figure 2.8.5.6.1-3](#) is the loop average temperature transient. The loop average temperature is maintained at approximately the initial value until the reactor trip occurs. The DNBR decreases initially, but increases rapidly following the reactor trip as demonstrated in LR [Figure 2.8.5.6.1-4](#). The DNBR remains above the limit value throughout the transient.

The calculated sequence of events is shown in LR [Table 2.8.5.6.1-1](#).

The results of the analysis show that the TM/LP RPS function provides adequate protection against the RCS depressurization event since the minimum DNBR remains above the safety analysis limit throughout the transient (refer to LR [Tables 2.8.5.6.1-1](#) and [2.8.5.6.1-2](#)). Therefore, no cladding damage or release of fission products to the RCS is predicted for this event.

For the DNB portion of the event, the pressurizer does not fill with liquid water during this event as shown in LR [Figure 2.8.5.6.1-5](#). The early part of the transient is terminated by the TM/LP reactor trip as described above. In the longer term, this event will be terminated with operator action by i) closing the affected PORV block valve and ii) controlling the pressurizer level by throttling the HPSI flow as necessary, following the plant procedures.

The results of this analysis are also compared to the results of the current analysis, St. Lucie Unit 2 Accidental Depressurization of the Reactor Coolant System for 30 percent SGTP. The results are shown in LR [Table 2.8.5.6.1-2](#). This comparison serves to ensure that expected trends are observed. The EPU increase in core power acts to slow the rate of depressurization slightly compared to the current analysis, resulting in a reactor trip on the low pressure signal of the TM/LP trip approximately two seconds later. The EPU case also models increased heat transfer from the primary to secondary side, 10 percent steam generator tube plugging (SGTP)

versus 30 percent SGTP of the current analysis. This increase in heat removal capacity has no significant impact and the same DNBR value is achieved for EPU even with the slight delay in the reactor trip signal.

2.8.5.6.1.3 Conclusion

FPL has reviewed the analysis of the inadvertent opening of a pressurizer relief valve event and concludes that the analyses have adequately accounted for operation of the plant at the proposed power level and was performed using acceptable analytical models. FPL further concludes that the analyses have demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB limits will not be exceeded as a result of this event. Based on this, FPL concludes that the plant will continue to meet its licensing basis with respect to the requirements of GDCs -10, -15, and -26 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to the inadvertent opening of a pressurizer relief valve event.

2.8.5.6.1.4 References

1. WCAP-11397-P-A and WCAP-11397-A (Non-Proprietary), Revised Thermal Design Procedure, A. J. Friedland, E. H Novendstern and S. Ray, April 1989.
2. WCAP-14882-P-A and WCAP-15234-A (Non-Proprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, May 1999.

Table 2.8.5.6.1-1 Time Sequence of Events – Accidental Depressurization of the RCS

Event	Time (sec.)*
Inadvertent Opening of Two PORVs	10.02
Low Pressurizer Pressure Reactor Trip (TM/LP) Setpoint Reached	26.87
Reactor trip	28.03
Rods begin to drop	28.77
Minimum DNBR occurs	29.0
* The time sequence includes ten seconds of steady state, therefore subtract 10 seconds to obtain the transient time.	

**Table 2.8.5.6.1-2
Comparison of Results**

Description	Current Analysis Results*	EPU Results*
Time of Reactor Trip on TM/LP	26.2 seconds	28.0 seconds
Minimum DNBR/DNBR Limit	1.73/1.42	1.73/1.42
Time of Minimum DNBR	27.5 seconds	29.0 seconds
* The time sequence includes ten seconds of steady state, therefore subtract 10 seconds to obtain the transient time.		

**Figure 2.8.5.6.1-1
RCS Depressurization
Nuclear Power vs. Time**

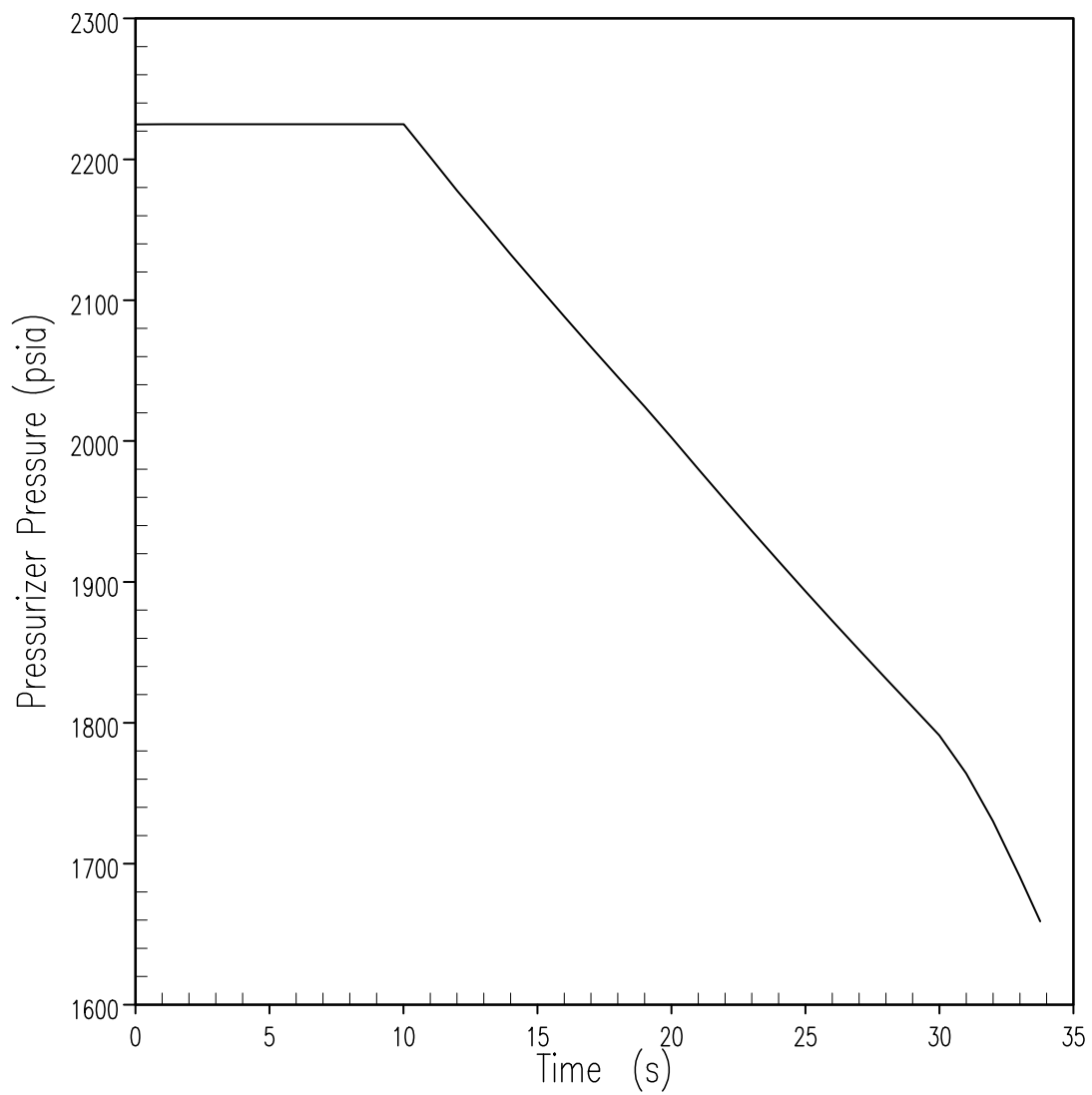


Figure 2.8.5.6.1-2
RCS Depressurization
Pressurizer Pressure vs. Time

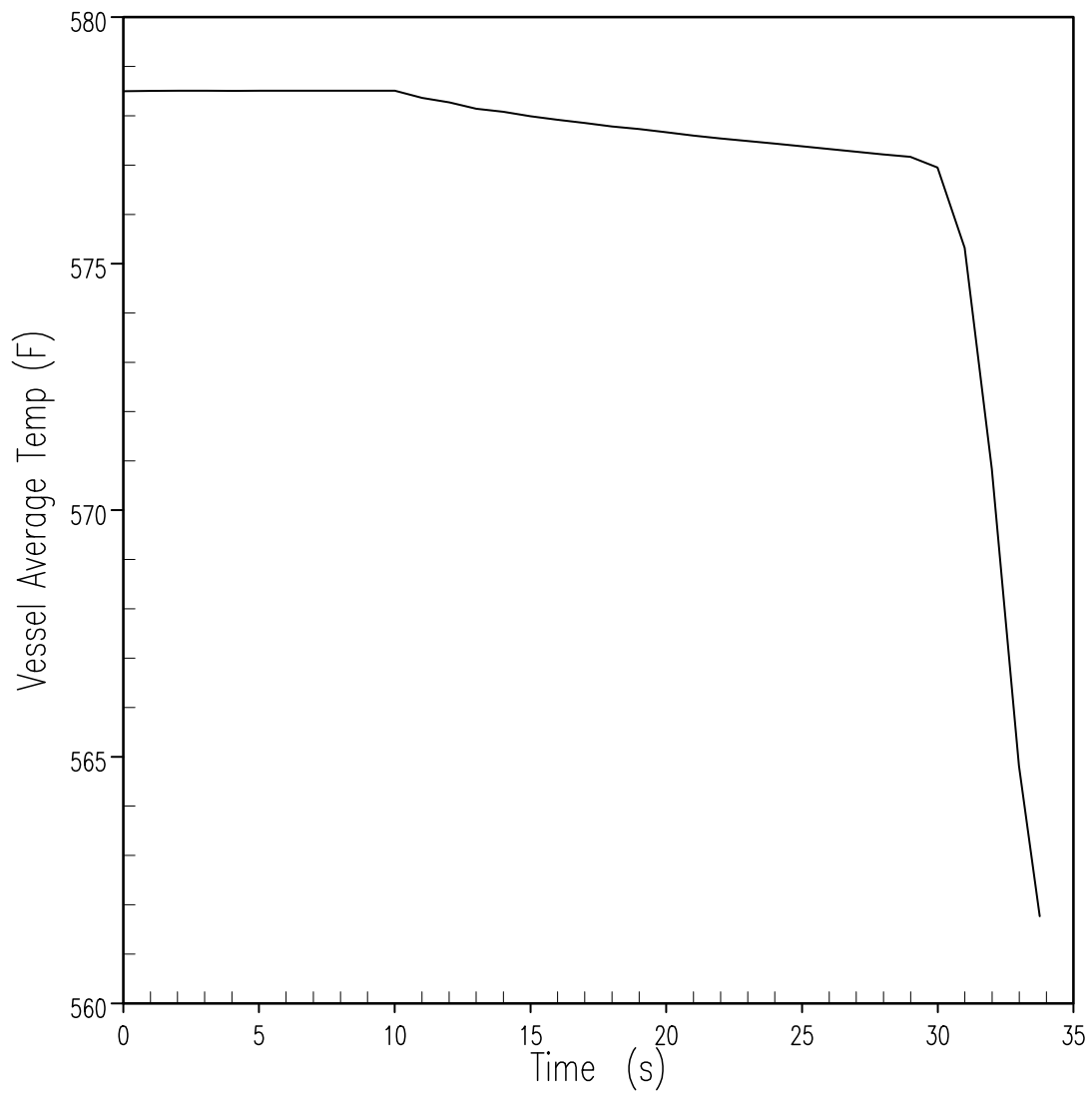


Figure 2.8.5.6.1-3
RCS Depressurization
Vessel Average Temperature vs. Time

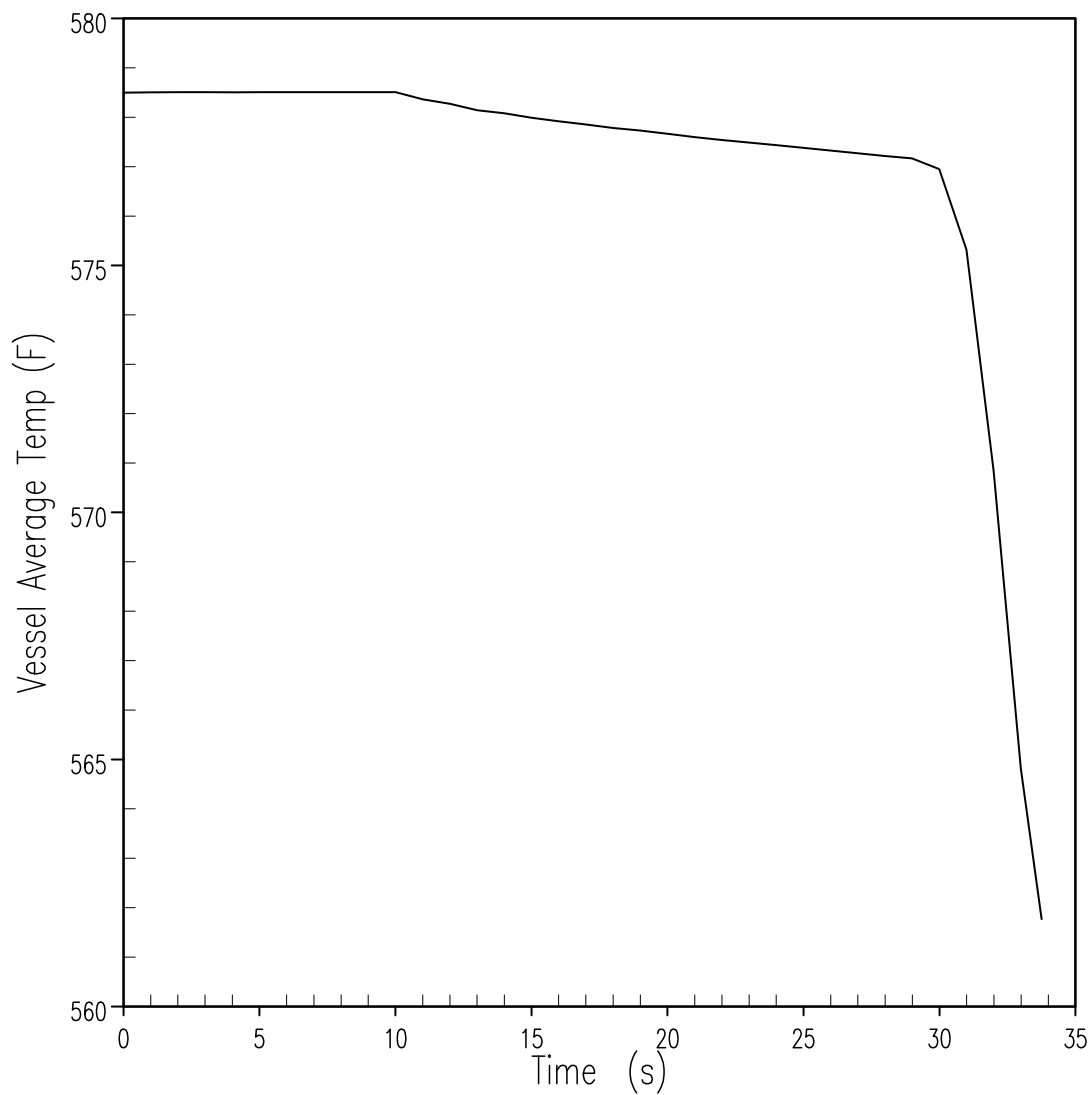


Figure 2.8.5.6.1-4
RCS Depressurization
DNBR vs. Time

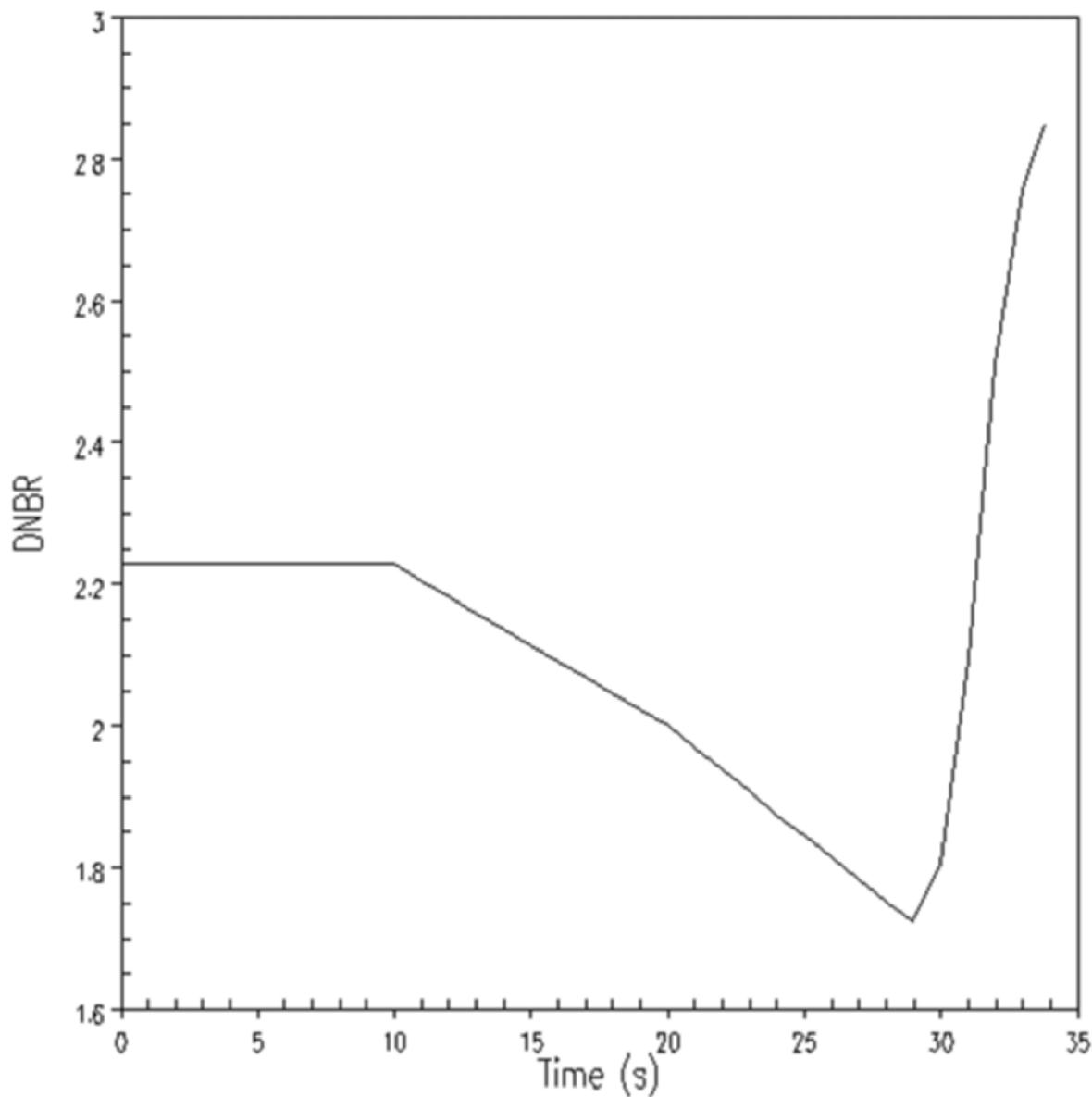
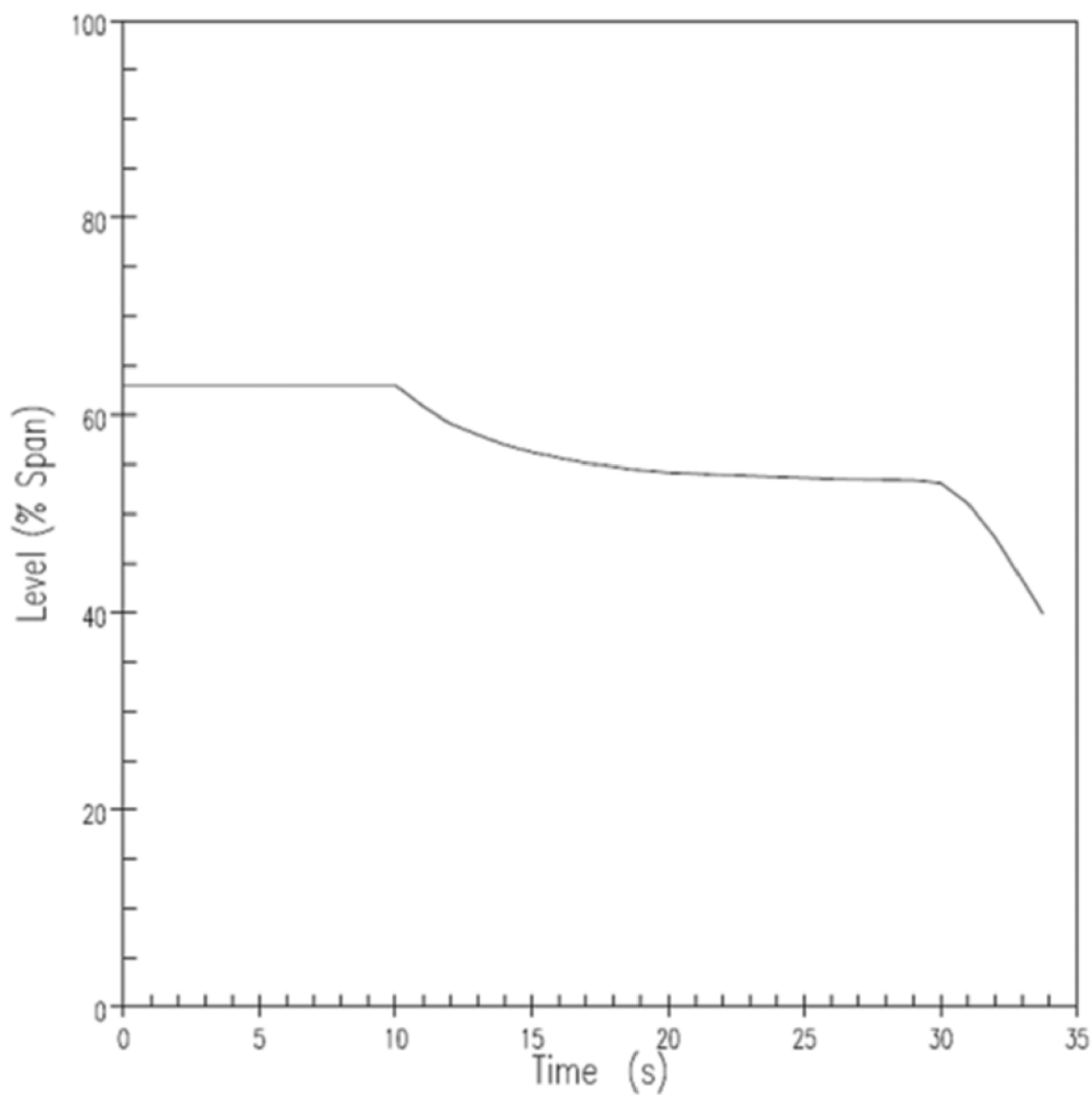


Figure 2.8.5.6.1-5
RCS Depressurization
Pressurizer Level vs. Time



2.8.5.6.2 Steam Generator Tube Rupture

2.8.5.6.2.1 Regulatory Evaluation

A steam-generator-tube-rupture (SGTR) event causes a direct release of radioactive material contained in the primary coolant to the environment through the ruptured steam generator (SG) tube and main steam safety valves (MSSVs) or atmospheric relief valves, referred to as atmospheric dump valves (ADVs). Reactor protection and engineered safety features are actuated to mitigate the accident and restrict the offsite dose to within the guidelines of the Code of Federal Regulations (CFR) 10 CFR 50.67.

The Florida Power and Light (FPL) review covered:

- Postulated initial core and plant conditions,
- Method of thermal and hydraulic analysis,
- Sequence of events,
- Assumed reactions of reactor system components,
- Functional and operational characteristics of the reactor protection system,
- Operator actions, and
- Results of the accident analysis.

A single failure of a mitigating system is assumed for this event.

The FPL review focused on the thermal and hydraulic analysis for the SGTR in order to:

- Determine whether 10 CFR 50.67 is satisfied with respect to radiological consequences, which are discussed in LR **Section 2.9.2**, Radiological Consequences Analyses Using Alternative Source Term (AST), and
- Confirm that the faulted SG does not experience an overfill.

Specific review criteria are contained in Standard Review Plan (SRP) Section 15.6.3 and other guidance provided in Matrix 8 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

The SGTR event is described in Updated Final Safety Analysis Report (UFSAR) Section 15.6.3.

NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Power Plant Units 1 and 2, dated September 2003, defines the scope of license renewal. Specific design transient analyses are not within the scope of license renewal.

2.8.5.6.2.2 Technical Evaluation

2.8.5.6.2.2.1 Introduction

The SGTR with a concurrent loss of offsite power (LOOP) event (concurrent with the reactor trip) provided in the UFSAR Section 15.6.3 was analyzed to account for the plant conditions

consistent with the extended power uprate (EPU) program. The analysis is performed to generate steam release data during a hypothetical SGTR accident as input to a bounding radiological consequence assessment. Radiological consequences of the SGTR event are addressed in LR [Section 2.9.2](#), Radiological Consequences Analyses Using Alternative Source Term (AST). The current SG overfill protection system design, associated plant procedures, and operator training as described and approved by the NRC in [Reference 2](#) remain in compliance with the recommendations of Generic Letter (GL) 89-19. As the EPU does not require changes to the SG overfill protection system, it remains in compliance with the recommendation of GL 89-19.

2.8.5.6.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The SGTR event was analyzed assuming the initial conditions in LR [Table 2.8.5.6.2-1](#). In addition, the following assumptions were made for the limiting analyzed scenarios (operator action at 45 minutes) presented herein. The listed assumptions are the same as the current analysis with the exception of Item 4 (which incorporates an operator action time of 45 minutes). See LR [Section 2.8.5.0](#), Accident and Transient Analyses, for additional inputs and assumptions.

1. While the reactor is operating at full power prior to trip, the steam mixture containing reactor coolant fission products passes through the turbine and the condenser.
2. Following the reactor and turbine trip, fission product activity release occurs via the MSSVs until operator action.
3. The break is a double-ended rupture of a single SG tube modeled at the cold end of the shortest tube such that the mass flow rate from the break is maximized. The enthalpy of the break flow is based on the hot leg; therefore additional conservatism is applied when modeling of the flashing of the break flow.
4. The affected SG is isolated by operator action at 45 minutes. At this time, plant cooldown is initiated using the unaffected SG ADVs. (Note the time of operator action was changed from the current 30 minutes to 45 minutes for the EPU analysis to provide additional margin to the operators to perform their required procedures).
5. The highest worth control element assembly (CEA) was stuck in its fully withdrawn position at reactor trip.
6. The maximum SG tube plugging level of 10 percent was used.
7. The maximum of the nominal pressurizer pressure range plus uncertainties was used. The use of the maximum initial pressurizer pressure provides conservatism as it maximizes the primary-to-secondary break flow.
8. Reactor trip occurred when the thermal margin / low pressure (TM/LP) floor setpoint was reached. No reactor trip delay was assumed since it maximized the secondary side inventory

in the ruptured SG and steam releases from both SGs. It was assumed that LOOP occurred at the time of reactor trip.

9. The turbine automatically tripped following a reactor trip. Zero delay was assumed since it minimized the steam flow to the turbine, and maximized the secondary side water inventory in the ruptured SG and steam releases from both SGs.
10. The feedwater flow rate is assumed to rapidly decrease to zero at the time of the reactor trip and LOOP.
11. The condenser is unavailable for steam dump following reactor trip due to the assumed LOOP. All subsequent steam relief is through the MSSV.
12. A low MSSV setpoint of 970 psia (-3 percent tolerance) was used since control at lower SG pressures caused earlier release of steam through the MSSVs and a greater primary-to-secondary side pressure differential and tube rupture flow.
13. Safety injection flow is based on the maximum high pressure safety injection (HPSI) pump flow injecting into the reactor coolant loops. Use of maximum HPSI pump flow conservatively increases the break flow through the ruptured tube.
14. Operation of charging system and pressurizer heaters was credited. Operating these systems does delay the time of reactor trip slightly; however it maintains the primary inventory and primary pressure such that the break flow through the ruptured tube is maximized.
15. Conservatively high decay heat rates were used. The increased heat input resulted in greater tube rupture flow after reactor trip due to the longer time needed for removing heat and depressurizing the reactor coolant system (RCS).
16. A single failure of a mitigating system is assumed for this event, which is the failure of one train of the reactor protection system. The protection function is carried out by the other train of the protection system, which remains functional during the event. There is no other worse case single failure for this event.

Following the SGTR, the RCS pressure drops until reaching the TM/LP floor setpoint, thus preventing violation of the departure from nucleate boiling ratio (DNBR) specified acceptable fuel design limits (SAFDL). Crediting the earliest trip maximizes the overall secondary steam releases. Offsite power is assumed to be lost at time of reactor trip. The RCS continues to depressurize and the pressurizer empties.

Subsequent to reactor trip, stored and fission product decay heat is dissipated by the RCS and main steam system. In the absence of forced reactor coolant flow (due to a LOOP), convective heat transfer is supported by natural circulation. The increasing SG pressure results in steam release to atmosphere via the MSSVs. At 45 minutes, the operators are assumed to isolate the affected SG and initiate plant cooldown through the unaffected SG ADVs. With the availability of stand-by power, auxiliary feedwater (AFW) is automatically initiated at a conservative low SG

level setpoint of 5 percent from the intact SG low SG water level signal. To maximize the offsite dose results, this analysis conservatively assumes that the normal feedwater flow ramps down immediately following LOOP. To ensure the plant is capable of cooling down on the intact SG while still maximizing the offsite dose results, the 45 minute scenario analysis conservatively assumes that the AFW actuates on low SG level in the intact SG.

LR [Table 2.8.5.6.2-1](#) documents the changes in input parameters for the EPU program from the current analysis values.

As noted in the UFSAR Section 15.6.3, no acceptance criteria are used for the SGTR thermal-hydraulic response steam-release analysis. The analysis is performed to generate steam release data during a hypothetical SGTR accident as input to the radiological consequence assessment fully described in LR [Section 2.9.2](#).

Since SG or RCS pressure limits are not challenged by SGTR, the TM/LP trip assures the DNBR SAFDL is met for the SGTR event, and the automatic SG overfill protection system and the supporting operator procedures ensure SG overfill is precluded.

2.8.5.6.2.2.3 Description of Analyses and Evaluations

The thermal-hydraulic response of the Nuclear Steam Supply System to the SGTR was modeled following UFSAR Section 15.6.3 and the thermal-hydraulic response of the transient was simulated using the RETRAN computer code. As documented in Table 1 of the SER for WCAP-14882 ([Reference 1](#)), the NRC has approved the use of the Westinghouse RETRAN models to analyze the SGTR event. This is a change from the current analysis of record for SGTR, however, the RETRAN code is utilized to perform the current Non-LOCA transient safety analyses.

2.8.5.6.2.2.4 Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

As discussed above, the design transient analyses were determined to be outside the scope of License Renewal; therefore, with respect to the design basis accidents and transients, the EPU does not impact any License Renewal evaluations.

2.8.5.6.2.2.5 Results

The radiological releases calculated for the SGTR event with a concurrent LOOP (concurrent with the reactor trip) are provided in LR [Section 2.9.2](#) and demonstrate that the radiological dose acceptance criteria are met for the SGTR event.

LR [Table 2.8.5.6.2-2](#) contains the sequence of events for the SGTR event with a LOOP.

LR [Figures 2.8.5.6.2-1](#) through [2.8.5.6.2-11](#) provide the thermal-hydraulic response for the system parameters important to the SGTR event.

The current SG overfill protection system design, associated plant procedures, and operator training are not impacted by the EPU and remain in compliance with the recommendations of GL 89-19. The analysis supports the acceptability of the existing SG high and high-high level

setpoints and, therefore, supports the conclusion that no changes to the SG overfill setpoints are required. As there are no changes to the current SG overfill protection system design and implementation, associated plant procedures, and operator training required by the EPU; the SG overfill protection system remains valid and acceptable for the EPU ([Reference 2](#)).

2.8.5.6.2.3 Conclusion

FPL has reviewed the analysis of the SGTR accident and concludes that the analysis has adequately accounted for operation of the plant at the proposed power level and was performed using acceptable analytical methods and approved computer codes. FPL further concludes that the assumptions used in this analysis are conservative and that the current SG overfill protection system design, associated plant procedures, and operator training remain valid and acceptable for the EPU. Therefore, FPL finds the proposed EPU acceptable with respect to the SGTR event.

2.8.5.6.2.4 References

1. WCAP-14882-P-A (Proprietary) and WCAP-15234-A (Non-Proprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, April 1999.
2. Letter from Jan Morris (NRC), PSL1 and 2 Response to GL 89-19 SG Overfill Protection, to J.H. Goldberg (FPL), dated April 4, 1994.

Table 2.8.5.6.2-1
Key Parameters Assumed for the SGTR Event with a LOOP

Parameter	Units	Current Value	EPU Value
Total RCS power (core thermal power ⁽¹⁾ + pump heat)	MWt	2774	3050
Initial core coolant average temperature (maximum plus uncertainties)	°F	579.5	581.5
Initial RCS vessel flow rate	gpm	335,000	375,000
Number of SG plugged tubes	---	30%	10%
Initial SG pressure ⁽²⁾	psia	770	879
SG U-tube break size ⁽³⁾	in ²	0.336	0.346
CEA worth at trip	%Δp	-5.4	-5.2
Initial pressurizer pressure (maximum of nominal range plus uncertainties)	psia	2395	2395
Notes: 1. The core thermal power value includes the applicable uncertainty. 2. The difference in the initial SG pressure is contributed to the tube heat transfer areas and the initial RCS conditions, i.e., power and temperature. 3. The difference in U-tube break size is attributed to the replacement SGs increased U-tube diameter. The replacement SGs were installed after the current analysis and prior to the EPU analysis.			

Table 2.8.5.6.2-2
Sequence of Events for the SGTR event with a LOOP

Event	Current Analysis		EPU Analysis	
	Time (sec)	Setpoint/ Value	Time (sec)	Setpoint/ Value
Tube rupture occurs	0.0	---	0.0	---
Reactor trip on TM/LP, psia	379.2	2142	284.0	2122
MSSVs open, ⁽¹⁾ psia	384.8 ⁽¹⁾	970	285.6 ⁽¹⁾	970.0
Maximum SG pressure, psia	391.8	996	287.6	1009.5
Pressurizer empties	487.0	---	657.3	----
Safety injection actuation signal (SIAS) generated on low pressurizer pressure, psia	490.8	1578 ⁽²⁾	570.8	1578 ⁽²⁾
HPSI pumps reach full speed or SI flow to RCS	520.8	---	868.2	----
AFW flow initiates, Low SG level, % narrow range scale (operator action below)	---	---	1189.5	5
1. Operator borates to cold shutdown concentration	1800	---	2700	----
2. Operator isolates affected SG by closing main steam isolation valve (MSIV)	1800	---	2700	----
3. Operator activates ADVs (intact SG) to commence cooldown of RCS	1800	---	2700	----
Steam releases via turbine to condenser prior to trip (50.1% affected SG / 49.9% intact SG), lbm	---	1,255,628 ⁽³⁾	---	1,050,872 ⁽⁴⁾⁽⁵⁾
Affected / intact SG steam releases, lbm (from reactor trip to Operator Action) ⁽⁸⁾	---	78,786 / 77,767 ⁽³⁾	---	131,269 / 103,333 ⁽⁴⁾
Affected SG tube leakage before trip, lbm	---	20,319 ⁽³⁾	---	17,190 ⁽⁴⁾⁽⁵⁾
Affected SG tube leakage from reactor trip to Operator Action, lbm ⁽⁸⁾	---	53,021 ⁽³⁾	---	90,347 ⁽⁴⁾
RCS to affected SG total tube leakage, lbm	---	73,340 ⁽³⁾	---	107,537 ⁽⁴⁾

Table 2.8.5.6.2-2 (Continued)
Sequence of Events for the SGTR event with a LOOP

Event	Current Analysis		EPU Analysis	
	Time (sec)	Setpoint/ Value	Time (sec)	Setpoint/ Value
Total intact SG steam releases via ADV (from operator action to 2 hrs), lbm	7200	494,259 ⁽⁶⁾	7200	492,200 ⁽⁷⁾
Total intact SG steam releases via ADV (from 2 hrs to 8 hrs), lbm	28800	907,828 ⁽⁶⁾	28800	911,300 ⁽⁷⁾

NOTES:

1. MSSVs cycle until operator activates ADVs @ 1800/2700 sec.
2. The analysis is insensitive to this value since the pressure drops to below the SI shut-off head much later, and an earlier SIAS would not initiate HPSI earlier.
3. The values used in the dose consequences analyses (UFSAR Table 15.6.3-6) have added margin compared to these values to produce conservative results.
4. The values used in the dose consequences analyses (LR Section 2.9.2) have added margin compared to these values to produce conservative results.
5. Reactor trip occurs earlier in the EPU analysis.
6. Based on a 75°F cooldown rate to maximize the steam releases over the first two hour period.
7. Based on a 100°F cooldown rate to maximize the steam releases over the first two hour period.
8. The time of operator action was changed from the current 30 minutes to 45 minutes for the EPU analysis to provide additional margin.

Figure 2.8.5.6.2-1
SGTR with LOOP
Core Power

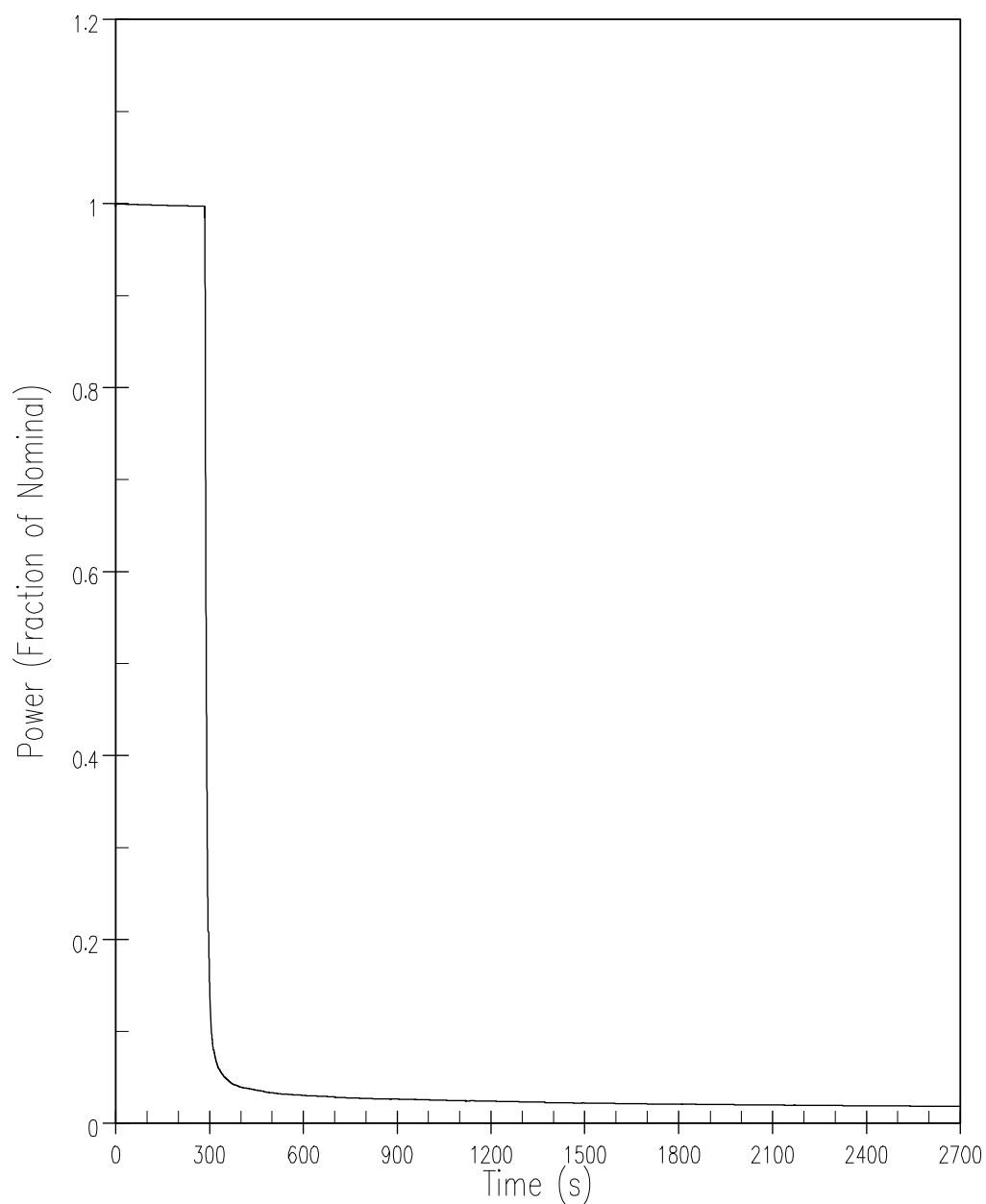


Figure 2.8.5.6.2-2
SGTR with LOOP
RCS Temperatures

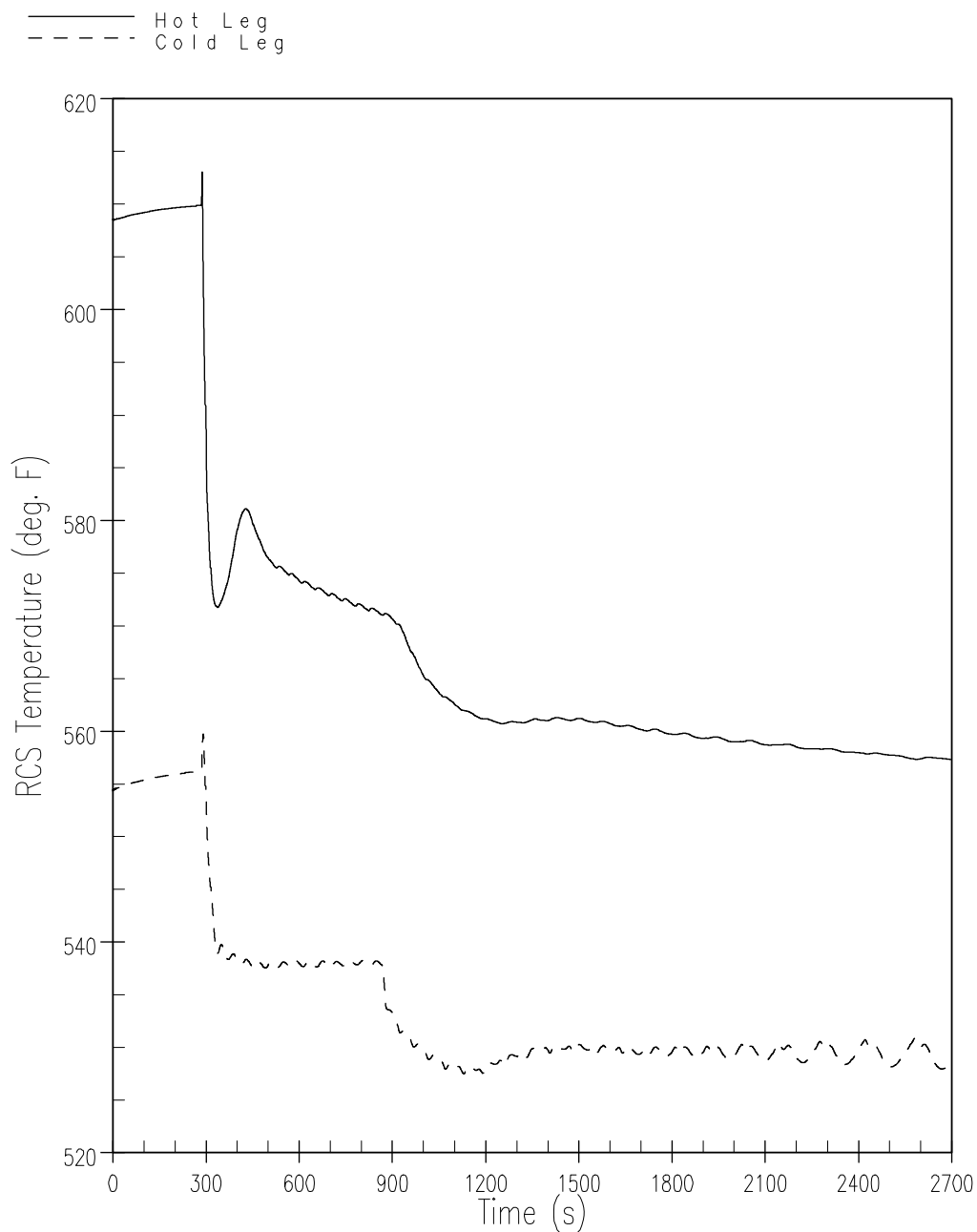


**Figure 2.8.5.6.2-3
SGTR with LOOP
Pressurizer Pressure**

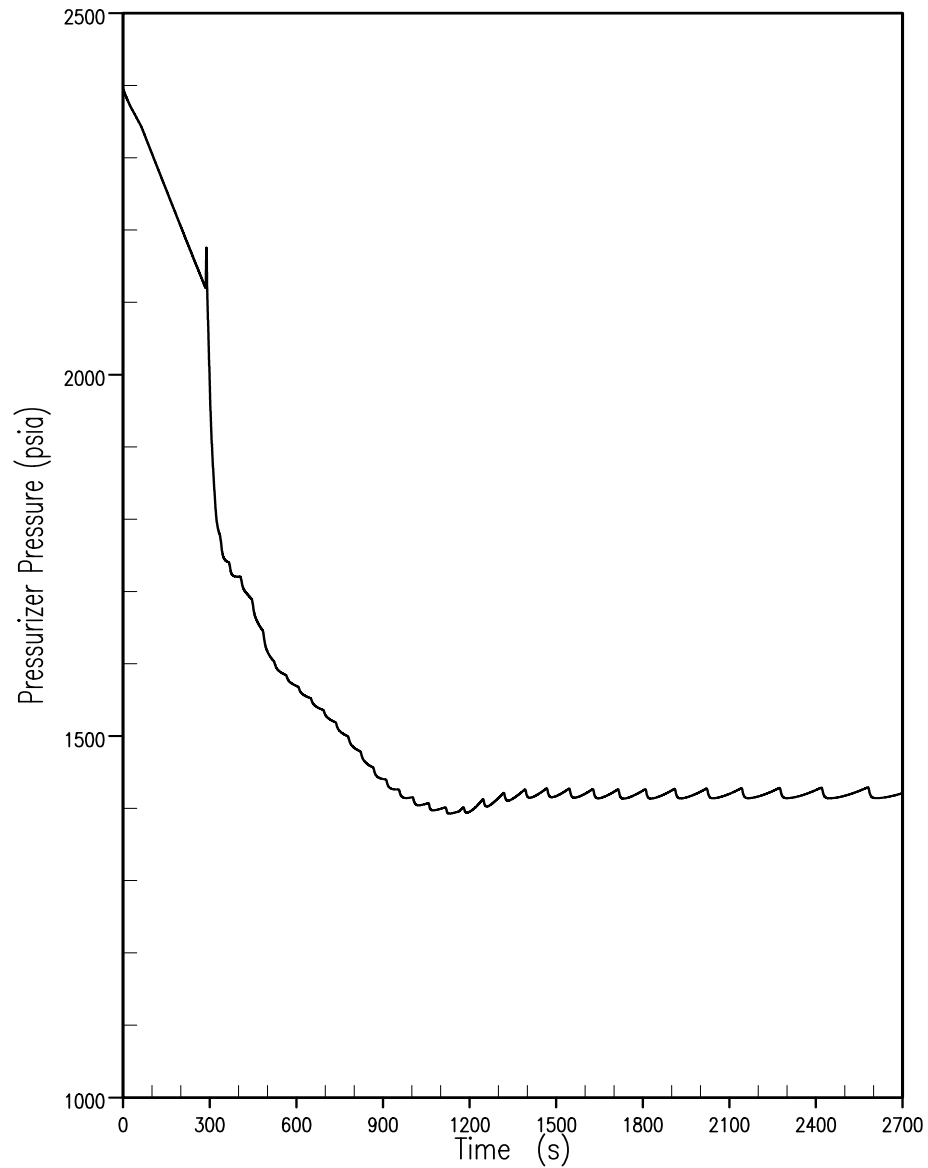


Figure 2.8.5.6.2-4
SGTR with LOOP
SG Pressure

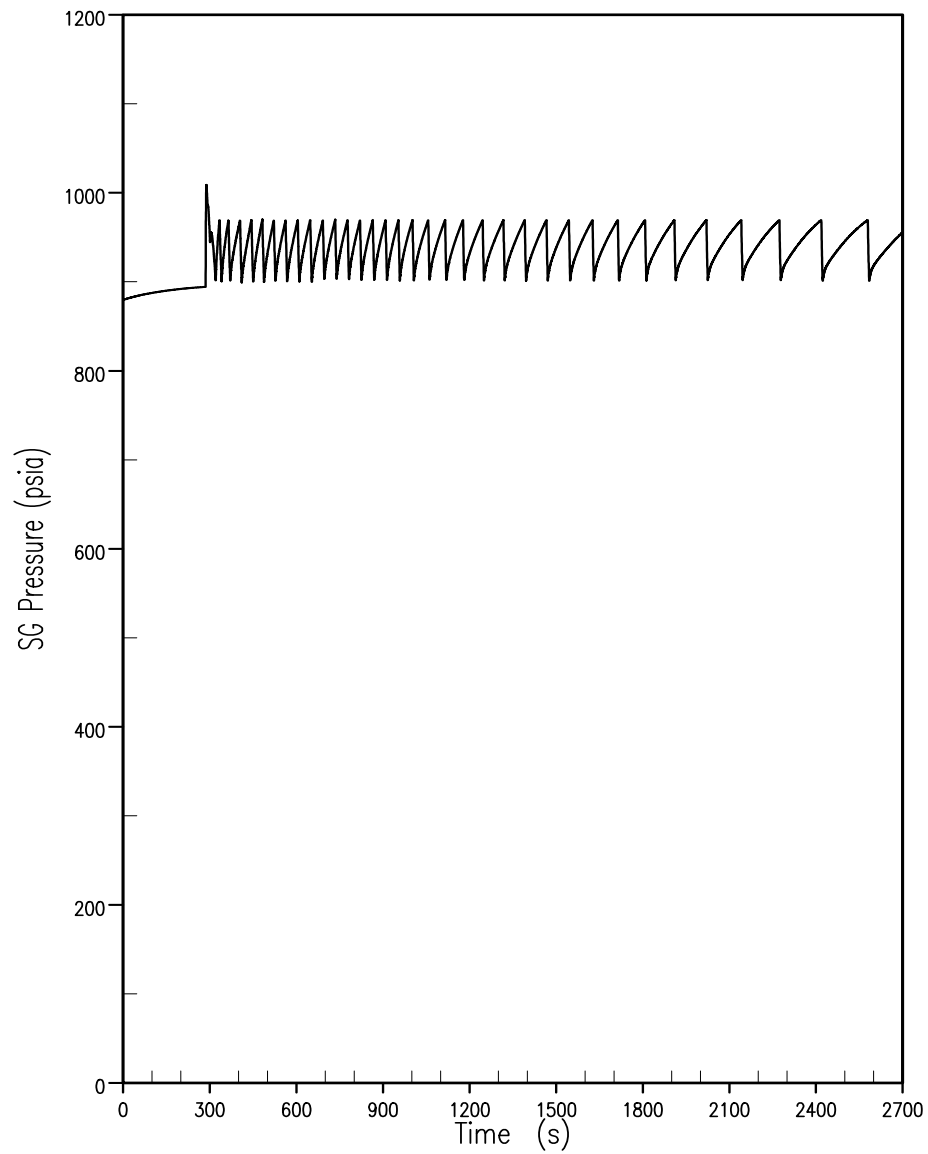


Figure 2.8.5.6.2-5
SGTR with LOOP
Integrated Break Flow

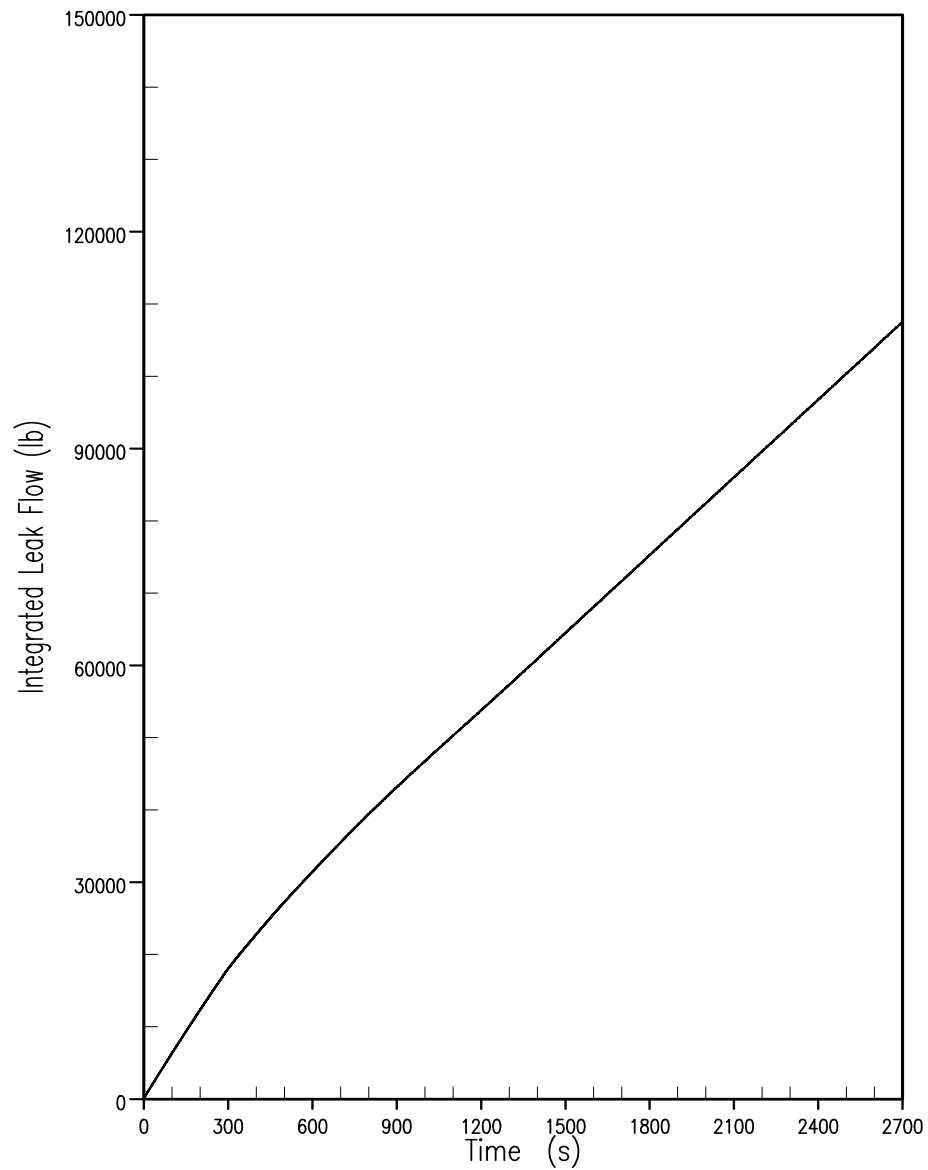


Figure 2.8.5.6.2-6
SGTR with LOOP
Integrated Steam Flow

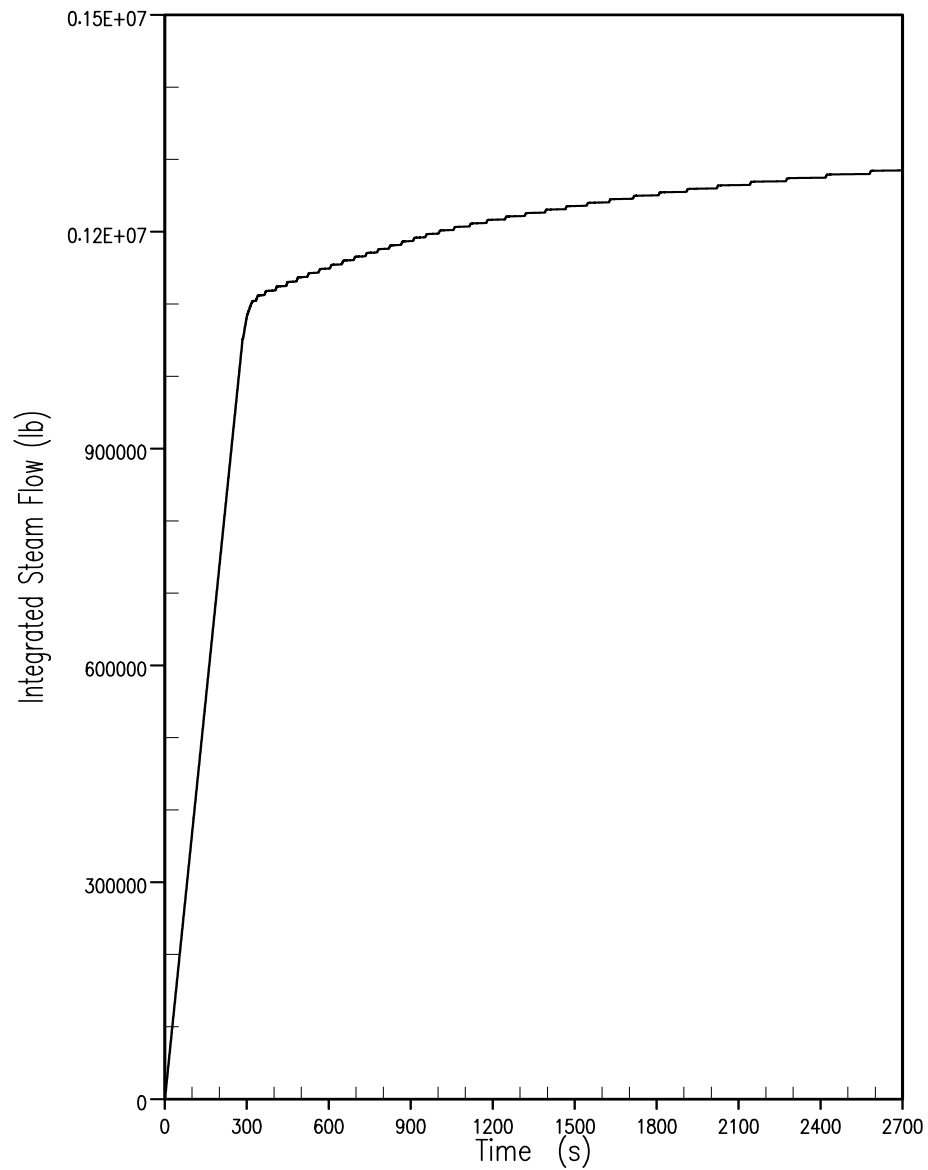


Figure 2.8.5.6.2-7
SGTR with LOOP
SG Liquid Mass

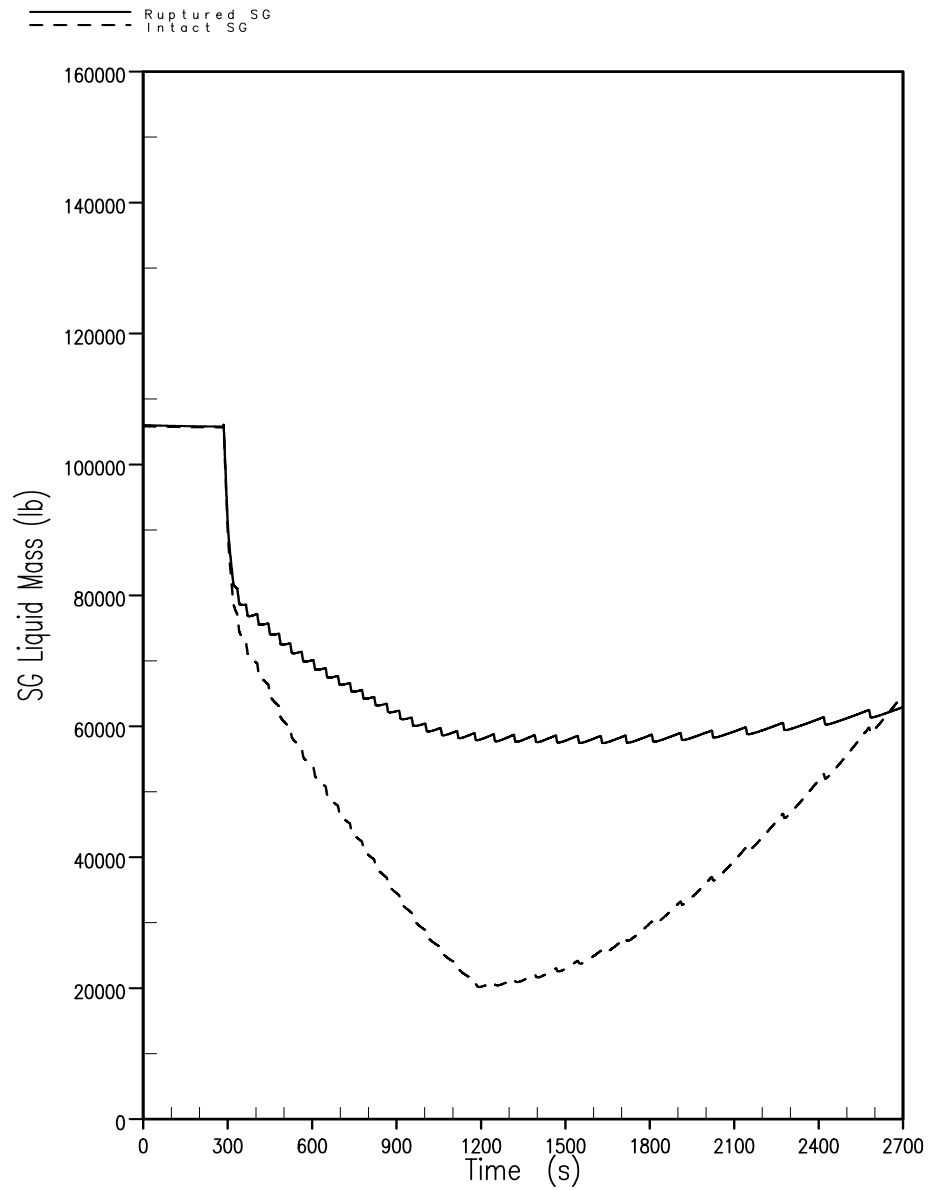


Figure 2.8.5.6.2-8
SGTR with LOOP
Integrated MSSV Steam Releases

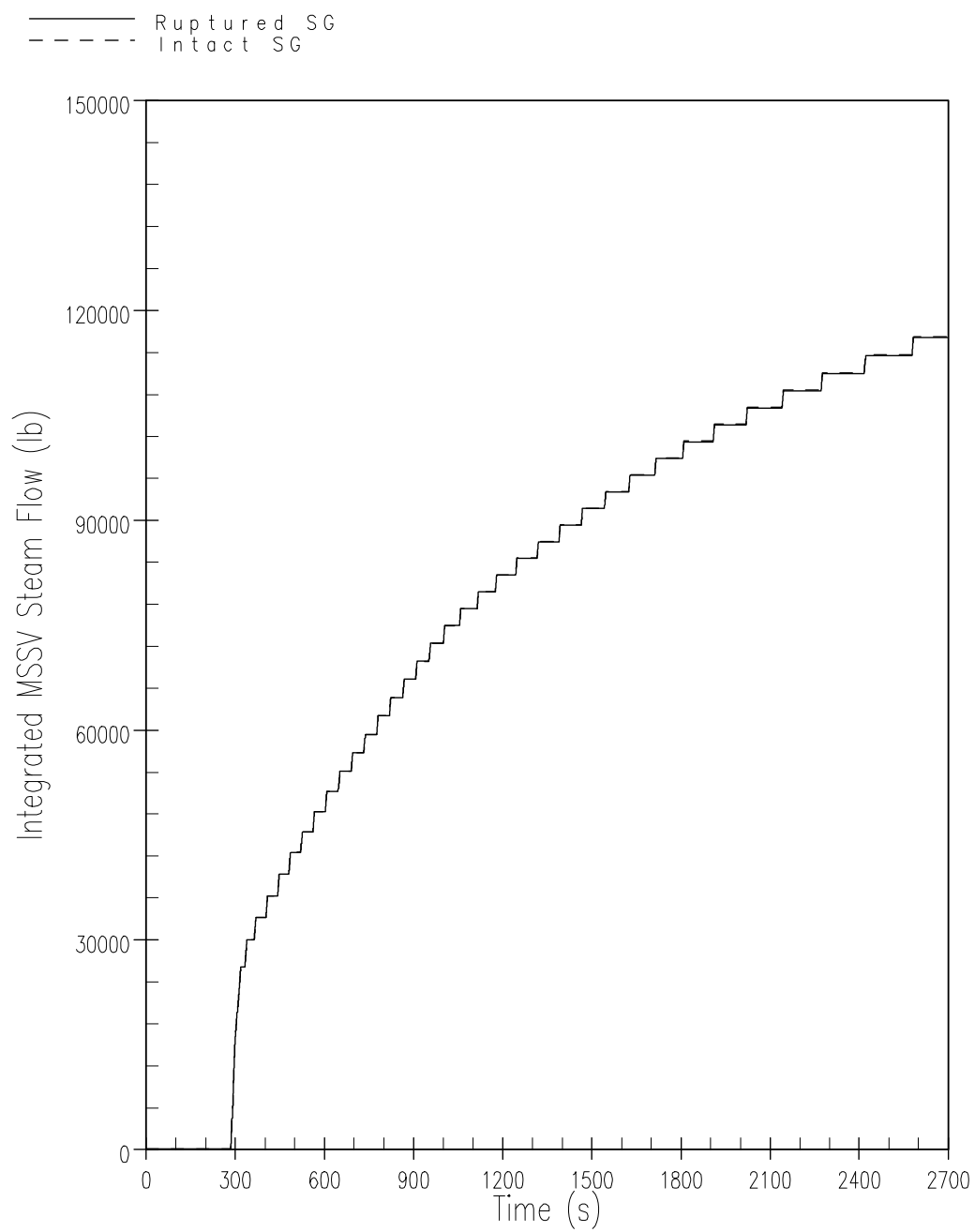


Figure 2.8.5.6.2-9
SGTR with LOOP
Main Feedwater and Auxiliary Feedwater Flow

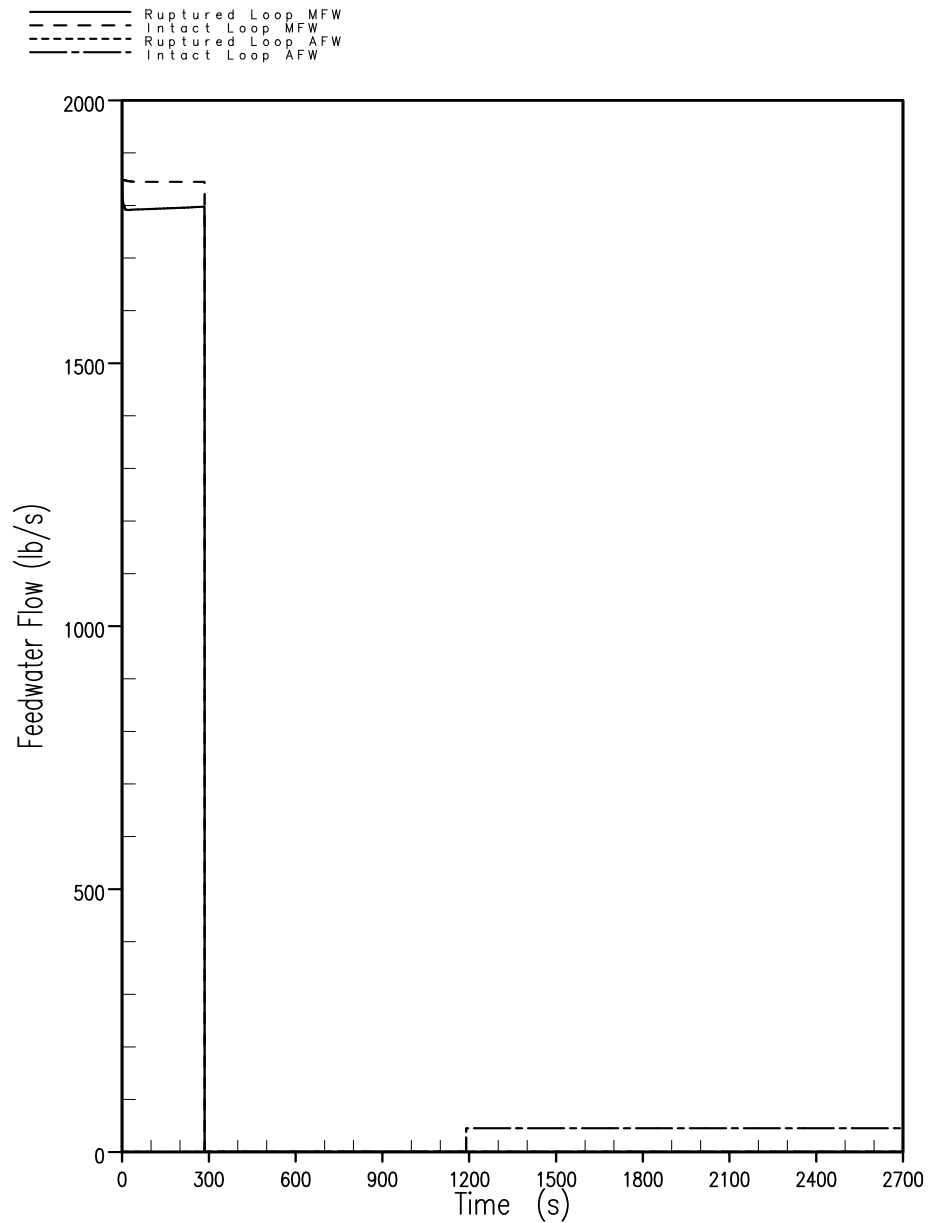


Figure 2.8.5.6.2-10
SGTR with LOOP
Vessel Upper Head Mixture Level

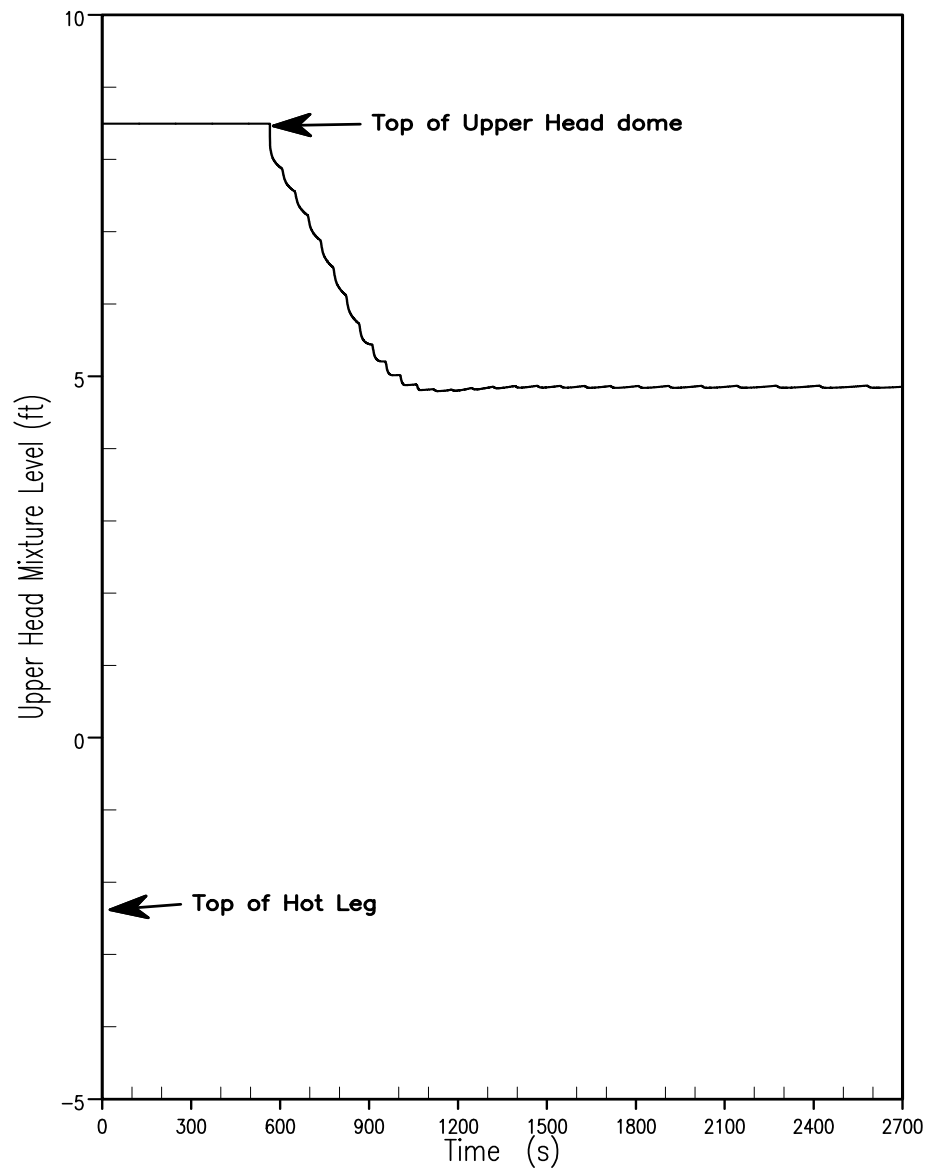
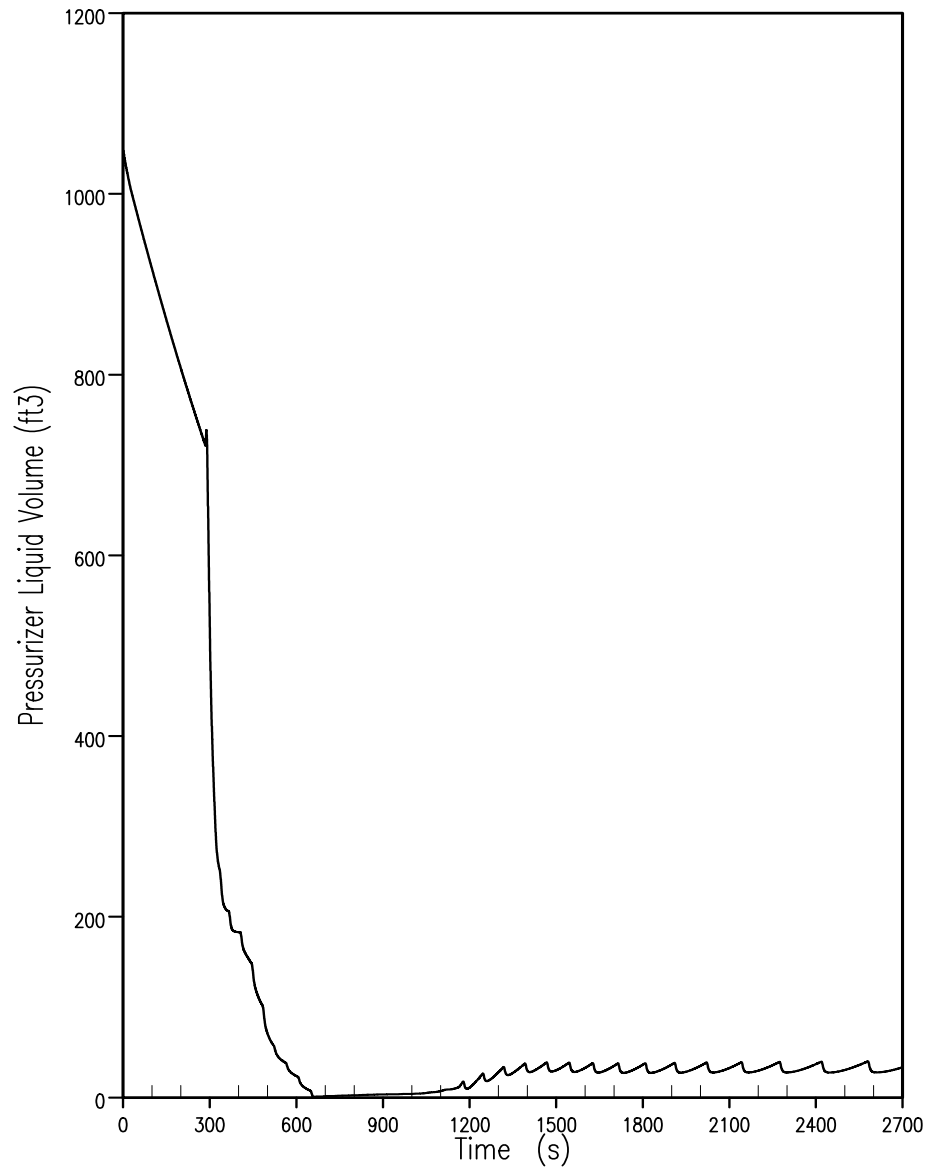


Figure 2.8.5.6.2-11
SGTR with LOOP
Pressurizer Liquid Volume



2.8.5.6.3 Emergency Core Cooling System and Loss-of-Coolant Accidents

2.8.5.6.3.1 Regulatory Evaluation

Loss-of-coolant accidents (LOCAs) are postulated accidents that would result in the loss of reactor coolant from piping breaks in the reactor coolant pressure boundary (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 system (RPS) and emergency core cooling system (ECCSs) are provided to mitigate these accidents. The Florida Power and Light (FPL) review covered:

- The determination of break locations and break sizes,
- Postulated initial conditions;
- The sequence of events;
- The analytical model used for analyses, and calculations of the reactor power, pressure, flow, and temperature transients;
- Calculations of peak cladding temperature (PCT), total oxidation of the cladding, total hydrogen generation, changes in core geometry, and long-term cooling;
- Functional and operational characteristics of the reactor protection and ECCS systems; and
- Operator actions.

The NRC's acceptance criteria are based on:

- 10 CFR 50.46, insofar as it establishes standards for the calculation of ECCS performance and acceptance criteria for that calculated performance;
- 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;
- General Design Criterion (GDC)-4, insofar as it requires that structures, systems and components (SSCs) important to safety be protected against dynamic effects associated with flow instabilities and loads such as those resulting from water hammer;
- 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
- 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.

Specific review criteria are contained in Standard Review Plan (SRP) Sections 6.3 and 15.6.5 and other guidance provided in Matrix 8 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDCs for the ECCS and LOCAs are as follows:

- GDC-4 is described in UFSAR Section 3.1.4 Criterion 4 – Environmental and Missile Design Basis.

Structures, systems and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analysis reviewed and approved by the Commission demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

SSCs important to safety are designed to accommodate the effects of and to be compatible with the pressure, temperature, humidity, and radiation conditions associated with normal operation, maintenance, testing, and postulated accidents including a LOCA, in the area in which they are located.

The structures inside the containment vessel are designed to sustain dynamic loads which could result from failure of major equipment and piping, such as jet thrust, jet impingement and local pressure transients, where containment integrity is needed to cope with the conditions.

Refer to UFSAR Sections 3.5, 3.6, 3.7, and 3.11 for details on missile protection, pipe rupture and jet impingement protection, seismic design criteria and environmental qualification, respectively.

- GDC-27 is described in UFSAR Section 3.1.27 Criterion 27 – Combined Reactivity Control Systems Capability.

The reactivity control systems shall be designed to have a combined capability, in conjunction with poison addition by the emergency core cooling system, of reliably controlling reactivity changes to assure that under postulated accident conditions and with appropriate margin for stuck rods the capability to cool the core is maintained.

The reactivity control systems that provide the means for making and holding the core subcritical under postulated accident conditions are discussed in UFSAR Sections 9.3 and 4.3. Combined use of control element assemblies (CEAs) and chemical shim control by the chemical and volume control system (CVCS) provides the shutdown margin required for plant cooldown and long-term xenon decay, assuming the highest worth CEA is stuck out of the core.

During an accident, the safety injection system (SIS) functions to inject concentrated boric acid into the reactor coolant system (RCS) for short-term and long-term cooling and for reactivity control. Details of the system are given in UFSAR Section 6.3.

- GDC-35 is described in UFSAR Section 3.1.35 Criterion 35 – Emergency Core Cooling.

A system to provide abundant emergency core cooling shall be provided. The system safety function shall be to transfer heat from the reactor core following any loss of reactor coolant at a rate such that (1) fuel and clad damage that could interfere with continued effective core cooling is prevented, and (2) clad metal-water reaction is limited to negligible amounts.

Suitable redundancy in components and features, and suitable interconnections, leak detection, isolation, and containment capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure.

The SIS provides cooling water at a rate sufficient (1) to assure that the zirconium-water reaction is limited to a negligible rate of less than one percent and (2) to assure that the fuel remains in a coolable geometry. Therefore, compliance with the intent of the acceptance criteria for ECCSs for light water power reactors of 10 CFR 50, paragraph 50.46(b) is satisfied.

The ECCS is described in detail in UFSAR Section 6.3.2 and 6.3.3. The ECCS is the SIS and is designed to provide cooling in the unlikely event of a loss-of-coolant (LOCA). The SIS prevents significant alteration of core geometry, precludes fuel melting, limits the cladding metal-water reaction, removes the energy generated in the core and maintains the core subcritical during the extended period of time following a LOCA.

The SIS accomplishes these functional requirements by use of redundant active and passive injection subsystems. The active portion of the SIS consists of high pressure and low pressure safety injection (LPSI) pumps and associated control valves. The passive portion consists of nitrogen pressurized safety injection tanks (SITs).

In addition, the SIS functions to inject borated water into the RCS to add negative reactivity to the core in the unlikely event of a steam line break. Safety injection (SI) may also be initiated in the event of a steam generator tube rupture or a CEA ejection accident. The system is actuated automatically.

Discussion of the large-break LOCA analysis is provided in UFSAR Section 15.6.5.2. Discussion of the small-break LOCA analysis is provided in UFSAR Section 15.6.5.3.

Discussion of the analysis of LOCA hydraulic forces is provided in UFSAR Section 3.9.2.5. The Post-LOCA long-term cooling analysis is provided in UFSAR Section 15.6.5.4 and consists of two separate analyses, a boric acid precipitation analysis and a decay heat removal analysis which support the realignment guideline procedures.

NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September, 2003, defines the scope of license renewal. Specific design transient analyses are not within the scope of License Renewal.

2.8.5.6.3.2 Technical Evaluation – Large Break LOCA

2.8.5.6.3.2.1 Introduction

To support the extended power uprate (EPU), the large-break loss-of-coolant accident (LBLOCA) was re-analyzed to evaluate the ECCS performance. The analysis demonstrated that St. Lucie Unit 2 will continue to meet the requirements of ECCS performance Criteria 1 through 4 of 10 CFR 50.46, ECCS Acceptance Criteria ([Reference 1](#)) following implementation of the proposed EPU.

The LBLOCA ECCS performance analysis used the 1999 evaluation model (1999 EM) version of the Westinghouse LBLOCA evaluation model for Combustion Engineering (CE) designed pressurized water reactors (PWRs). The model is documented in Supplement 4 to CENPD-132 ([Reference 3](#)). The 1999 EM methodology complies with the requirements of Appendix K to 10 CFR 50 ([Reference 2](#)) and was reviewed and approved by the NRC for ECCS performance analyses of the LBLOCA transient of CE designed PWRs. St. Lucie Unit 2 is a CE designed PWR, therefore the methodology applies to St. Lucie Unit 2 and is unchanged from that used in the current analysis of record (AOR).

2.8.5.6.3.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Key initial core, RCS, ECCS, and containment design data used in the LBLOCA analysis is listed in LR [Table 2.8.5.6.3-1](#). The listed fuel rod conditions are for rod average burnup of the hot rod that produced the highest calculated PCT. LR [Table 2.6.6-2](#) and [2.6.6-3](#) of LR [Section 2.6.6](#), Pressure Analysis for ECCS Performance Capability, document the containment passive heat sinks input data used for the LBLOCA analysis. Plant design data for the containment (e.g., for the containment initial conditions, containment volume, containment heat removal systems, and containment passive heat sinks) were selected to minimize the transient containment pressure. The core inlet temperature was the minimum RCS cold leg temperature at full power including uncertainty.

The initial steam generator (SG) mass used in the analysis is a nominal value of 133,800 lbm and is based on SG values at 100 percent EPU power and 10 percent SG tube plugging. The maximum asymmetry in the number of plugged tubes between the two SGs is 360 tubes (± 2 percent of the SG tubes).

As discussed above, the LBLOCA analysis was performed in accordance with the 1999 EM for CE designed PWRs ([Reference 3](#)) using methodology assumptions consistent with the approved evaluation model. There was no change in methodology assumptions made from the current AOR to the EPU analysis.

In performing the LBLOCA calculations, conservative assumptions were made concerning the availability of SI flow. It was assumed that offsite power is lost and all pumps must await diesel startup. It was assumed, however, that offsite power is available for the Containment Spray System (CSS) and containment fan coolers to minimize delay in actuation of systems designed to minimize containment pressure. Also, it was assumed that all SI flow delivered to the broken cold leg is lost directly to the containment.

10 CFR 50.46(a)(1)(i) requires the LBLOCA performance analysis to meet the ECCS acceptance criteria of 10 CFR 50.46(b) ([Reference 1](#)):

- Criterion 1: Peak Cladding Temperature (PCT): The calculated maximum fuel element cladding temperature shall not exceed 2200°F.
- Criterion 2: Maximum Cladding Oxidation: The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.
- Criterion 3: Maximum Hydrogen Generation: The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not exceed 0.01 times the hypothetical amount that would be generated if all the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.
- Criterion 4: Coolable Geometry: Calculated changes in core geometry shall be such that the core remains amenable to cooling.

Additionally, ECCS performance must be calculated in accordance with an acceptable evaluation model and must be calculated for a number of postulated LOCAs of different sizes, locations and other properties sufficient to provide assurance that the most severe postulated LOCAs are addressed. The evaluation model may either be a realistic evaluation model as described in 10 CFR 50.46(a)(1)(i) or must conform to the required and acceptable features of Appendix K ECCS Evaluation models ([Reference 2](#)). The evaluation model used to perform the LBLOCA ECCS performance analysis is an Appendix K evaluation model.

2.8.5.6.3.2.3 Description of Analyses and Evaluations

Several computer codes are used in the 1999 EM. The computer codes are described in references cited in the 1999 EM topical report ([Reference 3](#)). The CEFLASH-4A computer code is used to perform the blowdown hydraulic analysis of the RCS. The COMPERC-II computer code is used to perform the RCS refill/reflood hydraulic analysis and to calculate the containment minimum pressure. It is also used in conjunction with NRC approved methodology to calculate the FLECHT-based reflood heat transfer coefficients in the hot rod heatup analysis. The HCROSS and PARCH computer codes are used to calculate steam cooling heat transfer coefficients. The hot rod heatup analysis, which calculates PCT and maximum cladding oxidation, is performed with the STRIKIN-II computer code. Core-wide oxidation is calculated using the COMZIRC computer code. The initial steady state fuel rod conditions used in the analysis are provided by the NRC-approved FATES3B model evaluations summarized in LR [Section 2.8.1](#), Fuel System Design.

The limiting initial fuel rod conditions used in the LBLOCA analysis (i.e., the conditions that result in the highest calculated peak cladding temperature) were determined by performing burnup dependent calculations with STRIKIN-II using initial fuel rod conditions calculated by FATES3B. The calculations included the analysis of UO₂ and gadolinia burnable absorber fuel rods with ZIRLO® cladding.

A study was performed to determine the most limiting single failure of ECCS equipment under EPU conditions. The study analyzed no failure, failure of an emergency diesel generator (EDG)

and failure of a LPSI pump consistent with the 1999 EM approved methodology ([Reference 3](#)). Maximum SI pump flow rates were used in the no failure case; minimum SI pump flow rates were used in the EDG and LPSI pump failure cases. The pumps were actuated on a safety injection actuation signal (SIAS) generated by low pressurizer pressure with a startup delay of 30 seconds for high-pressure safety injection (HPSI) and LPSI. Minimum refueling water storage pool temperature was used for all three cases as a result of a sensitivity study of the refueling water storage pool temperature. The most limiting single failure (i.e., the failure that resulted in the highest calculated PCT) was no failure of ECCS equipment. This is the same limiting single failure described in the UFSAR for the current analysis.

No failure is the worst condition because it maximizes the amount of SI that spills into the containment. This acts to minimize containment pressure which, in turn, minimizes the rate at which the core is reflooded. The failure of either an EDG or a HPSI pump, or LPSI pump is not the most damaging failure because, in all cases, there is sufficient SI pump flow to keep the vessel downcomer full. This maintains about the same reflood rate as for no failure, but results in less spillage into the containment.

The study also investigated the impact of variation of safety injection tank (SIT) pressure, water volume, water temperature and intact legs SIT lines k-factor. Minimum SIT pressure, maximum SIT water volume, minimum SIT water temperature, and maximum SIT lines k-factor were determined to result in the highest PCT.

A spectrum of guillotine breaks in the reactor coolant pump (RCP) discharge leg was analyzed. The discharge leg is the most limiting break location and a guillotine break is more limiting than a slot break. In particular the 0.4, 0.6, 0.8 and 1.0 double-ended guillotine breaks in the RCP discharge leg (DEG/PD) were analyzed. The 0.6 DEG/PD break was determined to be the limiting LBLOCA (i.e., the break that results in the highest calculated PCT). The same break was also the limiting case in the current UFSAR analysis.

2.8.5.6.3.2.4 Results

LR [Table 2.8.5.6.3-2](#) lists the PCT and oxidation percentages for the spectrum of LBLOCAs for the EPU analysis. Times of interest are listed in [Table 2.8.5.6.3-3](#). For comparison, PCT and oxidation percentages for the spectrum of LBLOCAs of the current analysis are also shown in LR [Table 2.8.5.6.3-2](#). The impact of the EPU is offset in the analysis compared to the current AOR by beneficial aspects of the replacement SGs, which were not fully utilized in the current analyses.

The variables listed in LR [Table 2.8.5.6.3-4](#) are plotted as functions of time in LR [Figures 2.8.5.6.3-1](#) through [2.8.5.6.3-9](#) for the 1.0 DEG/PD break, in LR [Figures 2.8.5.6.3-10](#) through [2.8.5.6.3-18](#) for the 0.8 DEG/PD break, and in LR [Figures 2.8.5.6.3-19](#) through [2.8.5.6.3-27](#) for the 0.4 DEG/PD break.

The variables listed in LR [Tables 2.8.5.6.3-4](#) and [2.8.5.6.3-5](#) are plotted as functions of time for the 0.6 DEG/PD break, the limiting LBLOCA, in LR [Figures 2.8.5.6.3-19](#) through [2.8.5.6.3-38](#).

The results for the EPU analysis demonstrate conformance to the ECCS acceptance criteria as summarized below.

Parameter	Criterion	EPU Results
Peak Cladding Temperature	$\leq 2200^{\circ}\text{F}$	2087°F
Maximum Cladding Oxidation	$\leq 17\%$	14.48%
Maximum Core-Wide Oxidation	$\leq 1\%$	<1%
Coolable Geometry	Yes	Yes

2.8.5.6.3.3 Technical Evaluation – Small Break LOCA

2.8.5.6.3.3.1 Introduction

To support the EPU, the small break loss-of-coolant accident (SBLOCA) was re-analyzed to evaluate the ECCS performance. The evaluations demonstrated that St. Lucie Unit 2 will continue to meet the requirements of ECCS performance Criteria 1 through 4 of 10 CFR 50.46, ECCS Acceptance Criteria ([Reference 1](#)) following implementation of the proposed EPU.

The SBLOCA ECCS performance analysis was performed in accordance with the Westinghouse SBLOCA ECCS performance supplement 2 version (referred to as the S2M or Supplement 2 Model) evaluation model for CE designed PWRs, CENPD-137 ([Reference 4](#)). The S2M methodology complies with the requirements of Appendix K to 10 CFR 50 ([Reference 2](#)) and was reviewed and approved by the NRC for ECCS performance analyses of the SBLOCA transient of CE designed PWRs. St. Lucie Unit 2 is a CE designed PWR, therefore the methodology applies to St. Lucie Unit 2 and is unchanged from that used in the current AOR.

2.8.5.6.3.3.2 Input Parameters, Assumptions, and Acceptance Criteria

Key initial core, RCS, and ECCS design data used in the SBLOCA analysis for EPU are listed in LR [Tables 2.8.5.6.3-6](#) through [2.8.5.6.3-9](#).

The initial SG mass used in the analysis is a nominal value of 133,800 lbm and is based on SG values at 100 percent EPU power and 10 percent SG tube plugging.

As discussed above, the analysis was performed in accordance with the S2M evaluation model for CE designed PWRs ([Reference 4](#)) using methodology assumptions consistent with the approved evaluation model. There was no change in methodology assumptions made from the current AOR to the EPU analysis.

10 CFR 50.46(a)(1)(i) requires the SBLOCA performance analysis to meet the ECCS acceptance criteria of 10 CFR 50.46(b) ([Reference 1](#)):

- Criterion 1: Peak Cladding Temperature (PCT): The calculated maximum fuel element cladding temperature shall not exceed 2200°F.
- Criterion 2: Maximum Cladding Oxidation: The calculated total oxidation of the cladding shall nowhere exceed 0.17 times the total cladding thickness before oxidation.
- Criterion 3: Maximum Hydrogen Generation: The calculated total amount of hydrogen generated from the chemical reaction of the cladding with water or steam shall not

exceed 0.01 times the hypothetical amount that would be generated if all the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react.

Criterion 4: Coolable Geometry: Calculated changes in core geometry shall be such that the core remains amenable to cooling.

Additionally, ECCS performance must be calculated in accordance with an acceptable evaluation model and must be calculated for a number of postulated LOCAs of different sizes, locations and other properties sufficient to provide assurance that the most severe postulated LOCAs are addressed. The evaluation model may either be a realistic evaluation model as described in 10 CFR 50.46(a)(1)(i) or must conform to the required and acceptable features of Appendix K ECCS evaluation models ([Reference 2](#)). The evaluation model used to perform the SBLOCA ECCS performance analysis is an Appendix K evaluation model.

2.8.5.6.3.3 Description of Analyses and Evaluations

In the S2M evaluation model, the CEFLASH-4AS computer program is used to perform the hydraulic analysis of the RCS until the time the SITs begin to inject. After injection from the SITs begins, the COMPERC-II computer program is used to perform the hydraulic analysis. The hot rod cladding temperature and maximum cladding oxidation are calculated by the STRIKIN-II computer program during the initial period of forced convection heat transfer and by the PARCH computer program during the subsequent period of pool boiling heat transfer. Core-wide cladding oxidation is conservatively represented as the rod-average cladding oxidation of the hot rod. The initial steady state fuel rod conditions used in S2M analyses are provided by the NRC-approved FATES3B model evaluations summarized in LR [Section 2.8.1](#), Fuel System Design.

The COMPERC-II computer code was not run for this analysis because the limiting break size did not credit injection from the SITs. As is typical of S2M analyses, the limiting break size was determined to be the largest small break for which the PCT occurs at approximately the same time that injection from the SITs starts. In this case, the PCT for the limiting break size was calculated to occur approximately 36 seconds after SIT injection would have started had it been credited.

The SBLOCA analysis was performed for the fuel rod conditions that result in the maximum initial stored energy in the core. Since they are considered in the fuel management schemes, both UO₂ and gadolinia burnable absorber fuel rods with ZIRLO® cladding were analyzed. In addition, studies were performed using the PARCH computer code to determine the fuel rod internal pressures that cause cladding rupture to occur at the times that result in the maximum PCT and the maximum cladding oxidation for the spectrum of breaks analyzed.

The analysis was performed using the failure of an EDG as the most limiting single failure of the ECCS. This failure results in a loss of one train of SI pumps, namely, a HPSI pump, a LPSI pump and a charging pump. This results in a minimum of SI water being available to cool the core. Based on the failure of an EDG and the design of the ECCS, 75 percent of the flow from one HPSI pump and 40 percent of the flow from one charging pump are credited in the SBLOCA analysis. LPSI pump flow is not explicitly credited in the SBLOCA analysis since the RCS pressure never decreases below the LPSI pump shutoff head during the portion of the transient

that is analyzed. However, 50 percent of the flow from one LPSI pump is available to cool the core given an EDG failure and a break in the RCP discharge leg.

A spectrum of three break sizes, namely, 0.04, 0.05, and 0.06 ft² breaks in the RCP discharge leg, was analyzed. The RCP discharge leg is the limiting break location because it maximizes the amount of spillage from the ECCS. The limiting SBLOCA, the 0.05 ft²/PD (pump discharge) break, is the largest break size for which the hot rod cladding heatup transient is terminated solely by injection from a HPSI pump and a charging pump. The analysis of the 0.04 ft²/PD break demonstrates that break sizes smaller than the limiting break experience less and later core uncover and, therefore, are less limiting. The analysis of the 0.06 ft²/PD break demonstrates that breaks larger than the limiting break size are sufficiently large to allow injection from the SITs, in conjunction with the injection from a HPSI and charging pump, to recover the core and terminate the heatup of the cladding before the cladding temperature approaches the PCT of the limiting 0.05 ft²/PD break SBLOCA.

A sensitivity study of the comparison of the Supplement 1 Model (S1M) to the S2M was performed which complements the study presented in Appendix E of CENP-137 Supplement 2-P-A (Reference 4) for EPU. LR Table 2.8.5.6.3-12 provides a summary of the cases run and results of the study. The resultant “Figure of Merit” value is an indication of the conservatism provided by the S1M that is maintained in the S2M analysis. A higher ‘Figure of Merit’ is indicative of a larger amount of the S1M conservatism that is maintained in the S2M analysis. The results of this study do not indicate as much conservatism as for the 3400 MWt plant S2M study, but the EPU ‘Figure of Merit’ value of 1.054 confirms sufficient retained conservatism in the S2M analysis.

2.8.5.6.3.3.4 Results

LR Table 2.8.5.6.3-10 lists the PCT and oxidation percentages for the spectrum of SBLOCAs. Times of interest are listed in LR Table 2.8.5.6.3-11. The variables listed in LR Table 2.8.5.6.3-13 are plotted as a function of time for each break in LR Figures 2.8.5.6.3-48 through 2.8.5.6.3-71. The results for the 0.05 ft²/PD break, the limiting SBLOCA, demonstrate conformance to the ECCS acceptance criteria as summarized below.

Parameter	Criterion	EPU Results
Peak Cladding Temperature	≤2200°F	1903°F
Maximum Cladding Oxidation	≤17%	9.21%
Maximum Core-Wide Oxidation	≤1%	<0.94%
Coolable Geometry	Yes	Yes

For comparison, PCT and oxidation percentages for the spectrum of SBLOCA breaks of the current analysis are also shown in LR Table 2.8.5.6.3-10. The impact of the EPU is offset in the analysis compared to the current AOR by beneficial aspects of the replacement SGs.

2.8.5.6.3.4 Technical Evaluation – LOCA Hydraulic Forces

2.8.5.6.3.4.1 Introduction

In support of the EPU, an assessment was performed to determine whether the AOR LOCA hydraulic blowdown loads on the reactor vessel (RV) internals and fuel continue to be applicable for the EPU conditions.

LOCA hydraulic blowdown loads are calculated for use in the structural analysis of RV internals and the fuel. These blowdown loads are the thermodynamic and hydrodynamic induced forcing functions that occur throughout the RCS during a postulated LOCA. These forcing functions consist of the space-time distribution of fluid pressures, flow rates and densities.

Historical Background

The LOCA hydraulic blowdown loads were analyzed for Cycle 1 conditions and for Cycle 2 conditions. These analyses considered the large mechanistic breaks in the main coolant loop piping, at the RV inlet nozzle, at the RV outlet nozzle, and at the SG inlet nozzle, using the CEFLASH-4B computer code ([Reference 5](#)).

Two more recent evaluations assessed the impact of a reduction of T_{cold} to 546°F and an increase of the maximum allowable measured RCS flow to 405,500 gpm. Both evaluations concluded that the analyses of record remained valid. These evaluations credited the application of the leak-before break (LBB) methodology and thus were applicable to the tributary line breaks at the SI line, the shutdown cooling line, and the surge line.

2.8.5.6.3.4.2 Input Parameters, Assumptions, and Acceptance Criteria

For the purpose of assessing how the LOCA hydraulic blowdown loads at EPU conditions would compare to those in the AOR, the following operating parameters were considered:

- Nominal core power, including the RCPs net heat input,
- Nominal pressurizer pressure,
- Core inlet temperature down to 546°F,
- Steam generator tube plugging (SGTP) up to 10 percent, plus possible asymmetry of up to ± 2 percent, i.e. 8 percent in one SG and 12 percent in the other, and
- Nominal vessel flow rate corresponding to the SGTP.

The Cycle 1 analysis provides a more limiting scenario in terms of blowdown loads results than the Cycle 2 analysis. The Cycle 1 analysis was used as the AOR comparison basis.

The assessment was performed to demonstrate that a calculation of LOCA hydraulic blowdown loads on the RV internals and fuel at EPU conditions would produce loads that are bounded by those of the AOR calculation. This assessment was performed to cover core inlet temperatures from 546°F and higher, and SGTP of 0 percent through 10 percent, plus possible asymmetry of up to ± 2 percent.

2.8.5.6.3.4.3 Description of Analyses and Evaluations

For a given plant design, the parameters that can have a significant effect on the calculated blowdown loads on the RV internals and fuel are:

- Parameter a: Primary coolant temperature,
- Parameter b: Primary coolant pressure,
- Parameter c: Primary coolant flow rate,
- Parameter d: Core power,
- Parameter e: Design changes in and around the core (e.g., grid design),
- Parameter f: Break parameters – size, location, opening rate, and
- Parameter g: Steam generator tube plugging.

Conversely, certain system parameters can change significantly without having any significant effect on the calculated blowdown loads on the RV internals and fuel. The lag time associated with the impact on the RCS of such parameters is much longer than the time of interest of the calculated dynamic loads. These parameters are:

- Parameter h: SG secondary-side parameters (e.g., volume, pressure, inventory, steam flow, feedwater temperature, etc.), and
- Parameter i: Core neutronics parameters.

A discussion of the above parameters a-g follows:

Coolant Temperature - Lower temperature increases the magnitude and frequency of the blowdown loads created by decompression waves. For EPU, the nominal hot full power inlet temperature of 551°F is 3°F higher than in the AOR, with a lower bound of 546°F for blowdown load calculations.

Coolant Pressure - Higher initial system pressure increases the magnitude of the calculated blowdown loads. The system pressure at EPU conditions is the same as in the AOR.

Primary Coolant Flow Rate - The RCS flow rate has a negligible effect on calculated dynamic loads. However, the RCS flow rate does impact the temperature rise in the core, which affects the hot leg temperature and consequently the blowdown loads due to a hot-side break. For EPU, the best estimate RCS flow is 400,756 gpm, with an upper bound of 410,000 gpm for blowdown loads calculations, which is higher than the 370,000 gpm in the Cycle 1 AOR. However, its effect on lowering the hot leg temperature is matched or exceeded by the effects of higher core power, resulting in a net equal or higher hot leg temperature.

Core Power - The core power impacts the temperature rise in the core, which affects the blowdown loads due to a hot side break. In addition, a change in core power may introduce small changes in the load frequencies. The nominal licensed core power level with EPU is 3020 MWth, compared to 2560 MWth in the Cycle 1 AOR.

Core Grid Design - Discussion of the design in and around the core appears in LR [Section 2.2.3](#), Reactor Pressure Vessel Internals and Core Supports. Any changes relative to the AOR may

influence the calculated axial blowdown loads, principally by affecting the wave frequencies and initial static loadings. For EPU, the grid design may have evolved since the Cycle 1 analysis; however, the impact on calculated blowdown loads is small compared to the benefits of increased coolant temperature at nominal conditions and the application of LBB methodology at the lower bound inlet temperature.

Location, Size and Opening Rate of the Break - The break parameters of size, location and opening rate have a significant effect on the calculated blowdown loads, and are affected by the application of LBB methodology.

- Application of LBB methodology. The LBB methodology eliminates consideration of large mechanistic breaks of the main primary loop piping (cold leg or hot leg). The LBB methodology is discussed in LR [Section 2.1.6](#), Leak-Before-Break.

Accordingly, the assessment eliminated consideration of the mechanistic guillotine main loop piping breaks that had been analyzed for the design basis:

- Cold leg break at a RV inlet nozzle;
- Hot leg break at a RV outlet nozzle;
- Hot leg break at a SG inlet nozzle.

Instead, the assessment considered the impact of the EPU conditions for breaks of tributary piping attached to the RCS main loop:

- SI line inlet nozzle on the cold leg;
- Shutdown cooling line outlet nozzle on the hot leg;
- Surge line nozzle on the hot leg.

The break opening time for these tributary pipes is shorter than for the RCS main loop piping. This partly negates the benefit of analyzing smaller breaks.

- Impact of LBB methodology. The tributary line breaks analyzed per the LBB methodology produce less limiting blowdown loads than breaks of main coolant loop piping on which the original plant design basis analyses were based. Specifically crediting the LBB methodology was found to offset the effects of temperature reduction of up to 2°F in the cold leg and hot leg.

SG Tube Plugging (SGTP) - The SGTP impacts the dynamic loads on the RV internals due to a hot-side break by influencing the pressure wave reflection behavior in the hot leg. The assessment considered the two principal decompression waves:

- A primary wave moves from the break location toward the RV and is responsible for the main dynamic loads on the RV internals, and
- A secondary wave propagates from the break location toward the SG, reflects off the SG plenum wall and tube sheet, and travels to the RV.

The assessment of the effects of SGTP on the blowdown loads within the RV concluded the following:

- SGTP has minimal effect on cold-side breaks;
- SGTP has minimal effect on the primary wave from a hot-side break;
- Higher SGTP increases the initial pulse imparted by the secondary wave;
- A change in SGTP may introduce a frequency shift after the initial wave peaks; and
- An increase in SGTP would reduce the RCS flow and increase the hot leg temperature, providing a temperature-related reduction in the magnitudes of both the primary and secondary waves due to a hot-side break. Accordingly, 0 percent SGTP would provide the lowest hot leg temperature.

The assessment considered SGTP of up to 10 percent, whereas the AOR analyzed only SGTP of 0 percent. The assessment further extended the consideration to include the limiting SGTP asymmetry of ± 2 percent, i.e. one SG with 8 percent tubes plugged and the other with 12 percent.

The assessment demonstrated sequentially the continued applicability of the AOR blowdown loads with the following EPU conditions, which bound the potential nominal plant conditions:

- Nominal core inlet temperature of 551°F and SGTP of 0 percent through 10 percent with possible asymmetry of up to ± 2 percent, for a rupture of the main loop piping;
- Minimum core inlet temperature of 548°F and SGTP of 0 percent through 10 percent with possible asymmetry of up to ± 2 percent, for breaks of tributary lines per LBB; and
- Reduced core inlet temperature of 546°F and SGTP of 0 percent through 10 percent with possible asymmetry of up to ± 2 percent, for breaks of tributary lines per LBB.

2.8.5.6.3.4.4 Results

The assessment concluded that the blowdown loads on the RV internals and fuel that were calculated in the AOR for Cycle 1 bound the loads at the EPU conditions with 551°F core inlet temperature and 0 percent SGTP. This conclusion applied to breaks of the main loop piping as well as for breaks of tributary lines.

The assessment further extended this conclusion to core inlet temperatures as low as 546°F, and the range of SGTP of 0 percent through 12 percent. The blowdown loads from the AOR for Cycle 1 continue to be applicable to the RCS asymmetric loads structural analysis over this extended range of conditions. This extended-range conclusion applies to breaks of tributary lines.

Thus, the assessment met the acceptance criteria by demonstrating that the LOCA hydraulic blowdown loads on the RV internals and fuel at EPU conditions would produce loads that are bounded by those of the AOR calculation.

2.8.5.6.3.5 Technical Evaluation - Post-LOCA Boric Acid Precipitation

2.8.5.6.3.5.1 Introduction

To support the EPU, post-LOCA long term core cooling analytical evaluations of boric acid precipitation were performed. These evaluations demonstrated that the EPU is acceptable with respect to post-LOCA long term cooling Criterion 5 of 10 CFR 50.46, emergency core cooling system (ECCS) Acceptance Criteria ([Reference 1](#)).

The post-LOCA long term core cooling boric acid precipitation analysis was performed in accordance with the Westinghouse post-LOCA long term cooling evaluation model for CE designed PWRs, CENPD-254-P-A ([Reference 6](#)), with the exceptions described below. This evaluation model complies with the requirements of Appendix K to 10 CFR 50 ([Reference 2](#)) and was accepted by the NRC for referencing in licensing applications for CE PWRs.

However, in a letter dated August 1, 2005 ([Reference 7](#)), the NRC identified concerns regarding the CENPD-254-P-A post-LOCA long term cooling evaluation model. The letter states the following:

Until the NRC staff's concerns are sufficiently resolved, the staff will not approve the use of TR CENPD-254-P for license applications.

Specifically, the issues identified in [Reference 7](#) must be addressed to the Staff's satisfaction for any plant change that impacts the post-LOCA long term cooling (LTC) analysis and that requires NRC approval before implementation (e.g., a change that requires a license amendment, such as an EPU). This was confirmed by the NRC in a letter dated November 23, 2005 ([Reference 8](#)), wherein the following is stated:

Until a supplement to TR CENPD-254-P is issued addressing the staff concerns, the following four items will also need to be addressed by licensees on a plant-specific basis in any future submittals regarding post-LOCA LTC.

As indicated above, the NRC identified four items that must be addressed by licensees on a plant-specific basis in license submittals that are made prior to the ultimate resolution of the concerns identified in [Reference 7](#). The four items identified in [Reference 8](#) are as follows:

1. The mixing volume must be justified; its calculation must account for void fraction;
2. The calculation of the mixing volume must account for the loop pressure drop between the core and the break;
3. The boric acid solubility limit must be justified, especially if crediting containment pressures greater than 14.7 psia or chemical additives in the sump water; and
4. A decay heat multiplier of 1.2 must be used for all times if an Appendix K evaluation model is used.

The modifications to the CENPD-254-P-A methodology to address Items 1, 2, and 3 were previously included in the boric acid precipitation analysis that was performed in support of the Waterford 3 Extended Power Uprate (EPU). The methodology used in the Waterford 3 EPU boric acid precipitation analysis has since become known as the "Waterford approach." This approach

has been recognized by the NRC ([Reference 9](#)) as an acceptable interim methodology for performing boric acid precipitation analyses prior to the establishment of a new approved methodology that generically addresses the issues identified in [Reference 7](#).

The boric acid precipitation analysis used the CENPD-254-P-A post-LOCA boric acid precipitation analysis methodology as modified by the Waterford approach. In addition, it used a decay heat multiplier of 1.2 for all times. Thus, the methodology used addressed the four items identified in [Reference 8](#).

2.8.5.6.3.5.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters

The purpose of the boric acid precipitation analysis is to demonstrate that the maximum boric acid concentration in the core remains below the solubility limit, thereby preventing the precipitation of boric acid in the core. If boric acid were to precipitate in the core region, the precipitate could prevent water from remaining in contact with the fuel cladding and, consequently, result in the core temperature not being maintained at an acceptably low value. Therefore, the post-LOCA long term cooling analysis relies on precluding boric acid precipitation for satisfying the requirements of 10 CFR 50.46(b)(5).

The major input parameters to the boric acid precipitation analysis include core power, boric acid concentrations, and water masses, which are the significant contributors to the containment sump inventory post-LOCA. Important plant design data and selected input parameters used in the EPU boric acid precipitation analysis are given in LR [Table 2.8.5.6.3-14](#).

Assumptions

The boric acid precipitation analysis was performed with the BORON computer code ([Reference 6](#), Appendix C) using the CENPD-254-P-A post-LOCA boric acid precipitation analysis methodology as modified by the Waterford approach. The analysis assumptions are broken into three areas: (1) methodology assumptions employed by the Waterford approach (made in response to issues raised by the NRC during review of the EPU report), (2) analysis assumptions made since the Waterford approach (which address additional NRC issues), and (3) general assumptions used in the CENPD-254-P-A post-LOCA boric acid precipitation analysis. While some of these assumptions have been made since the first implementation of the Waterford approach, together these three areas of assumptions make up the "CENPD-254-P-A methodology as modified by the Waterford approach." These three areas of assumptions are as follows:

Methodology Assumptions Made in the Waterford Approach

The following are methodology assumptions employed by the Waterford approach, made in response to issues raised by the NRC during review of the EPU report.

The post-LOCA boric acid precipitation analysis for Waterford incorporated a change in the calculation of the mixing volume. The mixing volume is the region in the reactor inner vessel wherein boric acid accumulates as a result of borated water injected by the HPSI, LPSI, and charging pumps replacing the unborated water that leaves the mixing volume in the form of steam produced by boiling in the core. The mixing volume has previously been defined as the

entire lower plenum volume and the core region (includes the active core, guide tubes and core barrel/shroud bypass regions) from the bottom of the core to the bottom of the loop seals in the discharge legs. Furthermore, it was assumed that the mixing volume was subcooled, i.e., the void fraction was zero. The following methodology change in the calculation of the mixing volume was employed as a part of the Waterford approach. St. Lucie Unit 2 follows the Waterford approach, and thus incorporates this same methodology assumption.

1. The liquid volume in the core and upper plenum mixing volumes was calculated by applying the CEFLASH-4AS phase separation model to this region, thereby incorporating void fraction dependence into the boric acid concentration calculation. The phase separation model used in CEFLASH-4AS was previously approved by the NRC staff for computing the mixture level in the core following all SBLOCAs (Reference 10, 11, and 12). This model was shown to accurately predict the void fraction and the two-phase mixture level in regions experiencing high rates of heat addition following SBLOCAs. This methodology change satisfies NRC Item #1 (see LR Section 2.8.5.6.3.5.1), namely that the mixing volume must be justified and take into account the void fraction.

Furthermore, the mixing volume for computing the boric acid concentration was changed to include the additional volume from the top of the core to the top elevation of the hot leg piping at the RV outlet nozzles. This liquid volume in the outlet plenum is calculated by applying the core-to-outlet plenum area ratio to the core exit void fraction, which is calculated using the CEFLASH-4AS phase separation model as described above. The selection of the elevation of the top of the mixing volume is validated based on a hydrostatic balance between the head of liquid in the downcomer and the combination of the head of liquid in the mixing volume and the steam flow pressure drop between the core and the break, see Assumption #4 below.

Lastly, the mixing volume included only 50 percent of the lower plenum region of the RV. Experimental testing simulating the CE designed PWR justified expanding the mixing volume to include a portion of the lower plenum. The test results showed that the entire lower plenum volume contributed to the mixing. Hence, crediting only 50 percent of this volume is conservative.

In summary, the methodology changes to the mixing volume in the Waterford approach, and used for St. Lucie Unit 2, is as follows:

- The volume of liquid in the core was based on calculating the core void fraction axial profile using the CEFLASH-4AS core phase separation model;
- The volume of liquid in the outlet plenum was based on calculating the core exit void fraction using the CEFLASH-4AS core phase separation model, up to the elevation of the top of the core support barrel nozzles (i.e., nominally, to the top of the hot legs). (Note that the selection of this elevation was validated based on a calculation of system effects, see Assumption #4, below); and
- The mixing volume included 50 percent of the liquid volume of the lower plenum.

In addition to the methodology assumption regarding the mixing volume, the Waterford approach also incorporated a methodology assumption concerning the mixing of the SI flows.

2. The boric acid make-up tank (BAMT) inventory, which is injected via the charging pumps, was mixed with the HPSI pump delivery flow taking suction from the refueling water tank (RWT) during the injection phase of the LOCA. The maximum BAMT concentration used is 6240 ppm, whereas the RWT maximum concentration is conservatively set at 2600 ppm. The previously approved model assumed that the BAMT concentration was injected directly into the core without mixing in the cold legs, downcomer, and lower plenum. This methodology assumption is consistent with the NRC-accepted Waterford approach.

Analysis Assumptions Made Since the Waterford Approach

The following analysis assumptions were made since the Waterford approach and satisfy NRC Items #2 through #4 (see LR [Section 2.8.5.6.3.5.1](#)).

3. Decay heat is represented with the 1973 ANS Standard ([Reference 6](#)). In accordance with NRC Item #4 (listed in LR [Section 2.8.5.6.3.5.1](#)), a 1.2 multiplier is employed for all times. This is a conservative treatment of decay heat following shutdown of the reactor. Previously, as described on page 5 of Amendment 1 to CENPD-254-P-A ([Reference 6](#)), the analysis traditionally used a decay heat multiplier of 1.2 up to 1000 seconds and 1.1 thereafter.
4. The mixing volume (described in Assumption #1 above) is a time-dependent quantity due to core decay heat, variations in core void fraction and changes to loop pressure drop. However, this variability is not modeled, and instead a constant value is selected for the mixing volume as justified below.

As specified in NRC Item #2 (see LR [Section 2.8.5.6.3.5.1](#)), the pressure drop from the core to the break must be considered when calculating the mixing volume. In other words, the selection of the height of the mixing volume was justified with supporting calculations accounting for the loop pressure drop between the core and the break. The two steps of this justification for the height of the mixing volume are as follows: (1) First, the loop pressure drop was conservatively calculated at several time points. (2) Then it was confirmed for all times that the hydrostatic head for the coolant in the downcomer remains greater than the hydrostatic head for the two-phase mixture in the core plus the core to break pressure drop for the selected top elevation of the mixing volume.

Any minor impact from steam superheating due to SG reverse heat transfer was neglected. The steam flow rate is maximized by assuming saturated water enters the mixing volume. Frictional losses in the loop pressure drop calculation were increased by roughly 40 percent for conservatism and the geometric losses were conservatively modeled with a RCP locked rotor hydraulic loss coefficient. The geometric pressure drops were also increased for conservatism. Specifically, frictional pressure drops include an uncertainty of 10 percent. Geometric pressure drops include an uncertainty of 10 percent inside the RV and 20 percent outside the RV.

5. A core/containment pressure of 14.7 psia was used in the boric acid precipitation analysis for this bounding analysis scenario. The core/containment pressure sets the solubility limit of boric acid in the core. It is also used to determine the saturation properties of the liquid in the core. A value of 14.7 psia (i.e., atmospheric pressure) was used because minimizing the pressure minimizes the solubility limit. Per Figure C-3 in Amendment 1 of [Reference 6](#), the solubility limit at 14.7 psia (i.e., at 212°F) is 27.6 wt percent. The use of atmospheric pressure

is conservatively below the minimum containment pressure during this time period post-LOCA of roughly 20 psia. This assumed core/containment pressure of 14.7 psia is conservatively less than expected system pressures including the loop pressure drop, which would increase the solubility limit beyond that at the assumed 14.7 psia upper plenum pressure. Furthermore, basing the solubility limit on atmospheric pressure provides conservative margin to accommodate sudden or rapid depressurization of the RCS in later stages of the emergency response actions for LOCA. Lastly, no credit was taken for increased solubility due to boiling point elevation from high solids concentration, i.e., the effects of containment sump buffer chemical additives. Also, the effects of dirt, paint, and general post-LOCA containment debris were neglected. A solubility limit at a core/containment pressure of 14.7 psia without crediting a sump additive is in accordance with NRC Item #3.

General Assumptions used in the CENPD-254-P-A Methodology

The boric acid precipitation analysis evaluation model for was based on the following methodology assumptions and features:

6. Boric acid precipitation is prevented by producing a flushing flow through the core via SI flows (see LR [Section 2.8.5.6.3.5.3](#)). For a cold leg break, there is no natural flushing flow, as the SI flow would tend to flow around the downcomer and exit the cold legs without being forced through the RV. For hot leg breaks, however, there is a natural flushing flow created by the SI lined up to the cold legs. Simultaneous hot and cold side injection must be aligned in order to produce a flushing flow through the core if the break is in the cold leg. Thus, cold leg breaks are limiting for the boric acid precipitation analysis. It should also be noted that for a cold leg break, $\frac{1}{4}$ of the HPSI flow initially injected into the core spills out the break. There is no spillage if the break is in the hot leg (prior to simultaneous hot and cold side injection).

In addition, a large break results in a low RCS pressure, which yields a conservatively low boric acid solubility limit compared to a smaller break size (see Assumption #5). Therefore, the use of a large cold leg break scenario is intended to be bounding for all break sizes and locations.

7. The boric acid concentration is treated as spatially uniform within the mixing volume, i.e., complete mixing.
8. Uniform concentration of boric acid in the containment sump was assumed. Entrapment of sump fluid in isolated cavities was not considered.
9. Without hot side injection flushing flow, the only injection into the RV used for the boric acid concentration calculation was that flow required to replace core boil-off. That is, cold side injection flow constantly replenishes the downcomer inventory to the bottom of the cold leg (i.e., the bottom elevation of the cold leg break) as needed to replace core boil-off.
10. No credit was taken for subcooling of the injection flow and no condensation of steam was calculated. This conservatively maximizes core boil-off, which in turn, maximizes boric acid concentration.

11. The steam exiting the core is not assumed to contain any boric acid. No credit was taken for boric acid volatility. Furthermore, it is assumed that any possible boric acid plate-out in the SG U-tubes would be negligible considering the primary side flow area of the tubes for core-generated steam and the small amounts of boric acid being considered, and therefore would have an insignificant impact on loop pressure drop calculations.
12. Entrainment of liquid from the core during the initial injection phase was neglected. The entrainment removes large amounts of liquid in the early time period following reflood of the core, which minimizes the boric acid build-up during this period. In later time periods, core inventory carryover was neglected based on confirmatory evaluations that preclude potential entrainment of hot side injection flow after two hours post-LOCA.
13. HPSI pump delivery flow to the RV was conservatively modeled to maximize the boric acid concentration in the core. The worst single failure of ECCS equipment assumed in the boric acid precipitation analysis was the failure of an EDG, which results in a loss of one HPSI pump and one LPSI pump. However, the analysis showed that the injection flow rate considering the worst single failure with spillage out the break was still sufficient to replace water lost due to core boil-off.
14. For conservatism, minimum HPSI, LPSI, and containment spray pump flow rates were modeled in the boric acid precipitation calculation in order to maximize the duration of injection flow from the RWT. Minimum injection flow rates are sufficient to keep the downcomer filled to the level of the break, so there is no impact on the rate at which inventory is added to the core. Since the RWT boric acid concentration exceeds the calculated concentration in the sump, prolonging the injection flow from the highest concentration source maximizes the rate of boric acid accumulation in the mixing volume.
15. The boric acid precipitation analysis assumes that long term loop seal refilling does not significantly impact the loop pressure drop calculations, which are used to justify the mixing volume. St. Lucie Unit 2 is designed with a loop seal elevation that is above the elevation of the top of the core. Therefore, the loop resistance from possible refilling and re-clearing of the loop seals for breaks located above the bottom of the cold leg is not significant compared to the core and downcomer hydrostatic pressure drops, which dominate the pressure balance analysis in the inner vessel.

Technical Justification Regarding the Limiting Break Definition

To further clarify the information provided above, the assumed break geometry is confirmed to be limiting for the boric acid precipitation analysis using the following technical justification:

- Maximum Spillage – For the cold leg break configuration, ECCS injection to the broken cold leg is assumed to spill to the containment. Of the remaining injection flow to the intact cold legs, only the amount needed to maintain the RV downcomer level to the elevation of the bottom of the cold leg is credited in the boric acid precipitation calculation and the remainder is assumed to spill to the containment. By comparison, there is no spillage upstream of the core if the break is located in the hot leg and the fully developed SI flow to the cold legs provides hydrostatically driven flushing flow through the RV.

- Minimum Creditable Downcomer Head – The RV hydrostatic pressure balance calculation determines the mixing volume for the boric acid precipitation analysis. The methodology assumes that the hydrostatic head of coolant in the RV downcomer region extends to a height that is no greater than the elevation of the bottom of the cold leg, which is consistent with a guillotine or slot break located in the bottom of the RCP discharge section of the cold leg. For conservatism, no accumulation of coolant in the downcomer above this elevation is assumed; therefore, other break configurations would be less limiting from a hydrostatic pressure head viewpoint.
- Higher Loop Pressure Drop – The reactor coolant loop pressure drop from the core to the break is higher for cold leg breaks than for hot leg breaks. The pressure losses through the SG, loop seal, and the assumed locked rotor of the RCP add significantly to the loop pressure drop compared to the hot leg or suction leg break locations. The slot break at the top of the cold leg would allow for the possibility of long-term liquid accumulating in the loop seal or loop seal refilling, which adds to the loop pressure drop. However, the slot break at the top of the cold leg would also add to the height of the downcomer head. This item is discussed in greater detail below under “Comparative Study for Less Limiting Break Geometry.”
- Minimum Height of the Mixing Volume – The assumed break geometry of a large break in the bottom of the cold leg leads to a downcomer liquid height no greater than the bottom of the cold leg. Also, this break has an associated loop pressure drop that includes losses from the SG, loop seal, and locked rotor of the RCP. Using these conditions, the hydrostatic pressure balance analysis results in the lowest mixing volume height in the inner vessel compared to other conditions with larger downcomer liquid heights or smaller loop pressure drops.
- Maximum Break Size – Maximizing the break size with the LBLOCA scenario is bounding for all break sizes and locations for boric acid precipitation analyses. The LBLOCA transient results in a low RCS pressure, which yields a conservatively low boric acid solubility limit compared to a smaller break size scenario. Higher system pressure for the small break size transient results in lower core and upper plenum void fraction, thus increasing the mixing volume. Also, higher system pressure for the small break size transient leads to a higher core saturation temperature, thus increasing the SI subcooling for increased heat removal.

Basis for the Selection of the Height of the Mixing Volume

The items listed above explain how the assumed break configuration is conservative for the boric acid calculation, which is dependent on the core and upper plenum mixing volume. The mixing volume used in computing the boric acid concentration included the additional volume of two-phase mixture above the core. However, this additional volume was limited to be no greater than the volume from the top of the core to the top elevation of the hot leg piping at the RV outlet nozzles. The steps used to justify the height of the mixing volume included (1) conservatively calculating the loop pressure drop at several points in time for the assumed break configuration, then (2) confirming for all times that the hydrostatic head for the coolant in the downcomer remains greater than the hydrostatic head for the two-phase mixture in the core plus the core to break pressure drop. The results of a comparative study justifying the mixing volume as well as the analytical basis for the steps listed above are discussed below under “Comparative Study for Less Limiting Break Geometry.”

This analysis shows that the RV hydrostatic pressure balance including the impact of variations in loop pressure drop at EPU conditions does not result in a mixing volume height less than the top elevation of the hot leg. Furthermore, the calculations show that the actual mixing volume height using conservative assumptions is considerably higher than the elevation of the top of the hot leg. This conservatism in the actual mixing volume height compared to the value assumed in the analysis provides margin to cover other alternate break configurations with more limiting loop pressure drop but less limiting hydrostatic pressure parameters. Details of the hydrostatic pressure balance comparing the limiting break configuration to a slot break in the top of the cold leg are discussed in the following quantitative information in the following section below.

Comparative Study for Less Limiting Break Geometry

Conservatism in the RV hydrostatic pressure balance calculation is demonstrated by showing that the collapsed liquid height in the outlet plenum credited in the mixing volume is significantly less than the elevation of the mixing volume actually available for all break sizes, break types, and break locations, at all times throughout the post-LOCA transient. The collapsed liquid height of available liquid in the outlet plenum, or the hydrostatic head of the outlet plenum, is calculated using Equation (2.8.5.6.3-1) below:

$$\Delta P_{OP} = \Delta P_{DC} - \Delta P_{STM} - \Delta P_{CORE} \quad \text{Equation (2.8.5.6.3-1)}$$

where

- ΔP_{OP} = hydrostatic head of the outlet plenum (psi)
- ΔP_{DC} = hydrostatic head of the downcomer (psi)
- ΔP_{STM} = core-to-break steam flow pressure drop (psi)
- ΔP_{CORE} = hydrostatic head of the core (psi)

The calculation of each of these pressure drops is discussed below. Additionally, each pressure drop is calculated at three different times (1, 5, and 6 hours) to ensure that the most limiting condition during the critical time period of the transient just prior to switchover to simultaneous hot and cold side injection is evaluated. This considers multiple times through the transient, as 6 hours corresponds to the latest time for switchover to simultaneous hot and cold side injection.

- Hydrostatic head of the downcomer, ΔP_{DC}

The height of the downcomer is defined from the bottom elevation of the active core to the bottom elevation of the RCP discharge legs. This distance is 16.51 feet.

The specific volume of saturated liquid at 14.7 psia is 0.016714 ft³/lbm. Using this data, the downcomer hydrostatic pressure drop (ΔP_{DC}) is equal to the height of liquid divided by the specific volume (and multiplied/divided by the appropriate conversion factors) as shown in Equation (2.8.5.6.3-2) below:

$$\Delta P_{DC} = 16.51 \text{ ft} / 0.016714 \text{ ft}^3/\text{lbm} / 144 \text{ in.}^2/\text{ft}^2 * \text{g/g}_c = 6.86 \text{ psi} \quad \text{Equation (2.8.5.6.3-2)}$$

This results in a minimum, and thus conservative, value for the hydrostatic head of the downcomer, as discussed above under Minimum Creditable Downcomer Head. This value is not time dependent, since it is constant throughout the post-LOCA transient.

- Core-to-break steam flow pressure drop, ΔP_{STM}

The core-to-break steam flow pressure drop is calculated by Equation (2.8.5.6.3-3) below:

$$\Delta P_{STM} = K * v / 9266.112 * (W/A)^2 \quad \text{Equation (2.8.5.6.3-3)}$$

where

K = K-factor (friction and geometric loss coefficients, dimensionless)

v = specific volume of steam at 14.7 psia = 26.7952 ft³/lbm

A = area (ft²)

W = core boil off steam flow rate (lbm/sec)

Units Conversion: 9266.112 = the product of $2 * g_c$ (32.174 lbm-ft/lbf-sec²)*144 in.²/ft². Its units are, therefore, lbm-in.²/lbf-sec²-ft.

(Note: In using this equation, the steam flow rates are converted to lbm/sec.)

- Steam flow rate (core boil off)

The decay heat fraction (DHF) at 1 hour post-LOCA is determined using the BORON computer code decay heat model described in CENPD-254-P-A, reproduced as Equation (2.8.5.6.3-4) below. Using a time of 1 hour, or 3600 seconds, the DHF is:

$$\text{DECAY} = 0.75 * 10^{(0.75 * \log T - 0.778) / T} \quad \text{Equation (2.8.5.6.3-4)}$$

where

DECAY= normalized decay heat fraction including 1.1 conservative multiplier

T = time (seconds)

$$\text{DECAY} = 0.75 * 10^{(0.75 * \log(3600) - 0.778) / (3600)} = 0.016143$$

Consistent with NRC imposed restrictions on the acceptability of the boric acid precipitation methodology, a 1.2 decay heat multiplier is applied as follows:

Decay Heat Fraction (including 1.2 decay heat multiplier)

$$\text{Decay Heat Fraction} = 0.016143 * 1.2 / 1.1$$

$$\text{Decay Heat Fraction} = 0.01761$$

The core power level including power measurement uncertainty is 3030 MWt for EPU conditions.

Therefore, using the above data, the core boil-off rate (WBO) at 1 hour post-LOCA is equal to the core power times the decay heat fraction divided by the heat of vaporization, as given in Equation (2.8.5.6.3-5) below:

$$\begin{aligned} \text{WBO} &= 3030 \text{ MWt} * 948.04 \text{ Btu/sec-MWt} * 0.01761 / (1150.28 - 180.18) \text{ Btu/lbm} \\ \text{WBO} &= 52.15 \text{ lbm/sec} \end{aligned} \quad \text{Equation (2.8.5.6.3-5)}$$

This calculation is repeated at two additional times (5 and 6 hours) to cover the time frame of this comparative analysis at EPU conditions. The following table summarizes the core boil-off for all three times.

Time (hr)	Time (sec)	DHF	DHF (w/1.2)	WBO
1	3600	0.016143	0.017611	52.15
5	18000	0.010796	0.011777	34.87
6	21600	0.010314	0.011252	33.32

- K-Factor

The K-factor quantifies the resistance from the core to the assumed break location, i.e., the cold leg. This resistance is composed of the losses due to both friction and geometry. The geometry resistance K-factor, GK, is obtained directly from plant-specific pressure drop data, and with added conservatism is calculated to be 185. This geometric K-factor contains an additional 10 percent conservative margin for uncertainty in the geometric losses in the RV and 20 percent for geometric losses in the remainder of the RCS. The friction resistance, FK, was also obtained using plant-specific pressure drop data, and is calculated to be 38.806. This friction factor contains the same additional conservative margins for uncertainty as used for the geometric losses, and in addition, it is rounded up to 55 for conservatism. Additionally, these K-factors are for the entire RCS loop, including the friction and geometric losses in the core, which is more conservative than just including the resistances from the core outlet to the break.

Thus, the composite resistance factor is:

$$\begin{aligned} \text{Total K-Factor} &= \text{GK} + \text{FK} \\ \text{Total K-Factor} &= 185 + 55 \\ \text{Total K-Factor} &= 240 \end{aligned}$$

The core-to-break steam flow pressure drop is calculated using Equation (2.8.5.6.3-3):

$$\begin{aligned} \Delta P_{\text{STM}} &= K * v / 9266.112 * (W/A)^2 \\ \Delta P_{\text{STM}} &= (240 * 26.7952 \text{ ft}^3/\text{lbm}) / 9266.112 * (52.15 \text{ lbm/sec} / 54.82 \text{ ft}^2)^2 \\ \Delta P_{\text{STM}} &= 0.628 \text{ psi} \end{aligned}$$

Again, the calculation of ΔP_{STM} was repeated for all times mentioned above for EPU conditions. The following table summarizes ΔP_{STM} for all three calculated times post-LOCA.

Time (hr)	Time (sec)	ΔP_{STM} (psi)
1	3600	0.628
5	18000	0.281
6	21600	0.256

As expected, the core-to-break loop pressure loss for these conditions is an order of magnitude less significant than the hydrostatic head of the downcomer.

- Hydrostatic head of the core, ΔP_{CORE}

The head of the collapsed liquid in the core is dependent upon the liquid volume, which in turn is dependent on the void fraction of the core, and thus is time dependent. At EPU conditions, the liquid volume in the active core at 1 hour post-LOCA is determined to be 164.36 ft³. This calculation was performed using the liquid mass calculated by the BORON computer code, which is part of the CENPD-254-P-A methodology, in combination with applying the CEFLASH-4AS phase separation model for dynamic void fraction modeling, which is part of the NRC-approved small break LOCA ECCS performance methodology in CENPD-137 Supplement 1-P and CENPD-133 Supplement 3-P. In addition, the core flow area is 54.82 ft², and the specific volume of saturated liquid at 14.7 psia is 0.016714 ft³/lbm. Based on this data and using Equation (2.8.5.6.3-2), the core hydrostatic pressure drop, ΔP_{CORE} at 1 hour post-LOCA is:

$$\Delta P_{\text{CORE}} = (164.36 \text{ ft}^3 / 54.82 \text{ ft}^2) / 0.016714 \text{ ft}^3/\text{lbm} / 144 \text{ in.}^2/\text{ft}^2 * g/g_c$$

$$\Delta P_{\text{CORE}} = 1.25 \text{ psi}$$

The following table summarizes ΔP_{CORE} for all three times post-LOCA being evaluated, thus showing the variation due to the time dependent change in void volume calculated by the phase separation model and the CENPD-254-P computer code outputs.

Time (hr)	Time (sec)	ΔP_{CORE} (psi)
1	3600	1.25
5	18000	1.57
6	21600	1.61

- Hydrostatic head of the outlet plenum, ΔP_{OP}

The following hydrostatic pressure balance, given earlier as Equation (2.8.5.6.3-1), is used to calculate the hydrostatic head of the outlet plenum:

$$\Delta P_{\text{OP}} = \Delta P_{\text{DC}} - \Delta P_{\text{STM}} - \Delta P_{\text{CORE}}$$

ΔP_{DC} , ΔP_{STM} , and ΔP_{CORE} have been calculated above for three different times in the transient post-LOCA for EPU conditions. Once ΔP_{OP} is calculated, the height of static head of the outlet plenum (that is, the collapsed liquid level above the top of the active core) can be calculated using Equation (2.8.5.6.3-6) as follows:

$$H_{\text{OP}}, \text{ ft} = \Delta P_{\text{OP}}, \text{ psi} * v, \text{ ft}^3/\text{lbm} * 144 \text{ in.}^2/\text{ft}^2 * g/g_c \quad \text{Equation (2.8.5.6.3-6)}$$

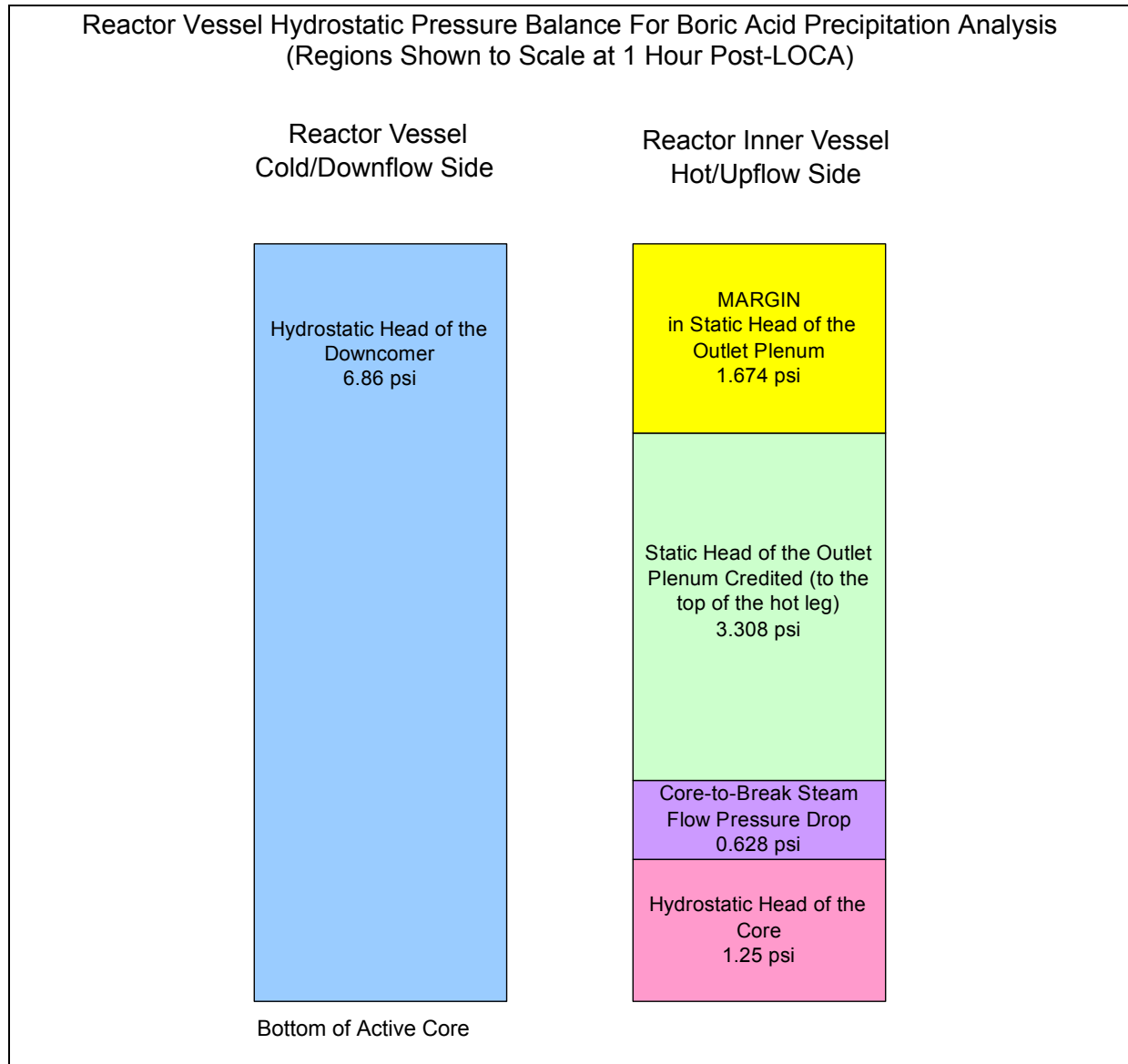
Since this height was derived from the pressure drop, it represents the collapsed height of the liquid in the outlet plenum, which is conservative for justifying the impact of the break configuration on the mixing volume. If this value was converted to a froth height based on the void fraction of the outlet plenum and volume, the static mixture level would increase, providing more margin to the limit specified as the top elevation of the hot leg. (At 6 hours, the area adjusted void fraction in the upper plenum is greater than 40 percent, which adds measurably to the two-phase mixture height above the core.

The following table summarizes the values for all pressure drops for each time, as well as the static head of the outlet plenum.

Time (hr)	Time (sec)	ΔP_{DC} (psi)	ΔP_{STM} (psi)	ΔP_{CORE} (psi)	ΔP_{OP} (psi)	H_{OP} (ft)
1	3600	6.86	0.628	1.25	4.982	11.99
5	18000	6.86	0.281	1.57	5.009	12.06
6	21600	6.86	0.256	1.61	4.994	12.02

From this table, the lowest static head of the outlet plenum occurs at 1 hour, when the core-to-break steam flow pressure drop is highest, and is 11.99 ft. For these comparative calculations examining the limiting conditions for the break configuration and the loop pressure drop, a lower height is more conservative, as discussed above under “Minimum Height of the Mixing Volume.”

While this demonstrates that at a minimum there is 11.99 feet available for the mixing volume in the outlet plenum, the analysis only credits up to the top of the hot leg (or 7.962 feet). When converted to a pressure drop using Equation (2.8.5.6.3-6), the analysis-credited height to the top of the hot leg of 7.962 feet is equivalent to 3.308 psi. Therefore, for a double-ended guillotine break, at 1 hour post-LOCA, there is 1.674 psi of margin in the hydrostatic balance. The following diagram visually depicts this hydrostatic balance at 1 hour for EPU conditions, including the available margin in the outlet plenum.



As can be seen for this limiting break configuration, there is 1.674 psi of margin (more than 24 percent of the hydrostatic head of the downcomer) in the hydrostatic pressure balance between the hot and cold sides of the RV.

The above quantitative evaluation represents the limiting break in the bottom of the cold leg. If a slot break at the top of the cold leg were assumed, there could be an additional pressure drop due to the loop seals refilling as well as an additional pressure drop due to a higher level for the downcomer liquid, described as follows:

- Loop seal refilling will increase the value of the core-to-break steam flow pressure drop, which will reduce the margin calculated above.

- However, with the slot break at the top of the cold leg, water in the cold leg can be credited, which is not currently done as discussed above under “Minimum Height of the Mixing Volume”. Crediting water in the cold leg will increase the hydrostatic head of the downcomer and increase the margin calculated above.

To demonstrate that a slot break at the top of the cold leg is not limiting, the pressure drop due to clearing the loop seals is calculated, and shown to be covered by the margin in the static head of the outlet plenum for the limiting double-ended break in the bottom of the cold leg.

Using the geometric information tabulated in LR [Table 2.8.5.6.3-6](#), the height of the loop seal (from top of cross-over leg to bottom of discharge leg) is 3.5 ft. The static head associated with the height of liquid in the cold leg above the loop seal inlet to the RCP is offset by the added static head for the downcomer from this liquid. Using Equation ([2.8.5.6.3-2](#)) given above to calculate the hydrostatic head of the downcomer, the pressure drop, ignoring the head of steam in the downflow side of the loop seal, associated with clearing the liquid in the upflow side of the loop seal is calculated as follows:

$$\Delta P_{DC} = 3.5 \text{ ft} / 0.016714 \text{ ft}^3/\text{lbm} / 144 \text{ in.}^2/\text{ft}^2 * g/g_c = 1.454 \text{ psi}$$

Because this pressure drop is less than the available margin of 1.674 psi, there is sufficient margin in the pressure balance for the break in the bottom of the cold leg to include clearing the loop seals for a slot break at the top of the cold leg.

Other potential break locations are even less limiting and do not need to be evaluated. For example, if the break was in the loop seal, the above calculation of the pressure drop due to loop seal refilling is not required, as discussed above under “Higher Loop Pressure Drop.”

Comparatively, the double ended break in the cold leg is still bounding. If the break was in the hot leg, all SI would go directly to the core (i.e., none would spill out of the break), as discussed above under “Maximum Spillage.” Therefore, based on the above evaluations, the double-ended break in the cold leg is confirmed to be the limiting break geometry for the boric acid precipitation analysis.

Acceptance Criteria

The acceptance criterion for the results of the boric acid precipitation calculations is Criterion 5, Long Term Cooling, of the ECCS Acceptance Criteria of 10 CFR 50.46 ([Reference 1](#)). Criterion 5 states:

Long-term cooling. After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

In addition, Paragraph (a) of 10 CFR 50.46 requires that the calculation of ECCS performance must be performed with an acceptable evaluation model and for a spectrum of postulated LOCAs. In particular, 10 CFR 50.46(a)(1)(i) states:

ECCS cooling performance must be calculated in accordance with an acceptable evaluation model and must be calculated for a number of postulated loss-of-coolant accidents of

different sizes, locations, and other properties sufficient to provide assurance that the most severe postulated loss-of-coolant accidents are calculated.

2.8.5.6.3.5.3 Description of Analyses and Evaluations

Boric acid precipitation is prevented when the appropriate amount of simultaneous hot and cold side injection is provided in a specified window of time. Simultaneous hot and cold side injection provides the flushing flow necessary to ensure that precipitation does not occur, regardless of the break location. In the boric acid precipitation analysis, the flushing flow is the difference between the RV injection flow rate and the boil-off flow rate. In particular, boric acid precipitation would be prevented by the SI flushing flow to the hot leg for a cold leg break, and by the SI flushing flow to the cold legs for a hot leg break. Boric acid precipitation is mitigated for a break in the hot legs by the flow that is produced by the SI lineup to the cold legs, i.e., SI flows through the cold legs and through the RV on its way out the hot leg break. In doing so, a flushing flow is created which prevents boric acid from precipitating. This is not true for cold leg breaks, in which the SI flow exits the break and is not forced through the RV, where the downcomer remains filled to the elevation of the break and thus only core boil off is replenished; i.e., there is no flushing flow. Thus, the cold leg break is the limiting break location for the boric acid precipitation results.

A requirement for simultaneous hot and cold side injection is that the total flow entering the RV must meet or exceed core boil-off at the early end of the hot and cold side injection time window. If it does not, core uncover could occur. Initiating simultaneous hot and cold side injection after the core boil-off drops below the combined injection to the RV prevents the potential for core uncover. At EPU conditions, the boil-off rate will be higher at a given time compared to current conditions. A decay heat multiplier of 1.2 for all times (addressing NRC Issue #4, see LR [Section 2.8.5.6.3.5.1](#)) also increases the boil-off flow rate compared to earlier methodology assumptions. Incorporating both will push out the time that simultaneous hot and cold side injection may be initiated compared to current conditions. This defines the early side of the simultaneous hot and cold side injection window.

The end of the simultaneous hot and cold side injection window is determined using calculations of the time that the boric acid concentration in the core reaches the solubility limit (27.6 wt percent). Simultaneous hot and cold side injection must be initiated prior to the time at which the solubility limit is reached. The calculation of the mixing volume, or the space in the RV where boric acid accumulates, is a main driver in determining the rate at which boric acid concentrates in the core. Addressing NRC concerns related to the mixing volume calculation (NRC Issues #1 and #2, see LR [Section 2.8.5.6.3.5.1](#)) decreases the amount of the inner vessel volume that may be credited compared to earlier methodology assumptions. A smaller mixing volume increases the rate at which the concentration of boric acid rises during the transient, and thus forces the end of the simultaneous hot and cold side injection window to occur earlier in time than calculated for current conditions. The analysis process included sufficient time between the beginning and end of the simultaneous hot and cold side injection window to allow time for operator action to align simultaneous hot and cold side injection.

2.8.5.6.3.5.4 Results

The results of the post-LOCA boric acid precipitation analysis for EPU along with a comparison to the current results are summarized in LR [Table 2.8.5.6.3-15](#). The boric acid precipitation analysis determined that a minimum flow rate of 250 gpm from a HPSI pump to the hot legs and 273 gpm to the cold legs of the RCS, initiated between four and six hours post-LOCA, successfully maintains the boric acid concentration in the core below the solubility limit of 27.6 wt percent and removes core decay heat for the limiting break, i.e., a large cold leg break. Furthermore, with a hot side injection of 250 gpm at six hours, which is the later end of the hot and cold side injection window, the maximum RCS boron concentration was determined to be 26.3 wt percent, a margin of 1.3 wt percent to 27.6 wt percent. In addition, it was shown that a flushing flow rate of 25 gpm started at six hours post-LOCA is sufficient to prevent the core boric acid concentration from reaching the solubility limit. With no hot side injection flow, the boric acid concentration was calculated to reach the solubility limit at 7.1 hours. LR [Figure 2.8.5.6.3-72](#) shows the results of the post-LOCA boric acid precipitation analysis by comparing the boric acid concentration as a function of time for various assumed hot side injection flow rate conditions. Therefore, the choice of 250 gpm for the minimum hot side injection flow rate from four to six hours post-LOCA was designed to preserve at least 1 wt percent of conservative margin to the criterion.

In separate studies, the analysis also determined that the potential for entrainment of the hot leg injection by the steam flowing in the hot legs ends prior to two hours post-LOCA.

LR [Figure 2.8.5.6.3-73](#) shows the RV flow rate comparison, which confirms a more generalized statement of the result that the minimum simultaneous flow rate to the hot and cold legs of the RCS, after accounting for spillage out the break, must equal or exceed core boil-off at the time the simultaneous injection is initiated. The impact of the EPU and of the NRC imposed methodology changes decreased the required minimum simultaneous hot and cold side injection flow rate as follows: (1) from 275 gpm for the current condition to 250 gpm to the hot side for the EPU, and (2) from 275 gpm for the current condition to 273 gpm to the cold side for the EPU.

The EPU post-LOCA boric acid precipitation analysis demonstrated that the four to six hour switchover time window for simultaneous injection is acceptable to control boric acid concentration and prevent boron precipitation in the core. The margin to precipitation was determined to be 1.3 wt percent. This switchover time is also shown to be after the time that entrainment of the hot side injection is predicted to occur. Also, the core is assured to remain covered with a two-phase mixture as the total flow rate entering the RV meets or exceeds the core boil-off rate at the early end of the switchover time window.

2.8.5.6.3.6 Technical Evaluation – Realignment Guidelines Procedures

2.8.5.6.3.6.1 Introduction

To support the EPU, post-LOCA long term core cooling analytical evaluations of decay heat removal were performed. The post-LOCA long term core cooling decay heat removal analysis was performed in accordance with the Westinghouse post-LOCA long term cooling evaluation model for CE designed PWRs, CENPD-254-P-A ([Reference 6](#)). These evaluations demonstrated that St. Lucie Unit 2 will continue to meet the requirements of ECCS Performance Criterion 5 of

10 CFR 50.46, emergency core cooling system (ECCS) Acceptance Criteria ([Reference 1](#)) following implementation of the proposed EPU. The exceptions described in the boric acid precipitation discussion (LR [Section 2.8.5.6.3.5](#)) are also applicable for the decay heat removal analysis.

The decay heat removal analysis showed that, regardless of break size, decay heat can be removed for the long term and that in doing so, the core remains covered with two-phase liquid, thereby ensuring that core temperatures are maintained at acceptably low values.

Per the Westinghouse methodology, the post-LOCA long term period is defined as beginning at the time the core is reflooded and ending when the plant is secured by operator action that is needed to assure core cooling is maintained until the plant can be brought to a cold shutdown condition. A long term cooling plan that culminates in a secured plant with a minimum number of decisions and actions of the plant operators was developed for the EPU analysis. The long term cooling plan was developed using the analytical evaluations of boric acid precipitation and decay heat removal described herein.

The Westinghouse methodology's long term cooling plan, documented in [Reference 6](#), is a sequence of automatic and operator actions that, as demonstrated by the results of the computer cases run for the EPU analysis, result in acceptable post-LOCA long term cooling. The plan has two major components, namely (1) actions that ensure decay heat is removed for the long term and (2) actions that ensure the concentration of boric acid in the core remains below the solubility limit, i.e., that boric acid precipitation does not occur.

The Westinghouse methodology for decay heat removal analysis identified a decision time for the EPU analysis from an analytical viewpoint. At the decision time, the decay heat removal plan is meant to show that for breaks as large as the largest small break, the RCS has refilled, and therefore, shutdown cooling may be used as the long term decay heat removal method. Likewise, for breaks as small as the smallest large break, decay heat may be removed in the long term by simultaneous hot and cold leg injection. The overlap in these two break ranges ensures that an appropriate long term decay heat removal method is possible for all break sizes.

2.8.5.6.3.6.2 Input Parameters, Assumptions, and Acceptance Criteria

The major input parameters to the EPU decay heat removal analysis included those parameters required to execute the CEPAC, NATFLOW, and CELDA computer codes ([Reference 6](#), Appendix D, Appendix B, and Appendix A, respectively).

The CEPAC computer code calculated the SG cooldown transient that is input to CELDA and NATFLOW. It also calculated the amount of auxiliary feedwater (AFW) that is used during the cooldown transient. Important inputs included core power, RCS/SG liquid and metal masses, atmospheric dump valve (ADV) area, and RCS/SG cooldown rate.

The NATFLOW computer code calculated the natural circulation flow rate and the RCS temperatures under natural circulation flow conditions following a LOCA. The results of NATFLOW were used to determine when the RCS is cooled down to the shutdown cooling entry temperature. Important inputs included core power, SG tube flow area (including tube plugging), core flow area, geometric and frictional resistances through the RCS, and initial RCS flow rate.

The CELDA computer code calculated the long term thermal hydraulic response of the RCS following a LOCA. It was run for a spectrum of break sizes. The results of the CELDA cases were used to develop the decay heat removal portion of the long term cooling plan. Important inputs included core power, SG parameters (same as NATFLOW), core flow area, geometric and frictional resistances through the RCS (same as NATFLOW), total RCS volume, the heat transfer coefficient and metal specific heat (sensible heat load), SG heat transfer area (including tube plugging), and minimum HPSI delivery curve.

The following major assumptions were used in the decay heat removal analysis.

1. For both frictional and geometric pressure drops, the uncertainty inside the RV was 10 percent. The uncertainty for frictional pressure drops outside the RV was also 10 percent, but an uncertainty of 20 percent was used for geometric pressure drops.
2. The most damaging single failure of ECCS equipment assumed in the analysis was the failure of an EDG. Of the equipment important to the LTC analysis, the failure of an EDG results in the loss of one HPSI pump and one motor-driven AFW pump. The HPSI pump(s) were explicitly modeled in the CELDA analysis. They were not modeled in the CEPAC or NATFLOW analyses. The AFW flow rate available after the single failure was evaluated as part of the development of the decay heat removal portion of the LTC plan.
3. Representation of SGTP in the decay heat removal analysis was assumed using average length tubes, such that the average heated length of the SG was unchanged.

The decay heat removal analysis was performed with the CELDA, NATFLOW, and CEPAC computer codes ([Reference 6](#)) for post-LOCA decay heat removal. The assumptions listed in CENPD-254-P-A ([Reference 6](#)) are listed below for each computer code and are applicable to the analysis for EPU.

For CEPAC

The following assumptions were made:

- No primary break,
- Metal walls cooldown at same rate as primary system fluid (isothermal),
- Primary to secondary temperature difference is constant at all times,
- Decay heat multipliers of 1.2 applied at all times (Note that this is a change from [Reference 6](#) in accordance with NRC Item #4 in [Reference 8](#)),
- Moody model for critical steam mass flow, and
- All sensible heat is removed through SGs (no ambient losses).

For NATFLOW

The following assumptions were made:

- HPSI pump delivery keeps the RCS filled with liquid and thus maintains the RCS pressures above the saturation pressure corresponding to the hot leg temperature in the RCS;

- Each of the RCS regions modeled were assumed to have a uniform average enthalpy which determines its fluid properties for a given pressure;
- RCP assumed to be in locked rotor position;
- SGs have already removed sensible heat from RCS (code models steady-state condition); and
- In order to maintain an average of 10 percent SGTP, 12 percent SGTP in one SG would necessitate the other SG having 8 percent SGTP. Both SGs could be evaluated at 12 percent SGTP as this would be more limiting in terms of pressure drops, heat transfer area, and cross sectional flow area. However, this was judged to be unnecessarily conservative as the asymmetric loops with 8 percent and 12 percent would behave more similarly to both loops at 10 percent SGTP than both loops at 12 percent SGTP. In addition, sensitivity studies were performed using the NATFLOW code and slight changes in the SGTP were found to have an insignificant impact on the results. Thus, a value of 10 percent SGTP was used throughout this technical evaluation of the realignment guidelines procedures.

For CELDA

The following assumptions were made:

- Primary system pressure was spatially uniform,
- Does not account for cooling effects of SI,
- Fluid state can either be subcooled liquid or saturated liquid and vapor in thermal equilibrium,
- Inertial and momentum flow effects are negligible,
- Phase separation model accounts for the axial variation in voids,
- Leak flow was computed from Henry Fauske / Moody critical flow model,
- Wall heat conduction model accounted for energy transfer between primary coolant and metal walls, and
- SG secondary temperature can be varied to simulate primary system cooldown.

The acceptance criterion for the results of the decay heat removal calculations is Criterion 5, Long Term Cooling, of the ECCS Acceptance Criteria of 10 CFR 50.46 ([Reference 1](#)). Criterion 5 states:

Long-term cooling. After any calculated successful initial operation of the ECCS, the calculated core temperature shall be maintained at an acceptably low value and decay heat shall be removed for the extended period of time required by the long-lived radioactivity remaining in the core.

In addition, Paragraph (a) of 10 CFR 50.46 requires that the calculation of ECCS performance must be performed with an acceptable evaluation model and for a spectrum of postulated LOCAs. In particular, 10 CFR 50.46(a)(1)(i) states:

ECCS cooling performance must be calculated in accordance with an acceptable evaluation model and must be calculated for a number of postulated loss-of-coolant accidents of

different sizes, locations, and other properties sufficient to provide assurance that the most severe postulated loss-of-coolant accidents are calculated.

2.8.5.6.3.6.3 Description of Analyses and Evaluations

As described in [Reference 6](#), there are two basic procedures in the long-term cooling plan, namely the large break and small break procedures. The large break procedure is applicable when the break flow is sufficient to remove the decay heat from the RCS in the long term. In the large break procedure, simultaneous hot and cold side injection from the HPSI pump replenishes the RCS inventory that is lost out the break. In addition, it maintains the boric acid concentration in the core below the solubility limit. SG heat transfer must be maintained for a period of time, which is determined by the analysis, in the large break procedure. After that time, the energy flow out the break is sufficient to remove decay heat.

If the break is small enough for the RCS to refill, then the small break procedure is applicable. In the small break procedure, the RCS is cooled down via the SGs to the shutdown cooling entry temperature and shutdown cooling is initiated. Decay heat is then removed by the shutdown cooling system (SDCS).

The decay heat removal portion of the long term cooling plan relies on the RCS inventory results from CELDA to show an acceptable plan. In other words, the analysis methodology can show acceptable results by demonstrating both of the following two criteria:

1. The break is small enough such that the RCS has refilled and the shutdown cooling (SDC) entry temperature has been met, and thus the SDCS is used to remove decay heat and prevent boric acid precipitation (small breaks), or
2. breaks that do not meet this requirement are large enough for the break flow and simultaneous H/C side injection to remove decay heat and prevent boric acid precipitation in the long-term (large breaks).

This analytical approach is consistent with LOCA emergency operating procedures (EOPs) and the underlying philosophy of CENPD-254-P-A, namely, that it can be analytically demonstrated that decay heat can be removed in the long-term for any size LOCA and that the operator can correctly identify and initiate an appropriate means of long-term decay heat removal.

2.8.5.6.3.6.4 Results

The long term cooling plan for the EPU analysis included the selection of the largest small break and the smallest large break at the decision time for 1 ADV per SG cooldown with a cooldown rate of 50 °F/hr (see the following paragraphs for a description of these steps of the long term cooling plan). The time that the SDC entry temperature of 300 °F was reached was 13.5 hours. The associated condensate storage tank (CST) inventory used at 13.5 hours at the aforementioned ADV conditions was 231,000 gallons. These results, along with the comparison to pre-EPU results, can be found in LR [Table 2.8.5.6.3-16](#).

In the Westinghouse methodology for the long term cooling plan, the decision time is the time that the operator decides whether to implement the large break or the small break procedure for decay heat removal (i.e., maintain simultaneous hot and cold side injection or initiate shutdown

cooling). Based on the need to allow time for the operator to apply shutdown cooling initiation procedures before the SGs are lost, a decision time of 16 hours was selected.

In the Westinghouse methodology, the largest small break is the largest break for which the RCS refills before the decision time. In the long term cooling analysis methodology for EPU, for all break sizes up to and including this break size, it was assured that the RCS has sufficient inventory to initiate shutdown cooling. From LR [Table 2.8.5.6.3-17](#), the largest small break was the 0.036 ft² break.

In the Westinghouse methodology, the smallest large break is the smallest break for which the break flow rate serves as an adequate means of RCS heat removal after the SGs are lost as heat sinks. In the long term cooling methodology for EPU, this was indicated by the core remaining covered with two-phase liquid after the steam generators are lost as heat sinks. When the SGs were lost as heat sinks, the RCS pressure will temporarily increase and then decrease. If the break area is sufficiently small, the increase in pressure may increase the break flow rate and decrease the HPSI flow rate sufficiently that the RCS inventory decreases to the point that the core uncovers. The breaks for which this occurs are too small for the large break procedure to be acceptable. Therefore, for the EPU, the large break procedure was acceptable for all breaks for which the core remained covered after the SGs were lost as heat sinks. From LR [Table 2.8.5.6.3-17](#), the smallest large break was the 0.013 ft² break.

Using these results, the two criteria described in LR [Section 2.8.5.6.3.6.3](#) were fulfilled. The following paragraphs describe the successful fulfillment of these two criteria.

Fulfilling Criteria 1/Small Breaks

The CST emptied between 18 and 18.5 hours post-LOCA, and SGs were conservatively modeled to be lost as heat sinks at 17 hours, with a decision time of 16 hours. Furthermore, the SDC entry temperature of 300 °F was met at 13.5 hours, which occurred before the decision time. Thus, any break which refills prior to 16 hours was small enough such that SDC could be entered successfully. From LR [Table 2.8.5.6.3-17](#), breaks 0.036 ft² and smaller were shown to have refilled prior to 16 hours, and thus employing the SDC system was the appropriate success path. The difference between 16 hours and 17 hours (time that the SGs are lost as heat sinks) preserved time for operator actions to get onto SDC. It should be noted that per the EOP, the operator is directed to ensure that pressurizer level is at least 30 percent prior to entering SDC. Thus, this analytical approach is conservative relative to the EOPs, since the analytical approach requires that the pressurizer be totally full, not just 30 percent full.

Fulfilling Criteria 2/Large Breaks

In order to demonstrate that this analytical approach covered all break sizes, it was shown that breaks larger than 0.036 ft² are large enough such that the break flow and simultaneous H/C side injection is adequate to remove decay heat and prevent boric acid precipitation in the long term. Decay heat removal for the long term was shown for the break sizes for which the core does not uncover after the SGs are lost as heat sinks. (The RCS begins to increase in pressure and temperature after the SGs are lost as heat sinks, i.e., termination of heat transfer to the SGs. A break that is too small to fulfill Criteria 2 is characterized by the core uncovering due to this pressurization and the resulting reduction in SI flow.)

From LR [Table 2.8.5.6.3-17](#), break sizes 0.013 ft² and larger showed that the core does not uncover after 17 hours, and thus these breaks fulfill Criteria 2.

From the analytical approach presented above, decay heat removal and boric acid precipitation prevention was achieved by the SDC system for breaks 0.036 ft² and smaller, and by simultaneous hot and cold side injection for breaks 0.013 ft² and larger. Hence, using the results of RCS inventory/pressurizer level, there is an overlap of break sizes such that an acceptable path was assured (i.e., either SDC or maintaining hot and cold side injection). The overlap of break sizes using the results of the RCS inventory/pressurizer level was conservative based on the calculation of the inputs in the CEPAC, NATFLOW, and CELDA as well as the inherent assumptions made in the methodology of these codes (see LR [Section 2.8.5.6.3.6.2](#)).

LR [Figure 2.8.5.6.3-74](#) is a plot of break area versus RCS refill time. LR [Figure 2.8.5.6.3-75](#) documents break size and core uncover at the decision time. It also indicates the range of break sizes that are large breaks (i.e., simultaneous hot and cold side injection is acceptable for long term decay heat removal) and the range of break sizes that are small breaks (i.e., shutdown cooling is acceptable for long term decay heat removal).

2.8.5.6.3.7 Technical Evaluation – Post-LOCA Criticality

2.8.5.6.3.7.1 Introduction

To support the EPU, post-LOCA long term core cooling analytical evaluations of post-LOCA criticality were performed. This section documents the post-LOCA criticality analysis, i.e., the calculation of the minimum sump boron concentration following a LBLOCA as a function of initial RCS boron concentration. The purpose of this analysis was to calculate the minimum boric acid concentration in the containment sump at the time of switchover to simultaneous hot/cold leg injection. The minimum boric acid concentration in the containment sump sets the limit to prevent core recriticality following switchover to simultaneous hot/cold side injection.

2.8.5.6.3.7.2 Input Parameters, Assumptions, and Acceptance Criteria

The major input parameters to the post-LOCA criticality analysis are documented in the boric acid precipitation analysis described in LR [Section 2.8.5.6.3.5.2](#). In addition, the inputs listed below were changed to be consistent with the methodology assumptions of this analysis.

- Nominal mass of inventory initially in RCS;
- Minimum mass of inventory initially in BAMT, RWT, and SITs;
- Minimum boric acid concentrations in BAMT, RWT, and SITs; and
- Maximum holdup volume.

The following major assumptions were used in this analysis, to support the input changes listed above:

- The post-LOCA criticality analysis was performed with the BORON computer code ([Reference 6](#), Appendix C), which calculates the boric acid concentration in the core and containment sump following a large break LOCA. BORON assumes that half of the RCS

inventory is ignored and does not contribute to the sump inventory. In order to compensate for this feature, the value used in BORON for a sump dilution analysis was doubled;

- Minimum mass initially in BAMT, RWT, and SITs was used to minimize the sump boron concentration;
- A minimum value was used for boric acid concentrations in order to minimize the sump boron concentration;
- A maximum containment liquid holdup volume may trap a portion of the containment spray pump flow, and prevent it from reaching the sump. This volume was accounted for in the post-LOCA criticality analysis since a portion of the RWT water volume held up in containment would decrease the sump boric acid concentration.

The results of this analysis are used as input to ensure that the containment sump boron concentration remains greater than the post-LOCA critical boron concentration to the time of ECCS switchover to hot/cold leg recirculation.

2.8.5.6.3.7.3 Description of Analyses and Evaluations

The analysis used the BORON computer code (Reference 6, Appendix C).

The method of analysis consisted of the following major steps:

1. The BORON computer code inputs for the boric acid precipitation analysis documented in LR Section 2.8.5.6.3.5.2 were used as the basis for the sump dilution BORON inputs, as they pertain to EPU conditions.
2. The boric acid precipitation inputs pertaining to the BAMT inventory and boric acid concentration were adjusted so that the preliminary minimum sump boric acid concentration vs. initial RCS boric acid concentration curve would be appropriate for this analysis.
3. The computer cases necessary to calculate the sump boron concentration as a function of RCS boron concentration were run.
4. Using the sump dilution BORON cases from Step 3, the sump boron concentration at the maximum switchover time to simultaneous hot/cold leg injection as a function of RCS boron concentration were plotted.

2.8.5.6.3.7.4 Results

This section documents the post-LOCA criticality analysis results, which calculated the minimum boric acid concentration in the containment sump following a LBLOCA at the maximum time for initiating simultaneous hot and cold leg injection. LR Figure 2.8.5.6.3-76 illustrates the minimum containment sump boron concentration as a function of initial RCS boron concentration at 6 hours post-LOCA, which was the maximum time for initiating simultaneous hot/cold leg injection following a LOCA (as determined by the boric acid precipitation results, see LR Section 2.8.5.6.3.5.4).

The sump concentrations displayed in LR Figure 2.8.5.6.3-76 span the range of no RCS boron concentration (i.e. 0 ppm) up to 2500 ppm, which covers the bounding maximum full power RCS

boron concentration of 2200 ppm specified in LR Table 2.8.5.6.3-14. Therefore, the results displayed in LR Figure 2.8.5.6.3-76 span the range that would be suitable for use to ensure that the containment sump boron concentration remains greater than the post-LOCA critical boron concentration to the time of ECCS switchover to hot/cold leg recirculation.

2.8.5.6.3.8 Impact of Renewed Plant Operating License Evaluations and License Renewal Programs

As discussed above, the design transient analyses were determined to be outside the scope of License Renewal; therefore, with respect to the design basis accidents and transients, the EPU does not impact any License Renewal evaluations.

2.8.5.6.3.9 Conclusion

FPL has reviewed the analyses of the LOCA events and the ECCS. FPL concludes that the analyses have adequately accounted for operation of the plant at the proposed power level and that the analyses were performed using acceptable analytical models. FPL further concludes that it has demonstrated that the RPS and the ECCS will continue to ensure that the PCT, 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, FPL concludes that the plant will continue to meet the requirements of GDCs -4, -27, -35, and 10 CFR 50.46 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to LOCA.

2.8.5.6.3.10 References

1. Code of Federal Regulations, Title 10, Part 50, Section 50.46, Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors.
2. Code of Federal Regulations, Title 10, Part 50, Appendix K, ECCS Evaluation Models.
3. CENPD-132, Supplement 4-P-A, Calculative Methods for the C-E Nuclear Power Large Break LOCA Evaluation Model, March 2001.
4. CENPD-137 P, Calculative Methods for the C-E Small Break LOCA Evaluation Model, August 1974.

CENPD-137, Supplement 1-P, Small Break Model, Calculative Methods for the C-E Small Break LOCA Evaluation Model, January 1977.

CENPD-137, Supplement 2-P-A, Calculative Methods for the ABB CE Small Break LOCA Evaluation Model, April 1998.
5. CENPD-252-P-A, Blowdown Analysis Method – Method for the Analysis of Blowdown Induced Forces in a Reactor Vessel, July 1979.
6. CENPD-254-P-A, Post-LOCA Long Term Cooling Evaluation Model, June 1980.

7. NRC letter Suspension of NRC Approval for use of Westinghouse Topical Report CENPD-254-P, 'Post-LOCA Long-Term Cooling Model,' Due to Discovery of Non-Conservative Modeling Assumptions During Calculations Audit, R. A. Gramm, August 1, 2005. (ADAMS No. ML051920310)
8. NRC letter, Clarification of NRC Letter Dated August 1, 2005, Suspension of NRC Approval for use of Westinghouse Topical Report CENPD-254-P, 'Post-LOCA Long-Term Cooling Model,' Due to Discovery of Non-Conservative Modeling Assumptions during Calculations Audit (TAC MB1365), D. S. Collins, November 23, 2005. (ADAMS No. ML053220569)
9. S. E. Peters (NRC) to S.L. Rosenberg (NRC), Summary of August 23, 2006 Meeting with the Pressurized Water Reactor Owners Group (PWROG) to Discuss the Status of Program to Establish Consistent Criteria for Post Loss-of-Coolant (LOCA) Calculations, October 3, 2006. (ADAMS No. ML062690017)
10. CENPD-133, Supplement 3-P, CEFLASH-4AS, A Computer Program for the Reactor Blowdown Analysis of the Small Break Loss of Coolant Accident, January 1977.
11. CENPD-137, Supplement 1-P, Small Break Model, Calculative Methods for the C-E Small Break LOCA Evaluation Model, January 1977.
12. K. Kniel (NRC) to A. E. Scherer (C-E), Evaluation of Topical Reports CENPD-133, Supplement 3-P and CENPD-137, Supplement 1-P, September 27, 1977.

Table 2.8.5.6.3-1
Large Break LOCA ECCS Performance Analysis
Key Initial Core and Plant Design Data

Quantity	Value	Units
Reactor power level (100.3% of rated power)	3030	MWt
Peak linear heat generation rate (PLHGR) of the hot rod	12.5	kW/ft
Peak linear heat rate of the average rod in assembly with hot rod	11.7	kW/ft
Average linear heat generation rate (100.3% of rated)	5.204	kW/ft
Gap conductance at the PLHGR	1555	BTU/hr-ft ² -°F
Fuel centerline temperature at the PLHGR	3067	°F
Fuel average temperature at the PLHGR	1974	°F
Hot rod gas pressure	1014	psia
Moderator temperature coefficient at initial density	0.3×10^{-4}	$\Delta\rho/^\circ\text{F}$
RCS flow rate (minimum)	144.3×10^6	lbm/hr
Core flow rate (minimum)	138.9×10^6	lbm/hr
RCS pressure (nominal)	2250	psia
Cold leg temperature (minimum)	532	°F
Hot leg temperature	587.4	°F
Plugged tubes per steam generator	900	---
Maximum asymmetry in number of plugged tubes between the two steam generators	360	---
Low pressurizer pressure SIAS setpoint (minimum)	1646	psia
Safety injection tank pressure (min/max)	485 / 665	psig
Safety injection tank water volume (min/max)	1388 / 1588	ft ³
Safety injection tank water temperature (min/max)	90/124.5	°F
LPSI + HPSI pump flow rate (min, 1 train / max, 2 trains)	2568/10,942	gpm
Containment pressure (minimum)	13.782	psia
Containment temperature (minimum)	90	°F
Containment humidity (maximum)	100	%
Containment net free volume (maximum)	2.6313×10^6	ft ³
Containment spray pump flow rate (maximum)	4500	gpm/pump
Refueling water tank temperature (min/max)	51/104	°F
Containment passive heat sinks	LR Tables 2.6.6-2, 2.6.6-3	---

Table 2.8.5.6.3-2
Large Break LOCA ECCS Performance Analysis Results

EPU Analysis			
Break Size (DEG/PD)	Peak Cladding Temperature (°F)	Maximum Cladding Oxidation (%)	Maximum Core-Wide Oxidation (%)
1.0	2065	13.31	<1.0
0.8	2076	13.75	<1.0
0.6	2087	14.48	<1.0
0.4	2054	12.71	<1.0
Current Analysis			
1.0	2081.8	14.28	<1.0
0.8	2086.0	14.49	<1.0
0.6	2104.0	16.06	<1.0
0.4	2078.1	14.20	<1.0

Table 2.8.5.6.3-3
Large Break LOCA ECCS Performance Analysis
Times of Interest (Seconds after Break)
EPU Analysis

Break Size (DEG/PD)	SITs Inject	End of Blowdown	Start of Reflood	SITs Empty	SI Pumps On	Hot Rod Rupture
1.0	11.86	22.79	38.64	113.61	36.59	58.42
0.8	13.35	24.30	39.77	115.14	36.62	56.82
0.6	15.78	27.00	41.85	117.62	36.69	55.01
0.4	20.61	32.47	46.07	123.07	36.88	76.42

Table 2.8.5.6.3-4
Large Break LOCA ECCS Performance Analysis
Variables Plotted as a Function of Time for Each Break

Variable
Core Power
Pressure in Center Hot Assembly Node
Break Flow Rate
Hot Assembly Flow Rate (below hot spot)
Hot Assembly Flow Rate (above hot spot)
Hot Assembly Quality
Containment Pressure
Mass Added to Core during Reflood
Peak Cladding Temperature ⁽¹⁾
1. The cladding temperature at the elevation of cladding rupture is also shown for the limiting break

Table 2.8.5.6.3-5
Large Break LOCA ECCS Performance Analysis
Additional Variables Plotted as a function of time for the Limiting Break

Variable
Mid Annulus Flow rate
Quality Above and Below the Core
Core Pressure Drop
Safety Injection Flow Rate into Intact Discharge Legs
Water Level in Downcomer During Reflood
Hot Spot Gap Conductance
Maximum Local Cladding Oxidation Percentage
Fuel Centerline, Fuel Average, Cladding, and Coolant Temperature at the Hot Spot
Hot Spot Heat Transfer Coefficient
Hot Rod Internal Gas Pressure
Core Bulk Channel Flow Rate

**Table 2.8.5.6.3-6
Small Break LOCA ECCS Performance Analysis
Key Initial Core and Plant Design Data**

Quantity	Value	Units
Nominal Reactor Power Level (including 0.3% uncertainty)	3030	MWt
Peak Linear Heat Generation Rate (PLHGR)	13.0	kW/ft
Nominal RCS Pressure	2250	psia
Minimum RCS Flow rate	375,000	gpm
Maximum Cold Leg Temperature	554.0	°F
Hot Leg Temperature	609.0	°F
Maximum Number of Plugged Tubes per Steam Generator	900	--
Main Steam Safety Valve First Bank Opening Pressure (nominal plus 3% accumulation)	1030	psia
Minimum Low Pressurizer Pressure Reactor Trip Setpoint (harsh environment)	1810	psia
Minimum Low Pressurizer Pressure Safety Injection Actuation Signal Setpoint (harsh environment)	1646	psia
Maximum Time Delay for Actuation of HPSI Flow (with Loss of Offsite Power)	30	sec
Minimum Charging Pump Flow Rate/pump	35	gpm
Maximum Time Delay for Actuation of Charging Flow (with Loss of Offsite Power)	330	sec
Minimum Safety Injection Tank Injection Pressure	485	psig
Minimum Axial Shape Index	-0.16	--
Maximum Moderator Temperature Coefficient (MTC)	0.3×10^{-4}	$\Delta p / ^\circ F$
Maximum Asymmetry in Number of Plugged Tubes between the two SGs	360	--
Hot Rod Gas Pressure ⁽²⁾	1016	psia
Fuel Centerline Temperature at Peak Linear Heat Generation Rate ⁽²⁾	2233	°F
Fuel Average Temperature at Peak Linear Heat Generation Rate ⁽²⁾	3623	°F
Bottom Elevation of Horizontal Section of Suction leg piping ⁽¹⁾	19.789	feet
Top Elevation of Core ⁽¹⁾	21.107	feet
Top Elevation of Discharge leg piping ⁽¹⁾	28.289	feet
Discharge leg piping diameter	2.5	feet

Table 2.8.5.6.3-6 (Continued)
Small Break LOCA ECCS Performance Analysis
Key Initial Core and Plant Design Data

Quantity	Value	Units
Maximum Safety Injection Tank Temperature	124.5	°F
Maximum Refueling Water Storage Tank Temperature	104	°F
Notes: 1. Relative to the bottom of the Reactor Vessel 2. These quantities correspond to the rod average burnup of the hot rod that yields the maximum initial stored energy.		

Table 2.8.5.6.3-7
Small Break LOCA ECCS Performance Analysis
Top Peaked Axial Power Shape

Core Elevation (% of Core Height)	Axial Peaking Factor
1.25	0.2353
5	0.6322
10	0.7712
15	0.8052
20	0.8152
25	0.8392
30	0.8792
35	0.9312
40	0.9951
45	1.0531
50	1.1207
55	1.1813
60	1.2253
65	1.2683
70	1.3113
75	1.3593
80	1.4103
85	1.4522
90	1.2903
95	0.3615
98.75	0.3605

Table 2.8.5.6.3-8
Small Break LOCA ECCS Performance Analysis
Moderator Density Feedback

$\Delta\rho$	Density (lbm/ft ³)
-0.31282	0.896
-0.06206	17.896
-0.01247	27.896
-0.00989	28.896
-0.00765	29.896
-0.00571	30.896
-0.00407	31.896
-0.0027	32.896
-0.00158	33.896
-0.0007	34.896
-0.00003	35.896
0.00043	36.896
0.0007	37.896
0.00081	38.896
0.00075	39.896
0.00055	40.896
0.00021	41.896
0	42.381
-0.00025	42.896
-0.00083	43.896
-0.00152	44.896
-0.00231	45.896
-0.00318	46.896
-0.00415	47.896

Table 2.8.5.6.3-9
Small Break LOCA ECCS Performance Analysis
High Pressure Safety Injection Pump Minimum Delivered Flow to RCS
(Assuming failure of an Emergency Diesel Generator)

RCS Pressure (psia)	Flow Rate (gpm)
1212	0
1205	63.6
1198	76.8
1177	109.6
1104	194.4
1035	244.4
943	290.4
829	340.4
699	393.2
551	448.8
393	500.4
217	551.6
0	608.4
Notes: 1. The flow is assumed to be split equally to each of the four discharge legs. 2. The flow to the broken discharge leg is assumed to spill out the break.	

Table 2.8.5.6.3-10
Small Break LOCA ECCS Performance Analysis Results

EPU Analysis			
Break Size	Peak Cladding Temperature (°F)	Maximum Cladding Oxidation (%)	Maximum Core-Wide Cladding Oxidation (%)
0.04 ft ² /PD	1810	6.80	< 0.72
0.05 ft ² /PD	1903	9.21	< 0.94
0.06 ft ² /PD	1839	3.44	< 0.39
Current AOR			
0.04 ft ² /PD	1672	3.26	< 0.28
0.05 ft ² /PD	1943	9.80	< 0.64
0.06 ft ² /PD	1818	5.61	< 0.42

Table 2.8.5.6.3-11
Small Break LOCA ECCS Performance Analysis
Times of Interest (seconds after break)

EPU Analysis				
Break Size	HPSI Flow Delivered to RCS	LPSI Flow Delivered to RCS	SIT Flow Delivered to RCS	Peak Cladding Temperature Occurs
0.04 ft ² /PD	153	(1)	2489 ⁽²⁾	2085
0.05 ft ² /PD	117	(1)	1766 ⁽²⁾	1802
0.06 ft ² /PD	93	(1)	1397	1400
Notes: 1. Calculation completed before LPSI flow delivery to RCS begins. 2. SIT injection is calculated to begin at this time but is not credited.				

Table 2.8.5.6.3-12
S1M vs. S2M

Case No.	Model	Decay Heat Multiplier	PCT (°F)
1	S1M	1.140	2240
2	S1M	0.950	1454
3	S2M	1.140	1664

Case 1

An S1M analysis which produces a PCT of about 2200°F by adjusting ANS-1971 decay heat multiplier. This serves as a basis for a hypothetical case of producing a very high PCT with the ANS-1971 decay heat multiplier of 1.2.

Case 2

S1M analysis with the effective ANS-1971 x 1.0 with respect to Case 1.

Case 3

S2M analysis with the same decay heat multiplier as Case 1.

$$\text{Figure of Merit} \equiv 1 + \left(1 - \frac{PCT_{S1M\_1.2} - PCT_{S2M\_1.2}}{PCT_{S1M\_1.2} - PCT_{S1M\_1.0}}\right) * 0.2$$

where: PCT is the peak cladding temperature and the subscripts are defined as follows:

S1M_1.2: S1M calculation with decay heat multiplier equivalent to 1.2

S1M_1.0: S1M calculation with decay heat multiplier equivalent to 1.0

S2M_1.2: S2M calculation with decay heat multiplier equivalent to 1.2

Plant	Figure of Merit
St. Lucie Unit 2 EPU	1.054
3400 MWt Plant	1.148

Table 2.8.5.6.3-13
Small Break LOCA ECCS Performance Analysis
Variables Plotted as a Function of Time for Each Break

Variable
Core Power
Inner Vessel Pressure
Break Flow Rate
Inner Vessel Inlet Flow Rate
Inner Vessel Two-Phase Mixture Level
Heat Transfer Coefficient at Hot Spot
Coolant Temperature at Hot Spot
Cladding Temperature at Hot Spot

Table 2.8.5.6.3-14
Post-Loca Boron Precipitation Analysis
Core and Plant Design Data

Analyzed reactor core thermal power level (includes uncertainty)	3030 MWt
Maximum RCS boric acid concentration	2200 ppm
Decay heat multiplier (for entire transient)	1.2
BAMT parameters	
Maximum number of tanks	2
Maximum liquid volume per tank	9975 gal
Maximum boric acid concentration	3.56 wt%
Minimum liquid temperature	51 °F
RWT parameters	
Maximum volume	350,300 gal ⁽¹⁾
Maximum boric acid concentration	2600 ppm
Minimum liquid temperature	51 °F
SIT parameters	
Maximum number of tanks	4
Maximum liquid volume per tank	1588 ft ³
Maximum boric acid concentration	2600 ppm
Minimum liquid temperature	90.0 °F
Maximum pressure	665 psig
Pump parameters	
Maximum number of charging pumps	3
Minimum number of HPSI pumps	1
Minimum number of LPSI pumps	1
Minimum number of containment spray pumps	1
Maximum charging pump flow rate per pump	49 gpm
Flow rates for emptying the RWT	
Minimum flow HPSI delivery	515 gpm
Minimum flow LPSI delivery	2213 gpm
Minimum containment spray pump flow rate	2701 gpm
RCS/SG parameters	
Number of plugged tubes per SG	10% (±2%)
RCS pressure measurement uncertainty	±90 psi
ADV flow rate, at 985 psia	275,000 lbm/hr ±5%

Table 2.8.5.6.3-14 (Continued)
Post-Loca Boron Precipitation Analysis
Core and Plant Design Data

Auxiliary feedwater flow requirement	231,000 gal
Core flow area	54 ft ²
Nominal RCS water mass	479,000 lbm
Mixing volume	7800 gal
1. The maximum RWT volume used in the analyses is conservative and bounds the actual maximum RWT volume.	

**Table 2.8.5.6.3-15
Summary of Results
For The Boric Acid Precipitation Analysis**

EPU Analysis	
CENPD-254-P-A Methodology Modified by the Waterford Approach	
Parameter	EPU Result
Boric acid solubility limit	27.6 wt%
Time boric acid concentration reaches solubility limit with no hot side injection	7.1 hours
Minimum simultaneous hot and cold side injection flow rates	
Hot Side	250 gpm
Cold Side	273 gpm
Initiation time for simultaneous hot and cold side injection	4 to 6 hours post-LOCA
Maximum core boric acid concentration with 250 gpm of hot side injection started at 6 hours	26.3 wt% at 7.3 hours post-LOCA
Maximum core boric acid concentration with 25 gpm flushing flow Initiated at 6 hours	24.6 wt% at 6.0 hours post-LOCA
Current AOR	
CENPD-254-P-A Methodology	
Parameter	Current Result
Boric acid solubility limit	27.6 wt%
Time boric acid concentration reaches solubility limit with no hot side injection	7.8 hours
Minimum simultaneous hot and cold side injection flow rates	
Hot Side	275 gpm
Cold Side	275 gpm
Initiation time for simultaneous hot and cold side injection	2 to 6 hours post-LOCA
Maximum core boric acid concentration with 275 gpm of simultaneous hot and cold side injection started at 6 hours	24.2 wt% at 6.0 hours post-LOCA
Maximum core boric acid concentration with 25 gpm flushing flow Initiated at 6 hours	24.2 wt% at 6.0 hours post-LOCA

Table 2.8.5.6.3-16
Summary of Results
for the Decay Heat Removal Analysis

EPU Analysis	
CENPD-254-P-A Methodology Modified by the Waterford Approach	
Parameter	EPU Result
Minimum SG/RCS cooldown rate	50 °F/hr
Shutdown cooling entry temperature	300 °F
Minimum time CST empties/SGs are lost as heat sinks	17 hours
Maximum time that Shutdown Cooling entry temperature can be reached	13.5 hours
CST inventory used at time SDC entry temperature was reached	231,000 gallons
Break Spectrum	
Smallest Large Break	0.013 ft ²
Largest Small Break	0.036 ft ²
Decision time	16 hours
Current AOR	
CENPD-254-P-A Methodology	
Parameter	Current Result
Minimum SG/RCS cooldown rate	75 °F/hr
Shutdown cooling entry temperature	300 °F
Minimum time CST empties/SGs are lost as heat sinks	20 hours
Maximum time that Shutdown Cooling entry temperature can be reached	8.5 hours
CST inventory used at time SDC entry temperature was reached	262,400 gallons
Break Spectrum	
Smallest Large Break	0.007 ft ²
Largest Small Break	0.038 ft ²
Decision time	16 hours

Table 2.8.5.6.3-17
Summary of Results for CELDA Break Spectrum
for The Decay Heat Removal Analysis

CELDA Case No.	Break Size (ft²)	Refill Time (sec/hr)⁽¹⁾	Core Uncovers after 17 hr?⁽²⁾
1	0.040	(3)	No
2	0.038	(3)	No
3	0.037	58695/16.6	No
4	0.036	55904/15.8	No
5	0.035	53378/15.1	No
6	0.030	43545/12.4	No
7	0.025	36788/10.5	No
8	0.020	31901/9.1	No
9	0.015	27743/8.0	No
10	0.014	26925/7.8	No
11	0.013	26096/7.5	No
12	0.012	25251/7.3	Yes
13	0.010	23504/6.8	Yes
14	0.005	18428/5.4	Yes

Notes:

1. Refill time is listed in units of seconds after start of CELDA and hours after start of LOCA. The CELDA start time was 1000 seconds after the start of the LOCA.
2. Seventeen hours is when steam generator heat transfer was terminated in the CELDA cases.
3. Refill was not calculated to occur.

Figure 2.8.5.6.3-1
Large Break LOCA ECCS Performance Analysis
0.01 DEG/PD Break
Core Power

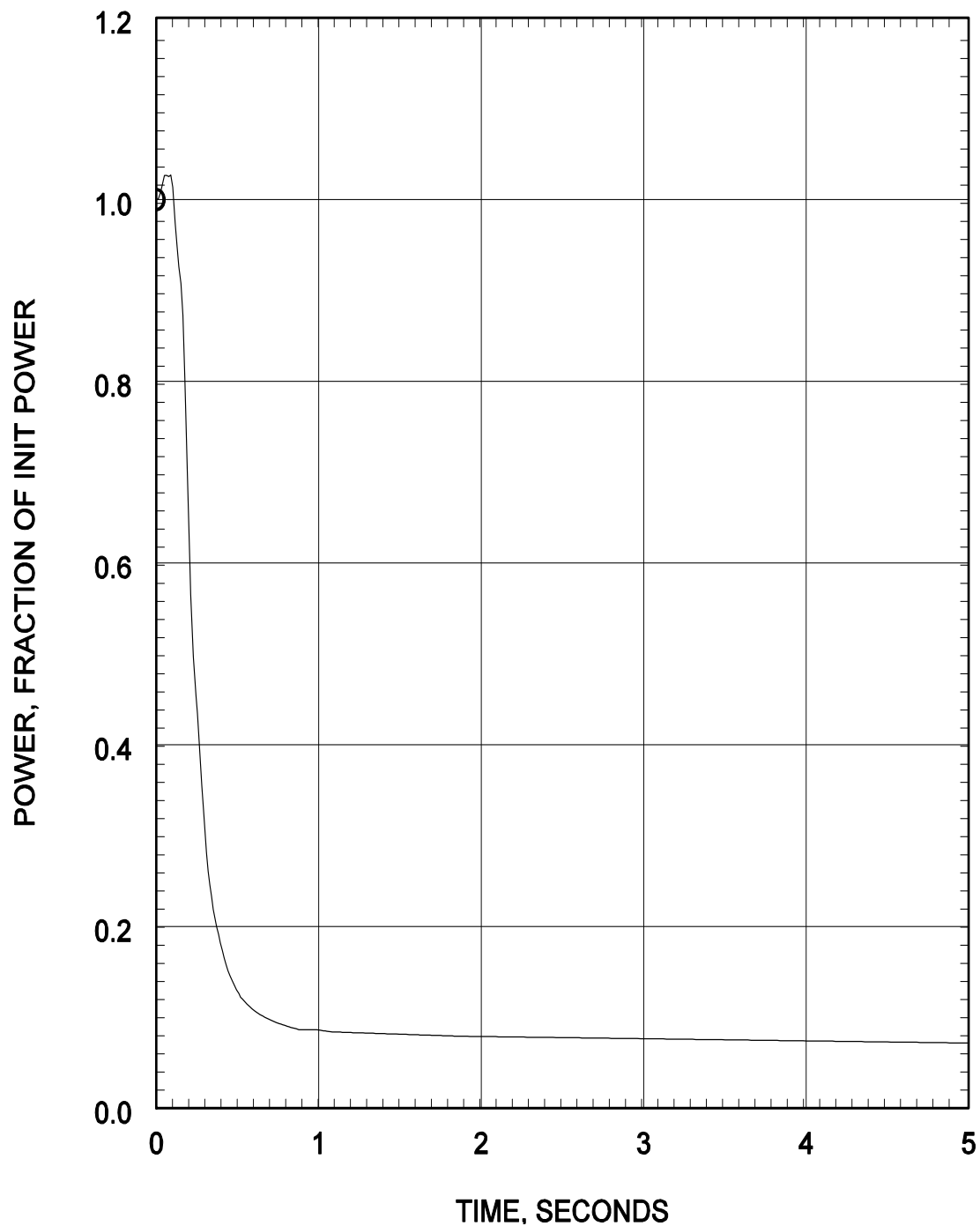


Figure 2.8.5.6.3-2
Large Break LOCA ECCS Performance Analysis
0.01 DEG/PD Break
Pressure in Center Hot Assembly Node

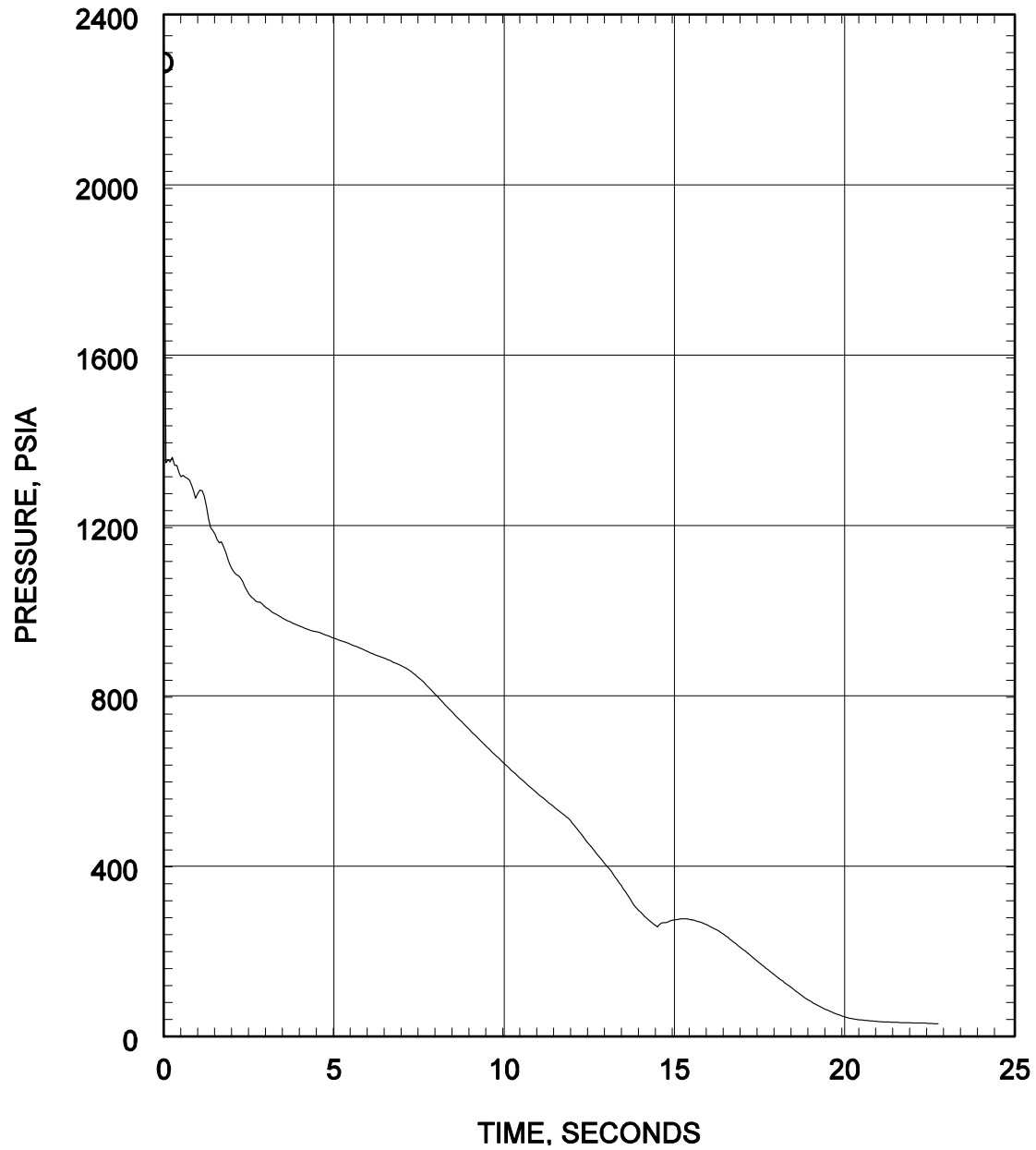


Figure 2.8.5.6.3-3
Large Break LOCA ECCS Performance Analysis
0.01 DEG/PD Break
Break Flow Rate

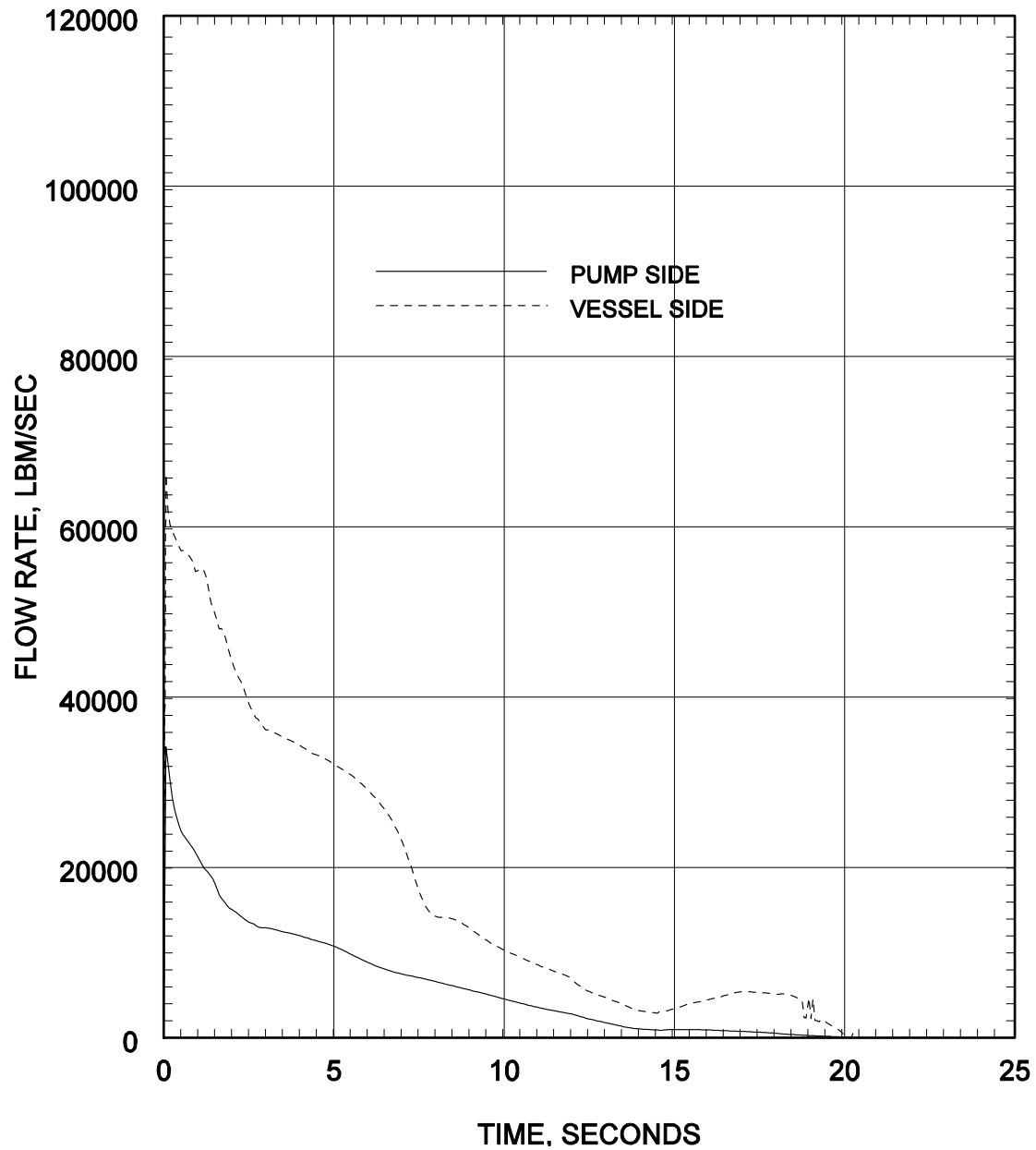


Figure 2.8.5.6.3-4
Large Break LOCA ECCS Performance Analysis
0.01 DEG/PD Break
Hot Assembly Flow Rate (Below Hot Spot)

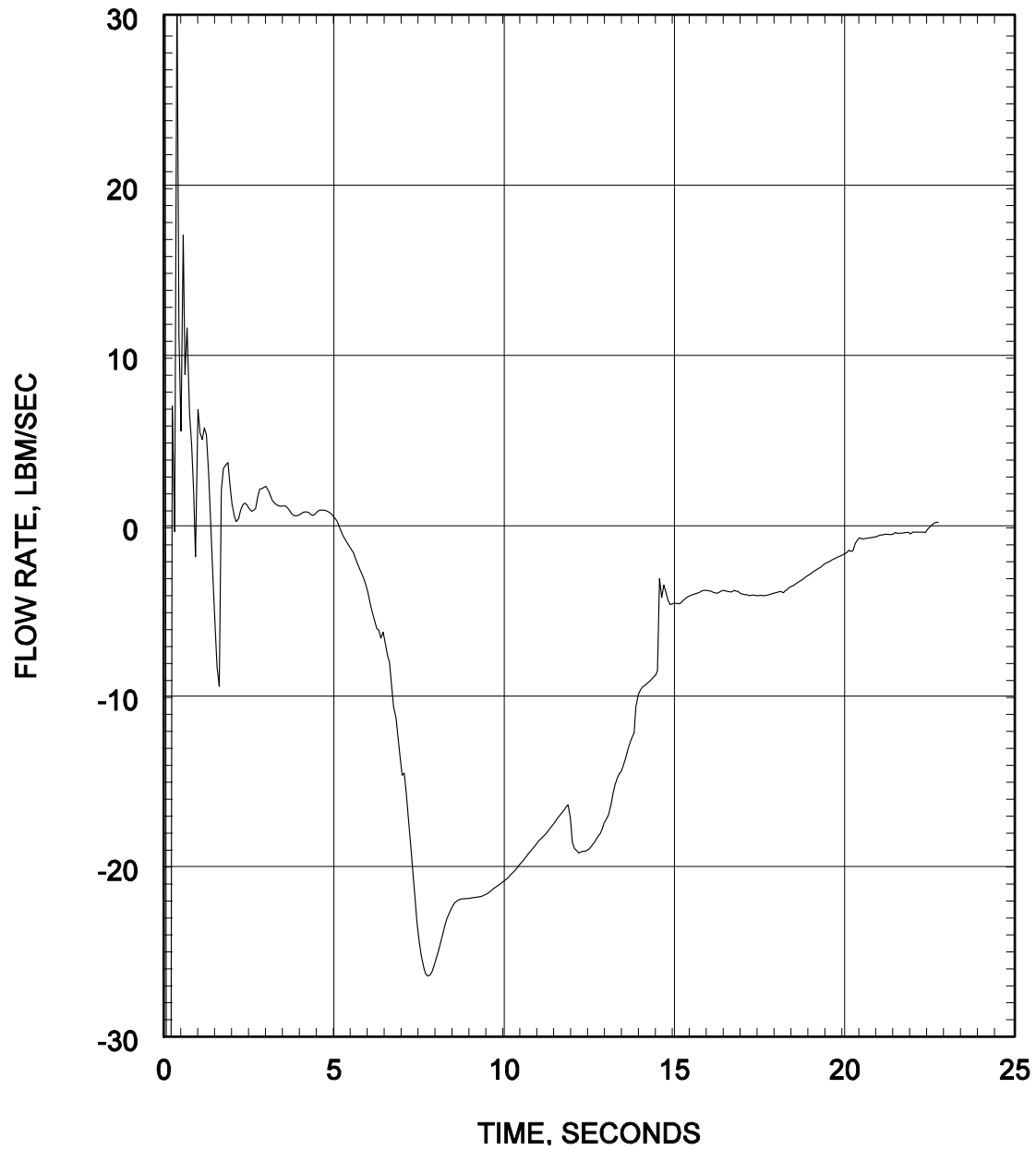


Figure 2.8.5.6.3-5
Large Break LOCA ECCS Performance Analysis
0.01 DEG/PD Break
Hot Assembly Flow Rate (Above Hot Spot)

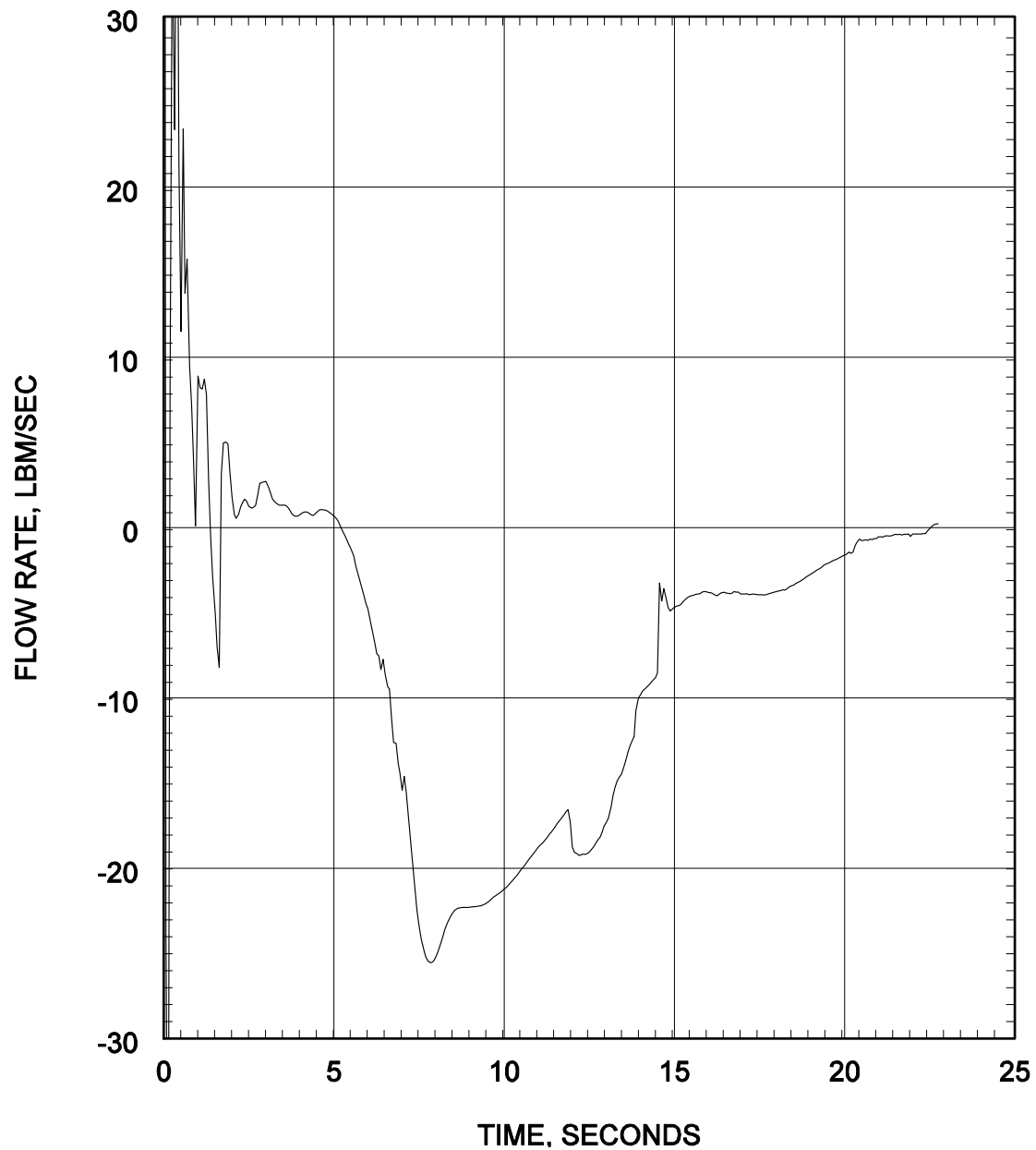


Figure 2.8.5.6.3-6
Large Break LOCA ECCS Performance Analysis
0.01 DEG/PD Break
Hot Assembly Quality

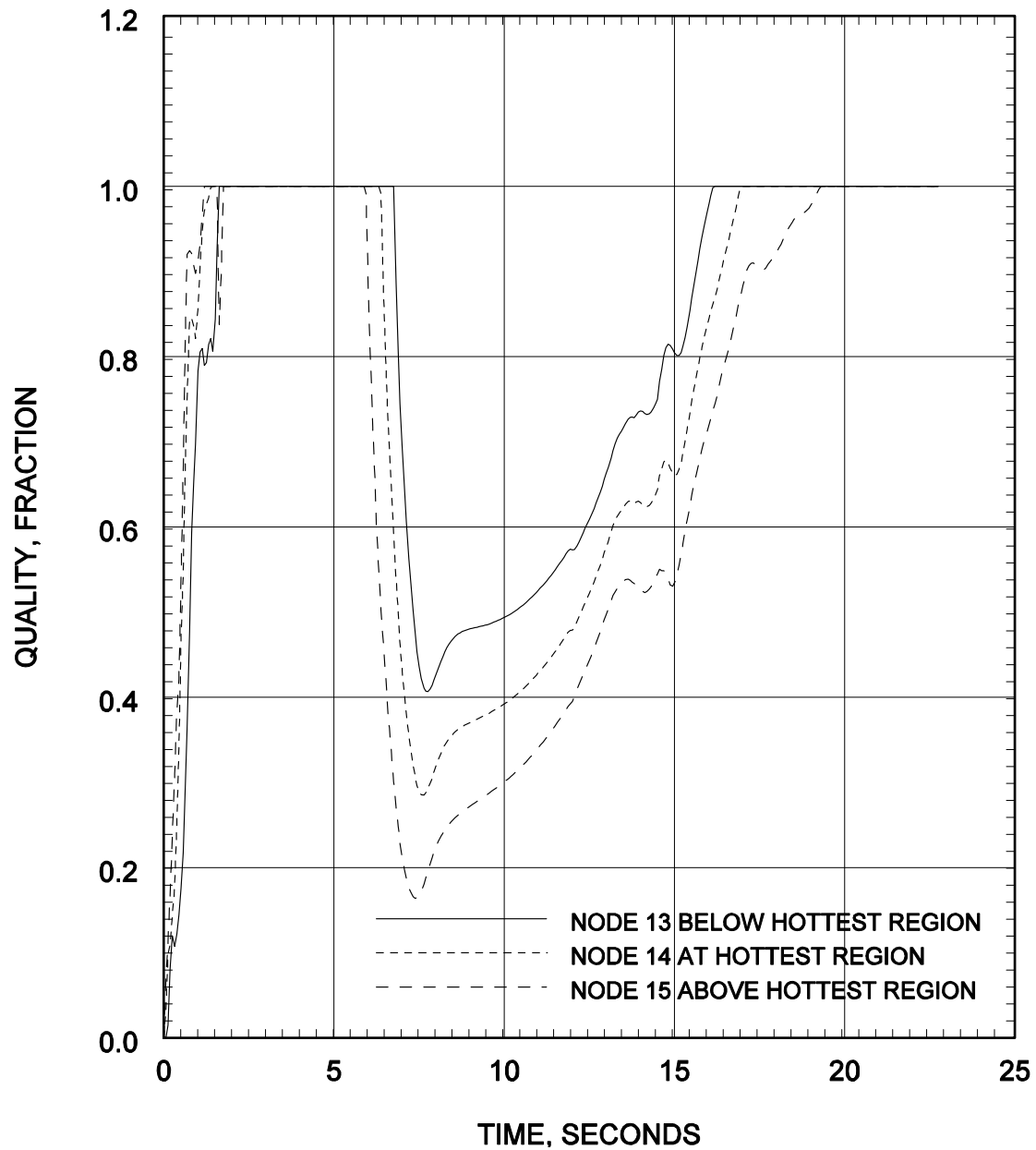


Figure 2.8.5.6.3-7
Large Break LOCA ECCS Performance Analysis
0.01 DEG/PD Break
Containment Pressure

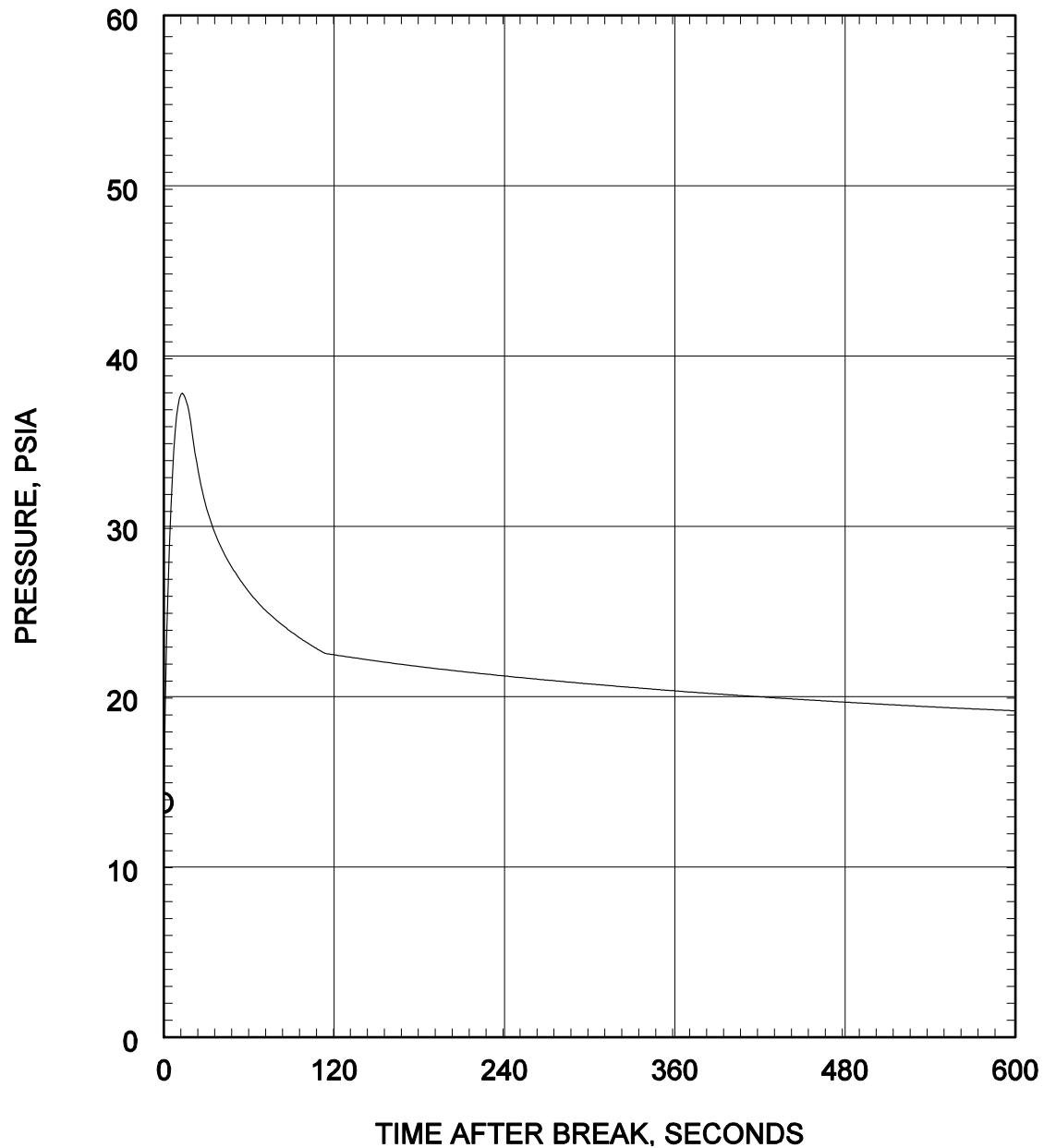


Figure 2.8.5.6.3-8
Large Break LOCA ECCS Performance Analysis
0.01 DEG/PD Break
Mass Added to Core During Reflood

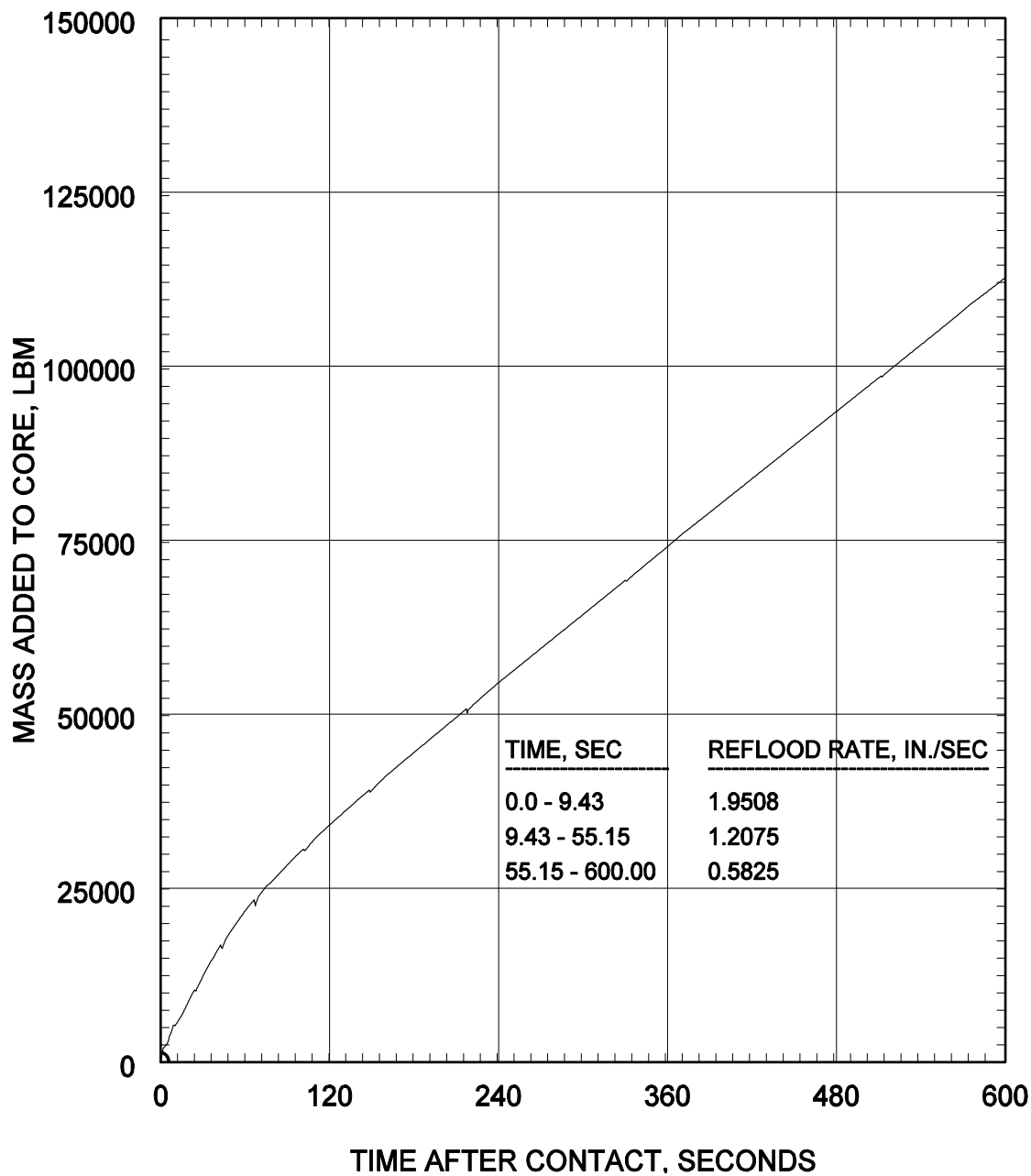


Figure 2.8.5.6.3-9
Large Break LOCA ECCS Performance Analysis
0.01 DEG/PD Break
Peak Cladding Temperature

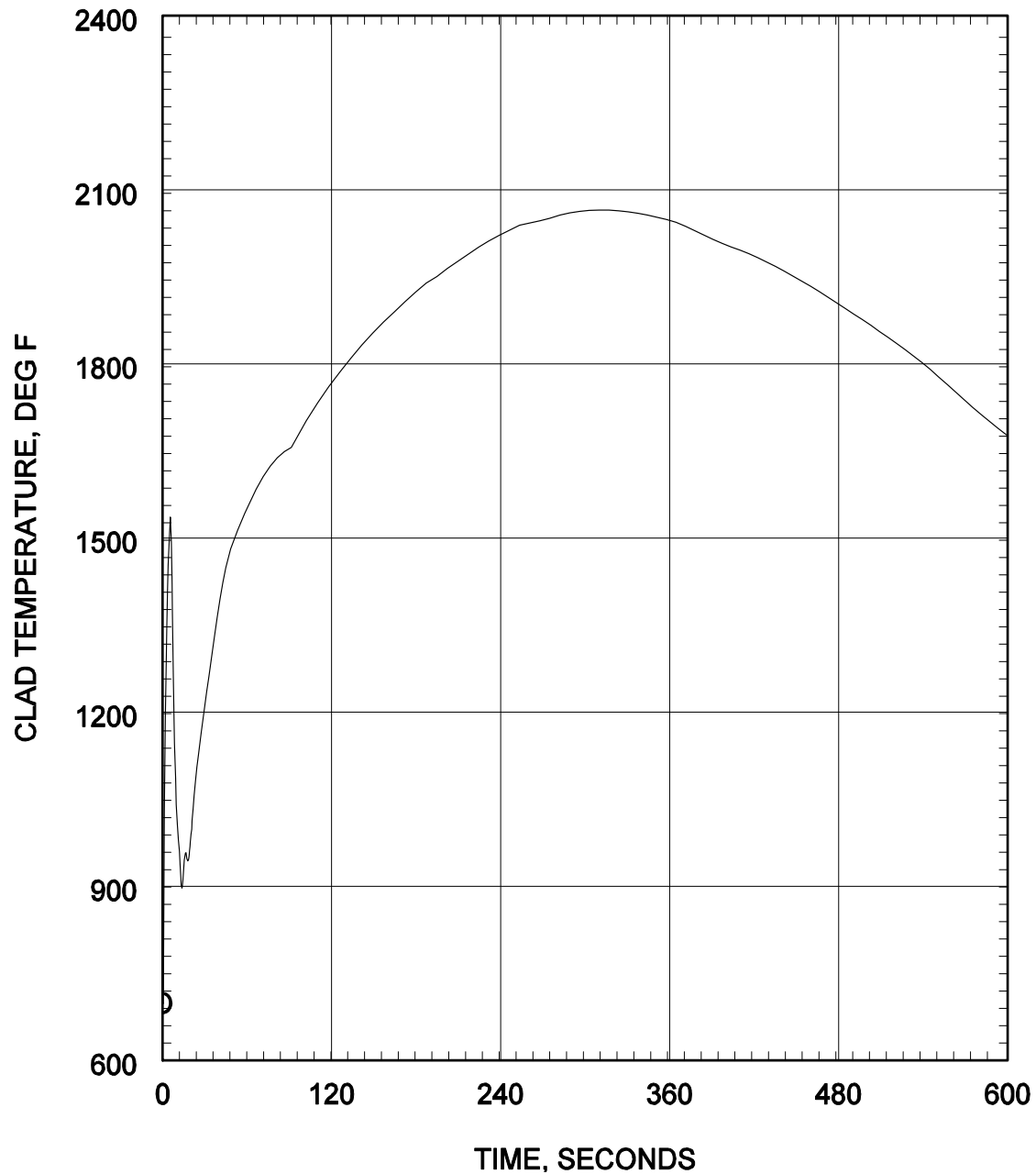


Figure 2.8.5.6.3-10
Large Break LOCA ECCS Performance Analysis
0.08 DEG/PD Break
Core Power

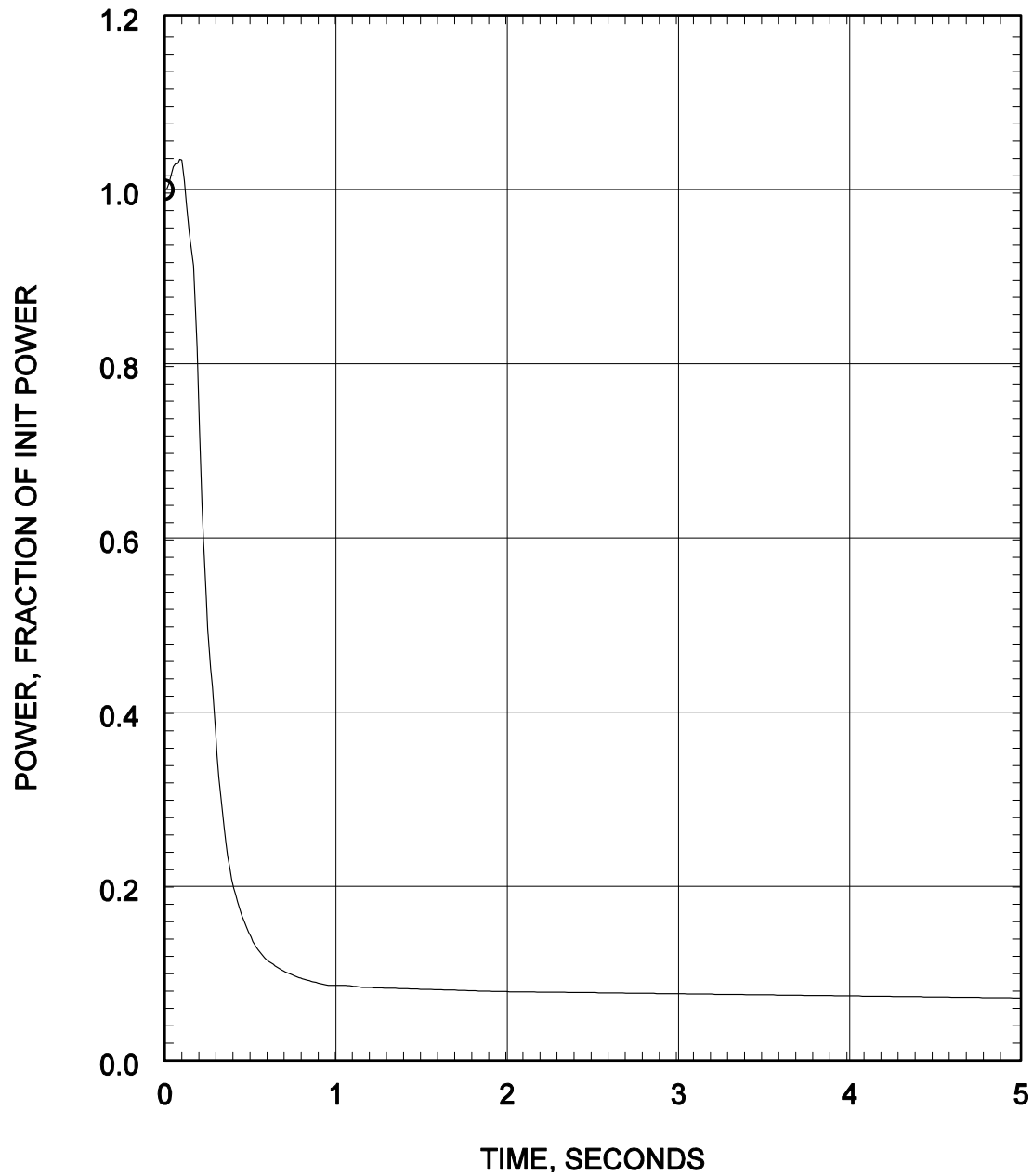


Figure 2.8.5.6.3-11
Large Break LOCA ECCS Performance Analysis
0.08 DEG/PD Break
Pressure in Center Hot Assembly Node

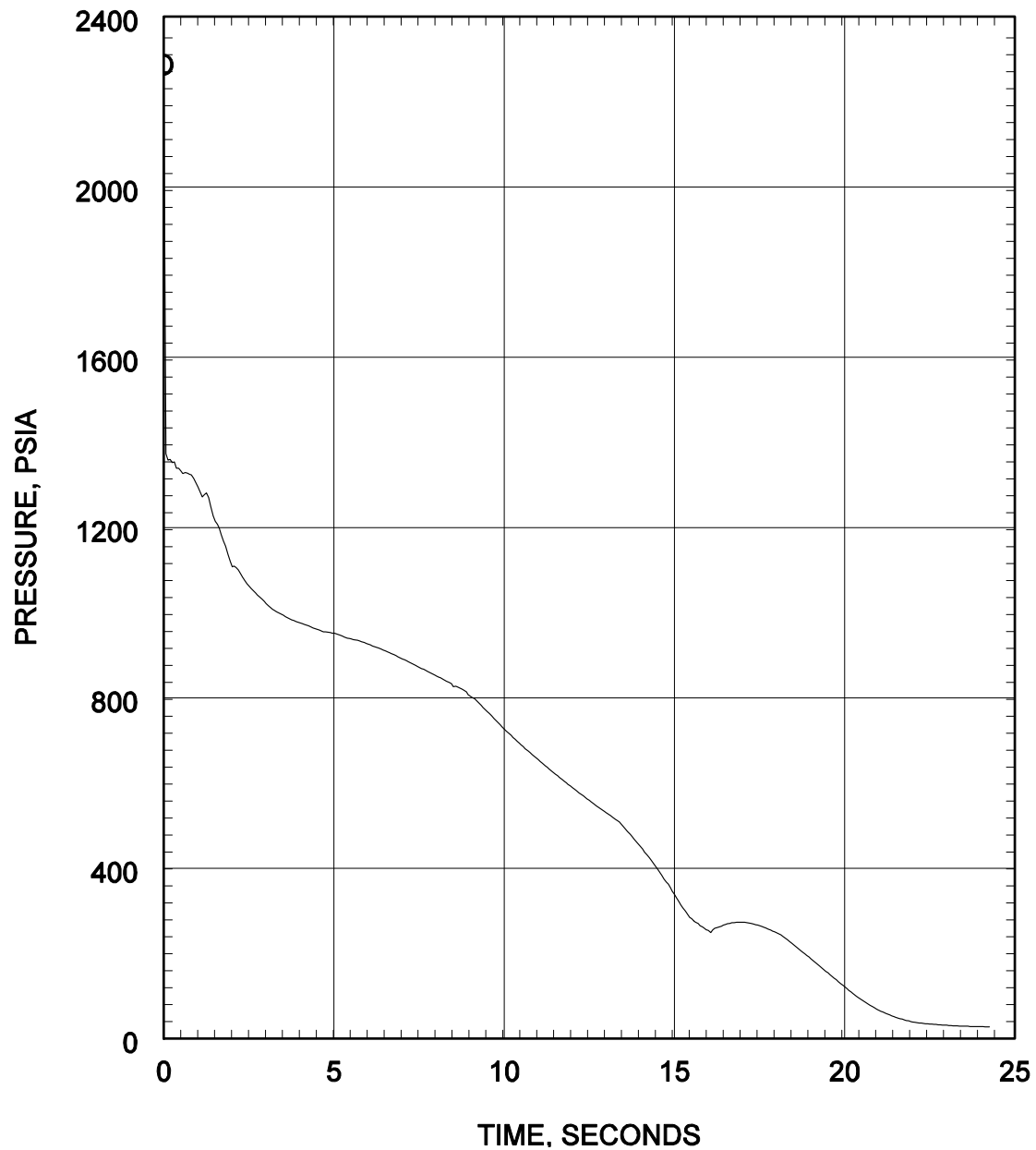


Figure 2.8.5.6.3-12
Large Break LOCA ECCS Performance Analysis
0.08 DEG/PD Break
Break Flow Rate

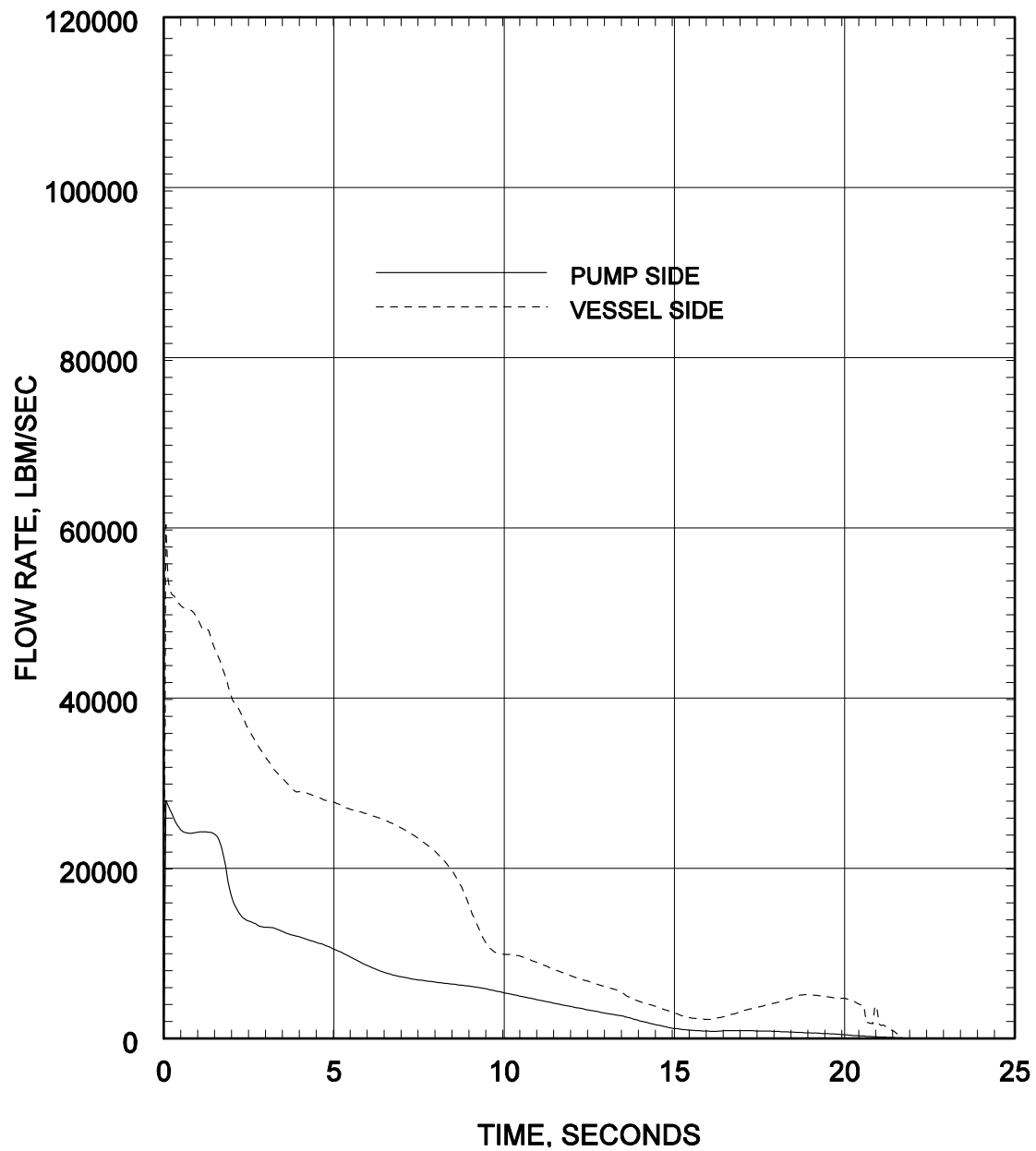


Figure 2.8.5.6.3-13
Large Break LOCA ECCS Performance Analysis
0.08 DEG/PD Break
Hot Assembly Flow Rate (Below Hot Spot)

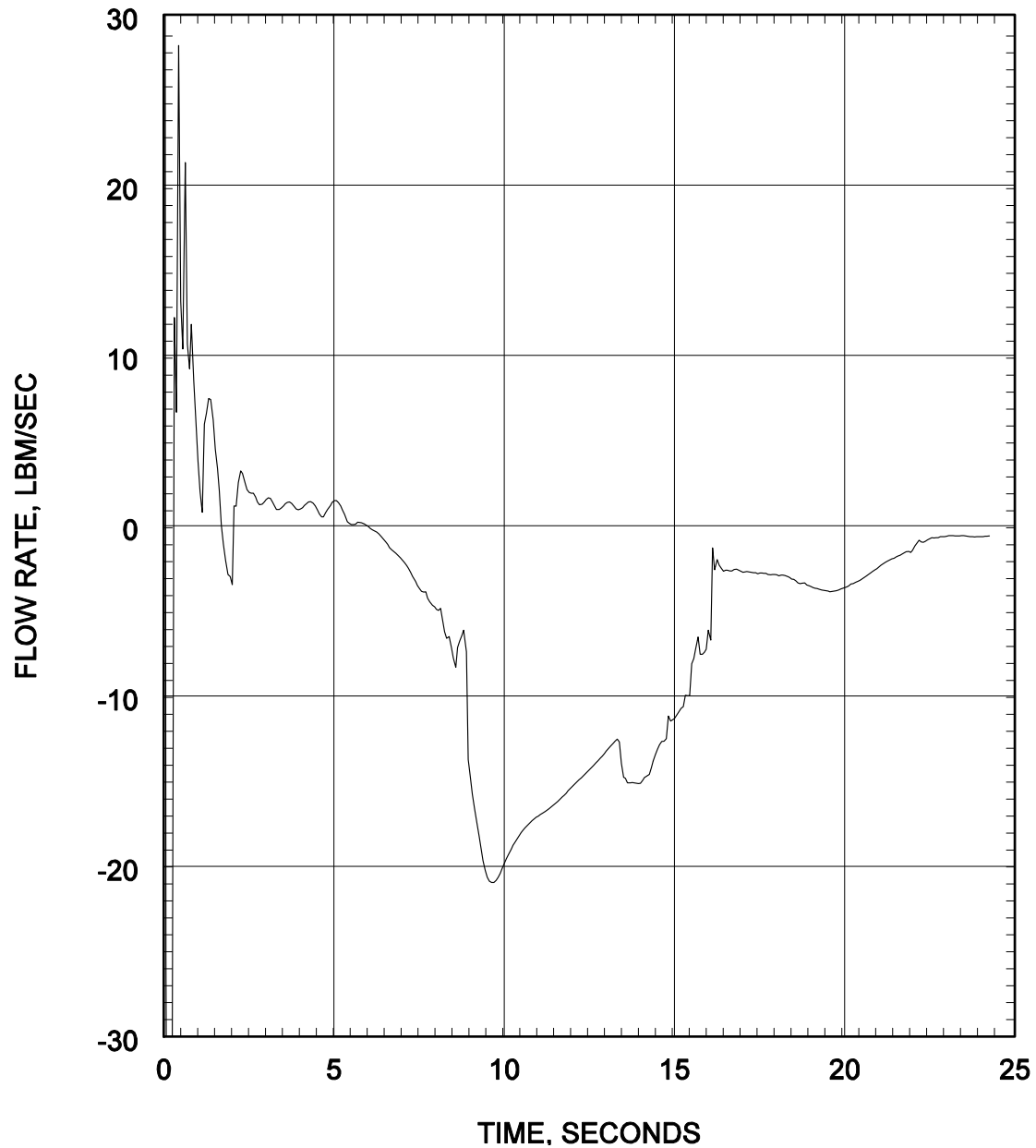


Figure 2.8.5.6.3-14
Large Break LOCA ECCS Performance Analysis
0.08 DEG/PD Break
Hot Assembly Flow Rate (Above Hot Spot)

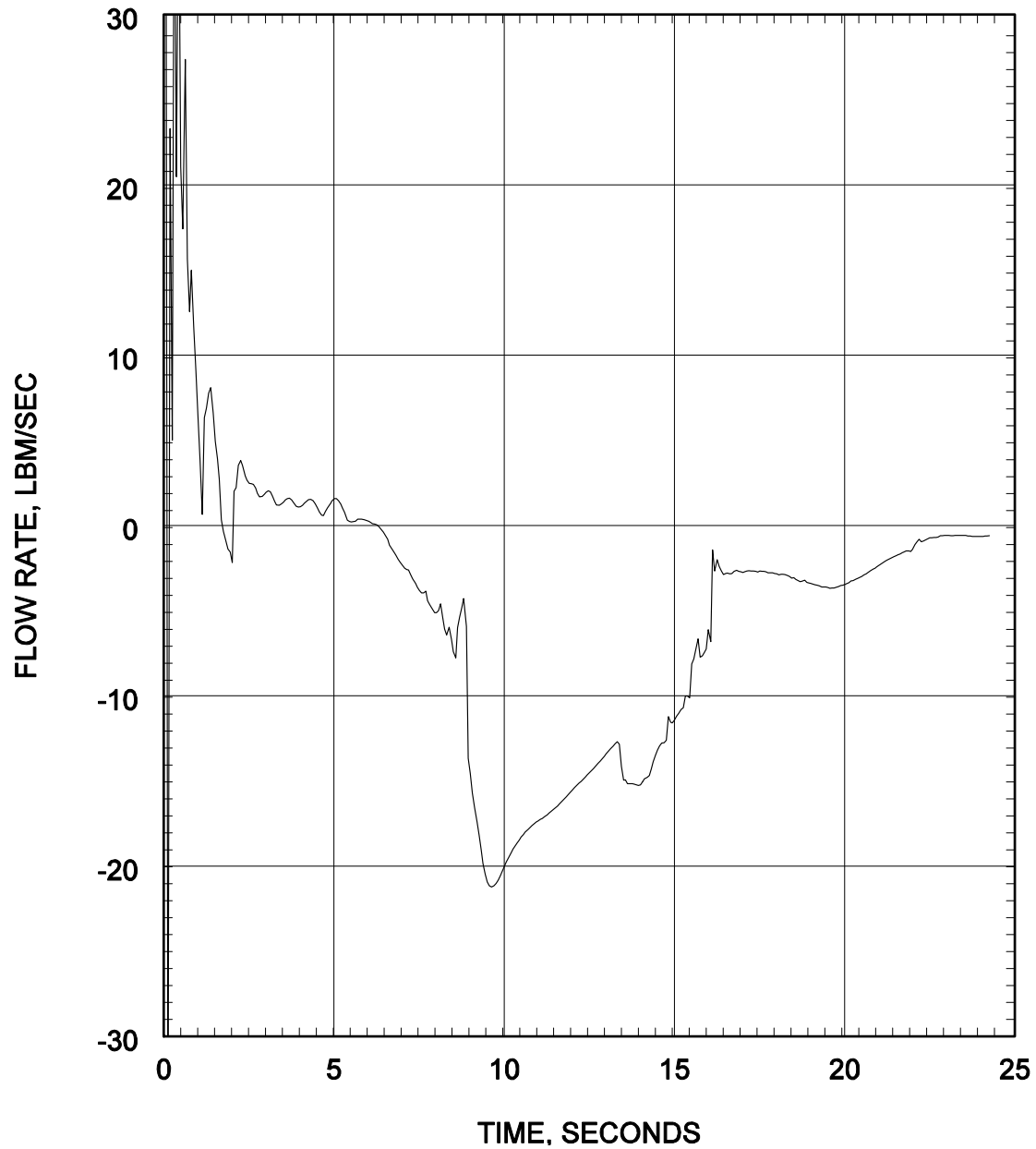


Figure 2.8.5.6.3-15
Large Break LOCA ECCS Performance Analysis
0.08 DEG/PD Break
Hot Assembly Quality

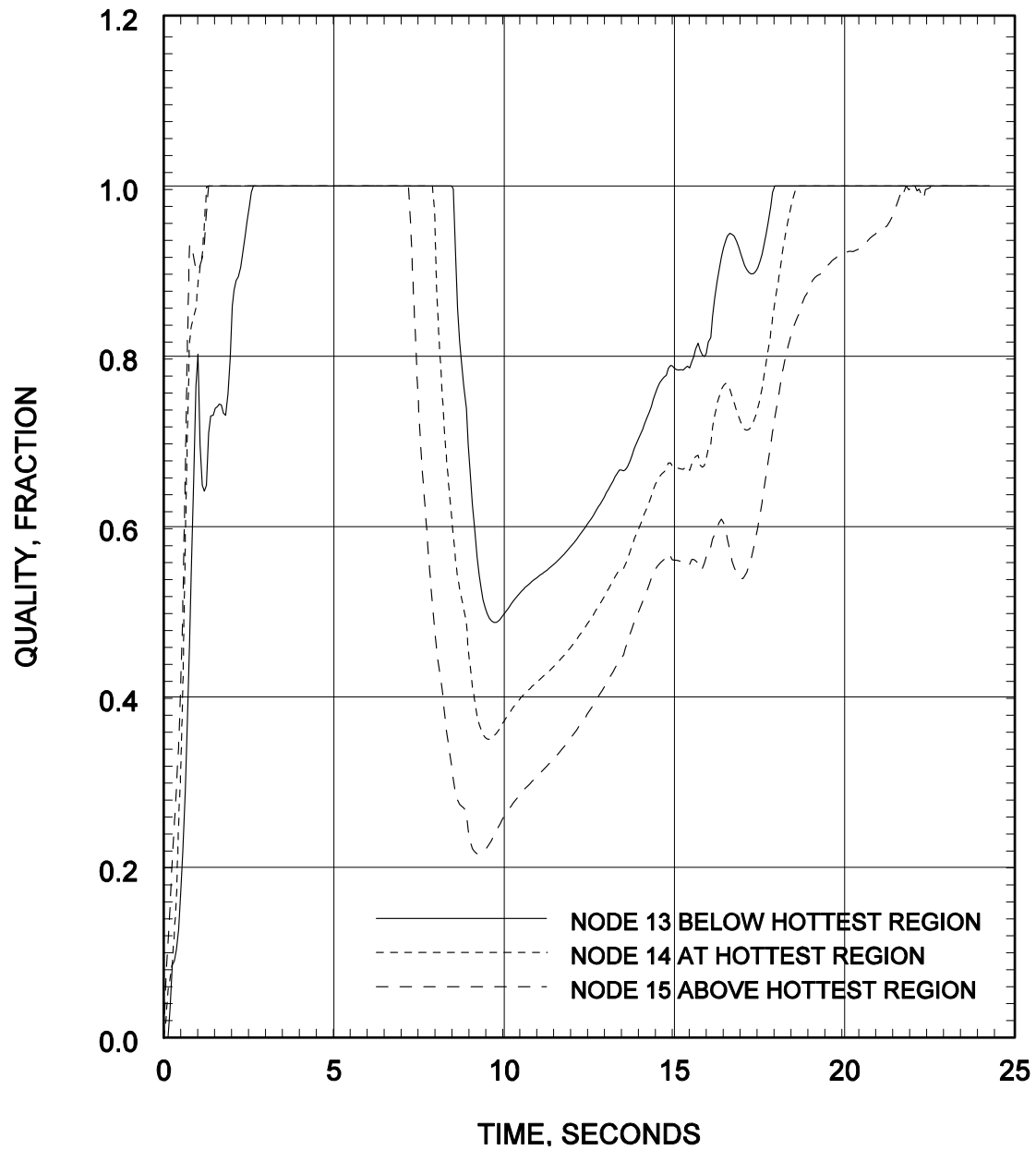


Figure 2.8.5.6.3-16
Large Break LOCA ECCS Performance Analysis
0.08 DEG/PD Break
Containment Pressure

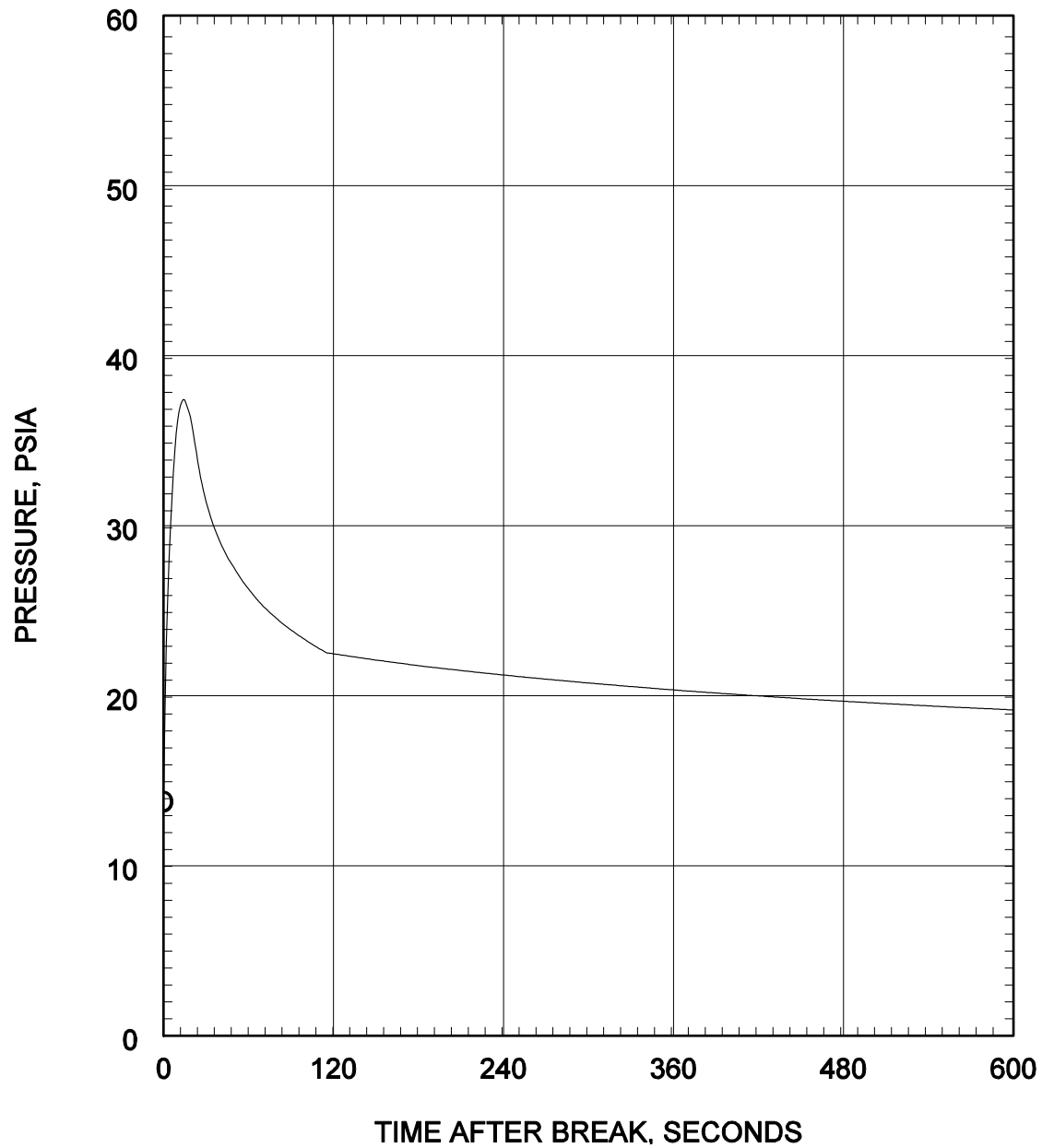


Figure 2.8.5.6.3-17
Large Break LOCA ECCS Performance Analysis
0.08 DEG/PD Break
Mass Added to Core During Reflood

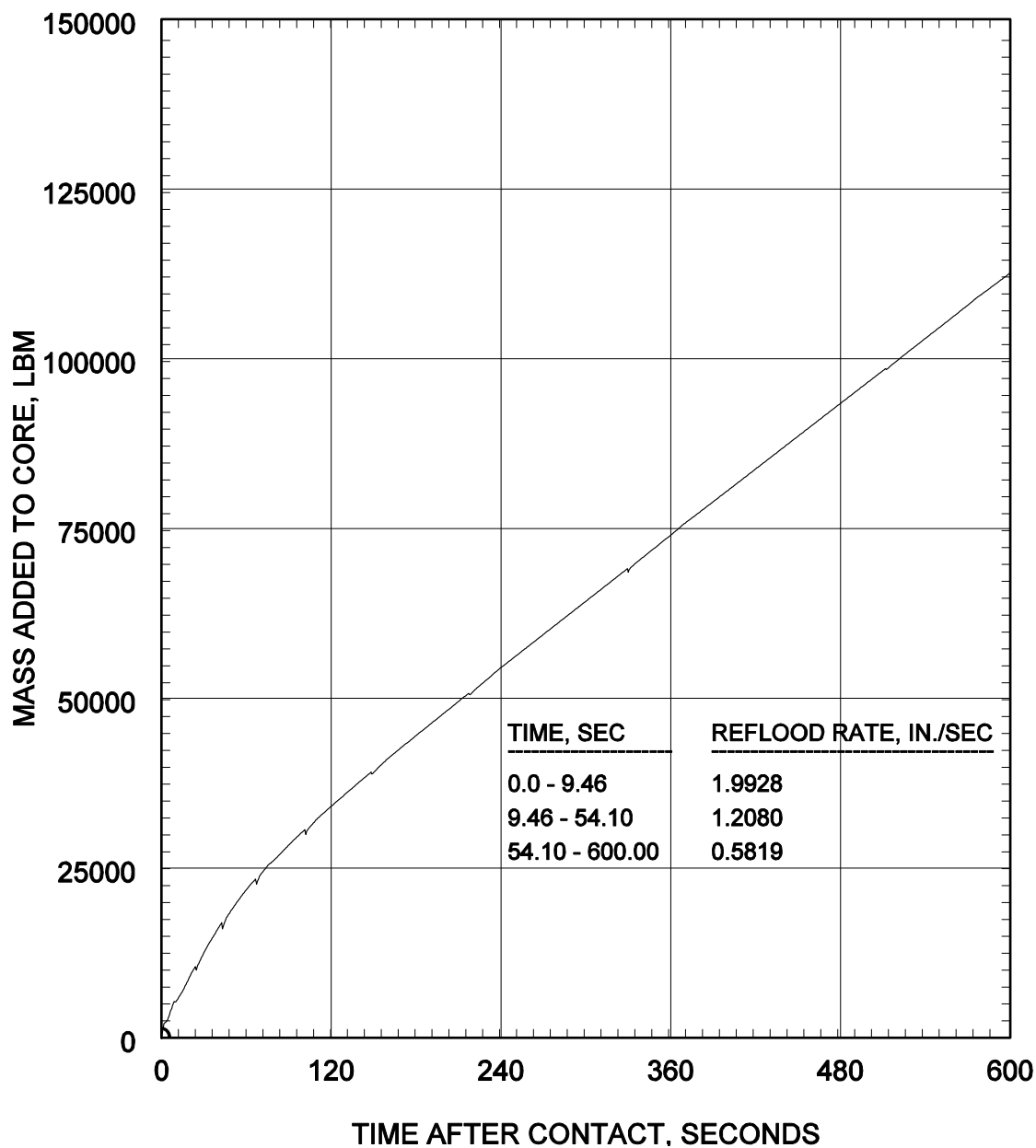


Figure 2.8.5.6.3-18
Large Break LOCA ECCS Performance Analysis
0.08 DEG/PD Break
Peak Cladding Temperature

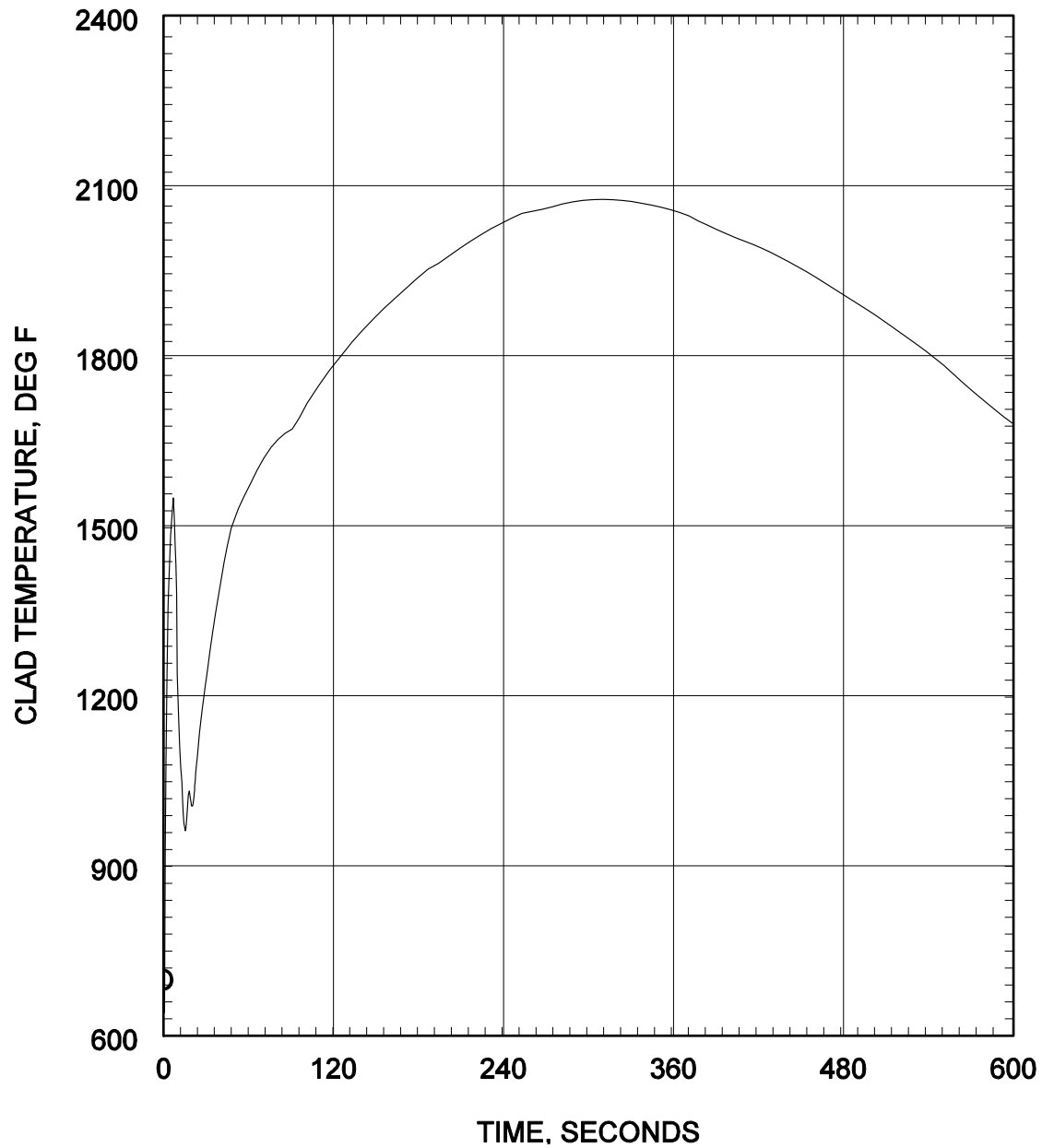


Figure 2.8.5.6.3-19
Large Break LOCA ECCS Performance Analysis
0.06 DEG/PD Break
Core Power

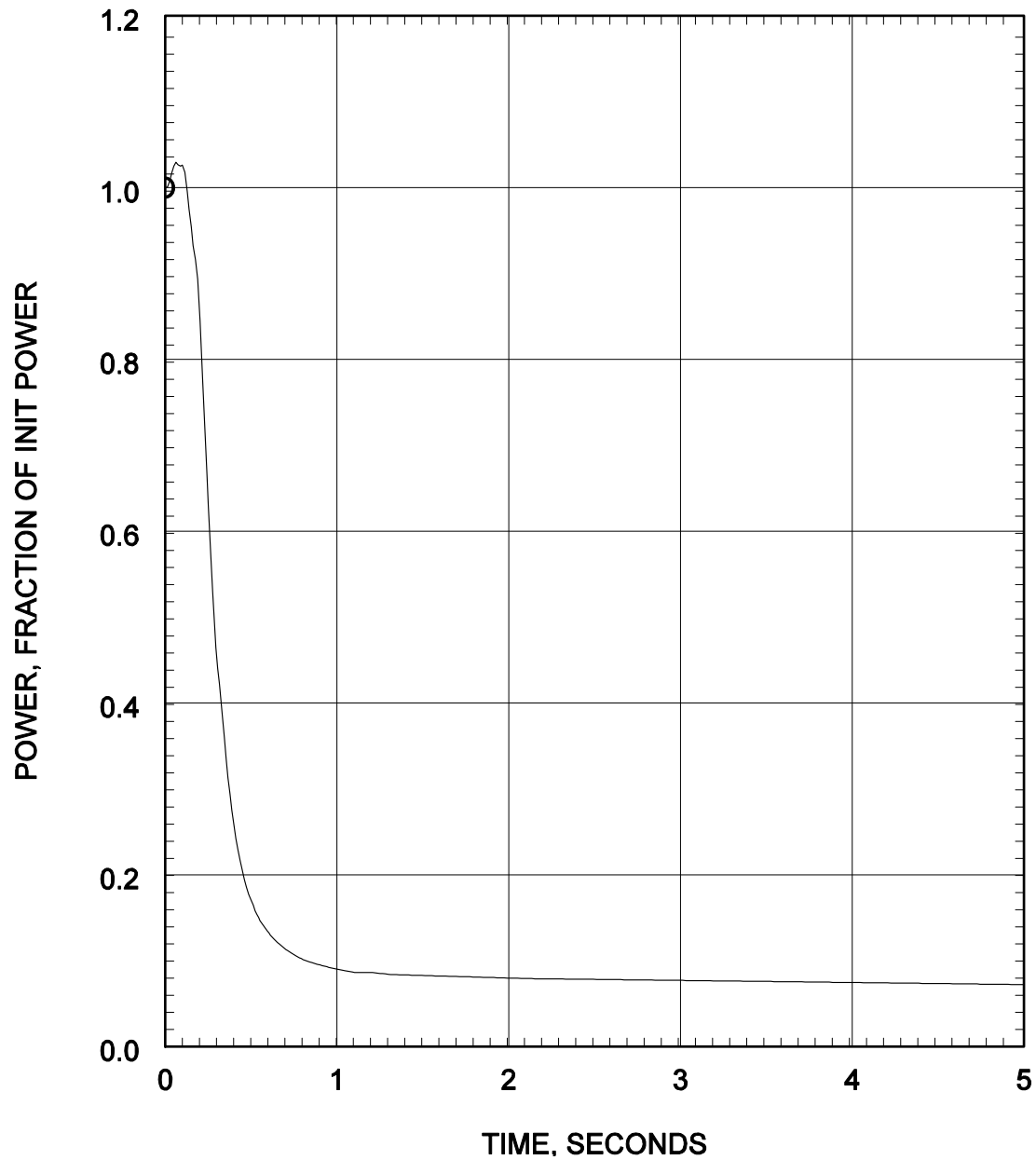


Figure 2.8.5.6.3-20
Large Break LOCA ECCS Performance Analysis
0.06 DEG/PD Break
Pressure in Center Hot Assembly Node

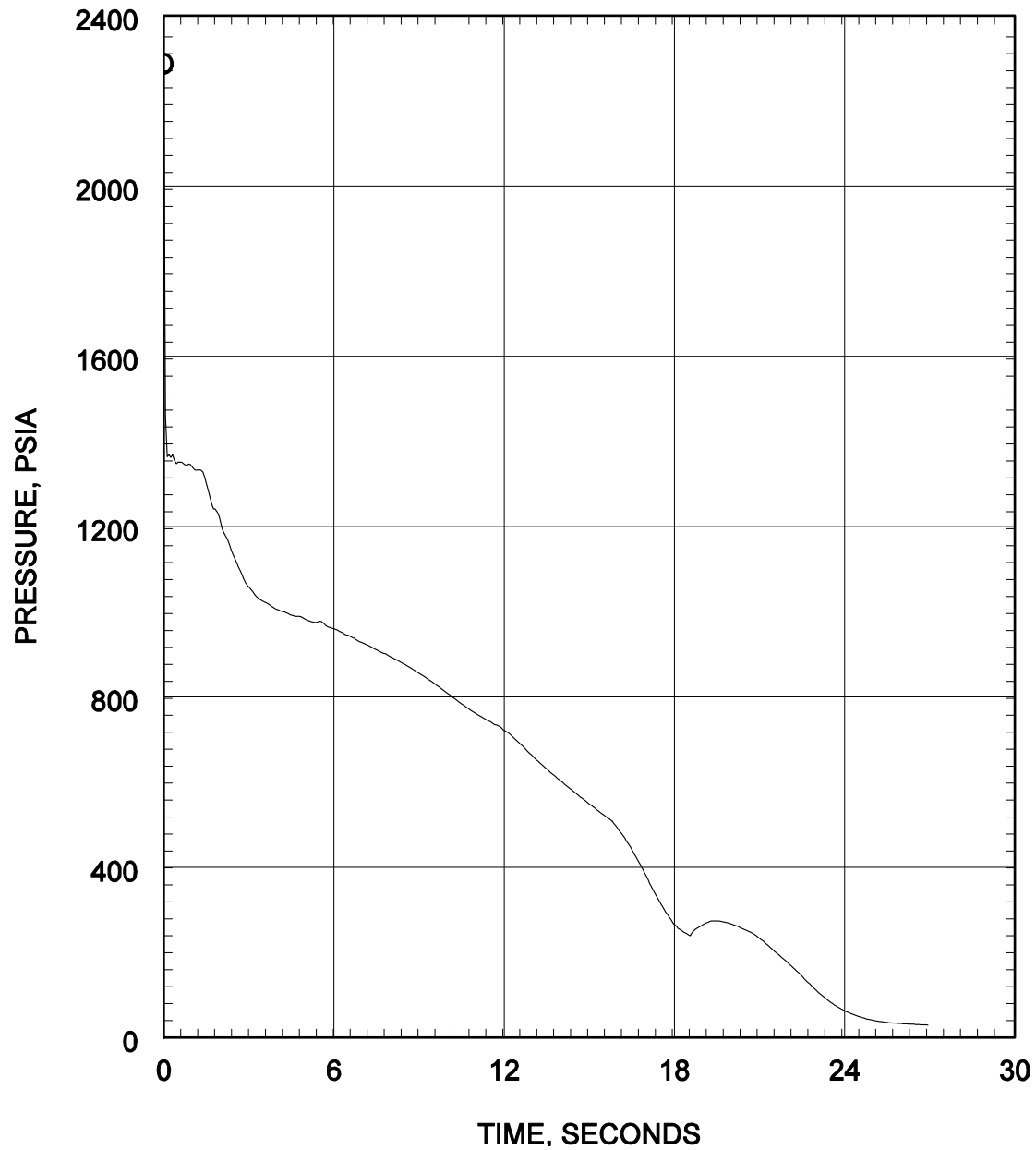


Figure 2.8.5.6.3-21
Large Break LOCA ECCS Performance Analysis
0.06 DEG/PD Break
Break Flow Rate

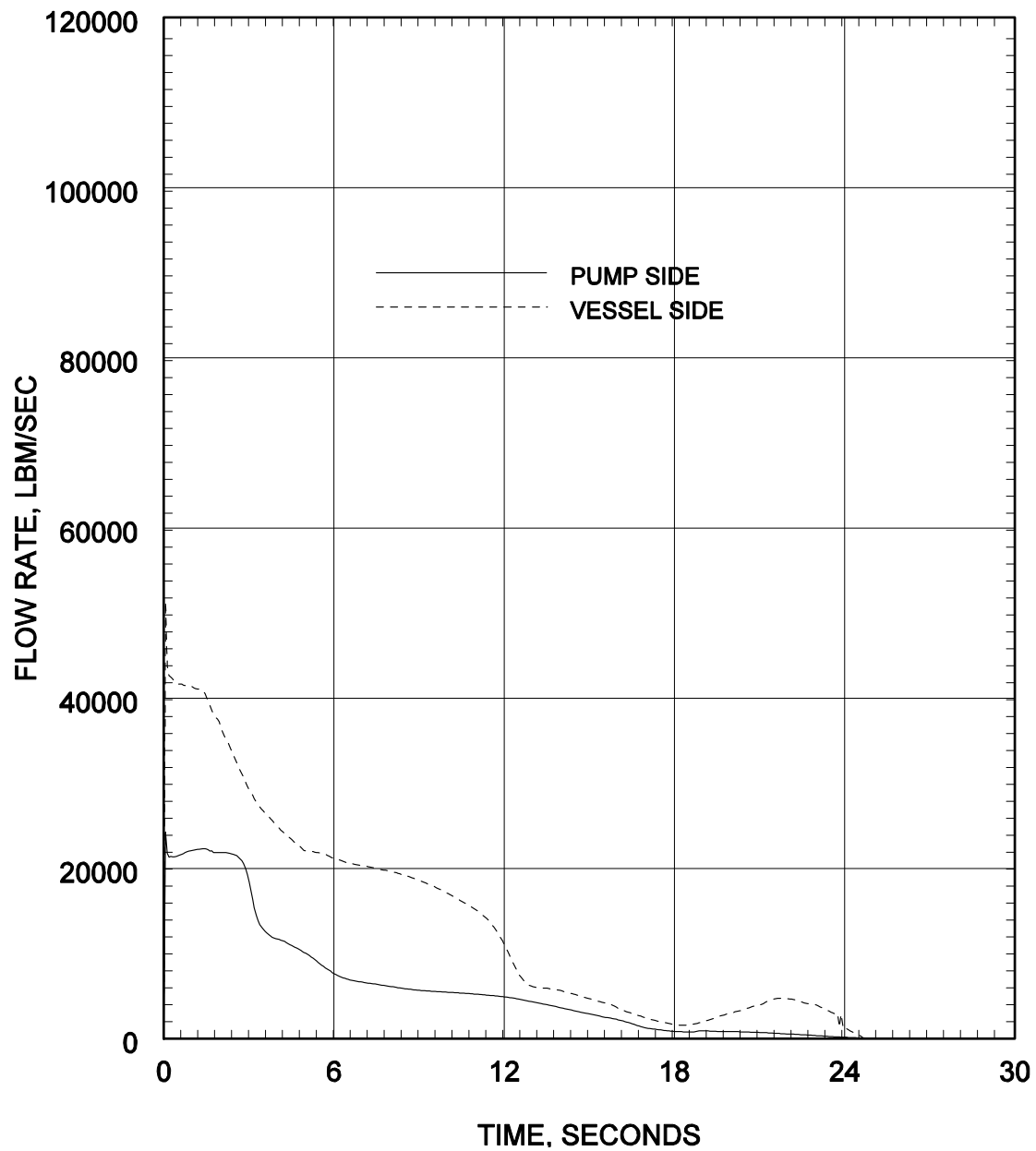


Figure 2.8.5.6.3-22
Large Break LOCA ECCS Performance Analysis
0.06 DEG/PD Break
Hot Assembly Flow Rate (Below Hot Spot)

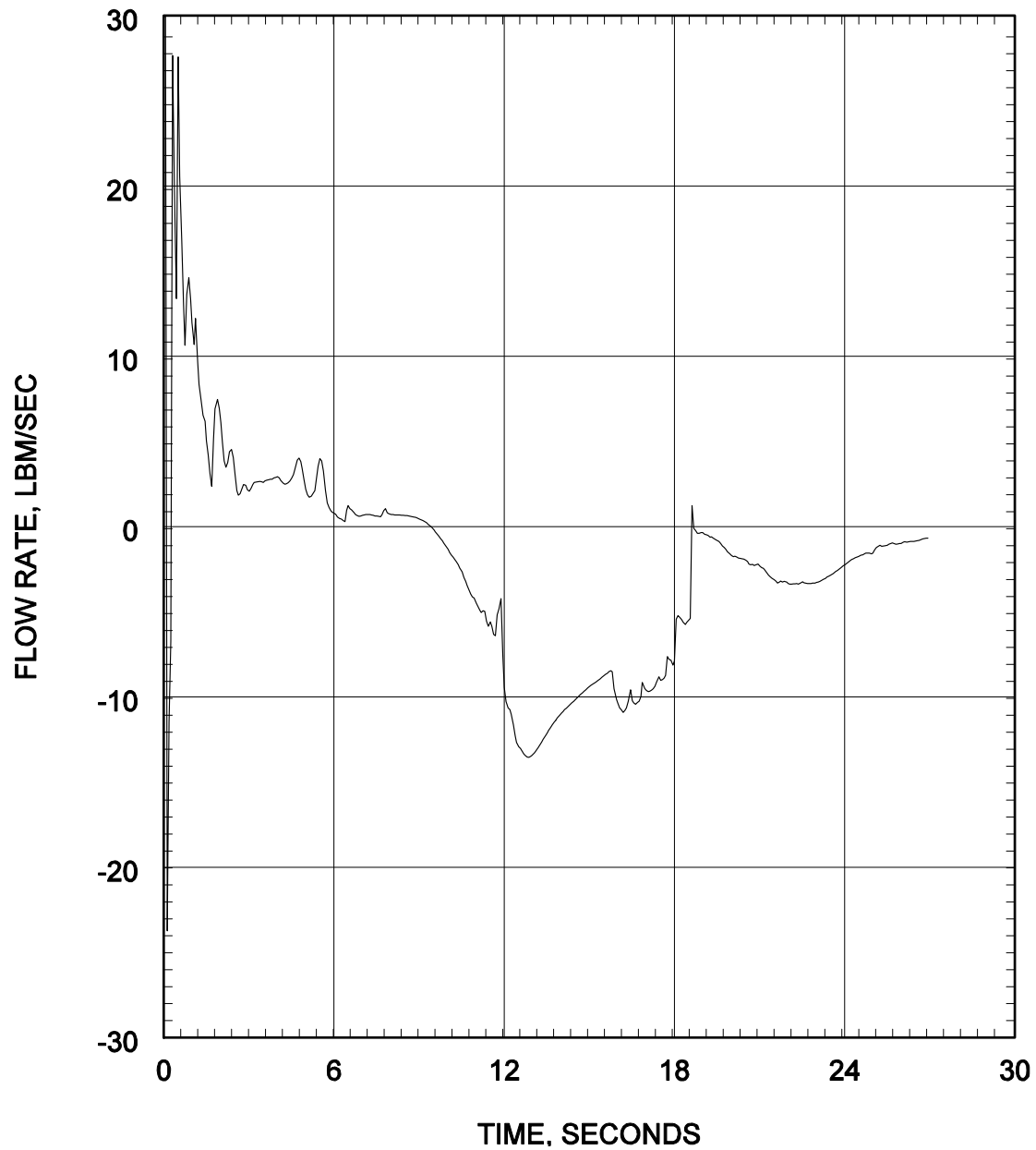


Figure 2.8.5.6.3-23
Large Break LOCA ECCS Performance Analysis
0.06 DEG/PD Break
Hot Assembly Flow Rate (Above Hot Spot)

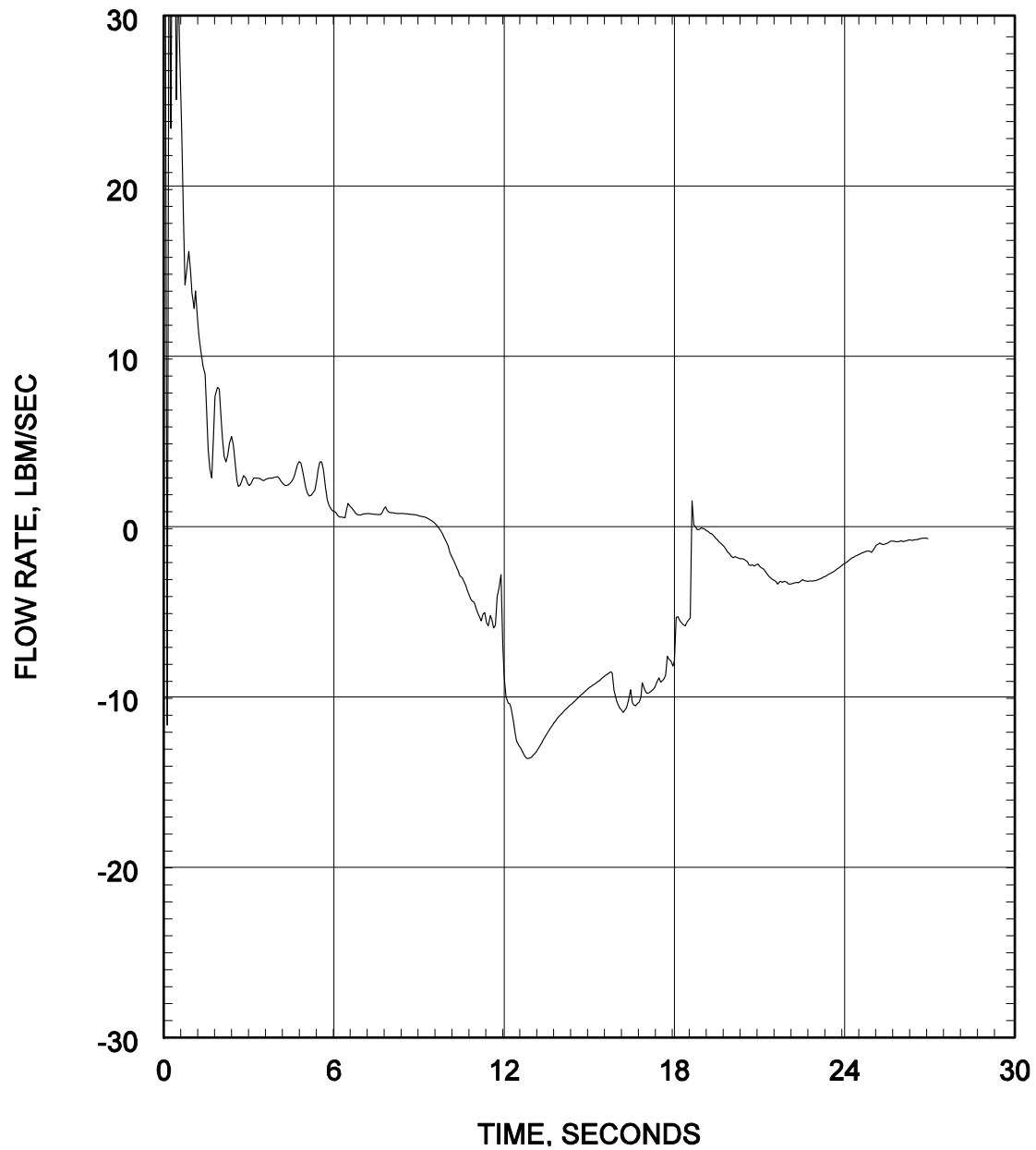


Figure 2.8.5.6.3-24
Large Break LOCA ECCS Performance Analysis
0.06 DEG/PD Break
Hot Assembly Quality

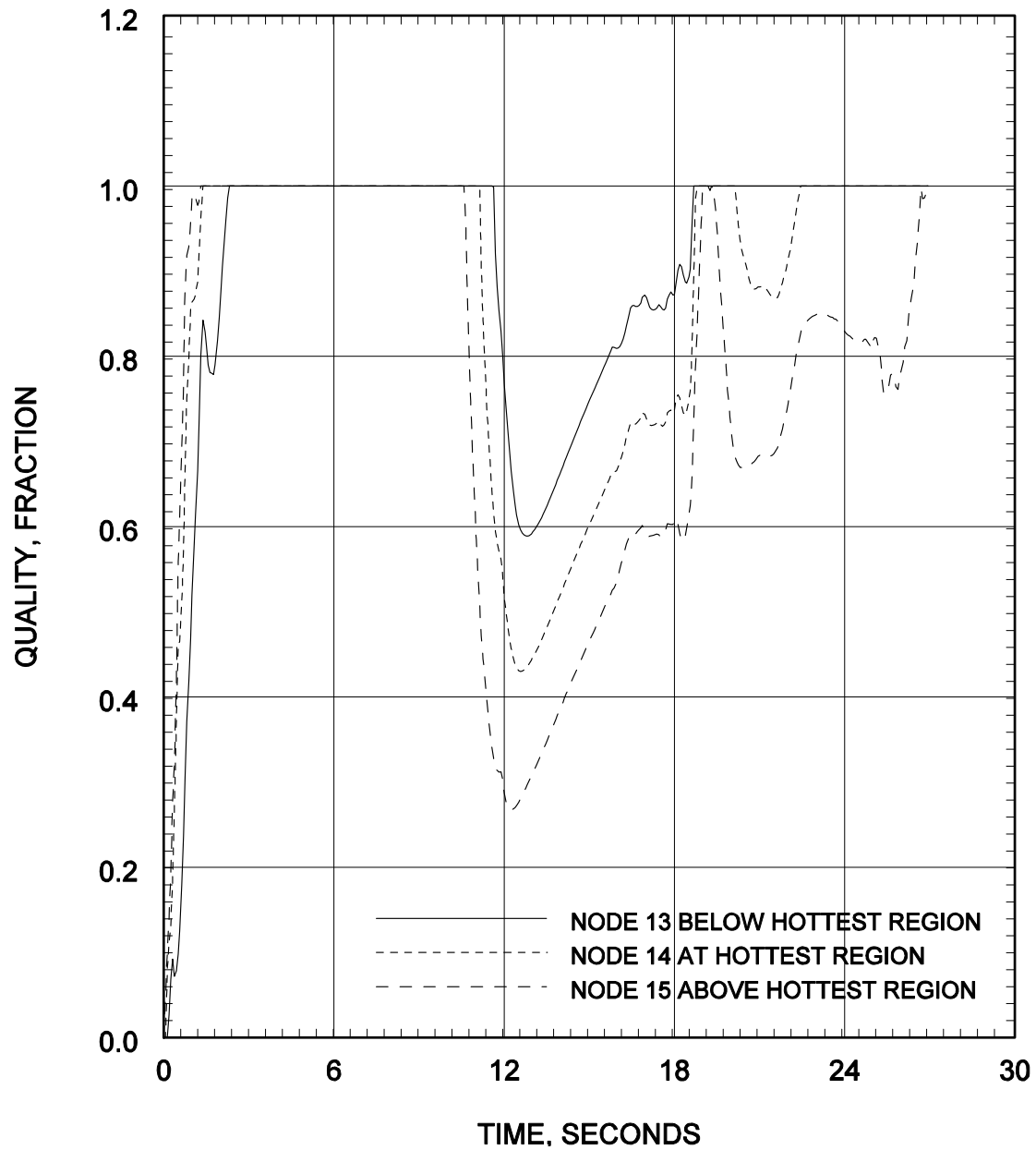


Figure 2.8.5.6.3-25
Large Break LOCA ECCS Performance Analysis
0.06 DEG/PD Break
Containment Pressure

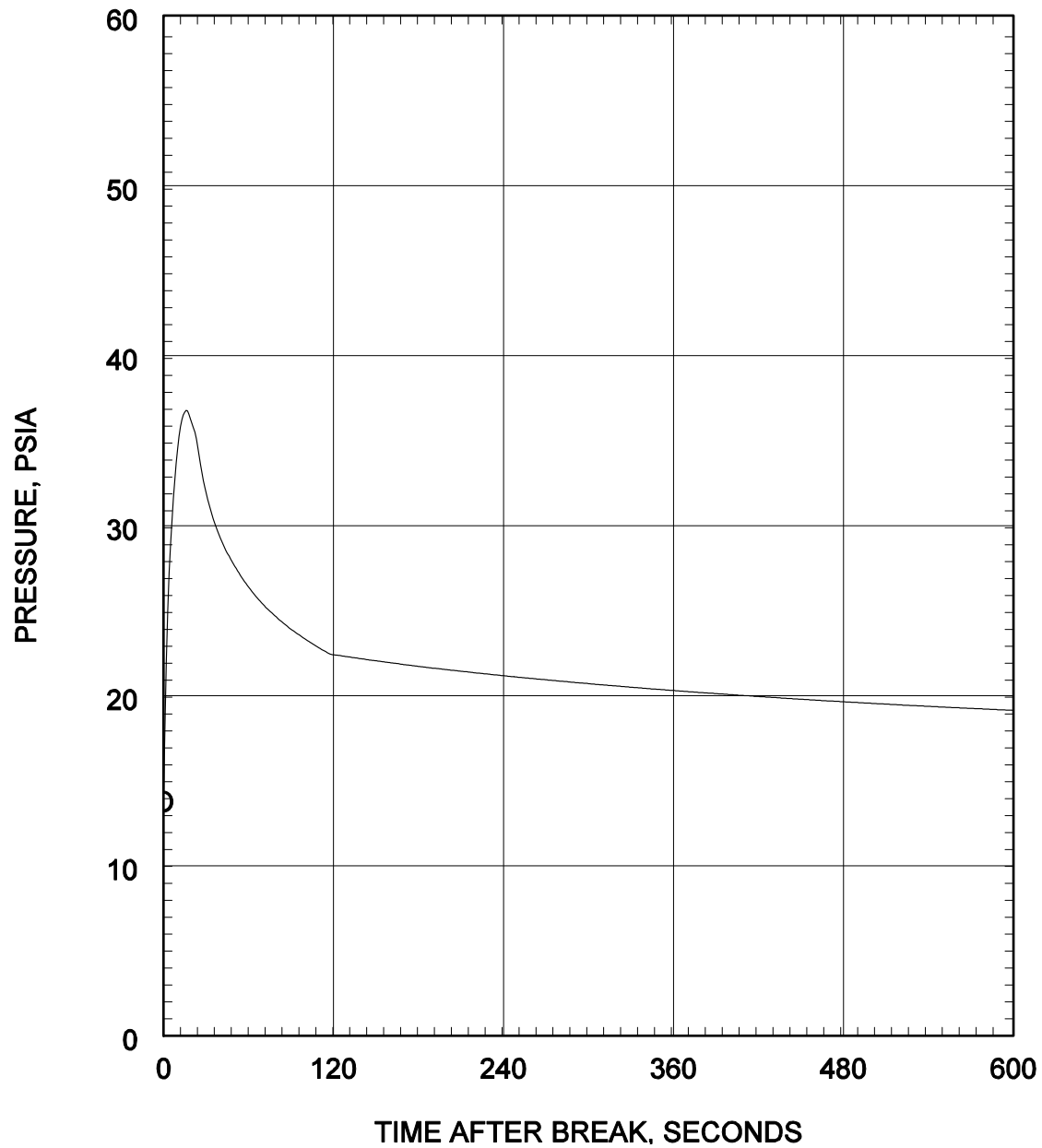


Figure 2.8.5.6.3-26
Large Break LOCA ECCS Performance Analysis
0.06 DEG/PD Break
Mass Added to Core During Reflood

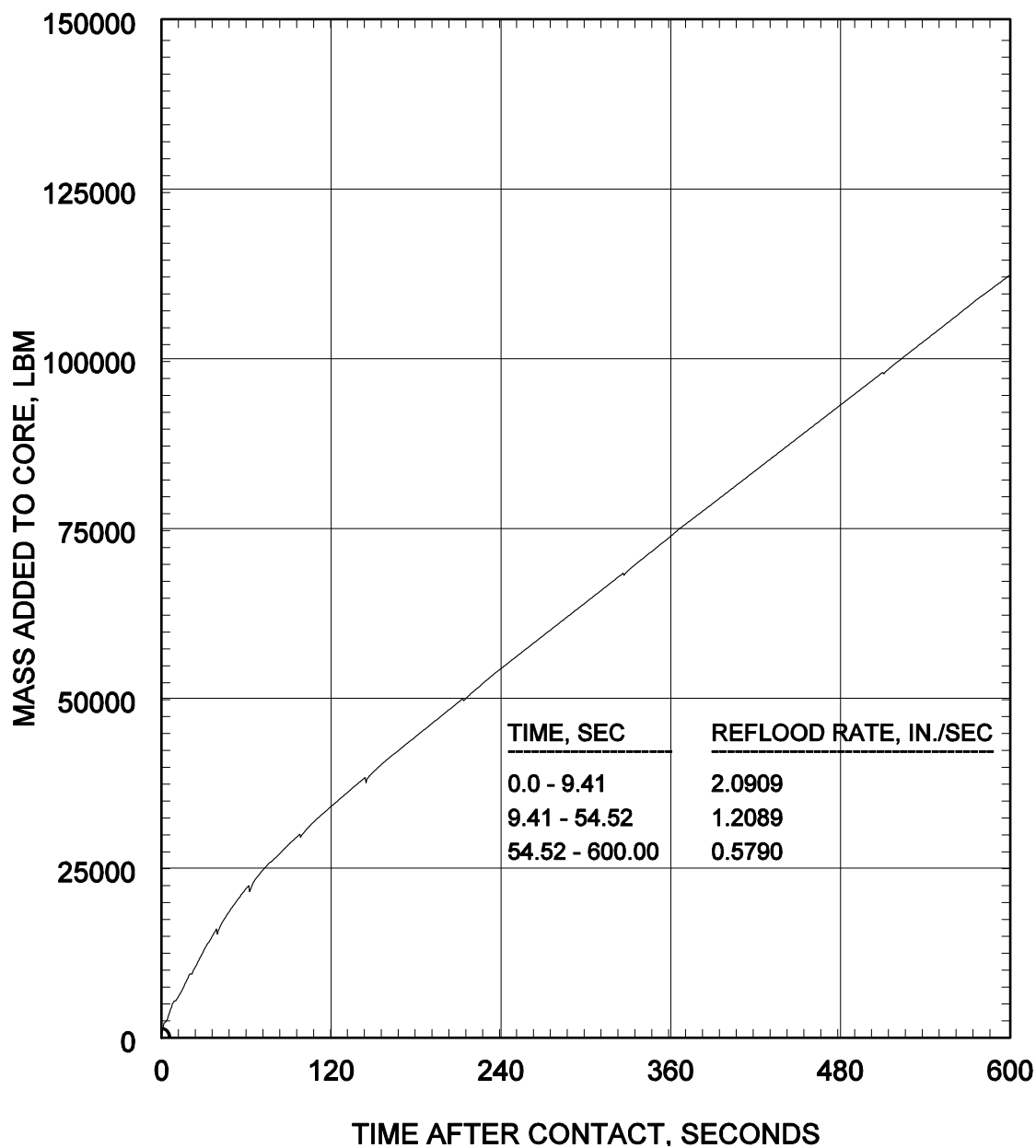


Figure 2.8.5.6.3-27
Large Break LOCA ECCS Performance Analysis
0.06 DEG/PD Break
Peak Cladding Temperature

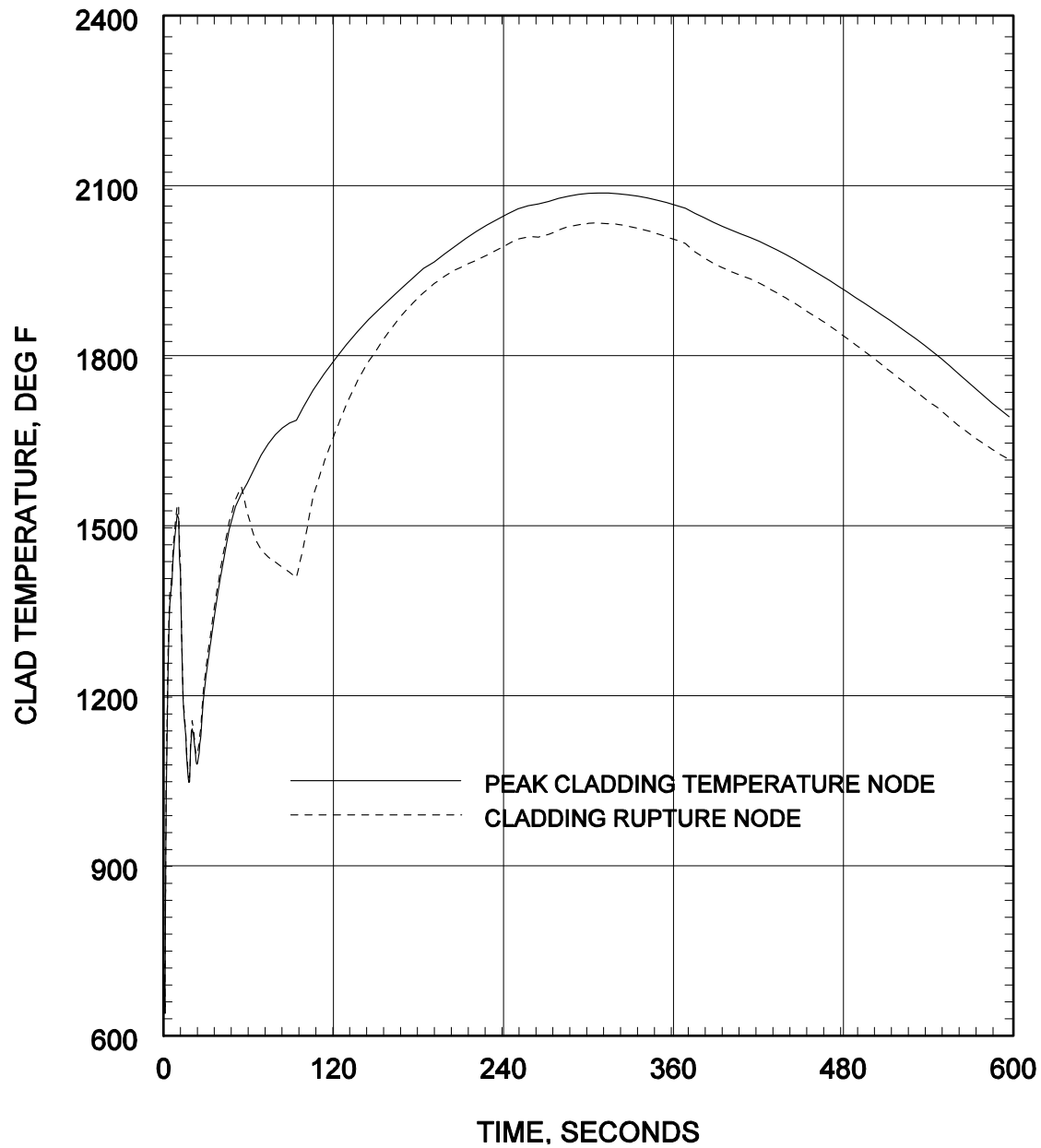


Figure 2.8.5.6.3-28
Large Break LOCA ECCS Performance Analysis
0.06 DEG/PD Break
Mid Annulus Flow Rate

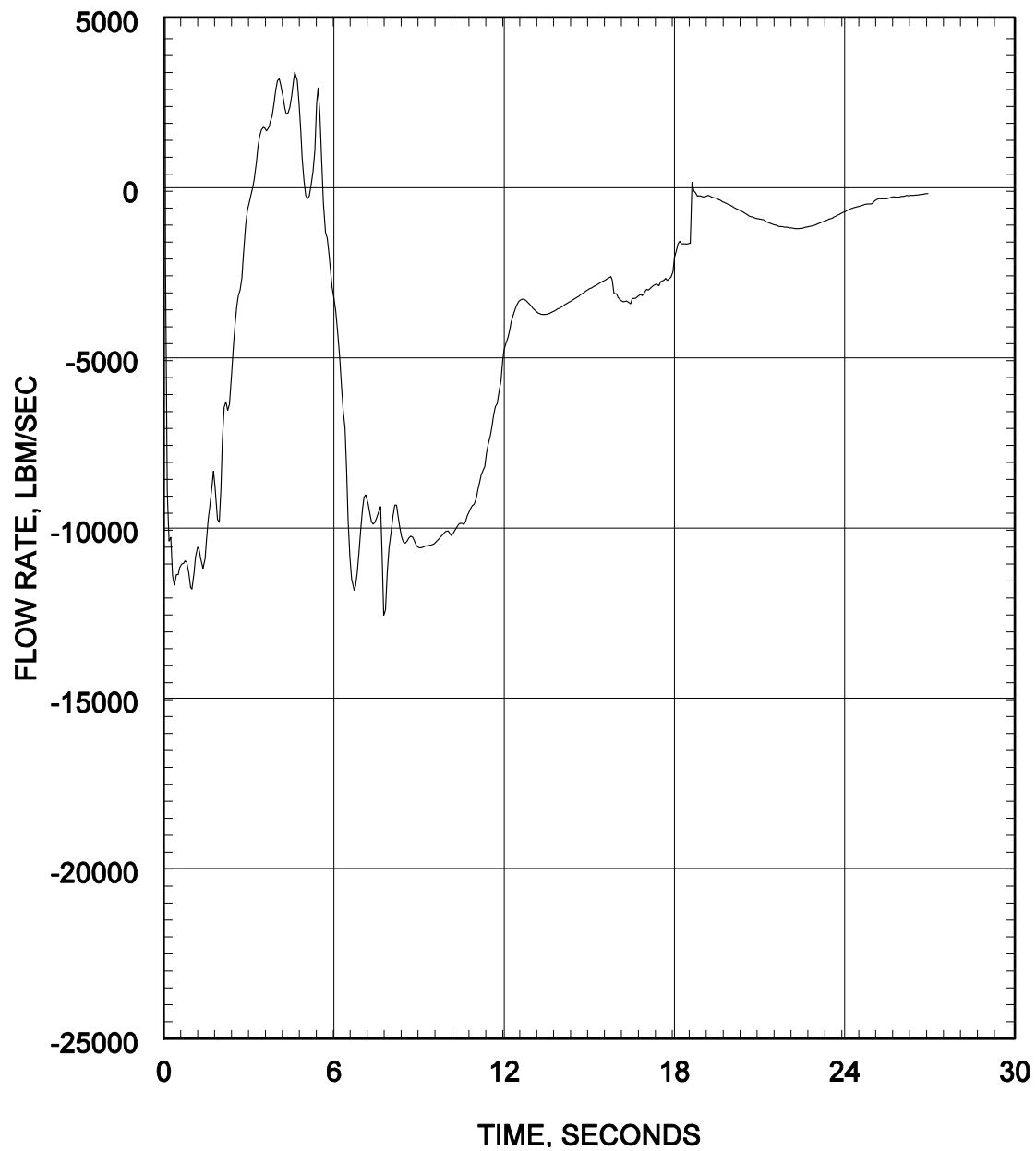


Figure 2.8.5.6.3-29
Large Break LOCA ECCS Performance Analysis
0.06 DEG/PD Break
Quality Above and Below the Core

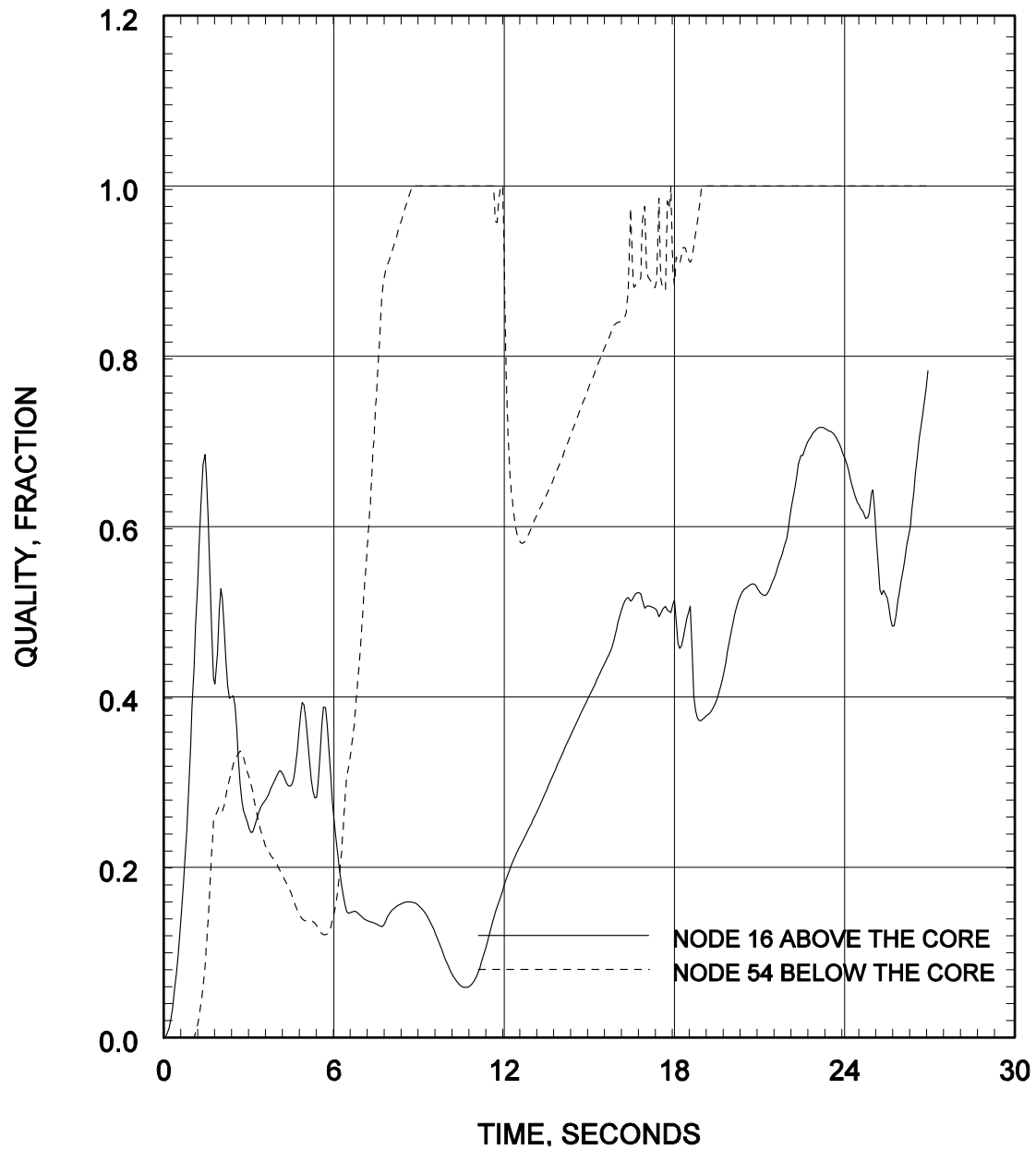


Figure 2.8.5.6.3-30
Large Break LOCA ECCS Performance Analysis
0.06 DEG/PD Break
Core Pressure Drop

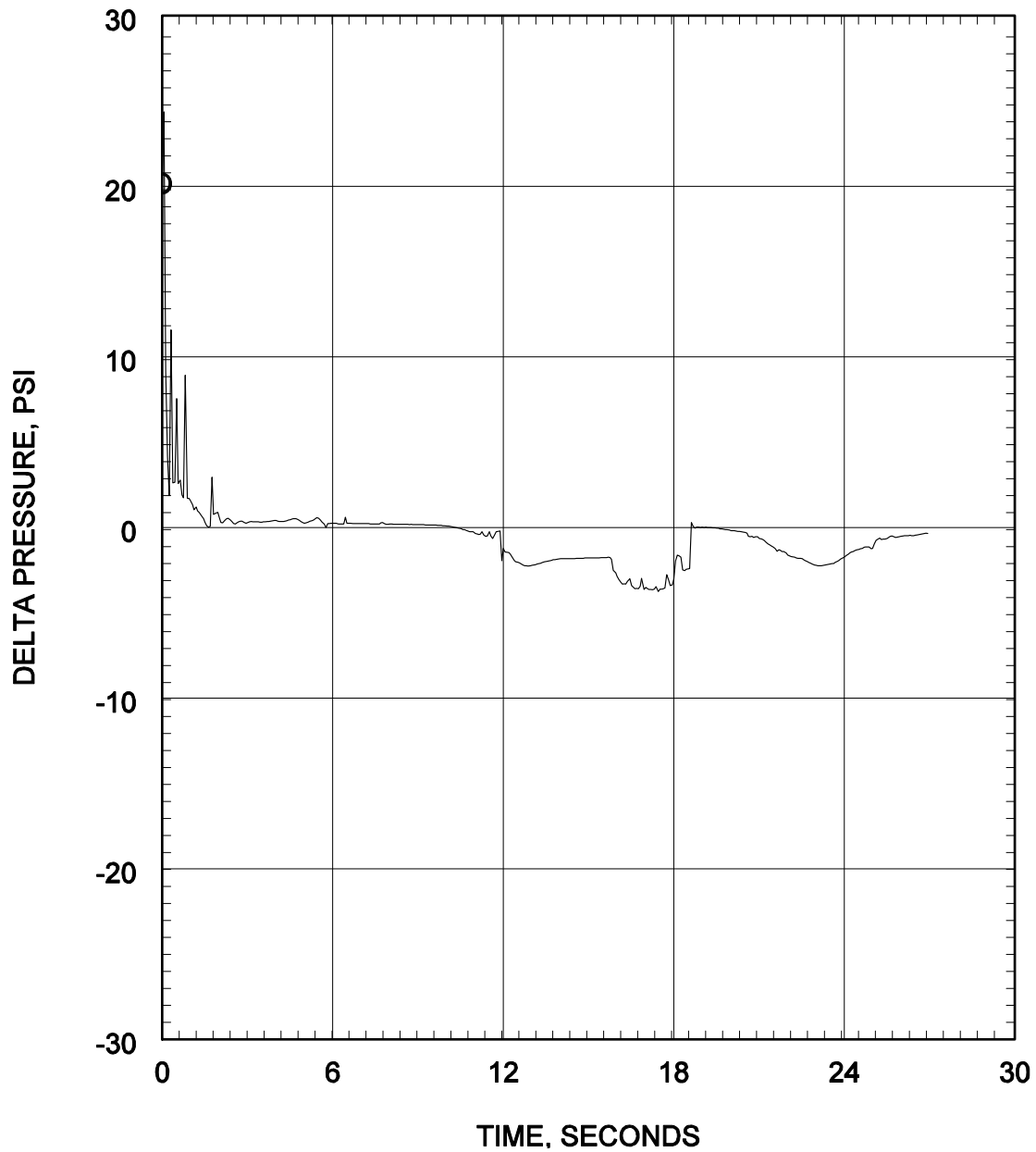


Figure 2.8.5.6.3-31
Large Break LOCA ECCS Performance Analysis
0.06 DEG/PD Break
Safety Injection Flow Rate into Intact Discharge Legs

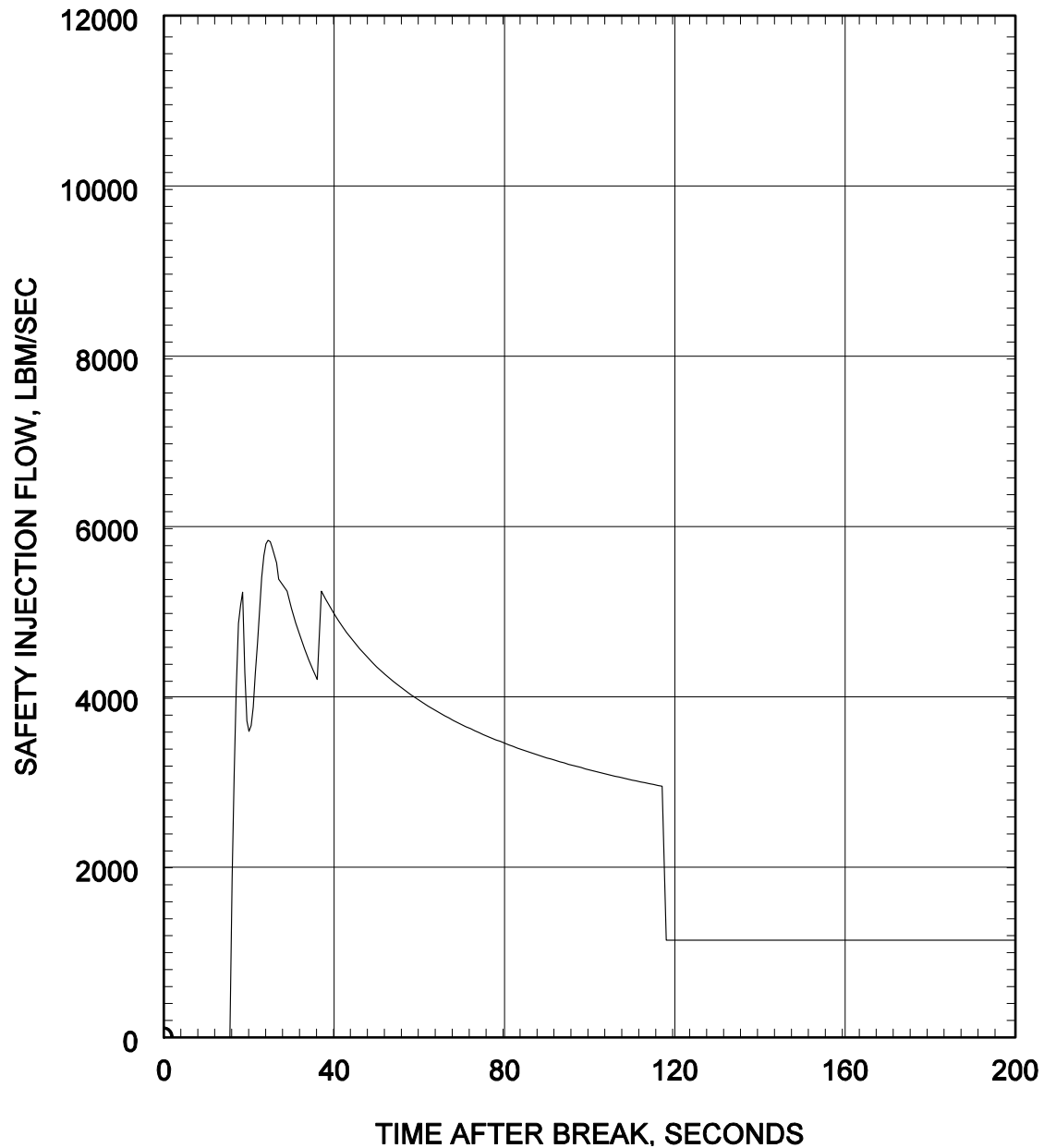


Figure 2.8.5.6.3-32
Large Break LOCA ECCS Performance Analysis
0.06 DEG/PD Break
Water Level in Downcomer During Reflood

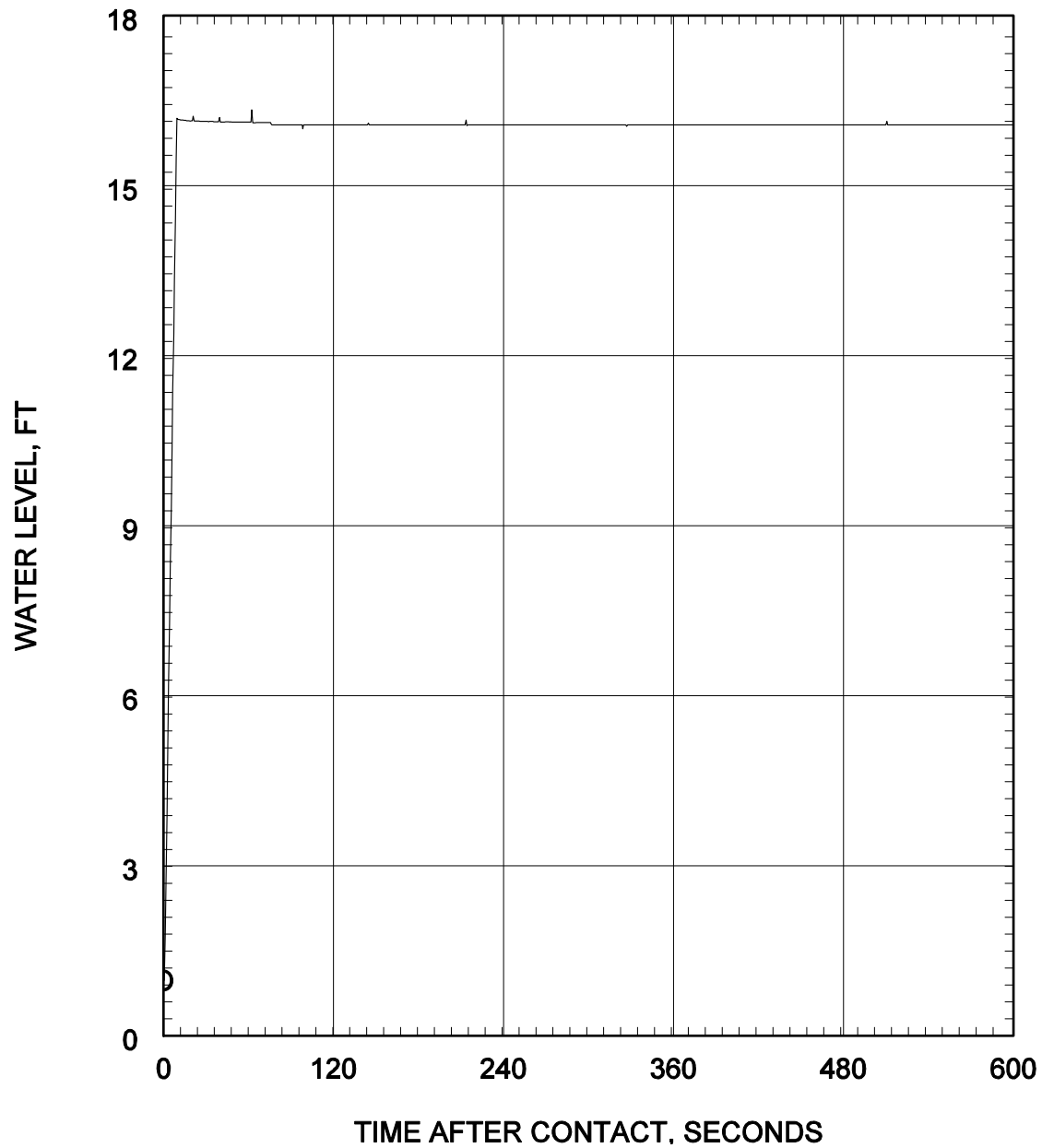


Figure 2.8.5.6.3-33
Large Break LOCA ECCS Performance Analysis
0.06 DEG/PD Break
Hot Spot Gap Conductance

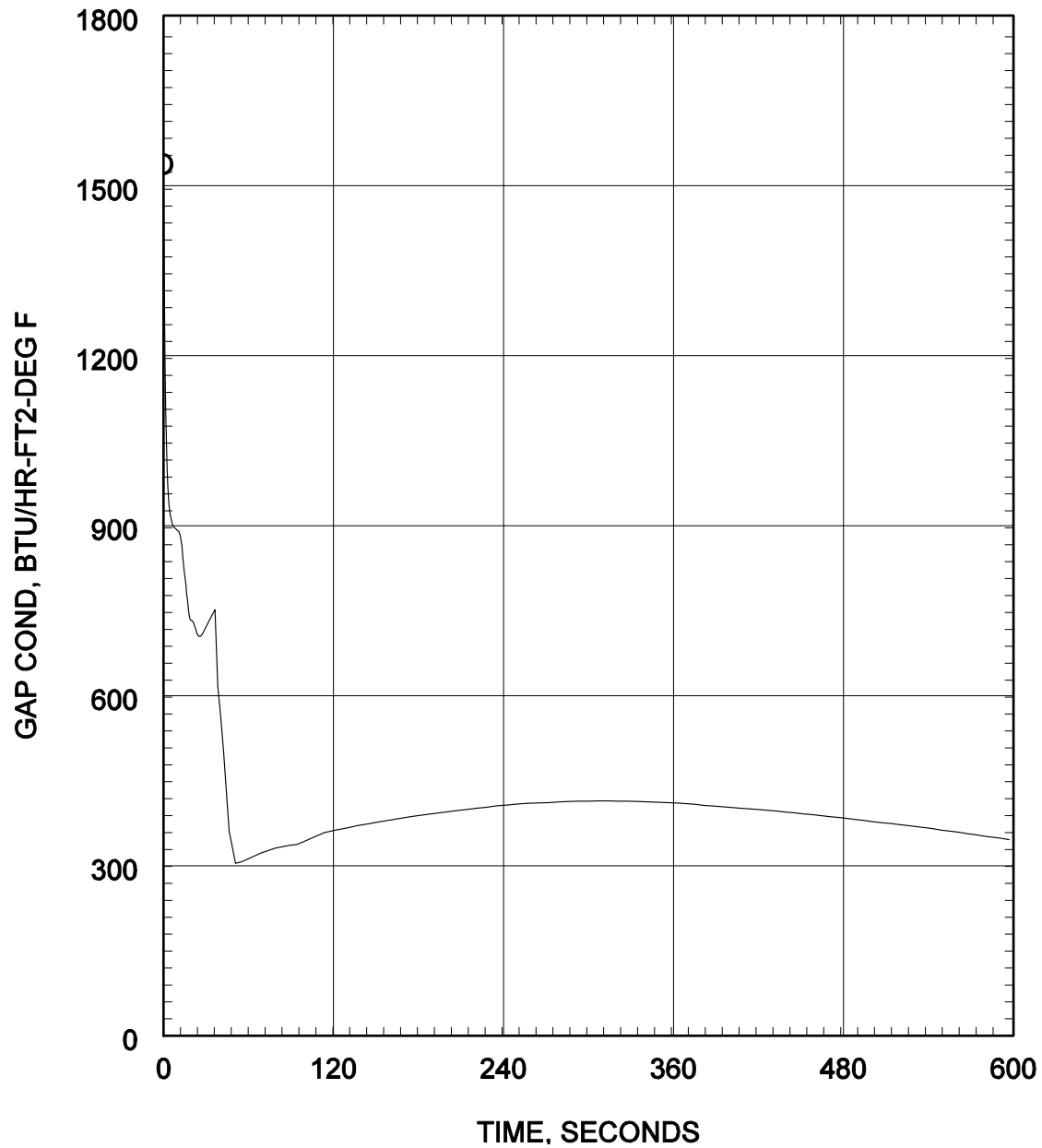


Figure 2.8.5.6.3-34
Large Break LOCA ECCS Performance Analysis
0.06 DEG/PD Break
Maximum Local Cladding Oxidation Percentage

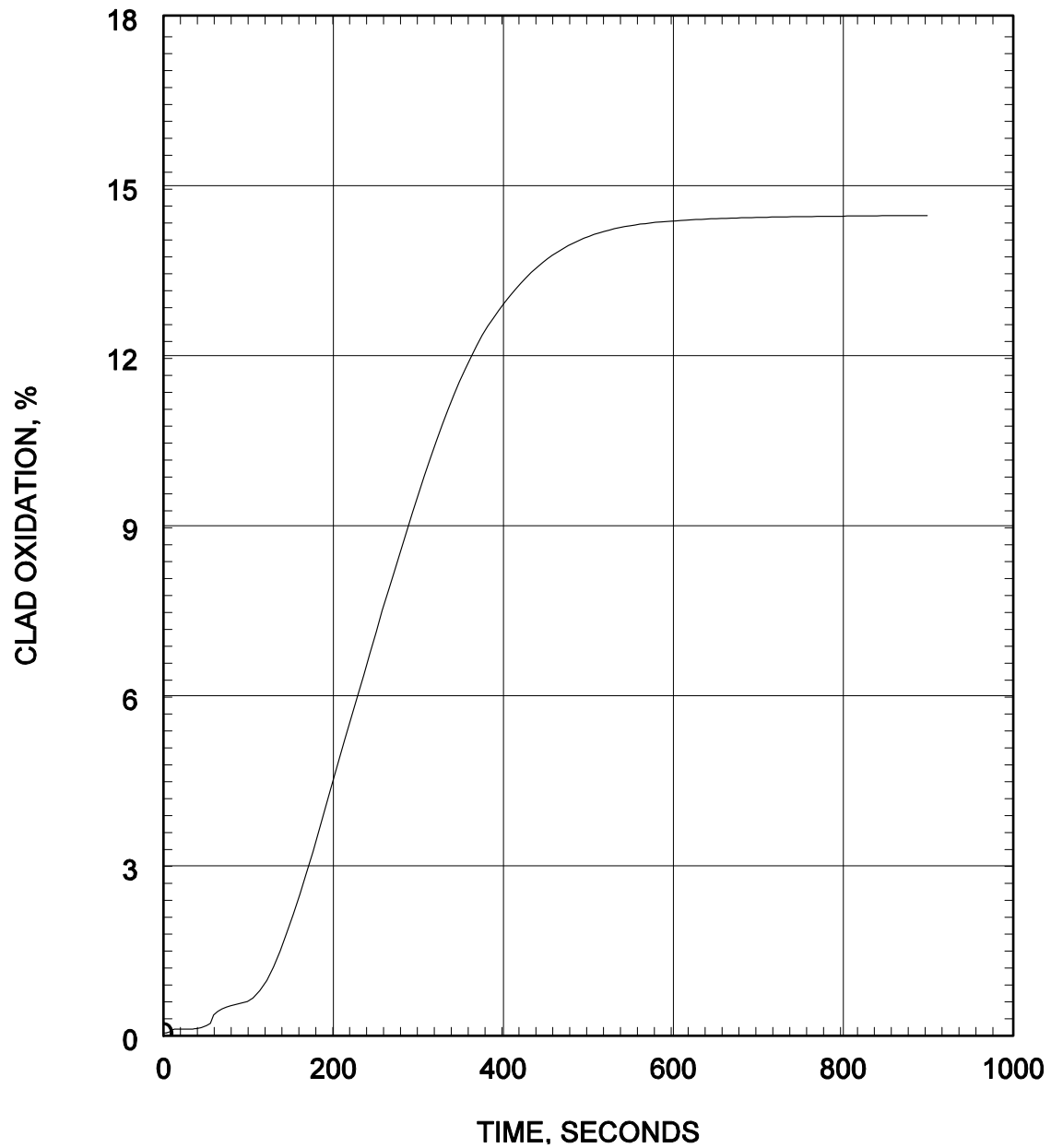


Figure 2.8.5.6.3-35
Large Break LOCA ECCS Performance Analysis
0.06 DEG/PD Break
Fuel Centerline, Fuel Average, Cladding, and Coolant Temperature at the Hot Spot

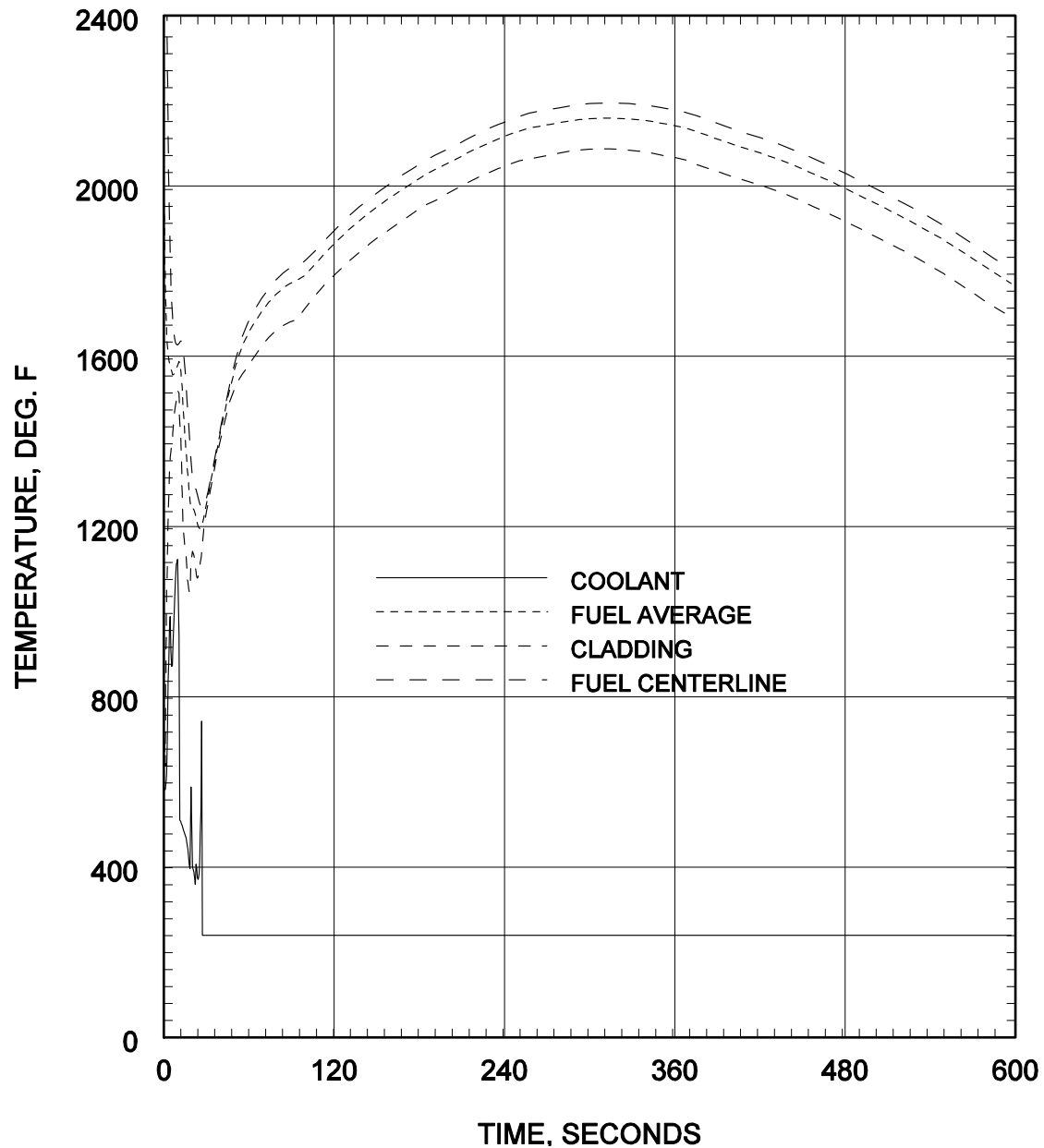


Figure 2.8.5.6.3-36
Large Break LOCA ECCS Performance Analysis
0.06 DEG/PD Break
Hot Spot Heat Transfer Coefficient

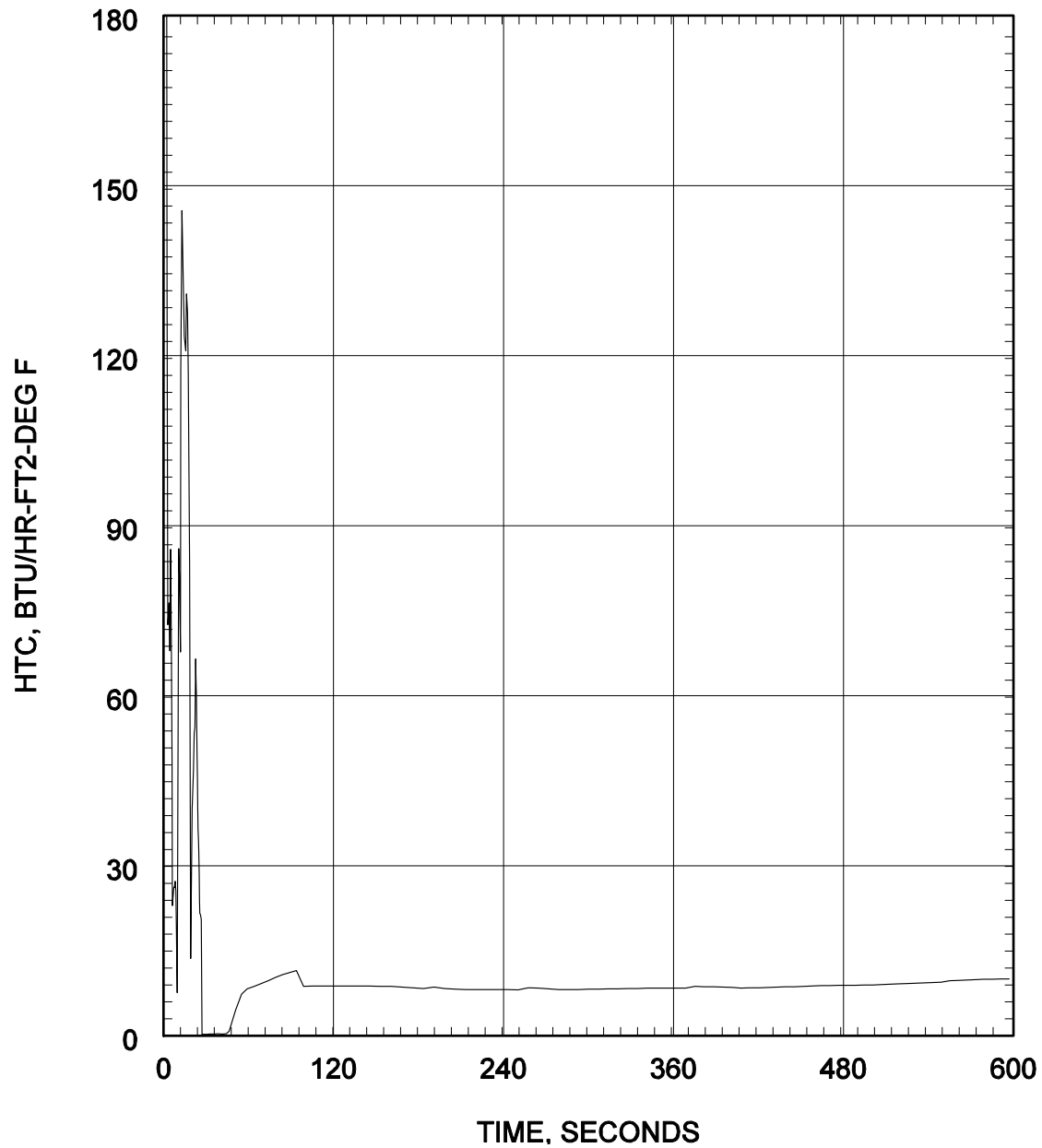


Figure 2.8.5.6.3-37
Large Break LOCA ECCS Performance Analysis
0.06 DEG/PD Break
Hot Rod Internal Gas Pressure

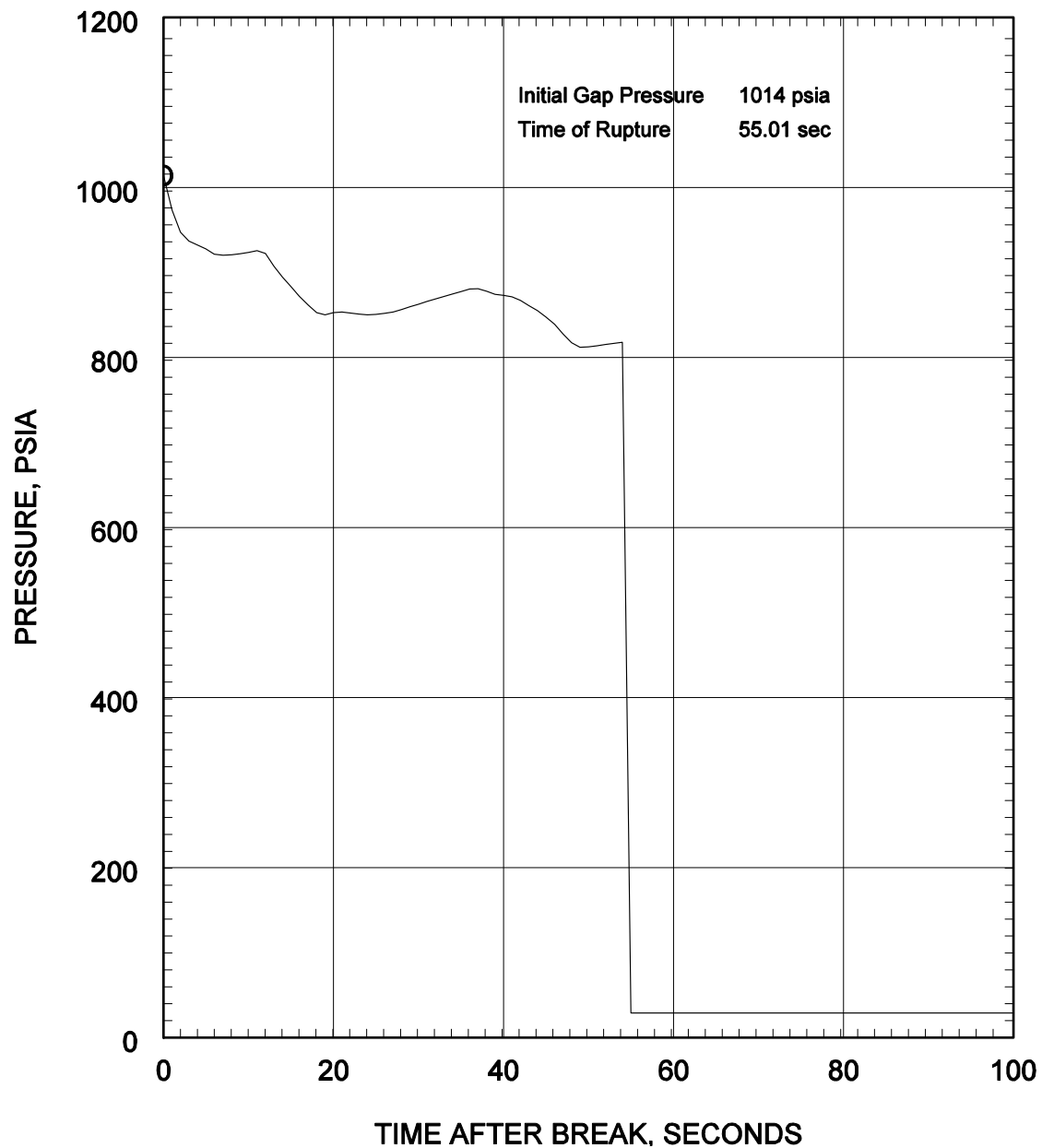


Figure 2.8.5.6.3-38
Large Break LOCA ECCS Performance Analysis
0.06 DEG/PD Break
Core Bulk Channel Flow Rate

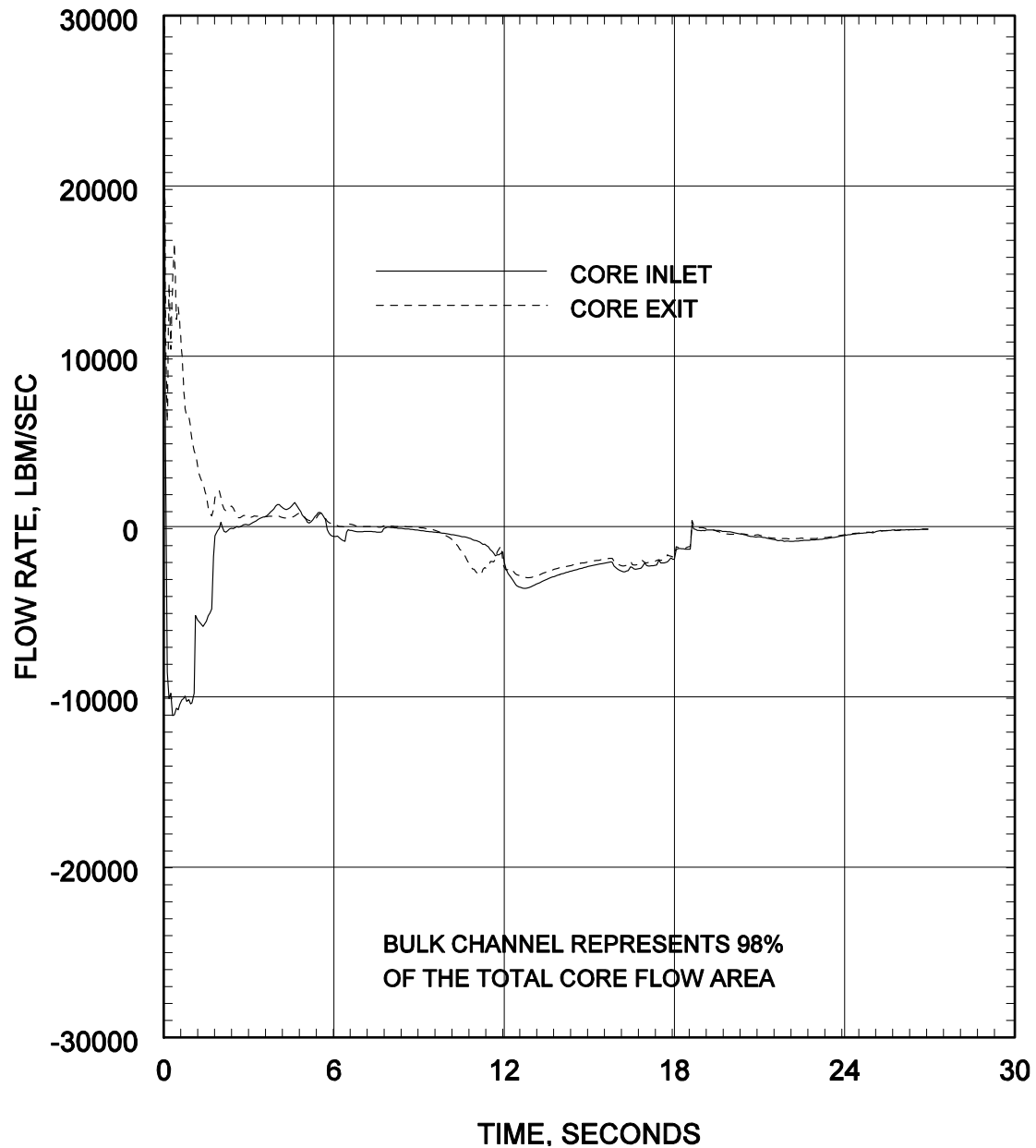


Figure 2.8.5.6.3-39
Large Break LOCA ECCS Performance Analysis
0.04 DEG/PD Break
Core Power

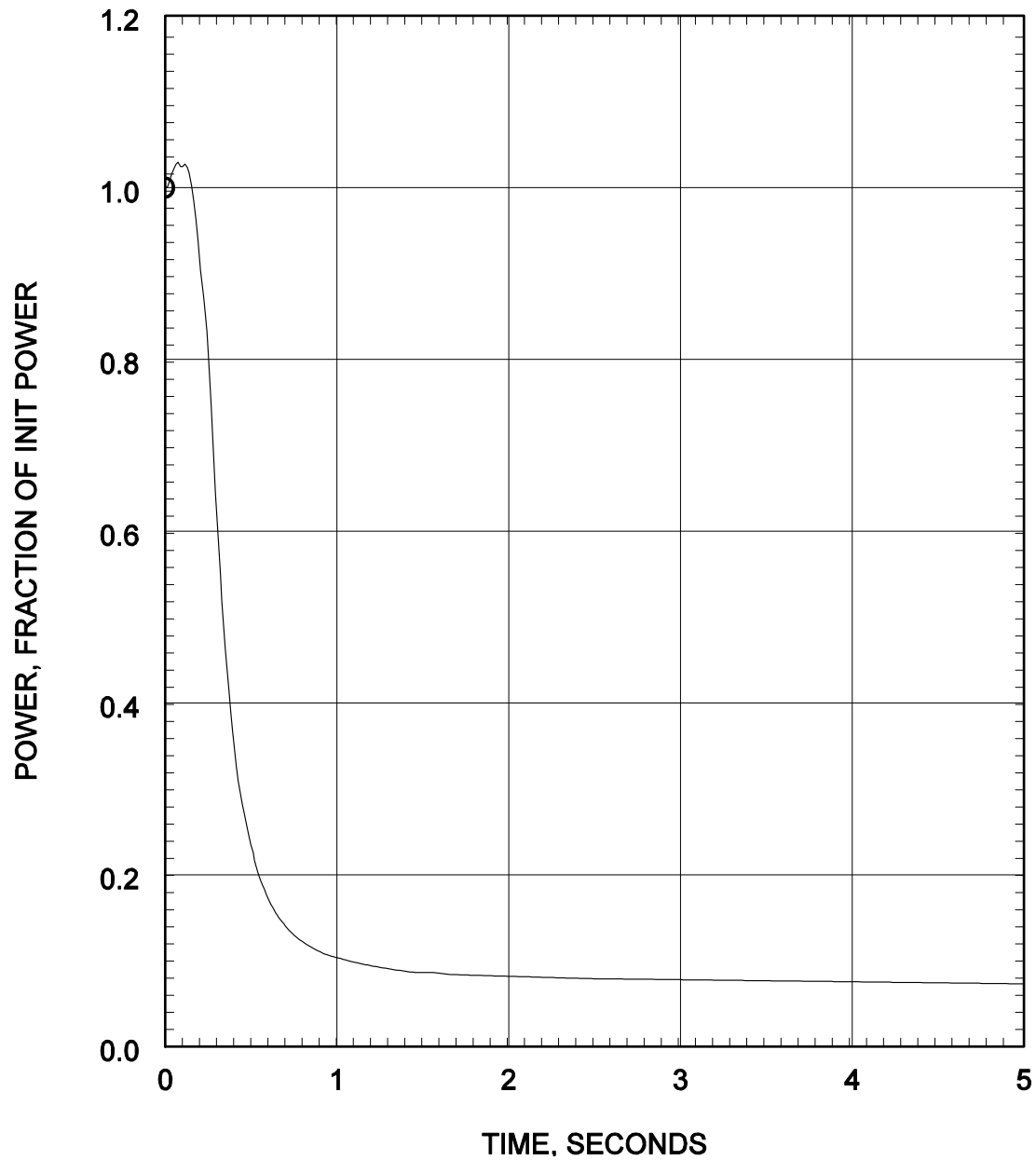


Figure 2.8.5.6.3-40
Large Break LOCA ECCS Performance Analysis
0.04 DEG/PD Break
Pressure in Center Hot Assembly Node

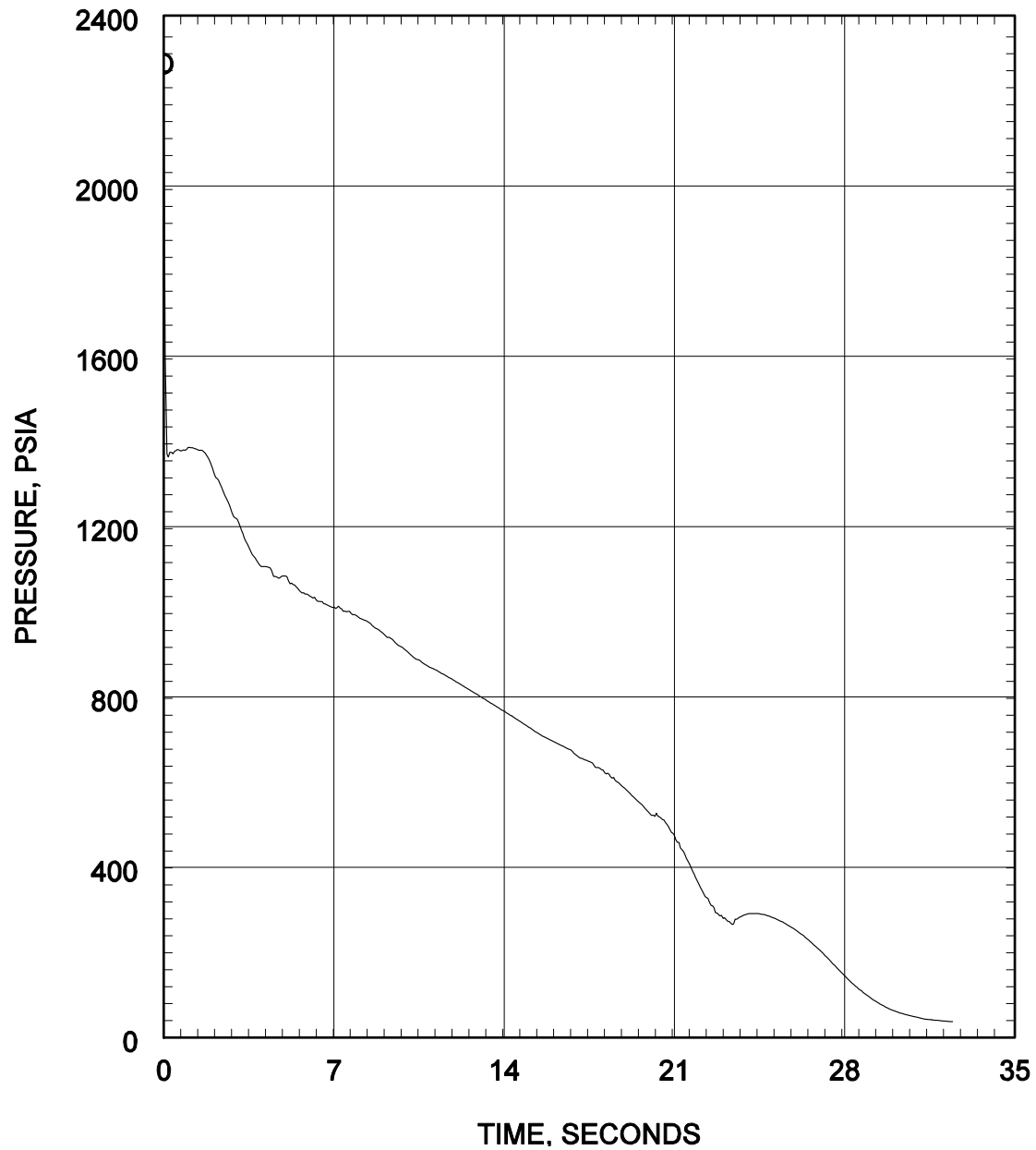


Figure 2.8.5.6.3-41
Large Break LOCA ECCS Performance Analysis
0.04 DEG/PD Break
Break Flow Rate

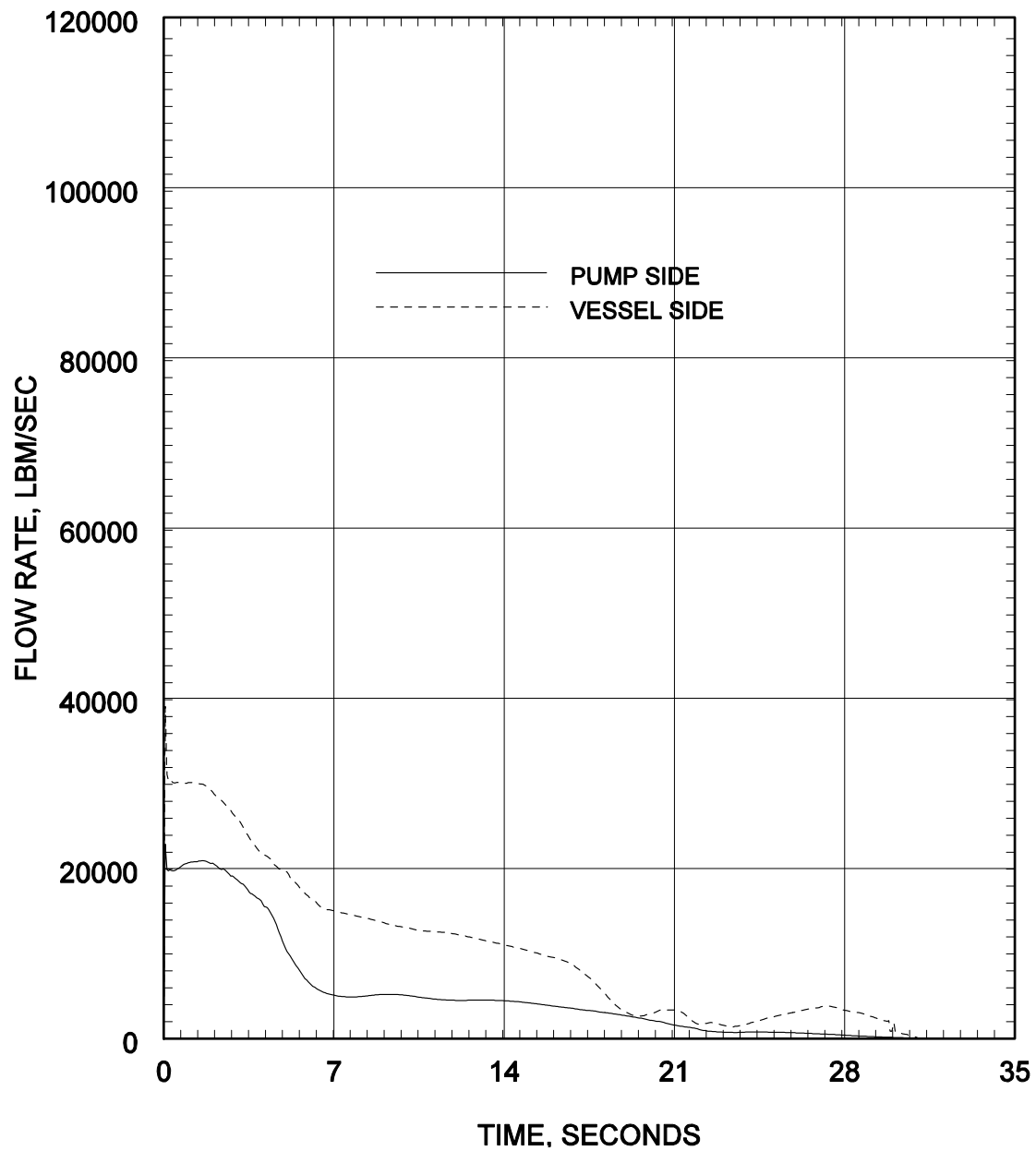


Figure 2.8.5.6.3-42
Large Break LOCA ECCS Performance Analysis
0.04 DEG/PD Break
Hot Assembly Flow Rate (Below Hot Spot)

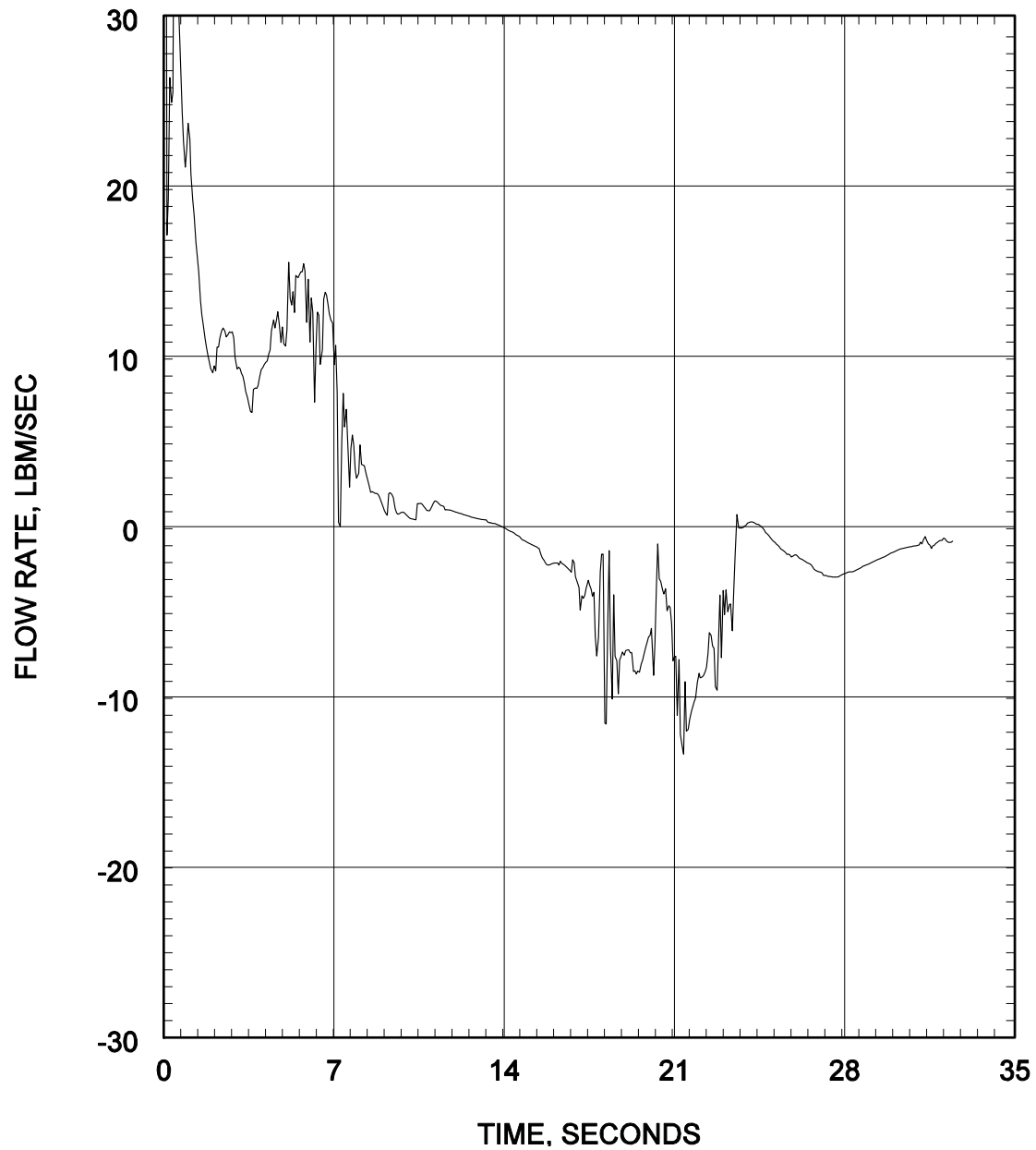


Figure 2.8.5.6.3-43
Large Break LOCA ECCS Performance Analysis
0.04 DEG/PD Break
Hot Assembly Flow Rate (Above Hot Spot)

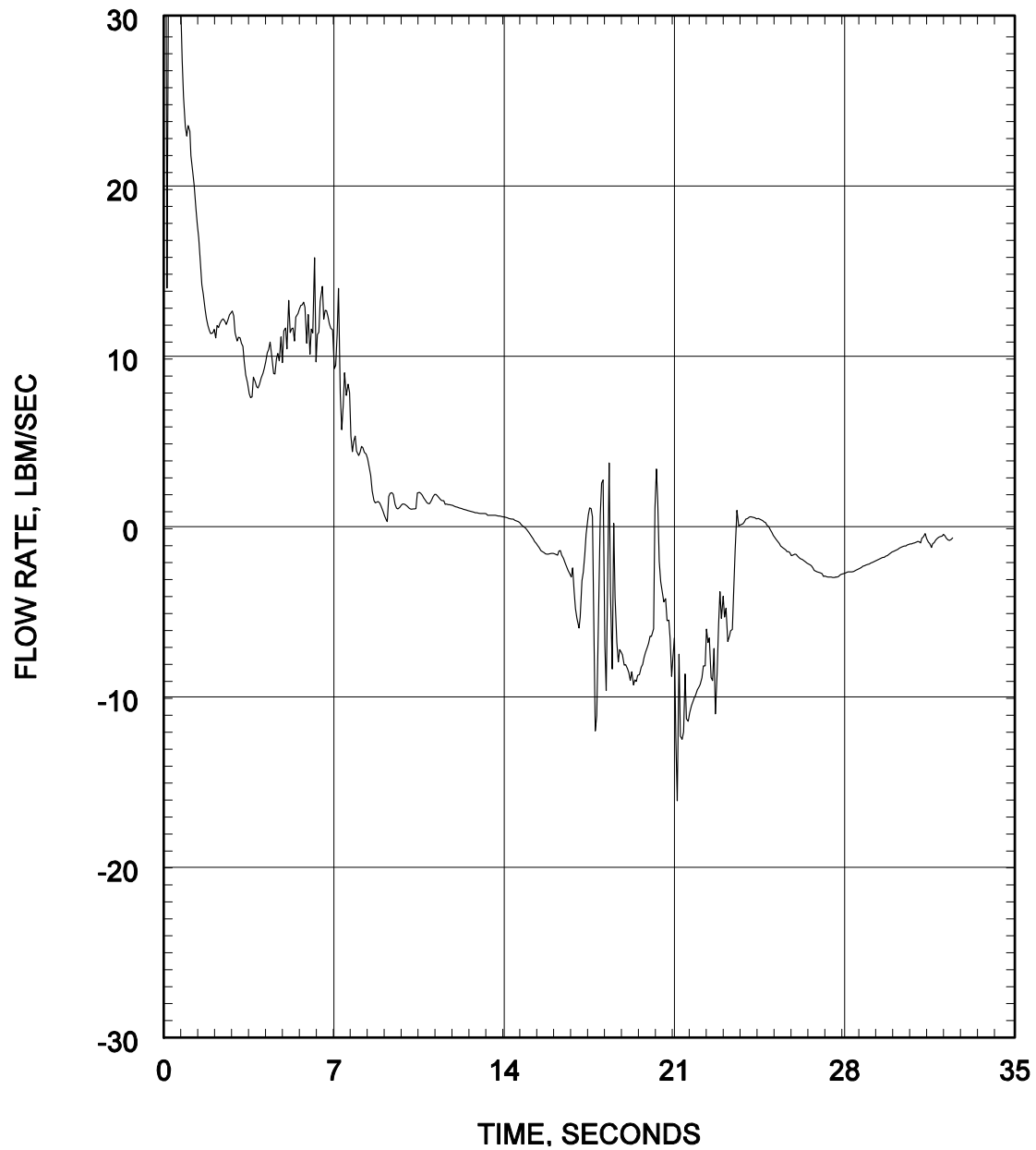


Figure 2.8.5.6.3-44
Large Break LOCA ECCS Performance Analysis
0.04 DEG/PD Break
Hot Assembly Quality

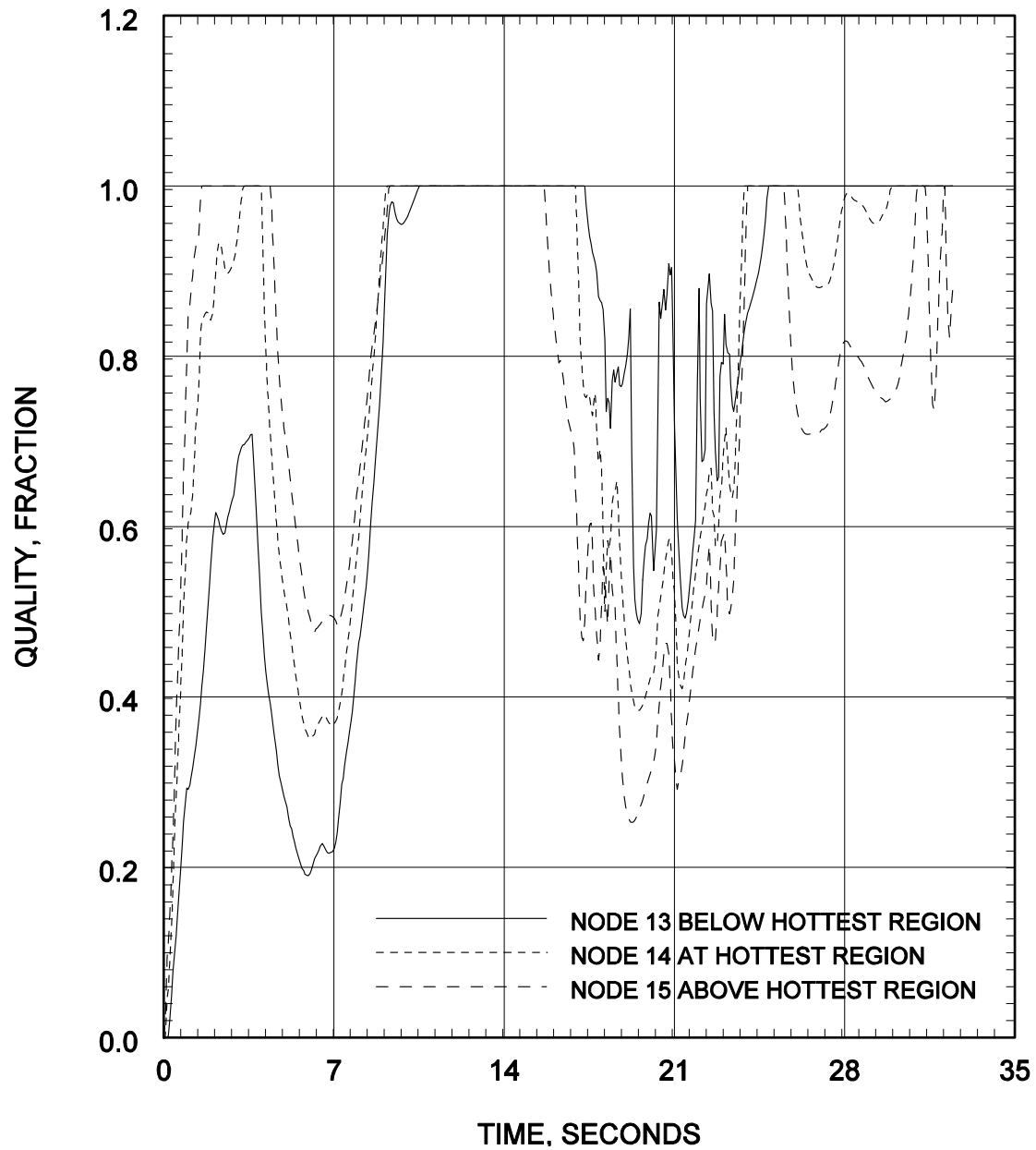


Figure 2.8.5.6.3-45
Large Break LOCA ECCS Performance Analysis
0.04 DEG/PD Break
Containment Pressure

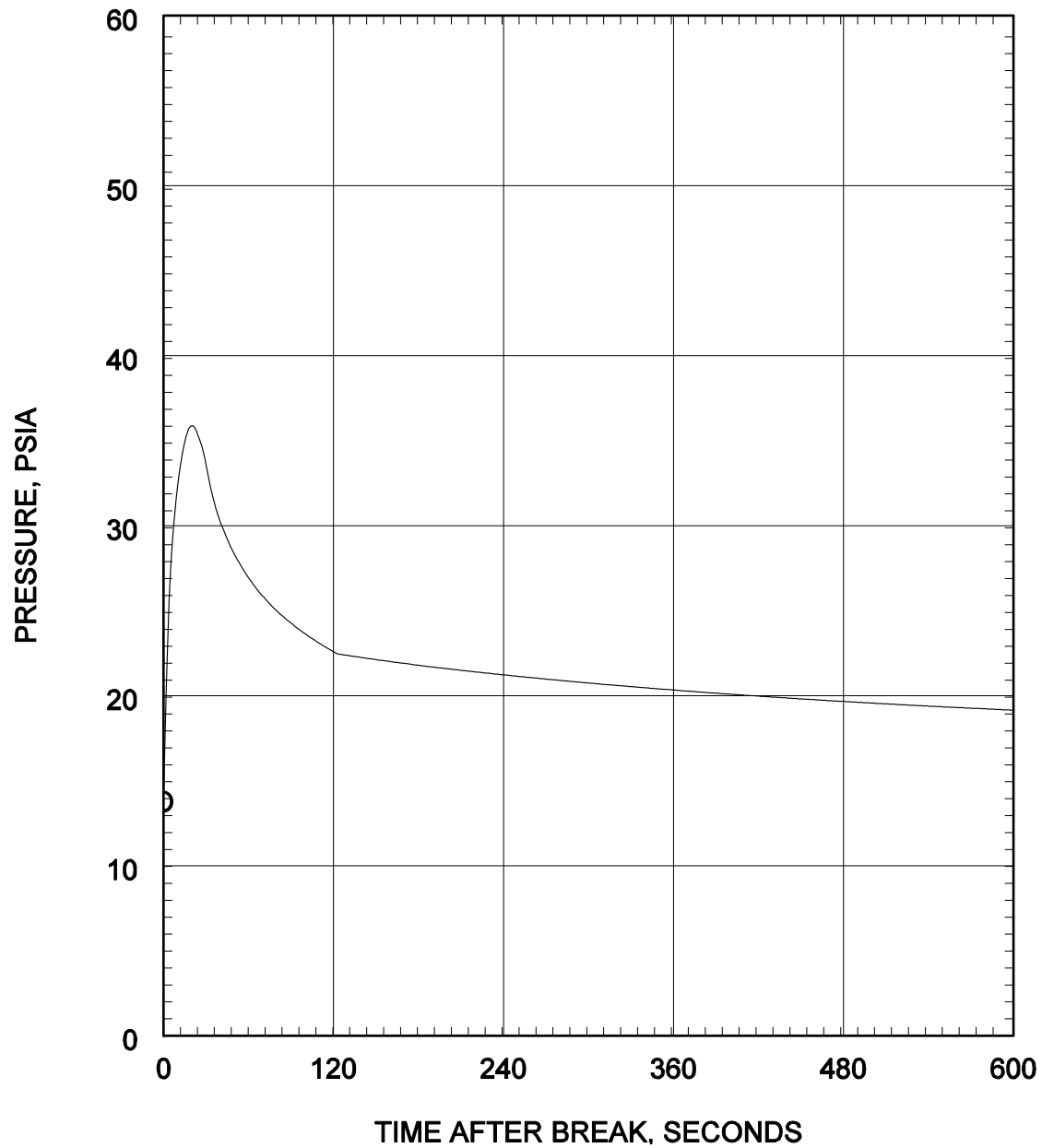


Figure 2.8.5.6.3-46
Large Break LOCA ECCS Performance Analysis
0.04 Mass Added to Core During Reflood

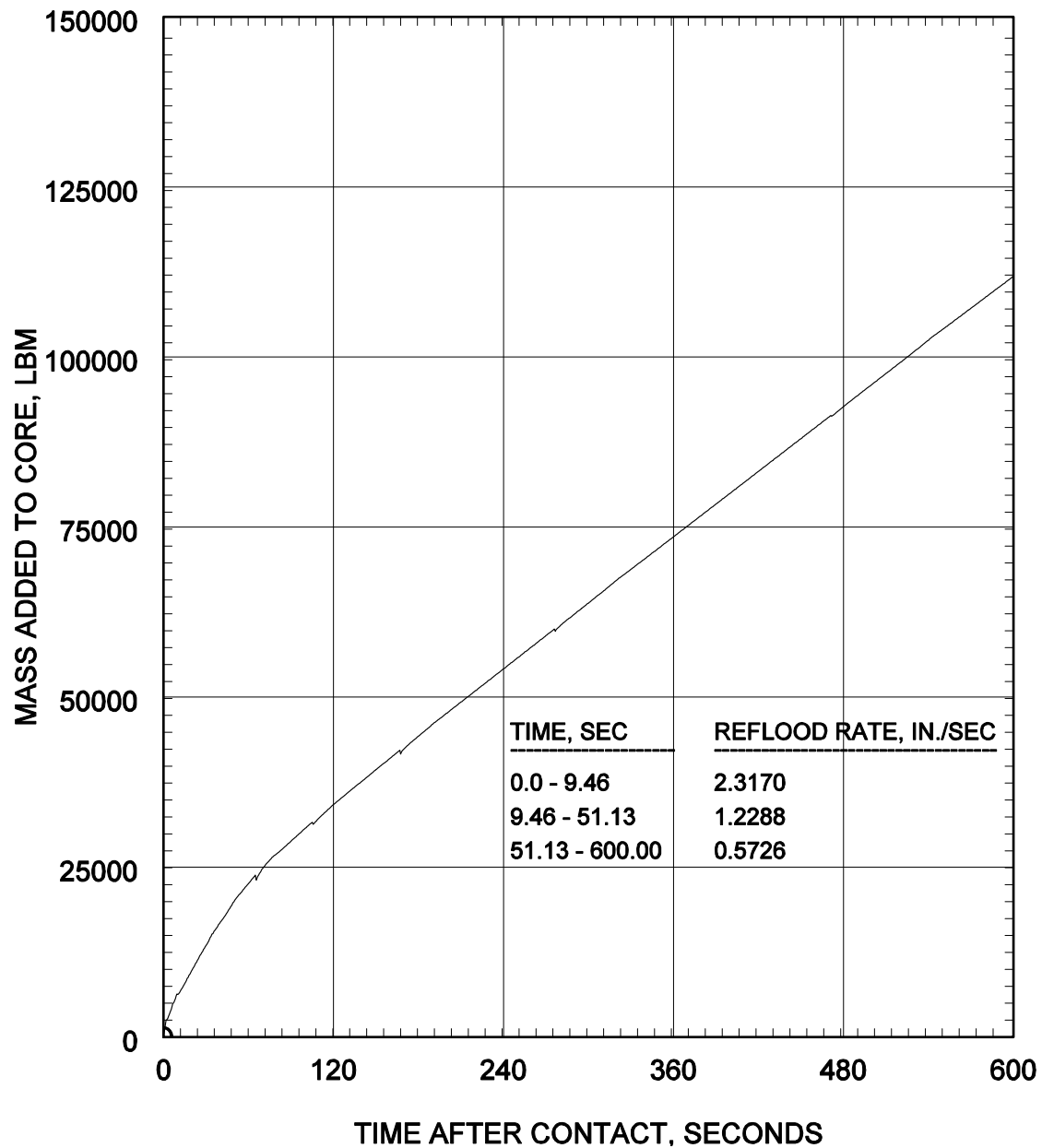


Figure 2.8.5.6.3-47
Large Break LOCA ECCS Performance Analysis
0.04 DEG/PD Break
Peak Cladding Temperature

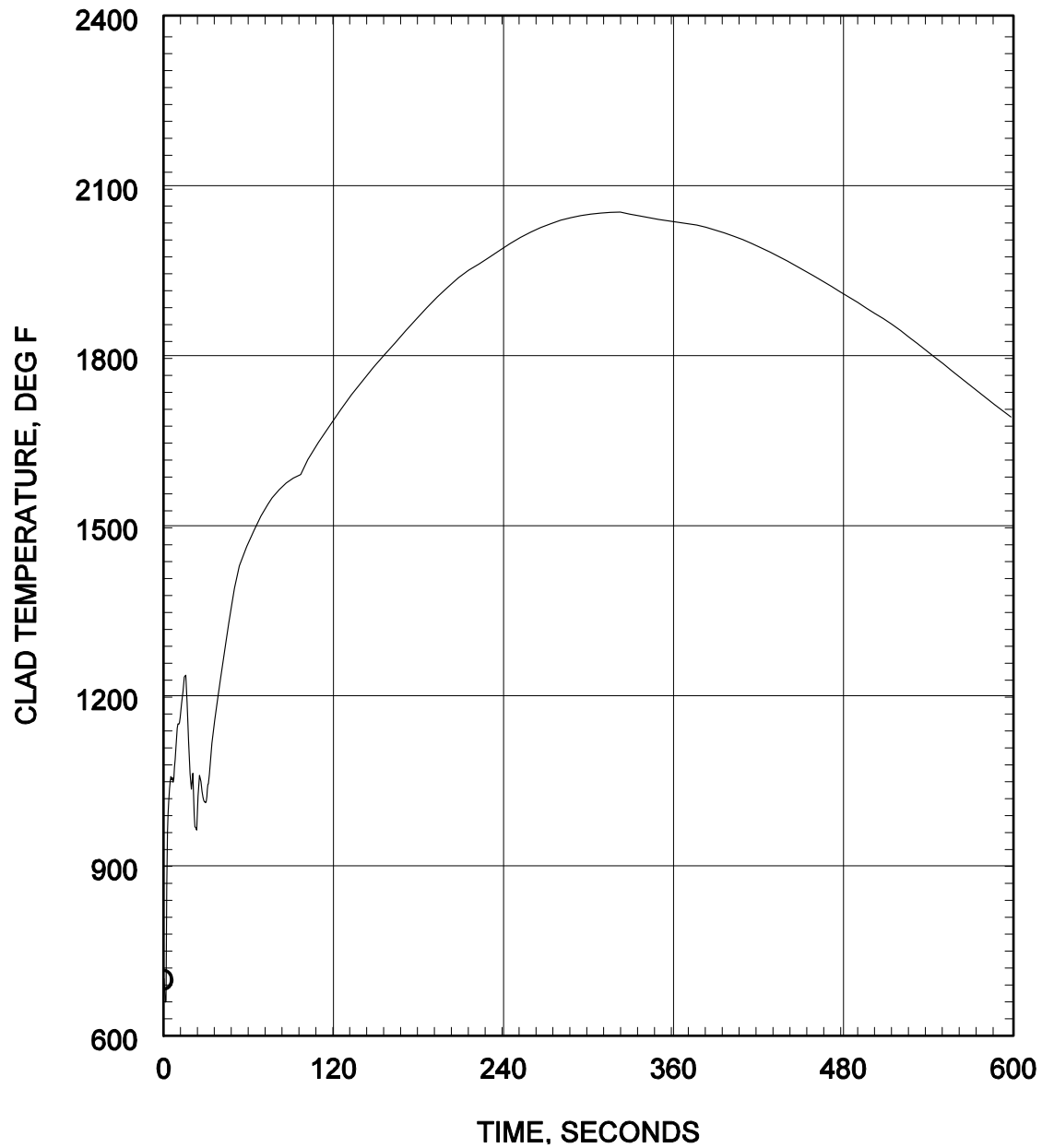


Figure 2.8.5.6.3-48
Small Break LOCA ECCS Performance Analysis
0.04 ft²/PD Break
Core Power

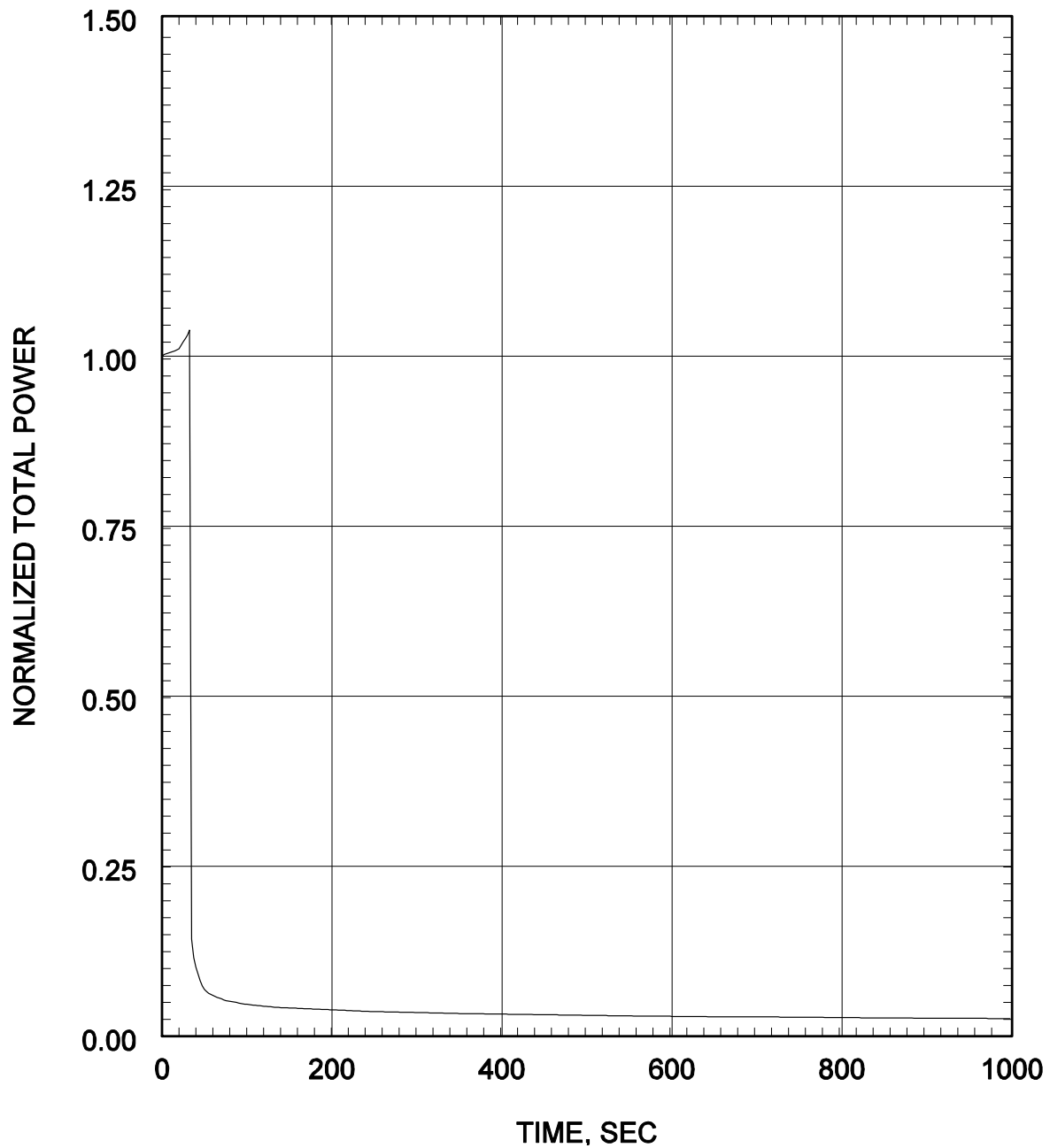


Figure 2.8.5.6.3-49
Small Break LOCA ECCS Performance Analysis
0.04 ft²/PD Break
Inner Vessel Pressure

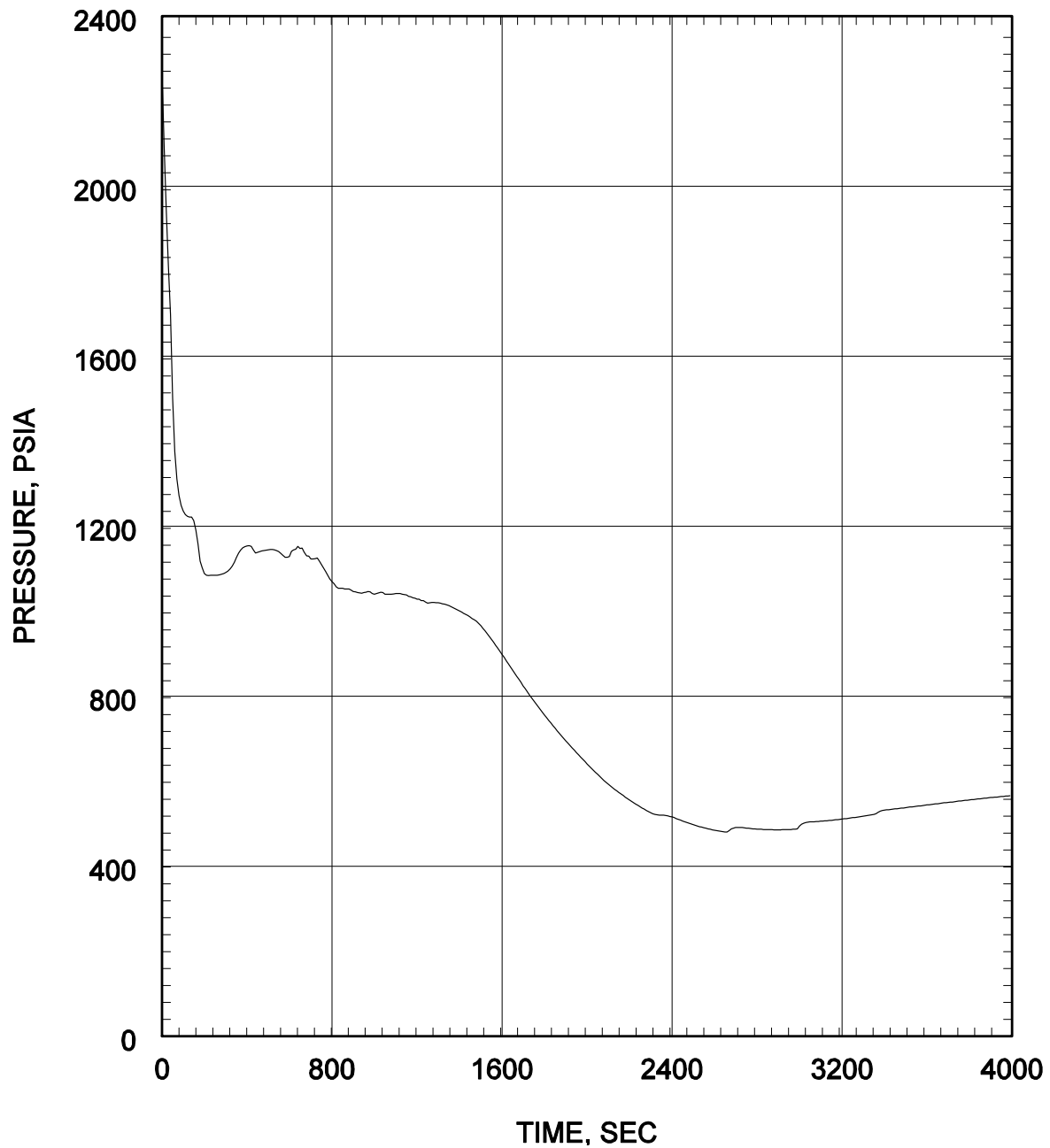


Figure 2.8.5.6.3-50
Small Break LOCA ECCS Performance Analysis
0.04 ft²/PD Break
Break Flow Rate

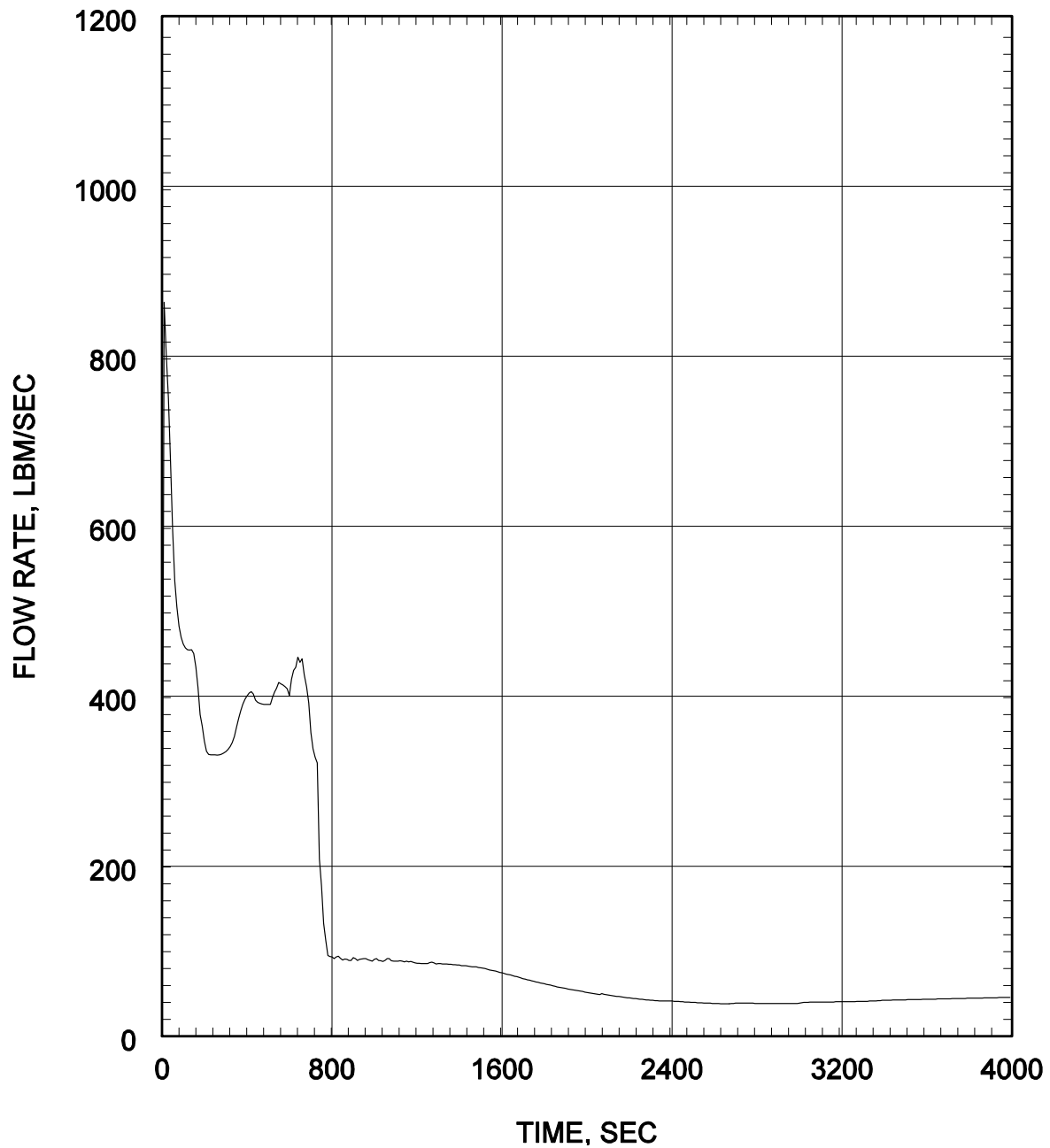


Figure 2.8.5.6.3-51
Small Break LOCA ECCS Performance Analysis
0.04 ft²/PD Break
Inner Vessel Inlet Flow Rate

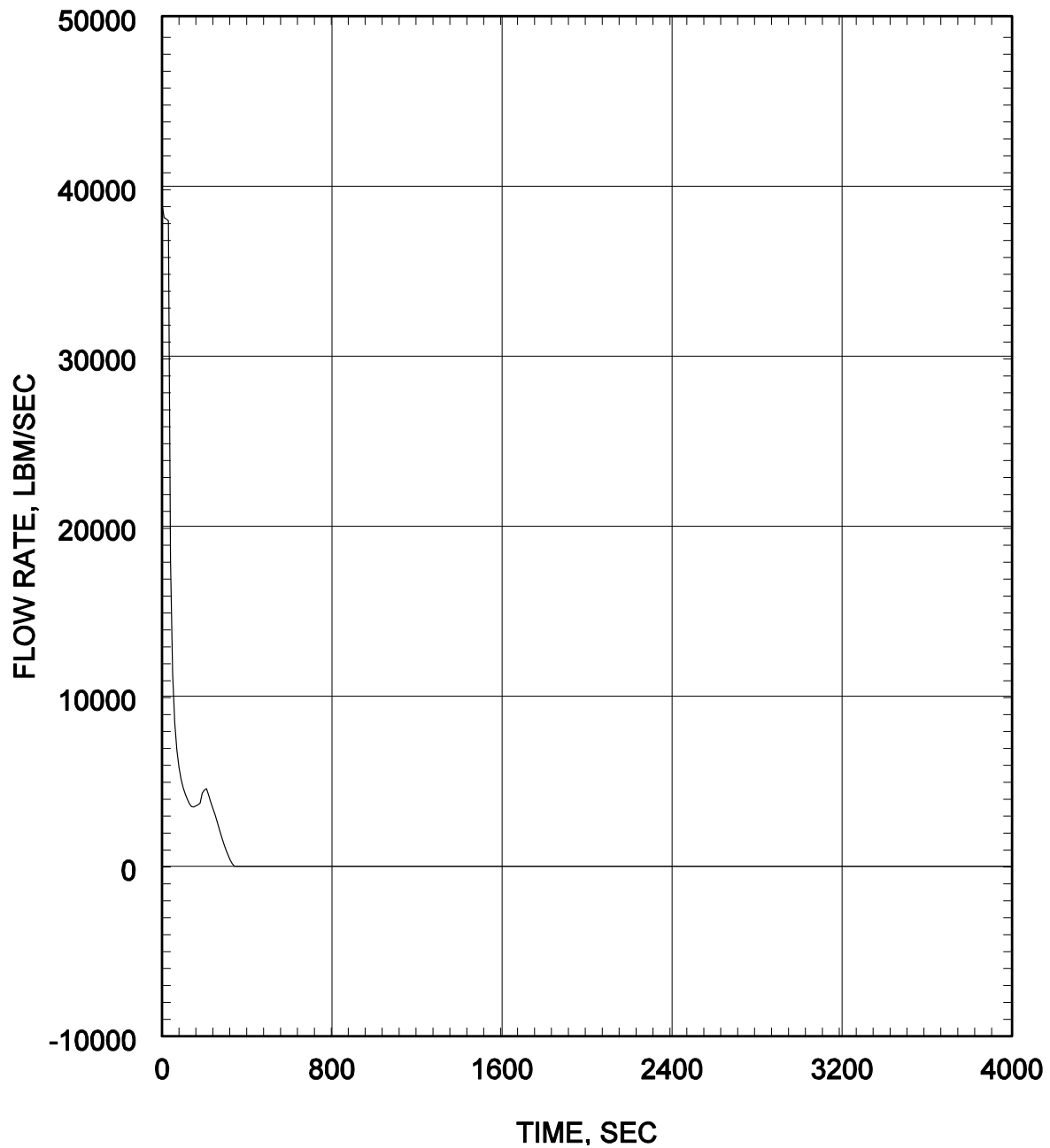


Figure 2.8.5.6.3-52
Small Break LOCA ECCS Performance Analysis
0.04 ft²/PD Break
Inner Vessel Two-Phase Mixture Level

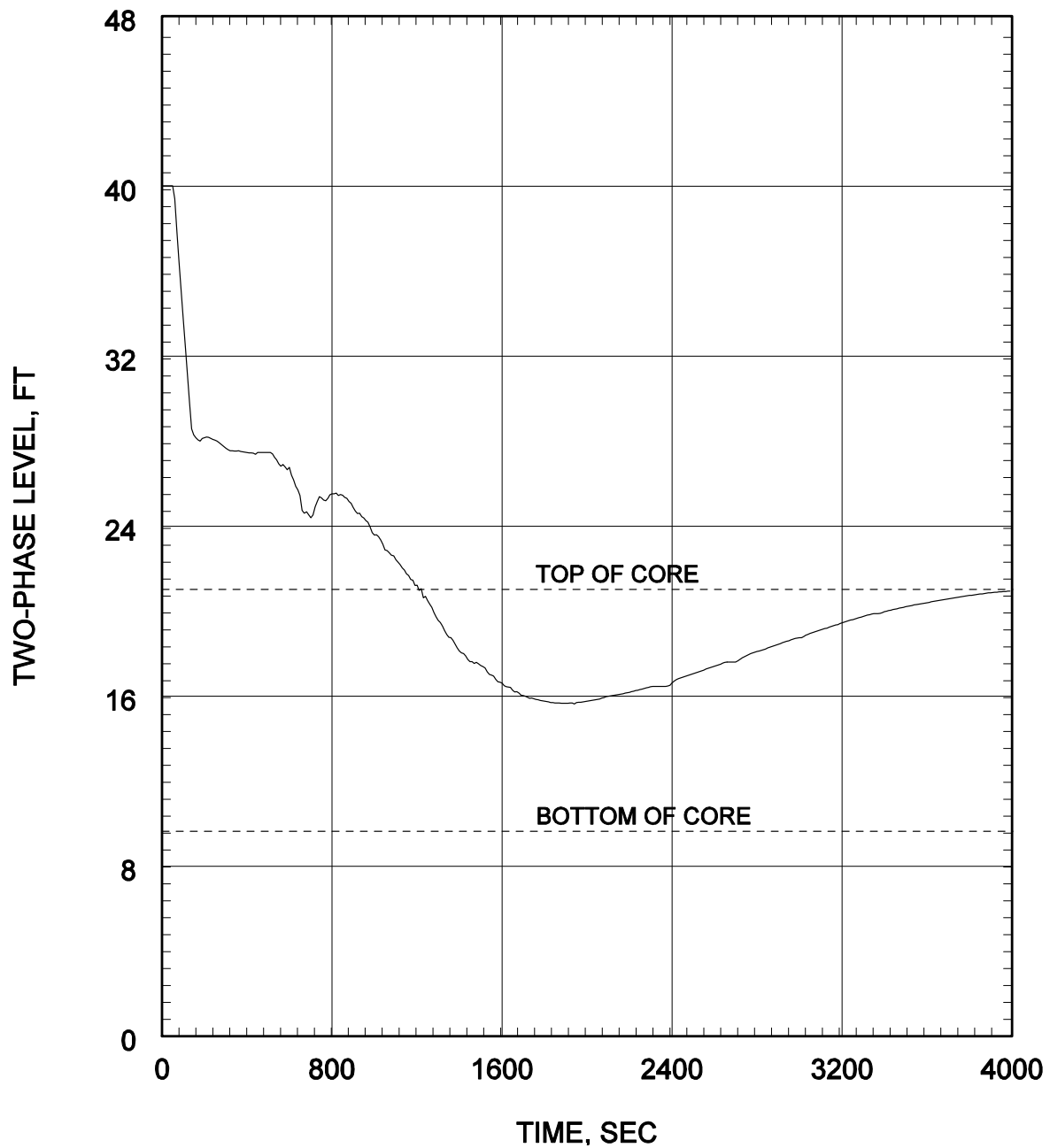


Figure 2.8.5.6.3-53
Small Break LOCA ECCS Performance Analysis
0.04 ft²/PD Break
Heat Transfer Coefficient at Hot Spot

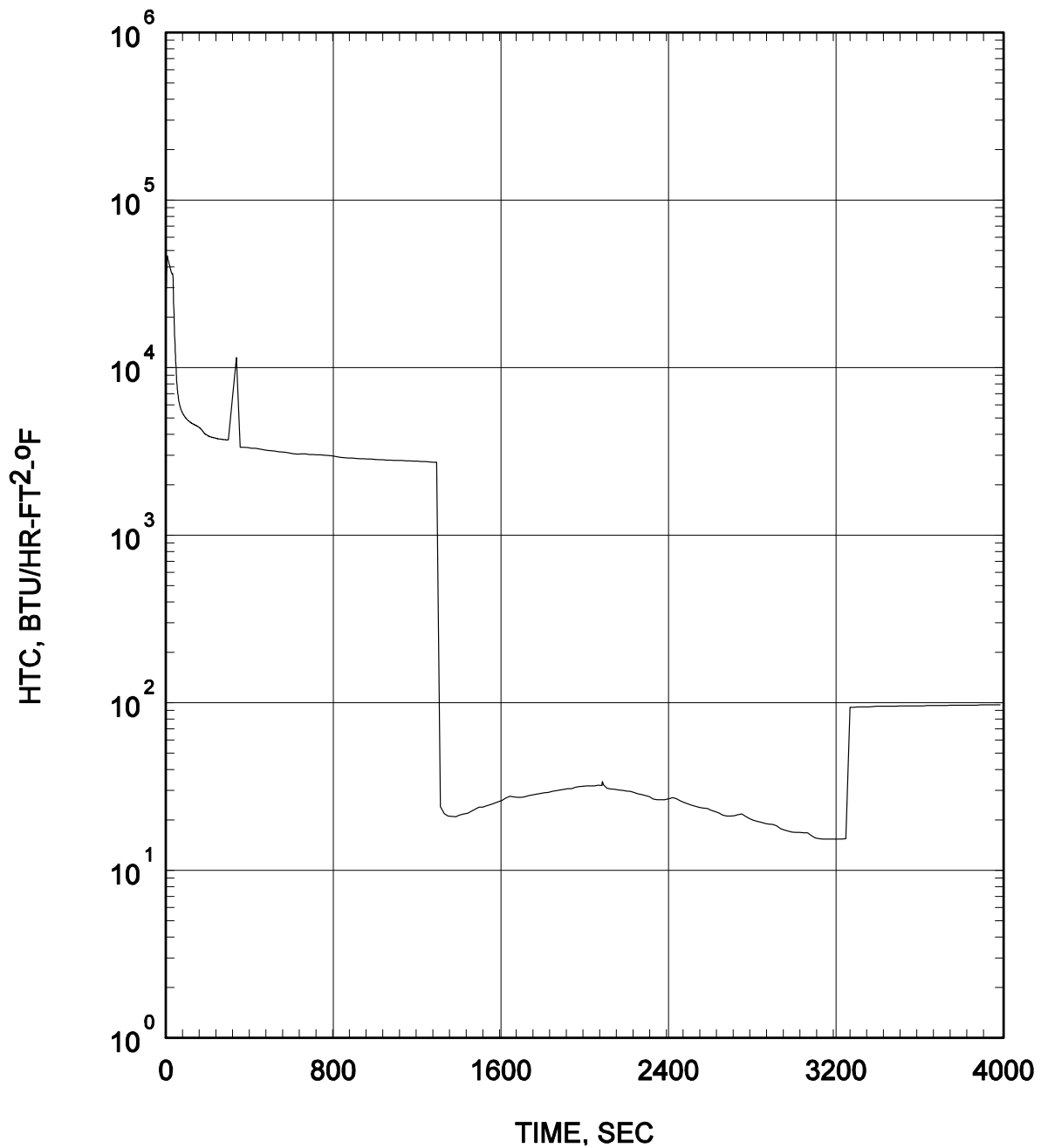


Figure 2.8.5.6.3-54
Small Break LOCA ECCS Performance Analysis
0.04 ft²/PD Break
Coolant Temperature at Hot Spot

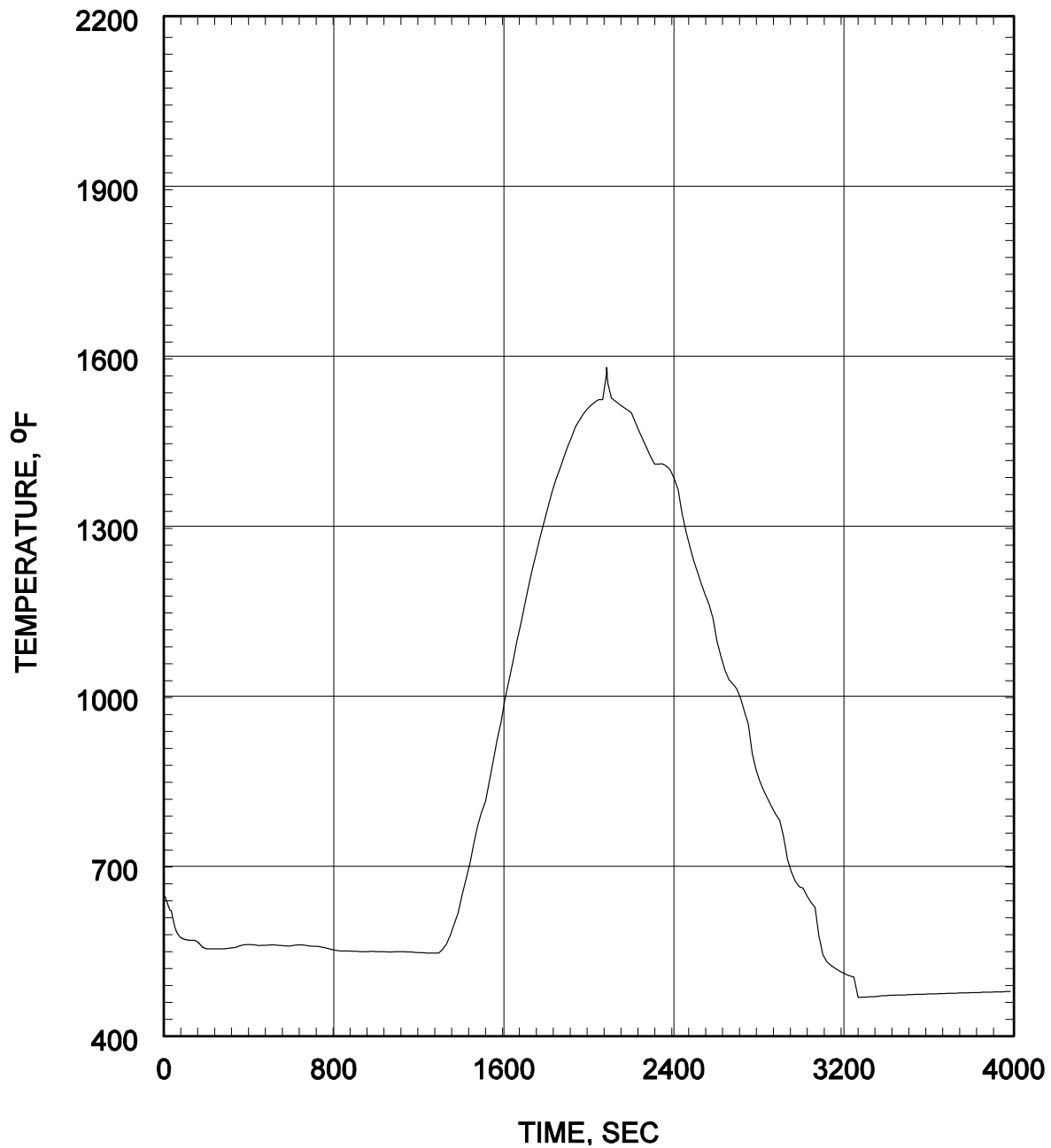


Figure 2.8.5.6.3-55
Small Break LOCA ECCS Performance Analysis
0.04 ft²/PD Break
Cladding Temperature at Hot Spot

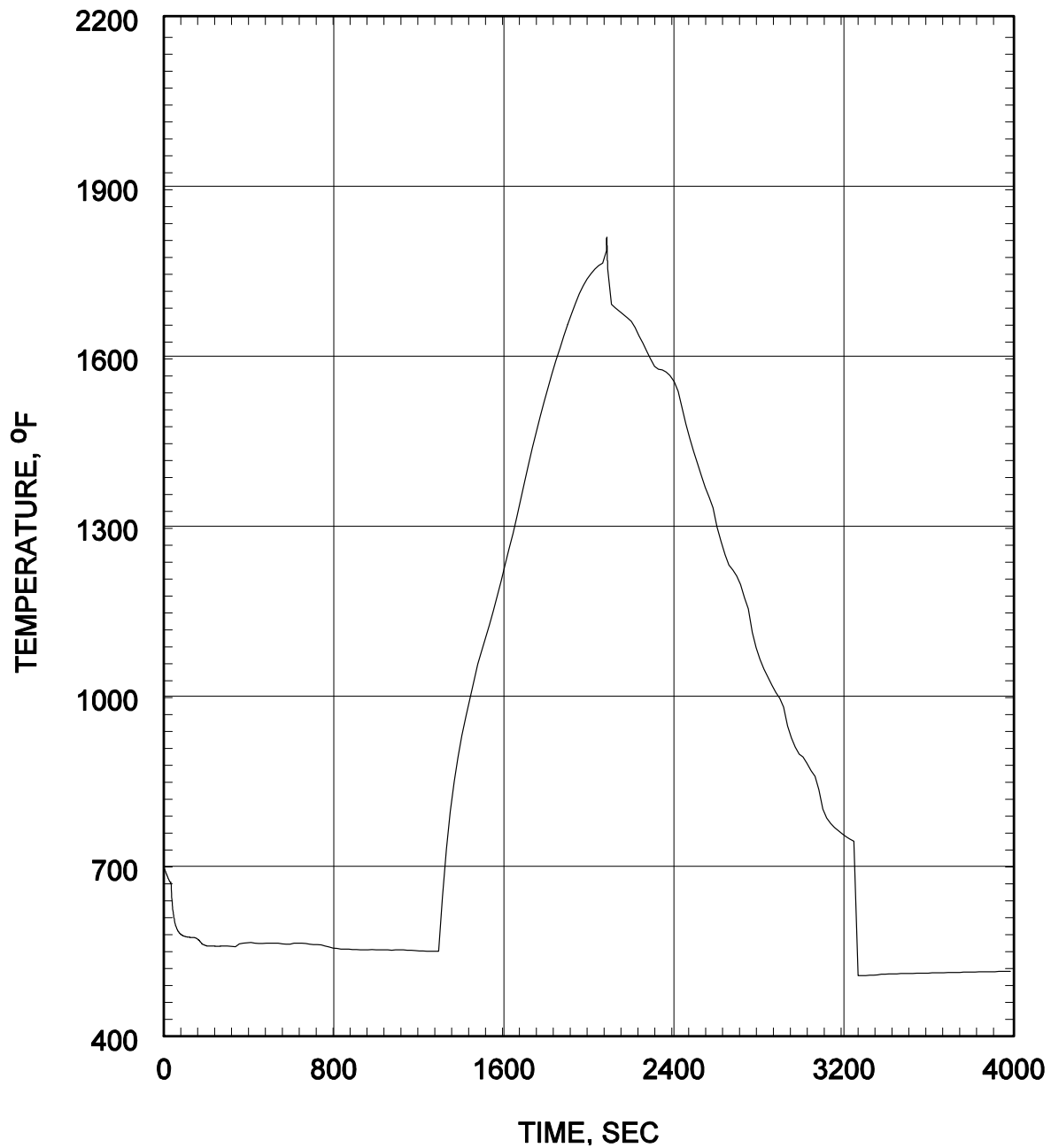


Figure 2.8.5.6.3-56
Small Break LOCA ECCS Performance Analysis
0.05 ft²/PD Break
Core Power

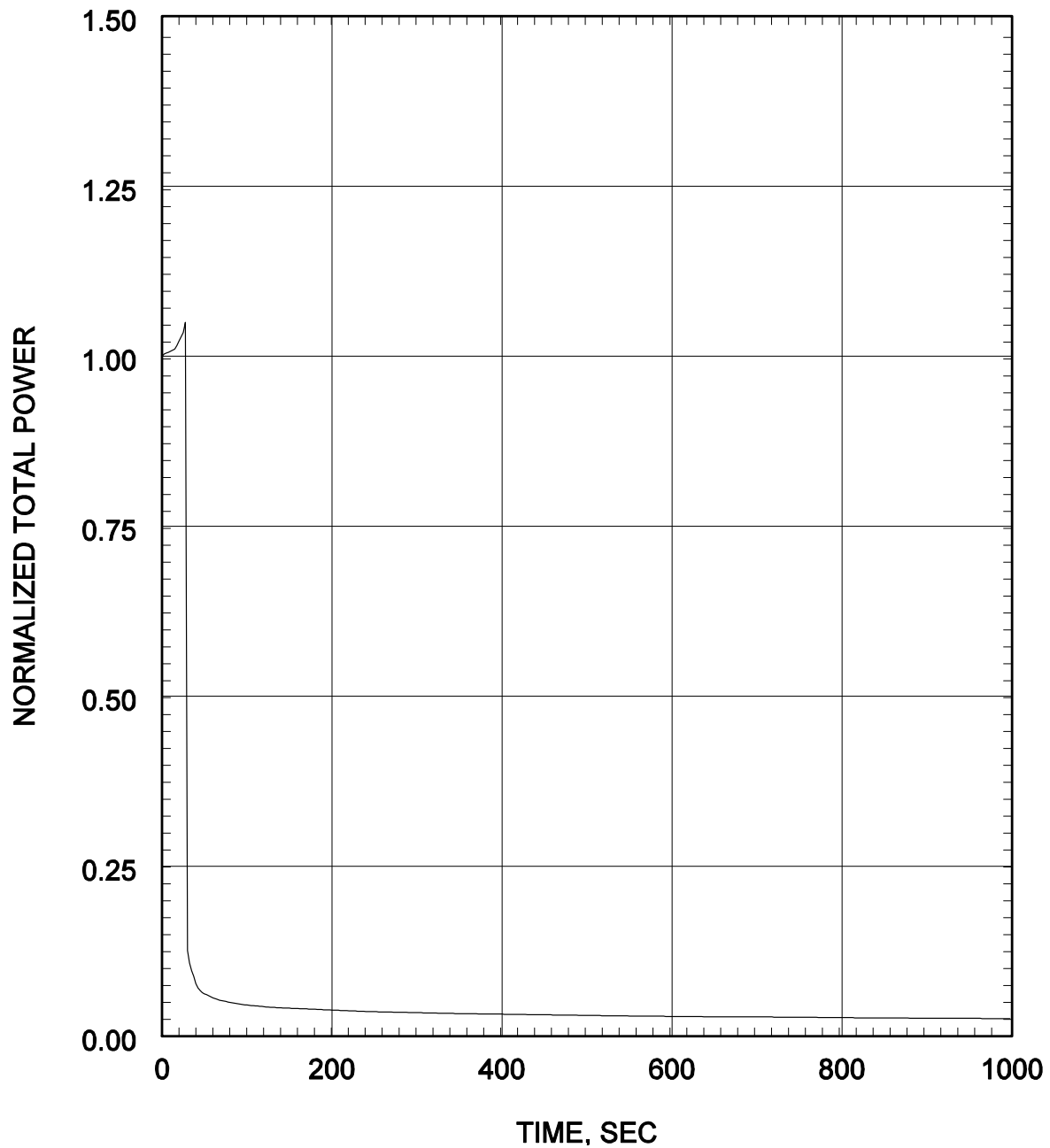


Figure 2.8.5.6.3-57
Small Break LOCA ECCS Performance Analysis
0.05 ft²/PD Break
Inner Vessel Pressure

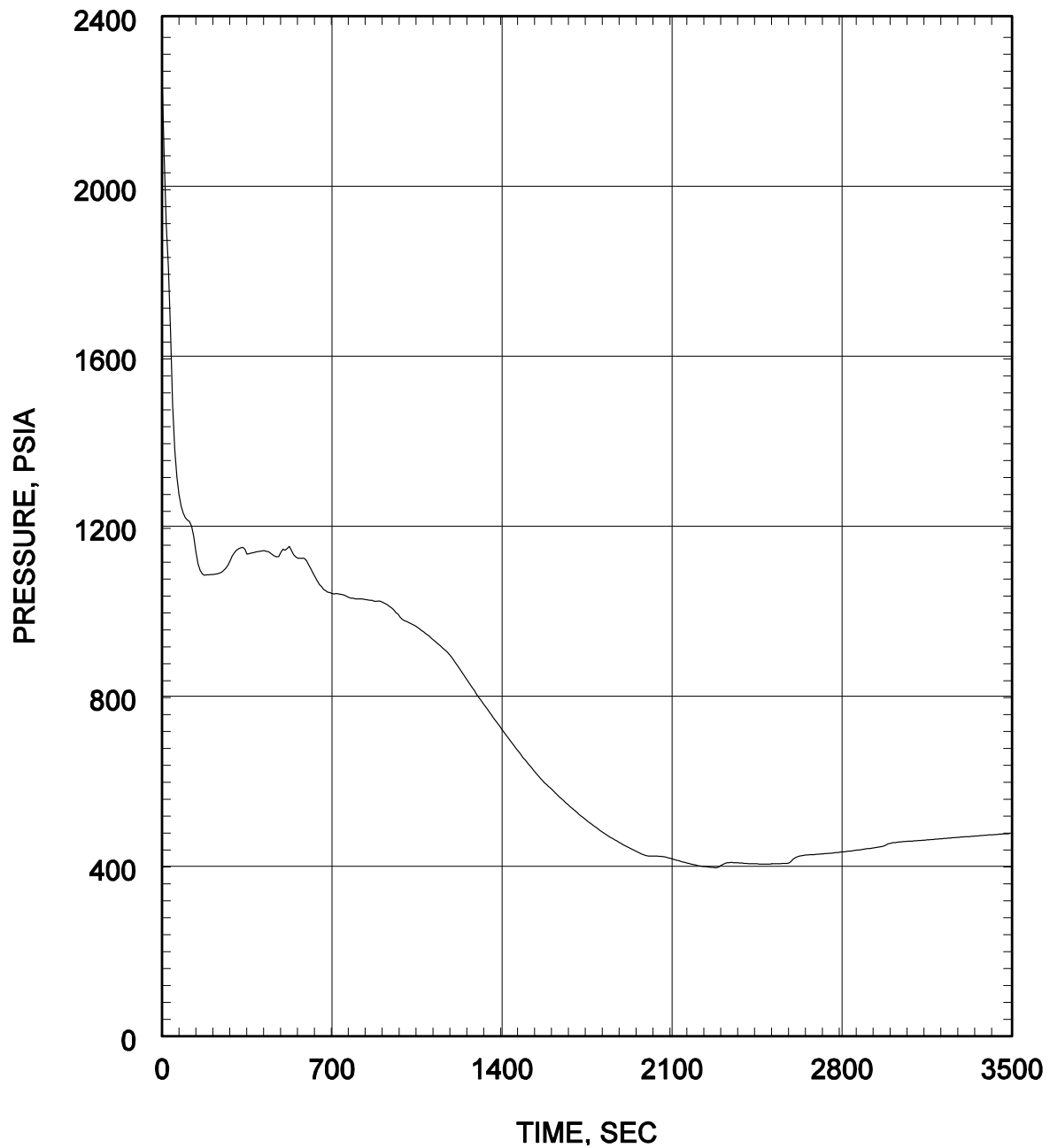


Figure 2.8.5.6.3-58
Small Break LOCA ECCS Performance Analysis
0.05 ft²/PD Break
Break Flow Rate

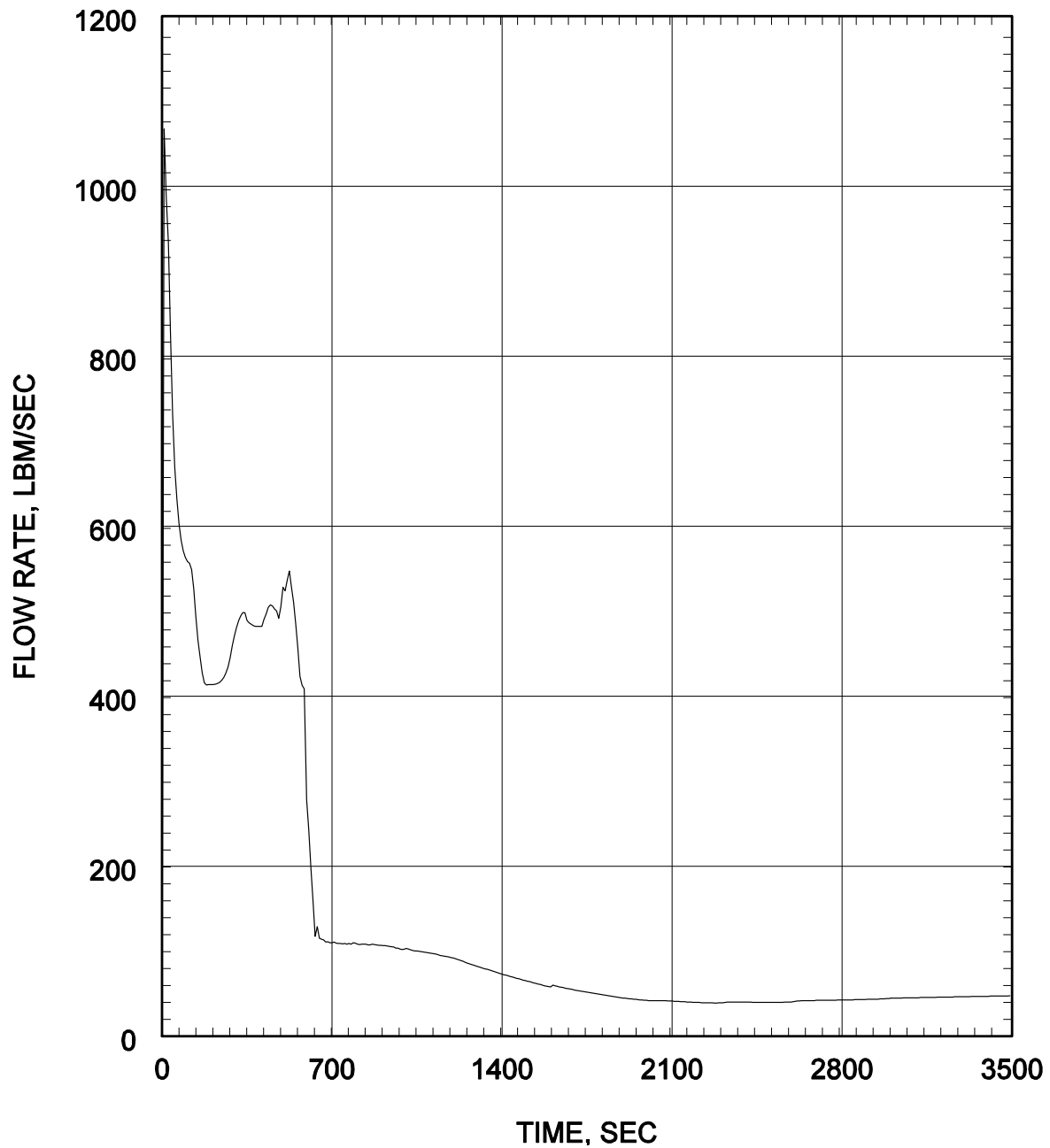


Figure 2.8.5.6.3-59
Small Break LOCA ECCS Performance Analysis
0.05 ft²/PD Break
Inner Vessel Inlet Flow Rate

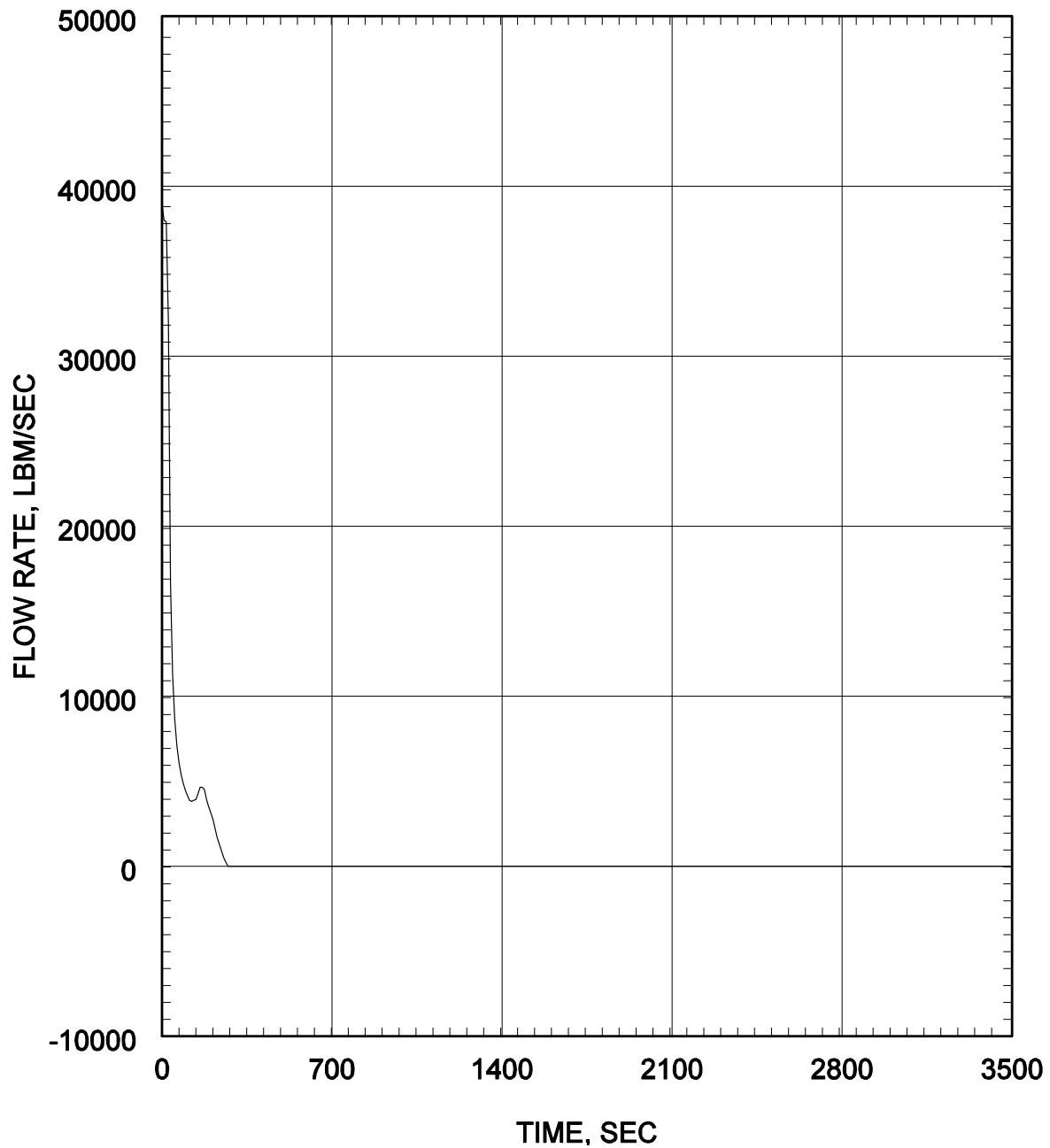


Figure 2.8.5.6.3-60
Small Break LOCA ECCS Performance Analysis
0.05 ft²/PD Break
Inner Vessel Two-Phase Mixture Level

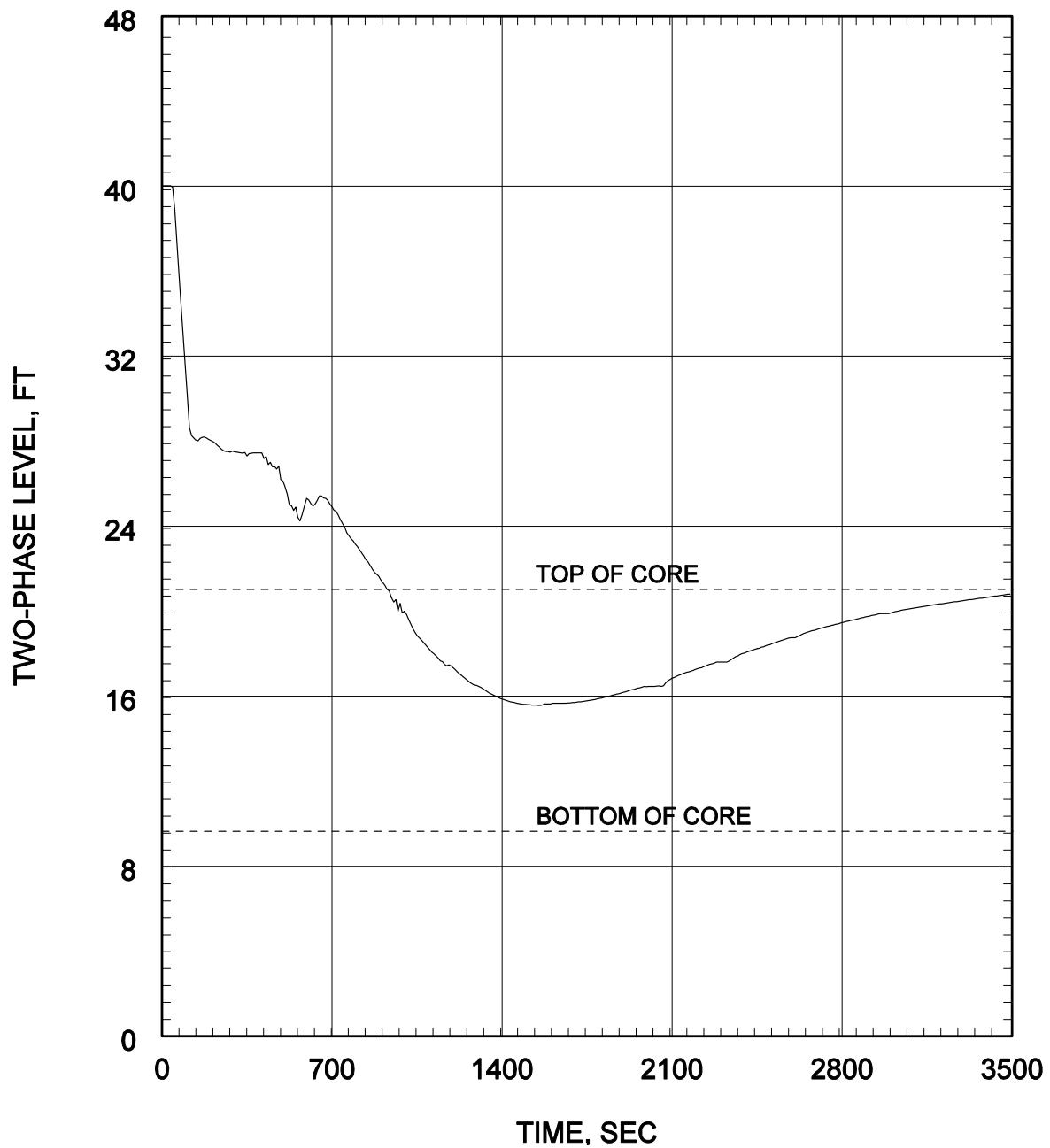


Figure 2.8.5.6.3-61
Small Break LOCA ECCS Performance Analysis
0.05 ft²/PD Break
Heat Transfer Coefficient at Hot Spot

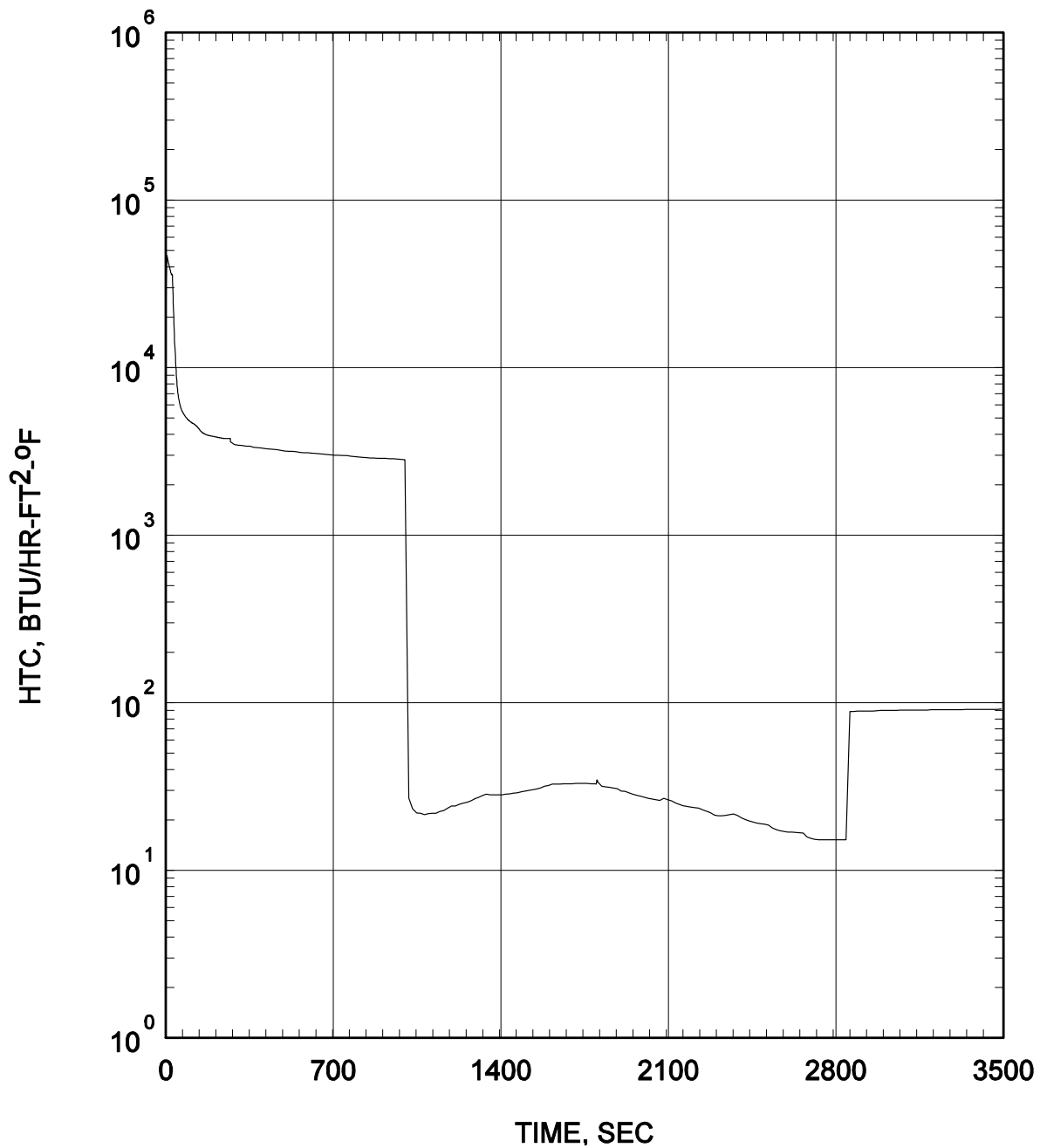


Figure 2.8.5.6.3-62
Small Break LOCA ECCS Performance Analysis
0.05 ft²/PD Break
Coolant Temperature at Hot Spot

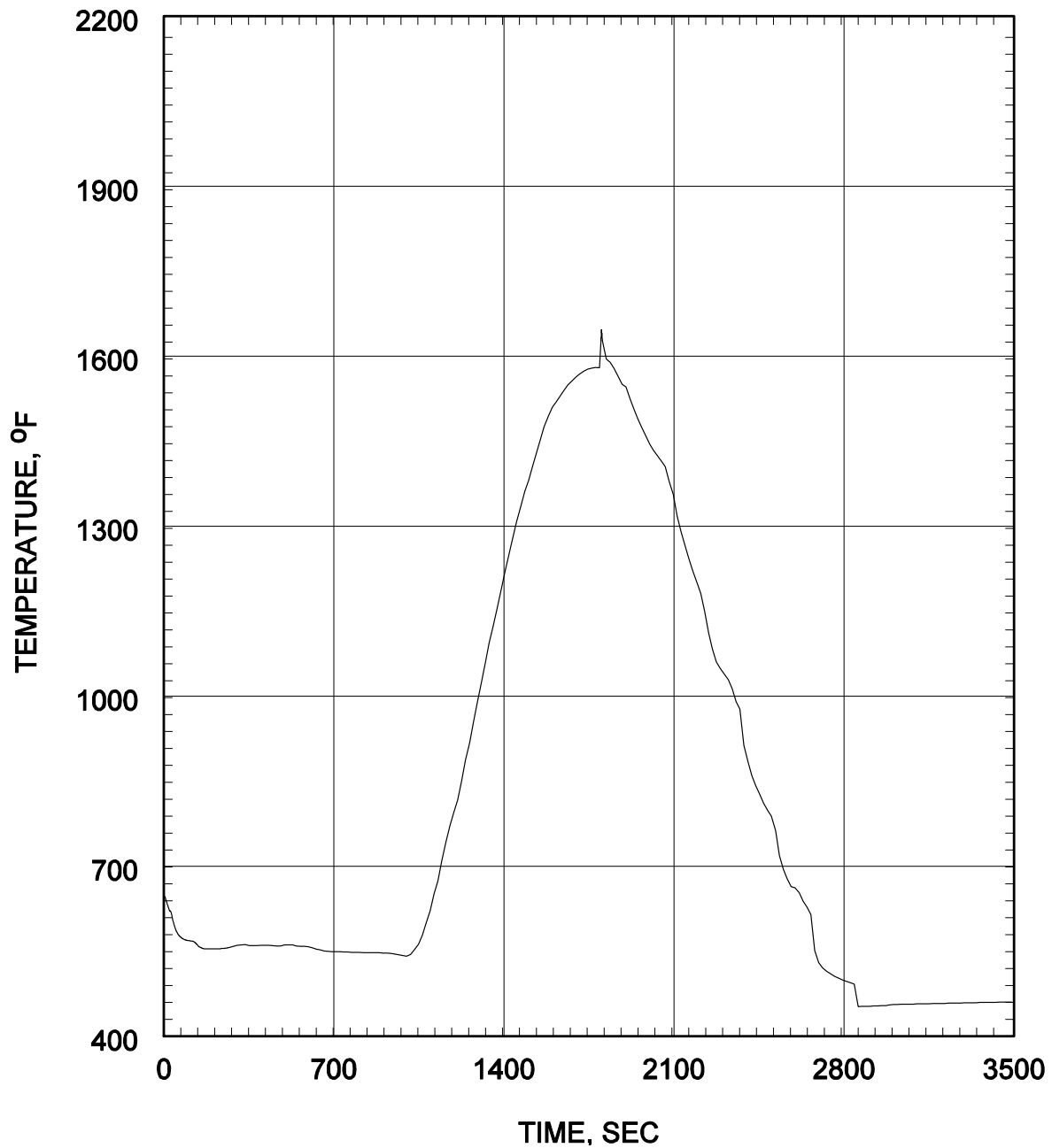


Figure 2.8.5.6.3-63
Small Break LOCA ECCS Performance Analysis
0.05 ft²/PD Break
Cladding Temperature at Hot Spot

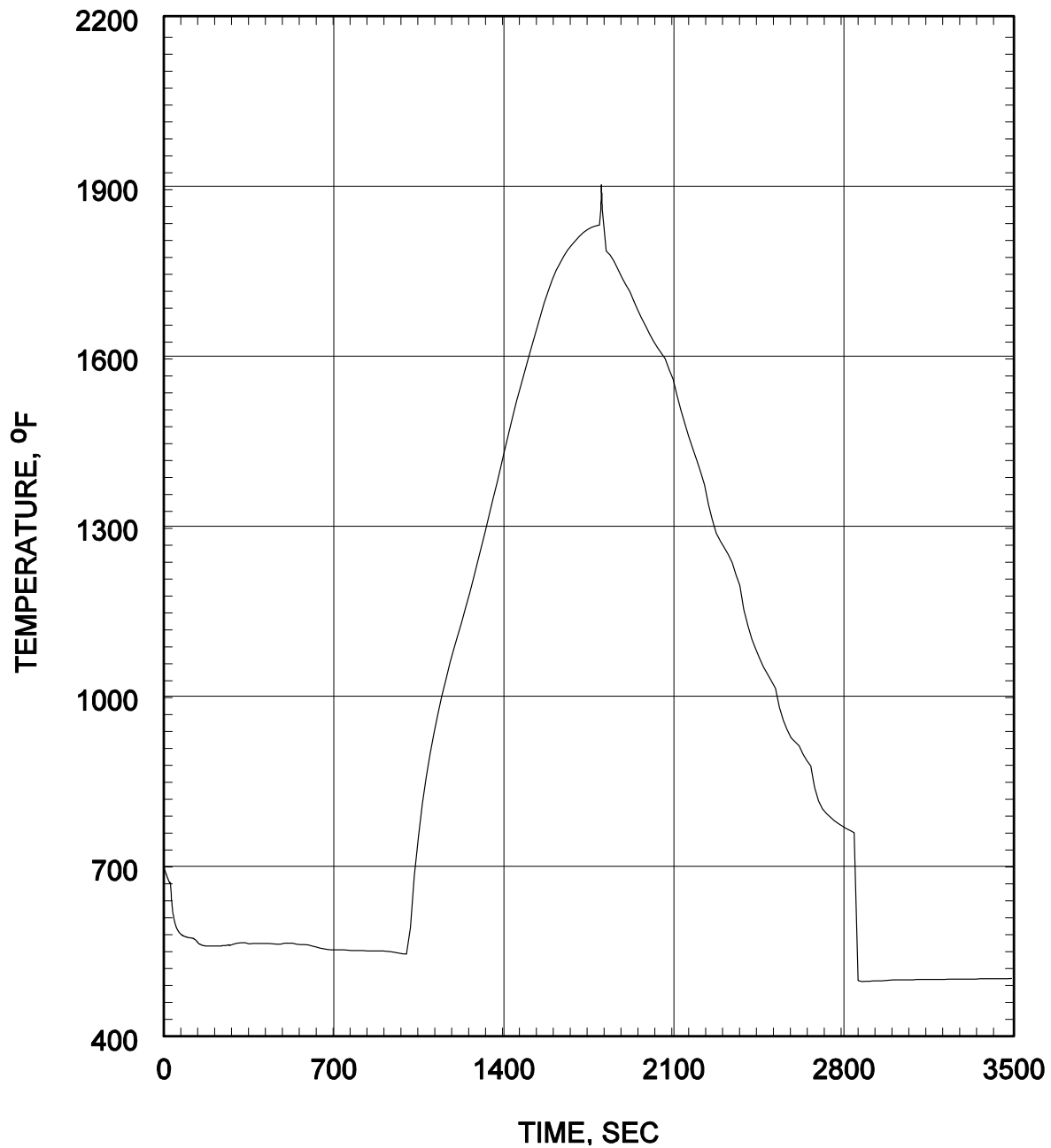


Figure 2.8.5.6.3-64
Small Break LOCA ECCS Performance Analysis
0.06 ft²/PD Break
Core Power

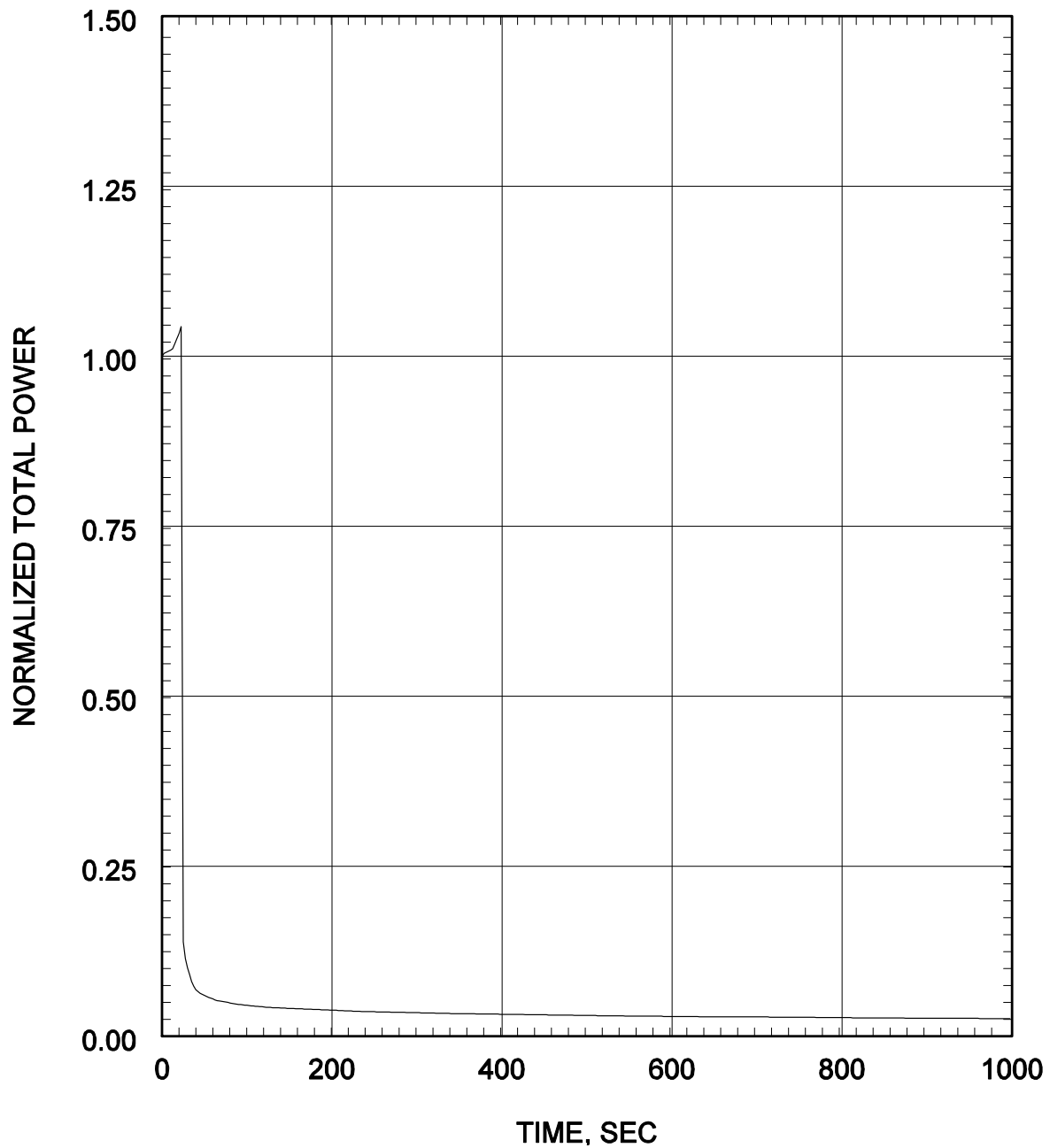


Figure 2.8.5.6.3-65
Small Break LOCA ECCS Performance Analysis
0.06 ft²/PD Break
Inner Vessel Pressure

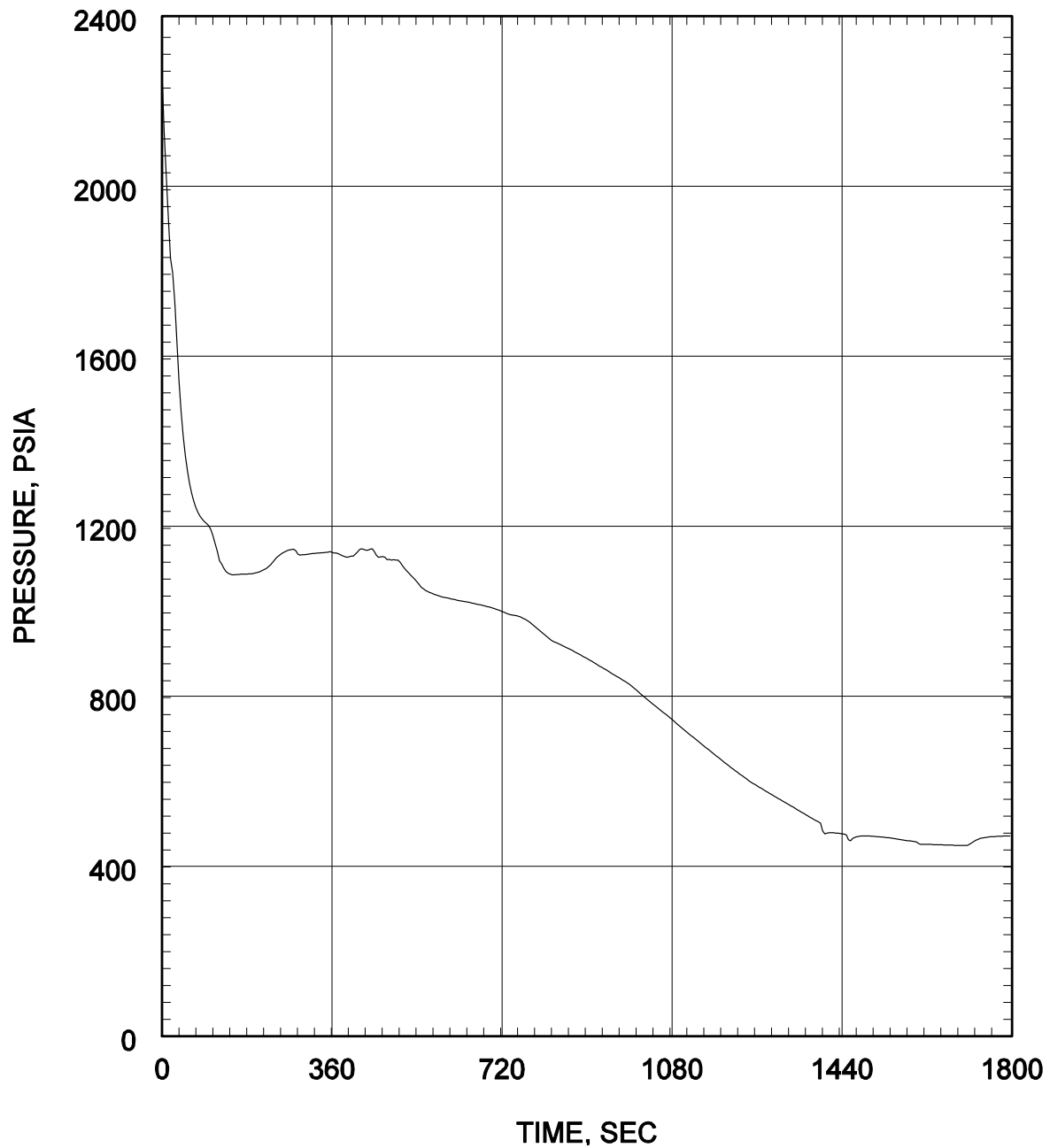


Figure 2.8.5.6.3-66
Small Break LOCA ECCS Performance Analysis
0.06 ft²/PD Break
Break Flow Rate

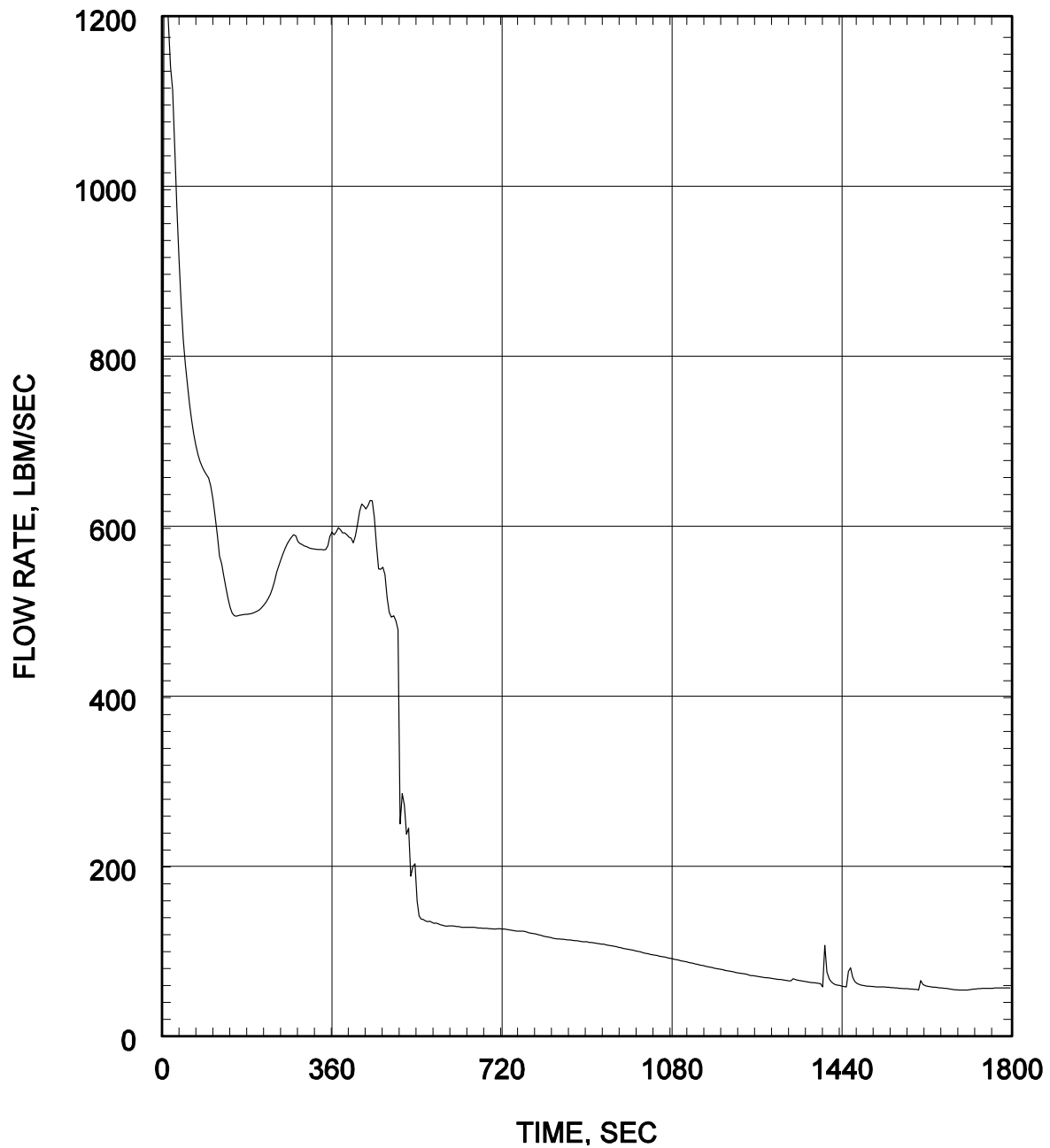


Figure 2.8.5.6.3-67
Small Break LOCA ECCS Performance Analysis
0.06 ft²/PD Break
Inner Vessel Inlet Flow Rate

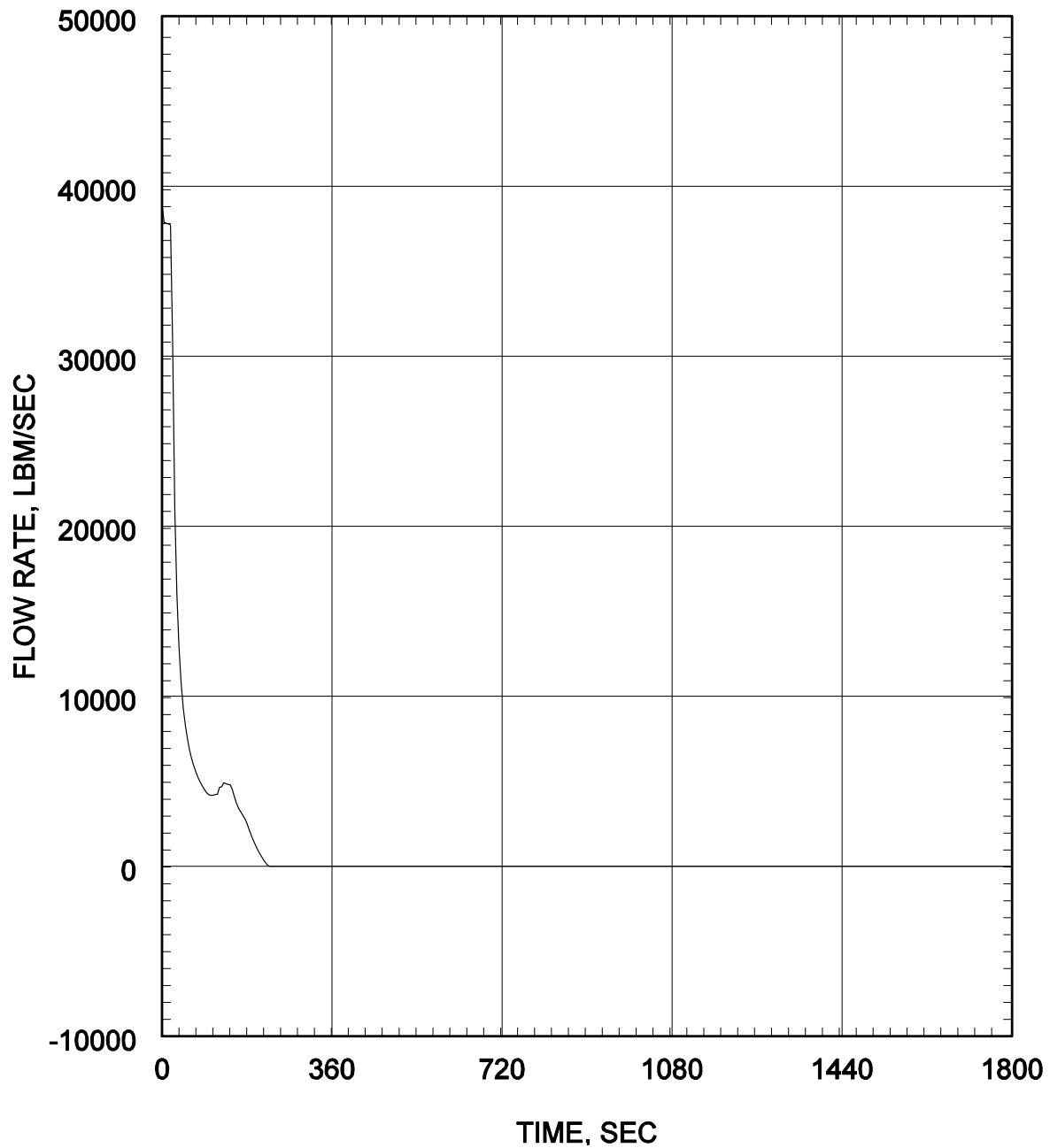


Figure 2.8.5.6.3-68
Small Break LOCA ECCS Performance Analysis
0.06 ft²/PD Break
Inner Vessel Two-Phase Mixture Level

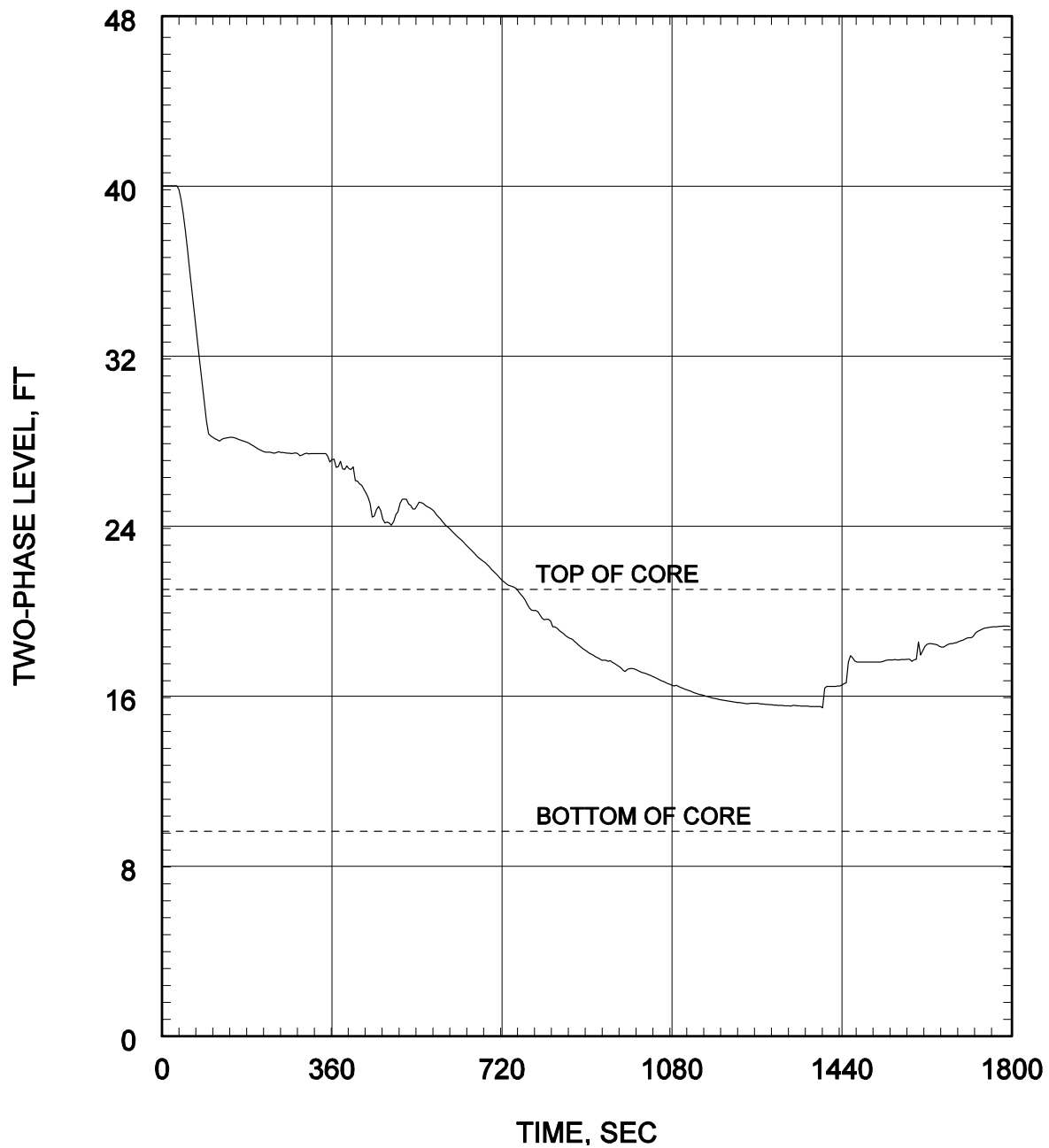


Figure 2.8.5.6.3-69
Small Break LOCA ECCS Performance Analysis
0.06 ft²/PD Break
Heat Transfer Coefficient at Hot Spot

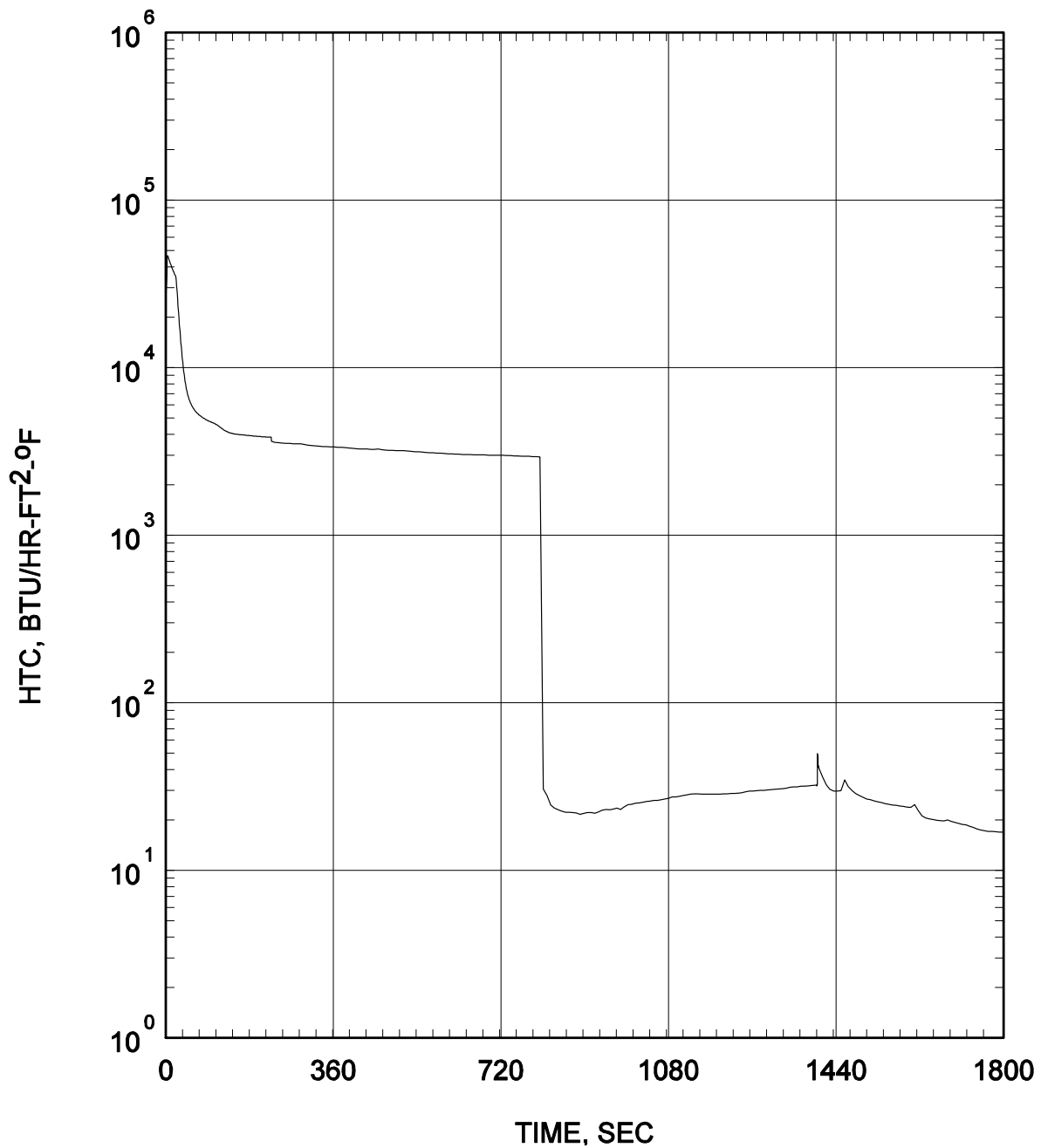


Figure 2.8.5.6.3-70
Small Break LOCA ECCS Performance Analysis
0.06 ft²/PD Break
Coolant Temperature at Hot Spot

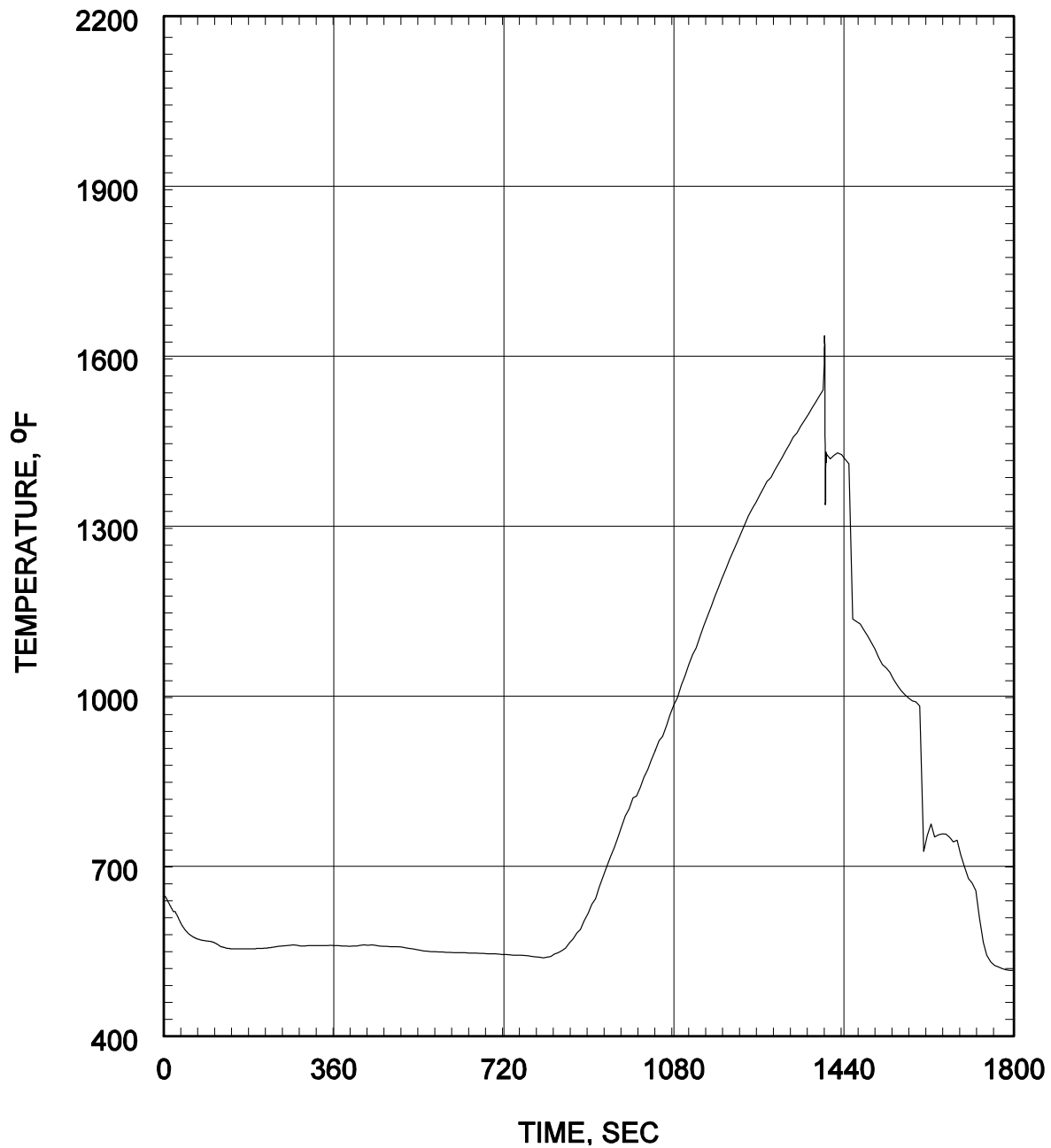


Figure 2.8.5.6.3-71
Small Break LOCA ECCS Performance Analysis
0.06 ft²/PD Break
Cladding Temperature at Hot Spot

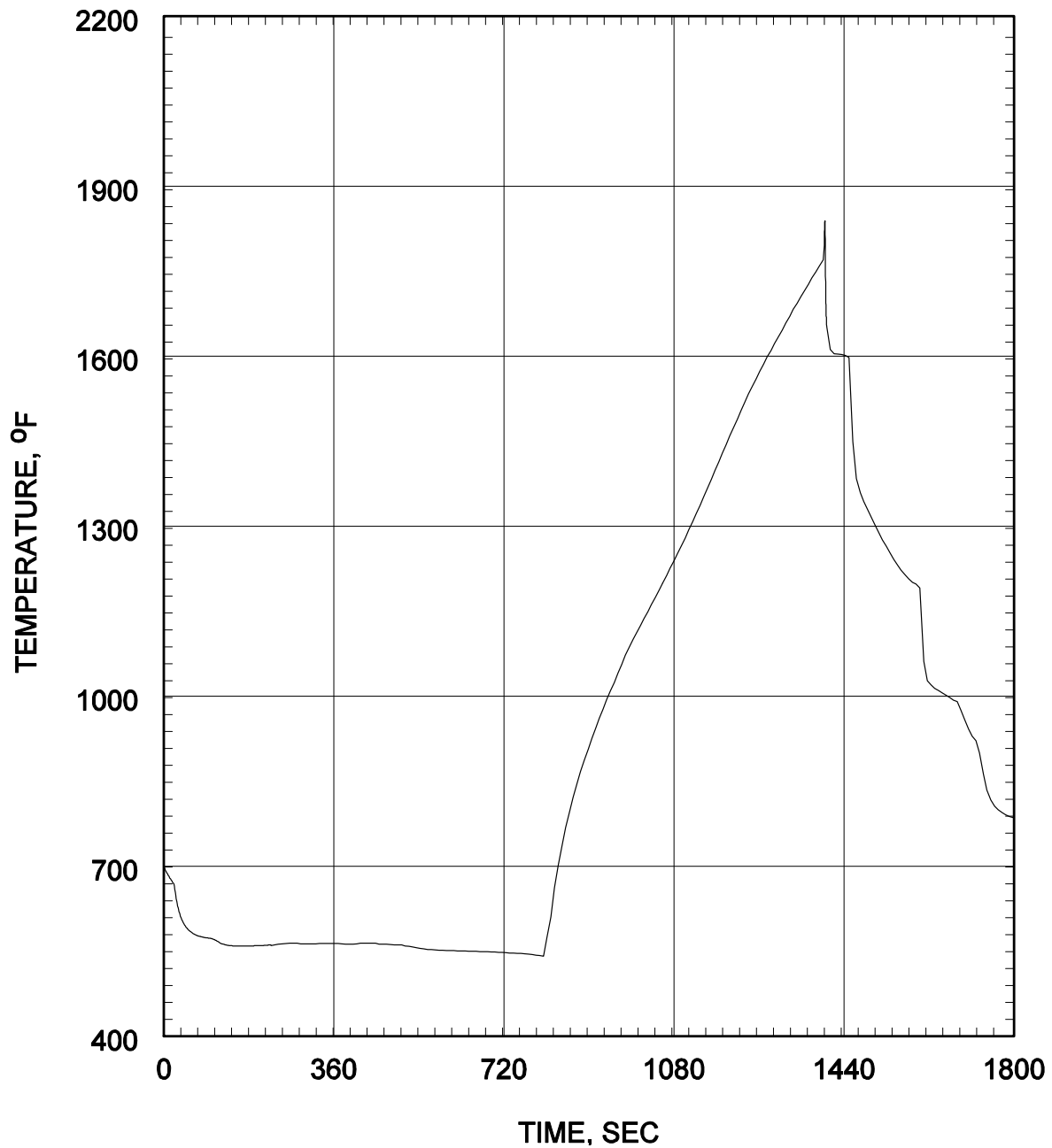


Figure 2.8.5.6.3-72
Boric Acid Concentration in the Core versus Time

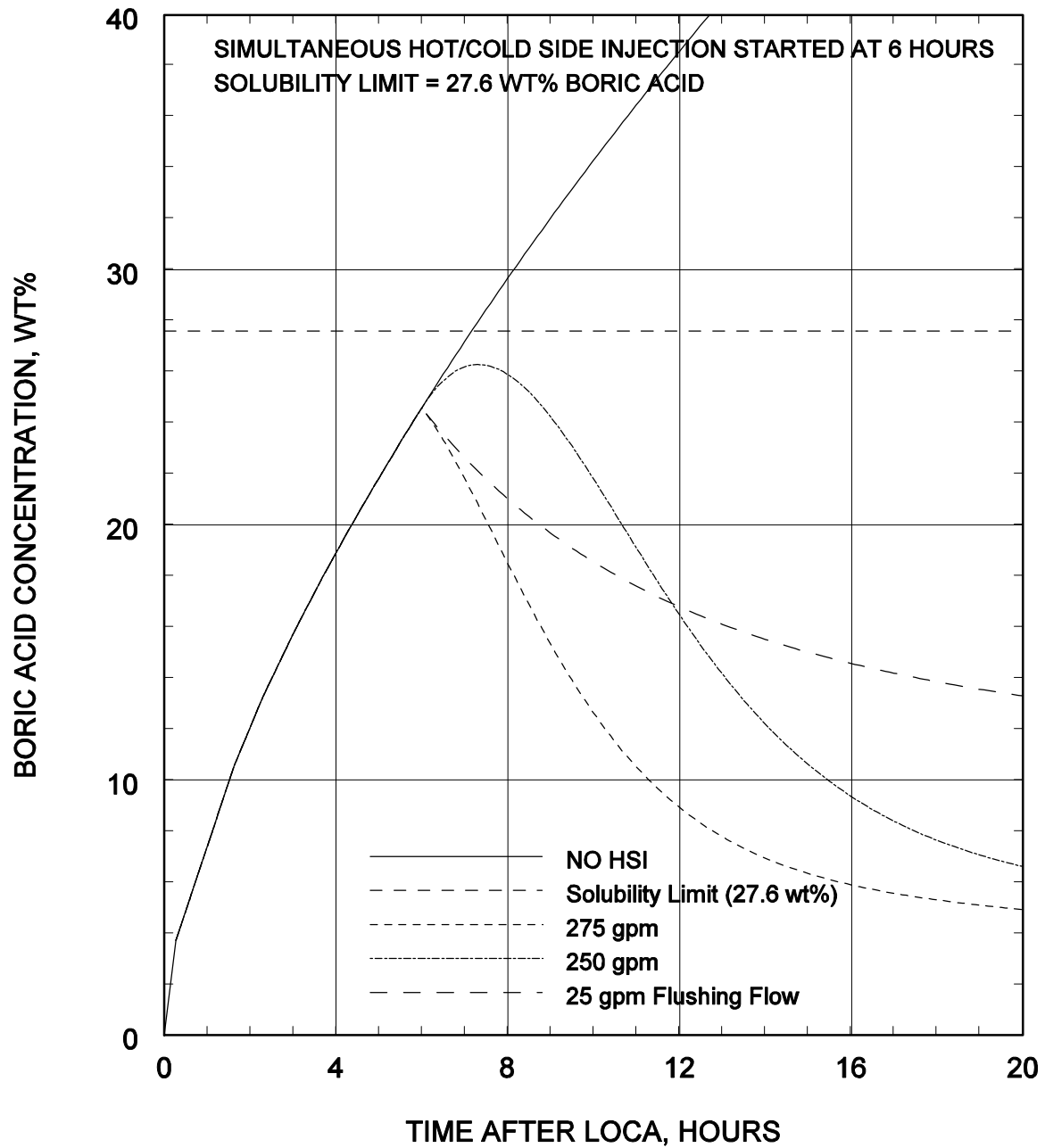


Figure 2.8.5.6.3-73
Core Boil-off and Simultaneous Hot/Cold Leg Injection versus Time

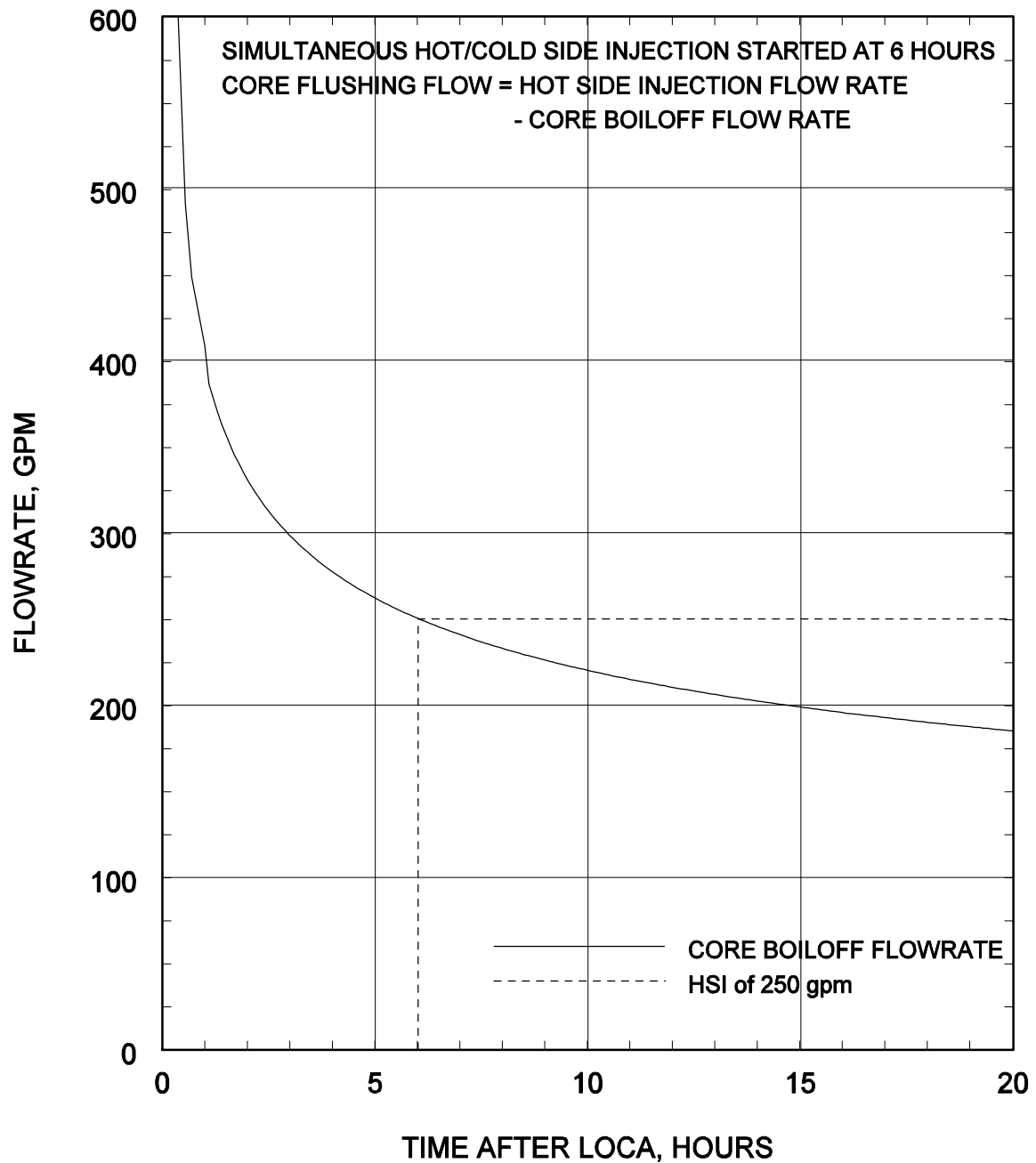


Figure 2.8.5.6.3-74
Break Area versus RCS Refill Time

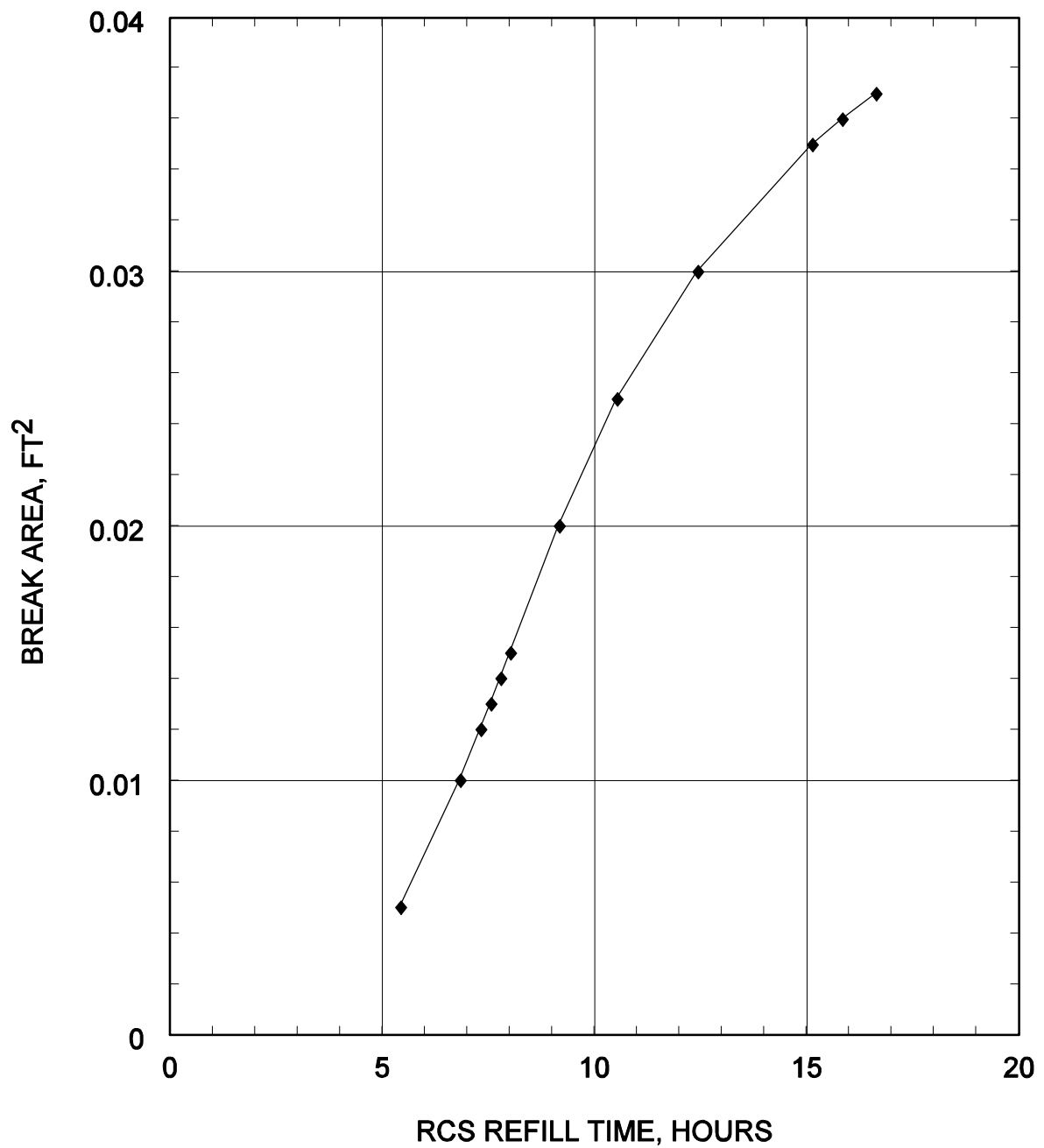


**Figure 2.8.5.6.3-75
Overlap of Acceptable LTC Procedures
In Terms of Cold Leg Break Size**

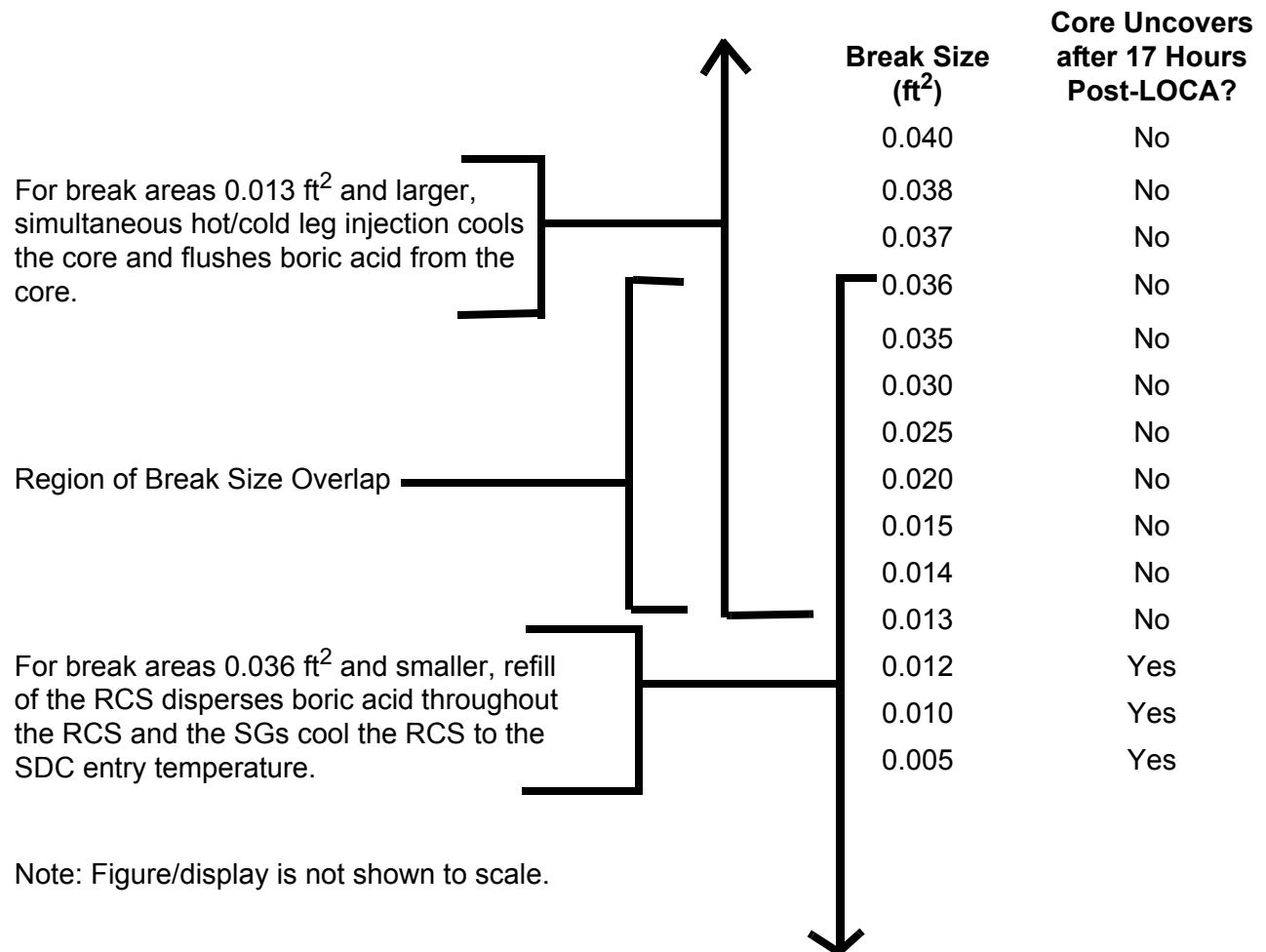
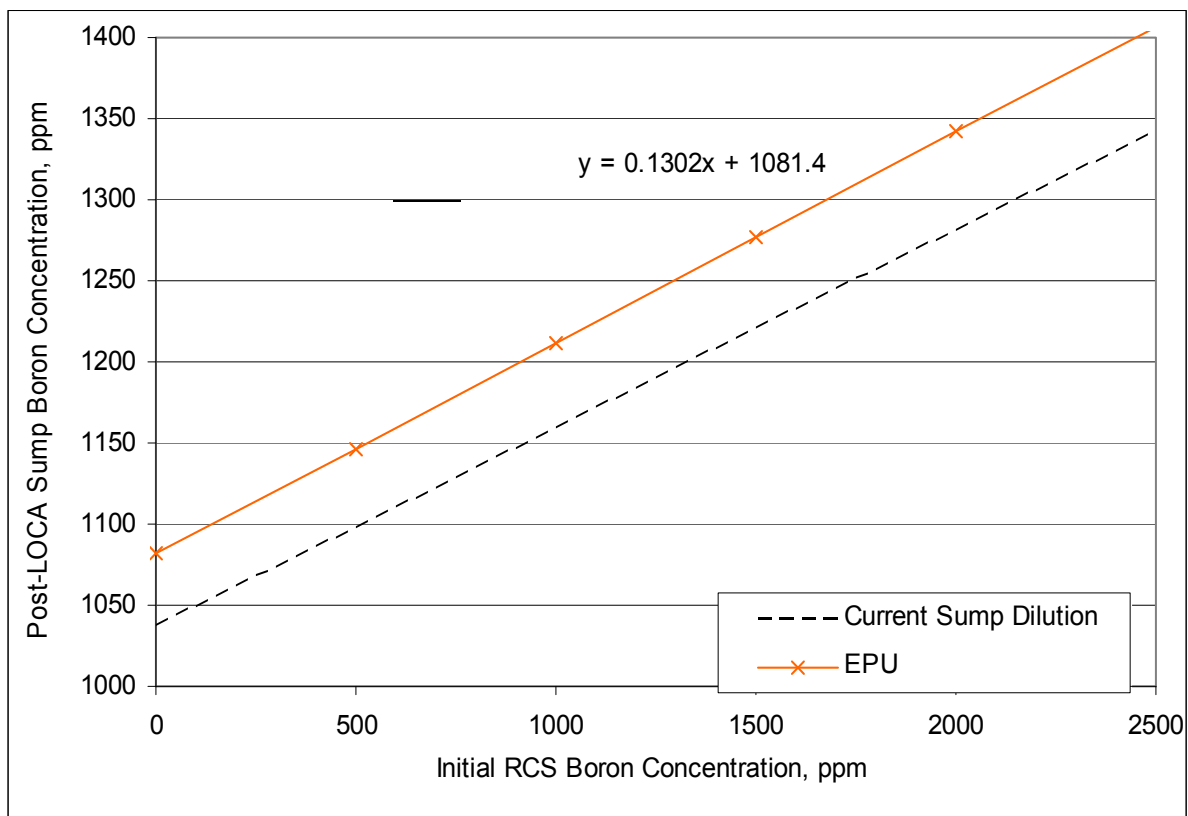


Figure 2.8.5.6.3-76
Minimum Containment Sump Boron Concentration Versus Initial RCS Boron Concentration at 6 Hours Post-LOCA



2.8.5.7 Anticipated Transients Without Scram

2.8.5.7.1 Regulatory Evaluation

Anticipated transients without scram (ATWS) is defined as an anticipated operational occurrence followed by the failure of the reactor portion of the protection system specified in GDC-20.

10 CFR 50.62 requires that:

- Each pressurized water reactor (PWR) must have equipment that is diverse from the reactor trip system to automatically initiate the auxiliary (or emergency) feedwater system and initiate a turbine trip under conditions indicative of an ATWS. This equipment must perform its function in a reliable manner and be independent from the existing reactor trip system, and
- Each PWR manufactured by Combustion Engineering (CE) or Babcock and Wilcox (B&W) must have a diverse scram system (DSS). This scram system must be designed to perform its function in a reliable manner and be independent from the existing reactor trip system.

The Florida Power and Light (FPL) review was conducted to ensure that:

- The above requirements are met, and
- The setpoints for the DSS, diverse turbine trip (DTT), and diverse auxiliary feedwater actuation system (DAFAS) remain valid for the proposed EPU. Note that since St. Lucie Unit 2 has a DSS, DTT, and a DAFAS, an ATWS event is not analyzed.

Review guidance is provided in Matrix 8 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to Title 10 of the Code of Federal Regulations (10 CFR) Part 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the General Design Criteria (GDC) as discussed in UFSAR Section 3.1.

On July 26, 1984, the Code of Federal Regulations was amended to include Section 10 CFR 50.62, Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants (also known as the ATWS Rule). The ATWS Rule requires specific improvements in the design and operation of commercial nuclear power facilities to reduce the likelihood of a failure to shut down the reactor following anticipated transients and to mitigate the consequences of anticipated transients which occur without a shutdown. The occurrence of an anticipated transient in conjunction with a failure of the reactor protection system (RPS) to produce a reactor trip is defined as an ATWS event.

The combination of an RPS failure and an anticipated transient is outside the present plant design basis. However, in order to comply with ATWS rule requirements Combustion Engineering (CE) performed an analysis of an RPS failure and an anticipated transient, the results of which are documented in CENPD-158 ([Reference 1](#)). The results of the analysis revealed that a complete loss of feedwater combined with a failure of the reactor to trip would result in a primary

coolant system pressure excursion well above reactor vessel service level C limits, and therefore, potentially challenge the integrity of the reactor coolant pressure boundary.

For CE plants, the ATWS regulations require the implementation of two methodologies for ensuring that an excessive primary coolant pressure excursion does not occur. These methodologies are called “prevention” and “mitigation”. Prevention takes the form of a DSS whose purpose is to initiate a shutdown of the reactor by control rod insertion upon conditions indicative of an anticipated transient, independently and diversely from the RPS. Mitigation is accomplished by tripping the turbine and initiating auxiliary feedwater (AFW) to conserve steam generator (SG) inventory and to ensure that a primary coolant heat sink is available. A combination of prevention and mitigation will limit the peak reactor coolant system pressure rise to within acceptable values. Detailed discussion pertaining to prevention and mitigation are provided in UFSAR Section 7.6.3.11.

FPL has installed a DSS designed to be diverse and independent from the RPS, except at the instrument loops, which satisfies the ATWS Rule requirements for ATWS prevention. Additionally, FPL has installed a DTT which is independent of the RPS and automatically initiates a turbine trip as well as a DAFAS which is diverse from the RPS and automatically initiates the AFW system. The DTT and DAFAS satisfy the ATWS Rule requirements for mitigation.

The Nuclear Regulatory Commission (NRC) has concluded that the St. Lucie Unit 2 DSS, DTT, and DAFAS designs were acceptable for compliance to 10 CFR Part 50.62, as documented in a letter from Jan A. Morris (NRC), Compliance with ATWS Rule, 10 CFR Part 50.62 – St. Lucie Plant, Unit Nos. 1 and 2 (TAC Nos. 59144 and 59145) to C.O. Woody (FPL) dated September 6, 1989 ([Reference 2](#)).

In addition to the licensing bases described in the UFSAR, the ATWS electrical and I&C cables and connectors and other related components were evaluated for License Renewal. For License Renewal, electrical and I&C systems were broken down into commodity groups and then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.5 of the SER identifies that the ATWS electrical and I&C cables and connectors and other related components are within the scope of License Renewal. The programs used to manage the aging effects associated with the electrical and I&C cables and connectors and other related components are discussed in SER Section 3.6 and UFSAR Chapter 18.

2.8.5.7.2 Technical Evaluation

2.8.5.7.2.1 Introduction

As discussed in LR [Section 2.8.5.7.1](#), Regulatory Evaluation, the regulations for CE plants require the implementation of two methodologies for ensuring that an excessive primary coolant pressure excursion does not occur. These methodologies are called “prevention” and “mitigation”. Prevention takes form as a DSS whose purpose is to initiate a shutdown of the reactor by control rod insertion upon conditions indicative of an anticipated transient, independently and diversely from the RPS. Additionally, the rule requires mitigation through an initiation of the turbine trip and AFW systems that is diverse from the RPS. Mitigation is

accomplished by a DTT function and initiating a DAFAS to conserve SG inventory and to ensure that a primary coolant heat sink is available. Through these diverse means of prevention and mitigation, peak reactor coolant system pressure will remain within acceptable values.

The requirements of 10 CFR 50.62 for prevention and mitigation were incorporated into the DSS, DTT, and DAFAS systems. Their design has been specifically approved in the USNRC Safety Evaluation of Compliance with ATWS Rule 10 CFR 50.62 ([Reference 2](#)).

2.8.5.7.2.2 Input Parameters, Assumptions, and Acceptance Criteria

The DSS, DTT, and DAFAS are specific improvements of design to reduce the likelihood of a failure to shut down the reactor following anticipated transients, and to mitigate the consequences of anticipated transients followed by a failure of the RPS.

The DSS is a safety-related system that utilizes existing pressurizer pressure instruments and signal converters and takes as inputs, signals from secondary current loops. These signals are wired to the engineered safety features actuation system (ESFAS) cabinets where they are processed by DSS bistable and logic components to provide reactor trip signals. The trip signals are used to open the non-safety related control element assembly (CEA) drive motor generator (MG) set output load contactors located between the CEA drive MG set output breakers and the reactor trip switchgear. The consequential loss of voltage on the reactor trip switchgear buses causes the CEAs to drop resulting in a reactor shut down. The DSS actuates on high pressurizer pressure, with the setpoint selected to be higher than the RPS high pressurizer pressure trip setpoint and less than the primary safety valve relief pressure setpoint.

The DTT is inherent in the design of the DSS and utilizes the DSS bistable and logic functions. When the DSS actuates during an ATWS event, the load contactors will open and de-energize the reactor trip switchgear buses. The loss of voltage on the reactor trip switchgear will be sensed by four undervoltage relays, which, in turn will operate one auxiliary relay each. The contacts on the four auxiliary relays are arranged in two-out-of-four logic to provide turbine trip signals. When a turbine trip signal is achieved hydraulic oil will be dumped from the turbine control oil system and turbine trip will occur.

Diversity of the auxiliary feedwater actuation system (AFAS) from the sensor output up to, but not including, the final actuating devices is required. This diversity from the RPS is achieved by utilizing different manufacturers or circuit designs for the bistables, comparators, matrix relays and initiation relays. Finally, the commonality of the electrical power system has been shown to be acceptable based on an analysis of common mode failure mechanisms for DSS, as discussed in UFSAR Section 7.6.1.4.1. The DAFAS, therefore, satisfied the ATWS Rule requirements for mitigation. The DAFAS actuation setpoint on low SG level is synonymous with the AFAS actuation setpoint as shown in Technical Specification Table 3.3-4, Function 7.c, SG 2A & 2B Level Low.

The ATWS acceptance criteria are to demonstrate that the requirements of 10 CFR 50.62 are still met and that the setpoints for the required DSS, DTT, and DAFAS equipment remain valid for the EPU. For 10 CFR 50.62, it is required to demonstrate that St. Lucie Unit 2, which was manufactured by CE, has DSS, DTT, and DAFAS equipment that is diverse from the reactor trip system to automatically initiate the auxiliary (or emergency) feedwater system and initiate a

turbine trip under conditions indicative of an ATWS. The equipment and corresponding setpoints must perform their function in a reliable manner and be independent from the existing reactor trip system.

2.8.5.7.2.3 Description of Analyses and Evaluations

An evaluation was performed to determine the potential impact of the EPU on the continued compliance with the requirements of 10 CFR 50.62. The evaluation included review of the setpoints for the DSS, DTT, and DAFAS to determine if they remain valid for the EPU.

The ATWS Rule, 10 CFR 50.62, required that the design be modified to include a DSS, DTT, and DAFAS. Paragraph (c)(2) of the rule required the installation of a DSS system for CE and Babcock and Wilcox manufactured plants. These system designs were approved by the NRC in the safety evaluation dated September 6, 1989 based on their reliability, independence and diversity from the plant protection system. The EPU does not modify the DSS or DAFAS designs, and therefore, these systems continue to comply with the ATWS Rule. The DTT logic is being modified as part of the turbine control system replacement. The modification will enhance the level of independence and redundancy employed in the logic. The revised system will continue to meet the requirements of the ATWS Rule pertaining to diverse turbine trip. Consistent with the respective safety evaluations approving these designs, the actuation setpoint for DSS/DTT remains above the RPS high pressurizer pressure setpoint and below the pressurizer safety valve relief pressure setpoint. The actuation setpoint for DAFAS is the plant protection system setpoint for the AFAS. The ATWS Rule imposed system design requirements, but ATWS events did not become design basis events required to be analyzed. Therefore, no ATWS event analysis was performed.

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

As discussed above, the ATWS electrical and I&C cables and connectors and other related components are within the scope of License Renewal. Operation of the ATWS electrical and I&C cables and connectors and other related components under EPU conditions has been evaluated to determine if there any new aging effects requiring management or if any existing aging management programs are affected. 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.

2.8.5.7.3 Results

The EPU does not modify the DSS or DAFAS designs, and therefore, these systems continue to comply with the ATWS Rule. The DTT logic is being modified as part of the turbine control system replacement. The modification will enhance the level of independence and redundancy employed in the logic. The revised system will continue to meet the requirements of the ATWS Rule pertaining to DTT.

The DSS actuates on high pressurizer pressure, with the setpoint selected to be higher than the RPS high pressurizer pressure trip setpoint and less than the primary safety valve relief pressure setpoint. As stated in LR **Section 2.4.1**, Reactor Protection, Safety Features Actuation and Control System, the high pressurizer pressure trip setpoint and pressurizer safety valve setpoint values are not impacted by the EPU. Therefore, the existing DSS setpoints are not impacted by the EPU.

The DTT is actuated at the time of a DSS. Since the DSS setpoints are not impacted by the EPU the existing setpoint for the DTT is not impacted by the EPU.

As stated in LR **Section 2.4.1**, Reactor Protection, Safety Features Actuation and Control System, the AFAS setpoint is not impacted by the EPU; therefore, the DAFAS setpoint is not impacted by the EPU.

Since the diverse protection and emergency actuation systems satisfy the licensing requirements for this event, it is concluded that ATWS does not need to be reanalyzed for the EPU. For St. Lucie Unit 2, these systems consist of the DSS, DTT, and DAFAS.

2.8.5.7.4 Conclusion

FPL has reviewed the information related to ATWS and concludes that it has adequately accounted for the effects of the proposed EPU on ATWS. FPL concludes that it has demonstrated that the DSS, DTT, and DAFAS will continue to meet the requirements of 10 CFR 50.62 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to ATWS.

2.8.5.7.5 References

1. CENPD-158, Rev. 1, Analysis of Anticipated Transients Without Reactor Scram in Combustion Engineering NSSS's, May 1976.
2. NRC Letter to FPL, Compliance with the ATWS Rule, 10 CFR Part 50.62 – St. Lucie Plant, Unit Nos. 1 and 2 (TAC Nos. 59144 and 59145), dated September 6, 1989.

2.8.6 Fuel Storage

2.8.6.1 New Fuel Storage

2.8.6.1.1 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 Florida Power and Light (FPL) review covered the ability of the storage facilities to maintain the new fuel in a subcritical array during 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:

- General Design Criterion (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.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conform with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDCs for the nuclear design are as follows:

- GDC-62 is described in UFSAR Section 3.1.62 Criterion 62 – Prevention of Criticality in Fuel Storage and Handling.

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

The new fuel storage and handling facilities are described in UFSAR Sections 9.1.1. New fuel assemblies are stored in racks in parallel rows having center-to-center distances of 23 inches in both directions. New fuel is stored in air in the new fuel handling area.

UFSAR Section 9.1.1.1 states that the new fuel storage rack is designed to:

1. Store 80 fuel assemblies,
2. Provide sufficient spacing between the fuel assemblies to maintain a subcritical array during flooding with unborated water,
3. Maintain a subcritical array under design loadings, including the design basis earthquake,
4. Preclude the possibility of a fuel assembly being placed between the new fuel cavities, and

5. Maintain a subcriticality of at least 2 percent for the simultaneous occurrence of design bases (b) and (c).

Additionally, in December of 1998, FPL elected to comply with the requirements of 10 CFR 50.68(b), which includes restrictions on the reactivity of stored fresh (i.e., new) fuel.

The new fuel in the storage rack is subcritical by at least 2 percent under the assumption of flooding with unborated water and 4.5 weight percent enriched uranium.

Calculations performed for the new fuel storage racks at various degrees of moderation, including full flooding, indicate that the limiting effective neutron multiplication factor (k_{eff}) meets regulatory limits at the 95 percent confidence level. This value is within the safety criteria limit of 0.98 required for new fuel storage racks under optimum moderation conditions.

The impact of changes in fuel design on the analyses for the new fuel storage facilities is addressed in LR [Section 2.8.6.1.2](#).

In addition to the licensing basis described in the UFSAR, the new fuel storage was evaluated for License Renewal. As documented in NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003; the new fuel storage was determined to be outside the scope of License Renewal.

2.8.6.1.2 Technical Evaluation

2.8.6.1.2.1 Introduction

This section provides an assessment of the effect of EPU-related changes on the current analysis of record for the storage of fresh fuel in the new fuel vault (NFV). As part of the EPU changes, the enrichment of new fuel may increase to a maximum planar average of 4.6 weight percent U-235, and therefore, a new bounding evaluation was performed, assessing the storage of fresh fuel with an average enrichment of 4.6 weight percent U-235.

2.8.6.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Nominal dimensions and characteristics of the fuel and NFV are used in the analyses, except future fuel may have a greater UO_2 mass. This is accounted for in the analyses by a slight increase in the fuel density.

Applicable and relevant tolerances of the fuel and vault dimensions are considered as uncertainties in the analyses.

The following lists other major assumptions that were used in the analyses:

- No rack material is modeled, i.e., the model only contains fuel, concrete (walls and floor) and the appropriate amount of unborated water;
- The presence of burnable absorbers in fresh fuel is not credited. This is conservative as burnable absorbers would reduce the reactivity of the fresh fuel assembly; and
- The eccentric fuel positioning condition is considered as part of the uncertainties.

The NFV is intended for the receipt and storage of fresh fuel under normally dry conditions where the reactivity is very low. To assure criticality safety under accident conditions and to conform to the requirements of 10 CFR 50.68, the following two accident condition criteria must be met:

- When fully loaded with fuel of the highest anticipated reactivity and flooded with clean unborated water at full water density, the maximum reactivity, including uncertainties, shall not exceed a k_{eff} of 0.95; and
- With fuel of the highest anticipated reactivity in place and assuming the optimum hypothetical low density moderation, (i.e., fog or foam), the maximum reactivity shall not exceed a k_{eff} of 0.98.

The double contingency principle does not require evaluation of another accident in addition to flooding of the NFV. It should be noted that the dry reactivity of the NFV is so low that no accident other than flooding could result in an approach to criticality.

2.8.6.1.2.3 Description of Analyses and Evaluations

The principal method for the criticality analysis of the NFV is the use of the Monte Carlo code MCNP4A. MCNP4A is a continuous energy three-dimensional Monte Carlo code developed at the Los Alamos National Laboratory. MCNP4A was selected because it has been extensively used and verified for criticality analyses for new and spent fuel storage racks, and has the necessary features for this analysis. MCNP4A calculations use continuous energy cross-section data based on ENDF/B-V.

Benchmark calculations indicate a bias of 0.0013 with an uncertainty of ± 0.0086 for MCNP4A, evaluated with a 95 percent probability at the 95 percent confidence level. The calculations for the NFV analysis utilize the same computer platform and cross-section libraries used for the benchmark calculations.

The maximum k_{eff} is determined from the MCNP4A calculated k_{eff} , the calculational bias, and the applicable uncertainties (bias uncertainty, calculational uncertainty, uncertainties from tolerances) using the following formula:

$$\text{Max } k_{\text{eff}} = \text{Calculated } k_{\text{eff}} + \text{bias} + [\sum_i (\text{Uncertainty})^2]^{1/2}$$

The analyses utilized full three-dimensional geometric models, where each fuel rod and its cladding were described explicitly.

Analyses were performed for various water densities, ranging from 0.01 percent to 100 percent of the full water density. The uncertainty evaluations were performed for 100 percent water density, and the water density corresponding to the optimum moderation condition.

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

In addition to the licensing basis described in the UFSAR, the new fuel storage was evaluated for License Renewal. As documented in NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003, the new fuel storage was determined to be outside the scope of License Renewal.

2.8.6.1.2.5 Results

The calculated reactivity of the NFV, when filled with fresh fuel having a maximum planar average enrichment of 4.6 weight percent U-235 was determined in support of the EPU activities. The maximum calculated reactivity of the NFV for 100 percent water density, including applicable uncertainties and applicable bias, is 0.9152. The optimum hypothetical low density moderation (i.e., fog or foam) occurs at 8 percent water density. The corresponding maximum calculated reactivity of the NFV for this 8 percent water density case, including applicable uncertainties and applicable bias, is 0.9358. The results are below the respective regulatory limits of 0.95 for full water density and 0.98 for the optimum moderation conditions. The regulatory requirements are therefore met for fuel under EPU conditions.

2.8.6.1.3 Conclusion

FPL has reviewed the 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 FPL finds the proposed EPU acceptable with respect to new fuel storage.

2.8.6.2 Spent Fuel Storage

2.8.6.2.1 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 credible storage conditions and to provide a safe means of loading the assemblies into shipping casks. The Florida Power and Light (FPL) review covered the effect of the extended power uprate (EPU) on the criticality analysis as related to the reactivity of the spent fuel storage arrays.

The NRC's acceptance criteria are based on:

- General Design Criterion (GDC)-4, insofar as it requires that structures, systems and components (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
- 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 Standard Review Plan (SRP) Section 9.1.2.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria for Nuclear Power Plants as specified in Appendix A to Title 10 of the Code of Federal Regulations (10 CFR) Part 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDC for the spent fuel storage are as follows:

- GDC-4 is described in UFSAR Section 3.1.4 Criterion 4 – Environmental and Missile Design Basis.
- GDC-62 is described in UFSAR Section 3.1.62 Criterion 62 – Prevention of Criticality in Fuel Storage and Handling.

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

The spent fuel storage and handling facilities are described in UFSAR Section 9.1.2. The high density spent fuel storage racks consist of 19 distinct modules of varying sizes in two regions. Region 1 spent fuel pool storage racks are designed for storage of fresh and irradiated fuel, with initial enrichments of up to 4.5 w/o U-235. Region 1 is also designed to store fuel assemblies with initial enrichments up to 4.5 w/o U-235 that have not achieved sufficient burnup to be stored in Region 2. The nominal center-to-center spacing in Region 1 is 8.96 inches. Generally, all Region 1 cells contain "L" inserts, which are stainless steel neutron absorbers. Vacant locations provide a flux trap for reactivity control.

Region 2 is used to store fuel that has experienced sufficient burnup such that storage in Region 1 is not required. Region 2 storage cells were designed for depleted fuel with initial enrichments up to 4.5 w/o U-235. The nominal center-to-center spacing in this region is also 8.96 inches. Vacant locations provide a flux trap for reactivity control.

The spacing and the allowable fuel configuration of the spent fuel racks are sufficient to maintain the effective neutron multiplication factor (k_{eff}) less than 1.0 for all fuel assemblies when in unborated water.

The spent fuel pool is designed to provide safe storage for irradiated fuel assemblies, control element assemblies, new fuel and the spent fuel shipping cask. A total of 1584 cells are in the spent fuel pool with 1360 storage cells available for placement of fuel assemblies and 131 cells required to be left as water holes based on the analyzed configurations. Other cells contain cell blocking devices. The system design includes interlocks, travel limits and other protective devices to minimize the probability of either mishandling or of equipment malfunction that could result in inadvertent damage to a fuel assembly and potential fission product release. Criticality is precluded by the spacing of fuel assemblies to ensure a subcritical array of k_{eff} 0.95 is maintained, assuming credit for a portion of the soluble boron present in the fuel pool water (520 ppm) and design basis earthquake loading. The pool always contains boric acid at the refueling concentration of at least 1720 ppm whenever fuel is being stored.

In conjunction with the fuel pool storage racks, an additional rack, the cask pit storage rack, is capable of being installed in the cask pit area of the spent fuel pool. The cask pit storage rack is a Region 2 type, which uses Boral as a neutron poison. The cask pit storage rack is designed for storage of irradiated fuel assemblies having initial enrichments of up to 4.5 wt % U-235. Fuel assemblies are stored at a nominal 8.8 inch center-to-center spacing in the cask pit storage rack. The cask pit storage rack is removable and designed to provide storage for an additional 225 assemblies. This brings the total storage capability to 1585 assemblies with the cask pit storage rack installed. The cask pit storage rack is designed to maintain $k_{\text{eff}} < 1.0$ with no soluble boron present in the spent fuel pool water and 0.95 when credit is taken for soluble boron.

UFSAR Section 9.1.3.3.2 evaluated an inadvertent boron dilution event in the spent fuel pool. It demonstrated that no credible dilution event can cause a reduction in boron concentration to less than 520 ppm.

UFSAR Section 9.1.2.3 describes a postulated misplaced fuel assembly event where a fresh, unburned fuel assembly could, in the absence of soluble poison, result in exceeding the regulatory limit of k_{eff} 0.95. A boron concentration of 1266 ppm is required to assure the regulatory limit of 0.95 for k_{eff} is not exceeded.

As stated in UFSAR Sections 9.1.1.1 and 9.1.2.1, in December of 1998, FPL elected to comply with the requirements of 10 CFR 50.68(b), which includes restrictions on the reactivity of stored fresh (new) and stored spent fuel. Following issuance of the license amendment regarding spent fuel pool soluble boron credit, St. Lucie Unit 2 now credits the presence of soluble boron in fuel pool water during normal operating conditions, consistent with requirements of 10 CFR 50.68(b)(4).

In addition to the licensing basis described in the UFSAR, the spent fuel storage racks were evaluated for License Renewal. For License Renewal, evaluation boundaries were established

for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.4.2.7 of the SER identifies components in the fuel handling building that are within the scope of License Renewal.

2.8.6.2.2 Technical Evaluation

2.8.6.2.2.1 Introduction

The purpose of this section is to provide a description of the criticality analysis performed to support the storage of fuel assemblies that operate at EPU conditions along with the existing fuel inventory that operated at pre-EPU conditions in the spent fuel pool. As part of the EPU changes, the enrichment of the new fuel may increase to a maximum planar average value of 4.6 w/o U-235 and the spent fuel pool minimum boron concentration is being increased to 1900 ppm. The core operating characteristics will also be different at EPU conditions, which has a direct impact on the criticality analysis for the spent fuel pool. Therefore, the current licensing basis analysis was replaced by an analysis that bounds both EPU and pre-EPU fuel, and blanketed and non-blanketed fuel, in a new evaluation with a single set of conditions (Cases, Enrichments, Burnups, Cooling Times, as applicable). This approach avoids having to distinguish between EPU and pre-EPU fuel, and between fuels with different axial enrichment variations from a criticality perspective in the spent fuel pool. Additionally, the cask pit rack was reanalyzed to qualify this rack for storing fuel with a maximum planar average enrichment of 4.6 w/o U-235.

This license amendment request (LAR) also proposes rack enhancements that equip the storage cells with inserts made of the metallic neutron absorber Metamic™. The inserts proposed for use are the Holtec DREAM (an acronym for Device for Reactivity Mitigation) Inserts, which consist of a chevron cross-section of Metamic™ positioned adjacent to two perpendicular faces of a fuel assembly and aluminum handling/lifting features. The inserts are functionally identical to and are fabricated from the same materials as the inserts currently in use at Turkey Point Units 3 and 4. In this document, the terms DREAM Insert, Metamic™ insert and Metamic™ panel are used interchangeably. These inserts are considered in the analyses.

This LAR also proposes the use of absorber rods in Region 2 racks. Absorber rods are control element assemblies (CEAs), or devices that meet the same criticality control parameters as CEAs but are not qualified for in-core operation. Absorber rods are currently already qualified for use in Region 1 racks.

The LAR also proposes to increase the spent fuel pool rack storage capacity TS limit from 1360 fuel assemblies to 1491 fuel assemblies.

The effects of EPU on the spent fuel pool cooling system are evaluated in Licensing Report (LR) [Section 2.5.4.1](#).

2.8.6.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

To account for the EPU fuel, and to reflect current NRC standards, input parameters and assumptions are revised compared to the current licensing basis criticality analyses, specifically in the following areas:

- Spent Fuel Racks
- Specific 2x2 arrays are used instead of the fixed pattern of fuel and water cells in both Region 1 and 2 evaluated for the whole pool;
- Planar average enrichments up to 4.6 w/o U-235;
- Bounding EPU core operating parameters for the depletion analyses: 1000 ppm core soluble boron, reactor specific power of 37.5 MW/mtU, a conservative fuel temperature of 1451°F, and a peak power assembly exit moderator temperature of 630°F;
- Revised pre-EPU core operating parameters: a conservative fuel temperature of 1402°F, and a peak power assembly exit moderator temperature of 630°F;
- Credit for Metamic™ DREAM inserts or absorber rods for additional reactivity control in some of the analyzed configurations;
- Cask Pit Rack; and
- Fresh and spent fuel with a fuel planar average enrichment up to 4.6 w/o U-235.

As in the current licensing basis criticality analyses, the objective of the spent fuel and cask pit rack analyses is to ensure that k_{eff} is less than or equal to 0.95 with the storage racks fully loaded with fuel of the highest permissible reactivity and the pool flooded with borated water at a temperature corresponding to the highest reactivity. In addition, it is demonstrated that k_{eff} is less than 1.0 under the assumed accident of the loss of soluble boron in the pool water, i.e. assuming unborated water in the spent fuel pool.

The maximum calculated reactivities include a margin for uncertainty in reactivity calculations, including manufacturing tolerances, and are calculated with a 95 percent probability at a 95 percent confidence level.

See Sections 3 and 5 of Appendix G to Attachment 5 for further details on acceptance criteria and input data for the analyses, respectively.

2.8.6.2.2.3 Description of Analyses and Evaluations

For the spent fuel and cask pit racks, the following ten fuel configurations (cases) are analyzed:

- Case 1: Cask pit rack with a checkerboard of fresh fuel and empty cells;
- Case 2: Region 1 storage rack with a checkerboard of fresh fuel and empty cells;
- Case 3: Region 1 storage rack 2x2 array of uniformly loaded spent fuel, with one cell containing a fuel assembly containing absorber rods;

- Case 4: Region 1 storage rack 2x2 array uniformly loaded with spent fuel in any three storage locations and one storage location empty;
- Case 5: Region 2 storage rack 2x2 array uniformly loaded with spent fuel, with any two of the four cells containing a Metamic™ insert;
- Case 6: Region 2 storage rack 2x2 array uniformly loaded with spent fuel, with any one of the four cells containing a Metamic™ insert;
- Case 7: Region 2 storage rack 2x2 array uniformly loaded with spent fuel, with one empty location out of the four storage locations;
- Case 8: Cask pit rack 2x2 array uniformly loaded with spent fuel, with one empty location out of the four storage locations;
- Case 9: Region 2 storage rack 2x2 array uniformly loaded with spent fuel, with any two of the four cells containing absorber rods in the fuel assemblies; and
- Case 10: Region 2 storage rack 2x2 array uniformly loaded with spent fuel, with any one of the four cells containing absorber rods in the fuel assemblies.

For each case with spent fuel (Cases 3 through 10), extensive calculations are performed to verify that, as a combined result of the revised operating parameters, the increased enrichment, and the additional neutron absorber (Cases 3, 5, 6, 9 and 10 only), the maximum reactivity is less than the allowed regulatory limit.

Additionally, for the spent fuel and cask pit racks, calculations with fresh fuel (normal and accident conditions as applicable) are re-performed, for the increased enrichment of 4.6 w/o U-235.

The principal method for the criticality analysis of the storage racks is the use of the Monte Carlo code MCNP5. MCNP5 is a continuous energy, three-dimensional Monte Carlo code developed at the Los Alamos National Laboratory. MCNP5 was selected because it has been extensively used and verified for criticality analyses for new and spent fuel storage racks and has the necessary features for this analysis. MCNP5 calculations predominantly used continuous energy cross-section data based on ENDF/B-V and ENDF/B-VI. Note that MCNP5 is used for all criticality analyses, including those to evaluate the reactivity effect of fuel and rack tolerances and temperature variations, and to perform various studies.

Actinide benchmarking of MCNP5 was performed based on calculations for a total of 291 critical experiments with fresh UO₂ fuel, fresh MOX fuel, and fuel with simulated actinide composition of spent fuel (HTC experiments). The results of these benchmarking calculations show few significant trends, and indicate a bias of 0.0036 with an uncertainty of ± 0.0085 , evaluated with a 95% probability at the 95 percent confidence level. The statistical analyses of the benchmark calculations also include the evaluation of trends and applicable subsets of the experiments, and the results of those analyses are considered. Note that the calculations for St. Lucie Unit 2 utilize the same computer platform and cross-section libraries used for the benchmark calculations. Additionally, the uncertainty in the reactivity worth of the fission products is considered in the overall uncertainty evaluation in a conservative manner.

Fuel depletion analyses during core operation were performed with CASMO-4, a two-dimensional multi-group transport theory code based on the Method of Characteristics. CASMO-4 is used to determine the isotopic composition of the spent fuel. The depletion uncertainty, i.e. the uncertainty of the isotopic composition of the spent fuel, is considered in the overall uncertainty evaluation.

The maximum k_{eff} is determined from the MCNP5 calculated k_{eff} , the calculational bias, the temperature bias, and the applicable uncertainties (bias uncertainties, calculational uncertainty, depletion uncertainty) by using the following formula:

$$\text{Max } k_{eff} = \text{Calculated } k_{eff} + \text{biases} + [i (\text{Uncertainty})^2]^{1/2}$$

In the geometric models used for the calculations, full three-dimensional models are used, each fuel rod and its cladding were described explicitly, and reflecting or periodic boundary conditions were used in the radial direction which has the effect of creating an infinite radial array of storage cells. The models use bounding parameters for the important rack and fuel tolerances, so that their effect is explicitly included in the calculated k_{eff} value. This is more conservative than including those as uncertainties.

For further details about the cases, criticality methodology and calculations see Sections 1, 2 and 7 of Appendix G to Attachment 5, respectively.

Technical Specifications Section 5.6.1 and associated figures and tables will be replaced based on the results of the new criticality analysis.

As discussed is the Current Licensing Basis above, the spent fuel pool currently has 1360 storage cells available for placement of fuel assemblies and 131 cells required to be left as water holes based on the analyzed configurations. The new criticality analyses described herein and the associated analyzed configurations support allowing the 131 cells currently required to be left as water holes to be used for the storage of fuel assemblies, resulting in the available analyzed storage capacity being increased from 1360 cells to 1491 cells. Both the thermal and the structural analyses of the spent fuel pool (References 3 and 4, respectively) also support this increase. As such, the LAR proposes to increase the spent fuel pool rack storage capacity TS limit from 1360 fuel assemblies to 1491 fuel assemblies.

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

As discussed above, the spent fuel racks are within the scope of License Renewal. Operation of the spent fuel racks under EPU conditions has been evaluated to determine if there any new aging effects requiring management or if any existing aging management programs are affected. Other than the Metamic™ inserts, 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. Furthermore, EPU does not introduce any new system or component functions nor does it change the functions of existing components.

The use of Metamic™ inserts is to provide a reactivity reduction device that can be easily inserted and relocated within the storage racks. The insert rests on the upper fitting of the fuel

assembly, and extends to cover most of the active length of the fuel assembly. This is functionally identical to the Metamic™ insert currently approved for use in the spent fuel pools at Turkey Points Units 3 & 4.

A Metamic™ insert surveillance program will be added to the plant monitoring program to verify the ongoing effectiveness of the Metamic™ inserts. This program is discussed in LR [Section 2.8.6.2.2.6](#).

2.8.6.2.2.5 Results

The new licensing basis criticality analyses for the spent fuel qualify cases and configurations for fuel enriched to a maximum planar average of 4.6 w/o U235. Some cases utilize Metamic™ inserts in the storage cells or absorber rods in the assembly guide/instrument tubes for reactivity control. The minimum soluble boron levels to ensure that k_{eff} is less than or equal to 0.95, including biases and uncertainties, is 500 ppm under normal conditions and 1500 ppm under accident conditions. k_{eff} is below 1.0 for all conditions with non-borated water.

The new licensing basis criticality analyses, as well as the thermal and structural analyses, support increasing the TS limit for available spent fuel pool rack storage capacity from 1360 cells to 1491 cells.

For further details about the results see Sections 7 and 9 of Appendix G to Attachment 5.

2.8.6.2.2.6 Metamic™ Insert Surveillance Program

The purpose of the Metamic™ insert surveillance program is to ensure the Metamic™ panels continue to meet the licensing basis requirements. This will be done by validating that physical and chemical properties of Metamic™ behave in a similar manner in-situ as portrayed in the pre-installation qualification data. The surveillance program will monitor how Metamic™ absorber material properties behave over time as a result of the 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.

There are three (3) essential elements in the Metamic™ surveillance program:

1. Visual inspection of the Metamic™ inserts,
2. Physical measurement of Metamic™ inserts, and
3. Neutron attenuation testing of Metamic™ coupons.

1. Visual Inspection

Visual inspections of Metamic™ inserts are performed to assess the physical condition of the Metamic™ material. Key goals of these inspections are to identify any surface-based

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

Visual inspection of Metamic™ inserts will be performed at 4, 8, 12, 20, and 30 years following initial installation of Metamic™.

Visual inspection of the Metamic™ inserts is proposed by FPL based on the previous testing performed by EPRI (Reference 1) and Holtec International (Reference 2). The results of these tests indicated a potential for local corrosion pitting on the surface of the Metamic™. This was later traced to surface contaminants left on the Metamic™ during either extrusion or rolling. While the EPRI testing pointed to the need to thoroughly clean and/or anodize the Metamic™ surfaces, only glass bead cleaning was used, as anodizing was extremely difficult due to its length. Therefore, FPL proposes a visual inspection program to check for signs of corrosion pitting.

2. Physical Measurements

Physical measurements of Metamic™ inserts are used to confirm the stability of the dimensions of Metamic™ material as noted in the testing (References 1 and 2). These measurements confirm the absence of swelling and shrinkage.

Weight and physical dimensional measurements (length, width, and thickness) of Metamic™ inserts will be performed at 4, 12, 20, and 30 years following initial installation of Metamic™.

3. Neutron Attenuation Testing

Neutron attenuation testing is required to provide a periodic validation of certain assumptions embedded in the fuel pool rack criticality analysis, and to also confirm that the neutron absorption capability of Metamic™ would remain unchanged throughout its service lifetime. While this has been demonstrated through the earlier Metamic™ qualification program, 10 smaller coupons will be added to the pool, from which 2 coupons would be periodically retrieved for each of the 4 scheduled neutron attenuation tests with 2 spares remaining. The tested coupons will not be returned to the spent fuel pool.

Neutron attenuation testing of Metamic™ coupons will be performed at 4, 12, 20, and 30 years following initial installation of Metamic™.

Anomalies and Corrective Actions

Each of the elements of the surveillance program described above will have pre-established acceptance criteria, which will be used to reject any Metamic™ inserts that do not meet the minimum functionality requirements of the material or the assumptions of the SFP rack criticality analysis.

Should any of the data obtained during surveillances fail to meet the established acceptance criteria, the subject insert(s) shall be removed from service and replacement(s) installed, as necessary, to comply with the criticality analysis requirements. Any anomalies and discrepancies identified during the testing will be entered into the correction action program for proper evaluation and corrective actions.

Some surface scratches and local marks in the Metamic™ inserts are expected and are not necessarily indicative of an out-of-specification condition.

2.8.6.2.3 Conclusion

FPL has reviewed the analyses related to the effects of the proposed EPU on the spent fuel storage capability and concludes that it has adequately accounted for the effects of the proposed EPU on the spent fuel rack criticality analyses. FPL 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, FPL concludes that the spent fuel storage facilities will continue to meet the requirements of GDCs -4 and -62 following implementation of the proposed EPU. Therefore, FPL finds the proposed EPU acceptable with respect to spent fuel storage.

2.8.6.2.4 References

1. EPRI 1003137, Qualification of Metamic™ for Spent-Fuel Storage Application
2. Holtec report HI-2043215, Sourcebook for Metamic™ Performance Assessment, Revision 1 (proprietary)
3. Holtec Report HI-2094395, Bulk Thermal Analyses for St. Lucie Unit 2 Spent Fuel Pool Extended Power Uprate (EPU), Revision 3 (proprietary)
4. Holtec Report HI-2094378, WPMR Structural/Seismic Analysis for St. Lucie Unit 2, Revision 2 (proprietary)

2.8.7 Additional Reactor Systems

2.8.7.1 Loss of Decay Heat Removal at Mid-loop Operation

2.8.7.1.1 Regulatory Evaluation

Loss of decay heat removal (DHR) during non-power operation and the consequences of such a loss prompted NRC issuance of Generic Letter (GL) 88-17, Loss of Decay Heat Removal ([Reference 1](#)).

GL 88-17 identified actions to be taken to preclude loss of decay heat removal during non-power 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 the residual heat removal (RHR) cooling or loss of reactor coolant system (RCS) inventory should such an event occur during mid-loop or reduced inventory conditions.

There are no specific NRC acceptance criteria within NRC regulations for operations at mid-loop or reduced inventory conditions. However, the NRC requested all holders of operating licenses to respond to the following recommended actions identified in GL 88-17 which states in part that licensees:

- Provide training prior to operating in a reduced inventory condition (reactor vessel level lower than 3 ft. below the reactor vessel 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 reactor vessel head is located on top of the reactor vessel;
- 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 reactor vessel; and
- Programmed enhancements should be developed in parallel with the expeditious actions and they may replace, supplement, or add to the expeditious actions.

Specific criteria and requirements are identified in GL 88-17 and UFSAR, Section 5.1.4.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Evaluation (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The adequacy of the design relative to GL 88-17 is described in UFSAR Section 5.1.4. The following are specific actions taken by Florida Power and Light (FPL) to conform to the NRC recommendations in GL 88-17:

GL 88-17 was issued to address concerns related to the loss of decay heat removal capability during non-power operations based on several industry incidents. The generic letter required the implementation of expeditious actions as well as programmed plant enhancements to address this issue. FPL provided commitments to the NRC to implement these requirements. The commitments made by FPL are documented in [Reference 2](#) and are represented in part in the following: 1) personnel training on the events; 2) availability of instrumentation to verify state of RCS and cooling systems performance; this includes the use of core exit thermocouples and shutdown cooling (SDC) supply/return line temperature for core exit conditions and RCS water level indicators for reduced inventory; 3) procedures for normal and off-normal reduced inventory SDC operation and administrative controls for containment closure prior to core uncover; 4) at least one high pressure safety injection (HPSI) pump and charging pumps available to maintain RCS in stable and controlled condition; 5) the performance of time to RCS boil off, core uncover and vent area analyses to supplement design information and support procedures/instrumentation; 6) guidelines to ensure perturbation-causing operations are minimized; and 7) controls to avoid RCS pressurization when hot leg nozzle dams are in place simultaneously. In addition, licensees were required to identify and submit appropriate changes for Technical Specifications that restrict or limit the safety benefit of the actions identified in the GL.

The FPL commitments to comply with and implement the expeditious actions identified in GL 88-17 were deemed acceptable by the NRC as documented in [Reference 3](#). In [Reference 4](#), FPL confirmed that all modifications associated with its GL 88-17 commitments have been completed and are operational.

NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003, defines the scope of license renewal. The programmatic commitments regarding GL 88-17 are not within the scope of license renewal.

2.8.7.1.2 Technical Evaluation

2.8.7.1.2.1 Introduction

The purpose of this evaluation is to determine whether provisions ensuring safe operation during mid-loop and reduced inventory conditions following EPU will continue to meet the current licensing basis commitments described in the FPL response to GL 88-17, discussed above in LR [Section 2.8.7.1.1](#).

St. Lucie Unit 2 is considered to be in “mid-loop” conditions when the reactor vessel water level is below the top of the hot leg (el. 31 ft, 3 in) and at or above the mid-plane of the hot leg piping (el. 29 ft, 6 in). The term “reduced inventory” refers to a water level beginning 3 feet below the reactor vessel flange and continuing down to the top of the hot leg. (Three feet below the flange corresponds to an elevation of 33 ft, 0 in.) This definition is consistent with that used by the NRC in GL 88-17.

Operating procedures provide limitations during reduced-inventory or mid-loop conditions that minimize the risks associated with a loss of decay heat removal, ensure the core can remain covered if decay heat removal is lost, and ensure timely containment closure in the event of core boiling. With respect to each of the commitments made in the FPL response to GL 88-17, the procedural limitations are implemented as follows:

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 also been adequately briefed.

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 reactor head is on the reactor vessel 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 shutdown cooling system supply and return temperatures is available for operators in the control room.

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 which 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. Beyond a certain point, a single charging pump is capable of providing all the required makeup flow.

5. The performance of time to RCS boil-off, core uncover, and vent area analyses to supplement design information and support procedures/instrumentation:

Analyses of the time to RCS boil, time to core uncover, and required RCS vent area to preclude excessive pressurization are maintained. The analyses consider various initial conditions for RCS temperature, volume, and time since shutdown. Results of the analyses support 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,
- Required number of charging pumps as a function of time since shutdown,
- Containment closure requirements associated with the calculated time to core boil., and
- Required secondary water level in a steam generator to maintain additional heat sink capacity before primary manways are removed.

6. Guidelines to ensure perturbation-causing operations are minimized:

FPL minimizes perturbation-causing operations by the following procedural limitations:

- Concurrent switchyard maintenance is restricted to preclude a loss of offsite power.
- Concurrent maintenance or operations are prohibited on systems that could jeopardize the RCS, RCS makeup, shutdown cooling system, or support systems. This includes limitations on switchgear maintenance, restrictions on personnel access to vital switchgear areas, and maintaining emergency diesel generators available during reduced inventory conditions.
- Access to the power block is restricted to individuals who have been briefed on reduced inventory operations.
- Two shutdown cooling loops are required to be operable in reduced inventory or mid-loop operations.
- Shutdown cooling flow and RCS draindown rates are procedurally limited to preclude low pressure safety injection (LPSI) pump failure due to insufficient net positive suction head (NPSH), 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.

7. Controls to avoid RCS pressurization when hot leg nozzle dams are in place simultaneously:

Steam formed during core boiling at mid-loop or reduced inventory would collect in the reactor vessel head and exit the vessel through the RCS hot leg piping. If the cold leg were open to atmosphere under these conditions with an inadequate vent on the hot leg, the increasing steam pressure in the reactor vessel could depress the water level within the vessel and expel coolant from the cold leg opening, possibly leading to rapid core uncover.

Evolutions requiring the removal of steam generator primary side manways and the installation of nozzle dams present a significant risk of core uncover during a sustained loss of SDC. To minimize this risk, procedural controls sequence their removal and installation such that no cold leg openings are created until the hot leg is adequately vented. Similarly, the hot leg vent path is maintained until the cold leg pressure boundary is restored. These measures prevent a loss of inventory due to inadvertent RCS pressurization should SDC becomes inoperable during reduced inventory or mid-loop conditions.

2.8.7.1.2.2 Input Parameters, Assumptions, and Acceptance Criteria

FPL calculates RCS time to boil, time to core uncover, and RCS vent area requirements based on the major inputs given in LR [Table 2.8.7.1-1](#) for pre-EPU and EPU conditions.

Assumptions

Major assumptions used in the decay heat and time to boil analyses are documented in LR [Table 2.8.7.1-2](#)

Acceptance Criteria

Per the regulatory evaluation described in LR [Section 2.8.7.1.1](#) above, there are no specific acceptance criteria associated with the analyses for a loss of decay heat removal at reduced inventory or mid-loop conditions. The analyses' results provide the basis for the procedural limitations that FPL imposes to ensure the licensing commitments relative to GL 88-17 can be achieved.

2.8.7.1.2.3 Description of Analyses and Evaluations

As a result of the EPU, the decay heat at a given time after shutdown increases roughly in proportion to the EPU power increase. This, in turn, reduces the time to boiling and the time to core uncover following a postulated loss of decay heat removal. Analyses have been performed to determine the new RCS time to boil and time to core uncover. The specific analyses, operating procedures, administrative procedures, and the applicable sections of the UFSAR relating to GL 88-17 have been reviewed to identify any additional information that may be impacted due to the proposed EPU. Based on these reviews, the procedures will be revised to reflect the shorter times available to reach saturation and core uncover and the impact this has on shutdown operations. The commitments described in LR [Section 2.8.7.1.2.1](#) above are evaluated to ensure EPU conditions will permit continued compliance.

2.8.7.1.2.4 Renewed Plant Operating License Evaluations and License Renewal Programs

The loss of decay heat removal at mid-loop operation analysis is not within the scope of License Renewal. Systems and components that are credited in natural circulation cooldown analysis are evaluated as part of their system evaluation.

2.8.7.1.3 Results

Results of the analyses for reduced inventory and mid-loop operations are summarized in LR [Table 2.8.7.1-3](#). The impacts on procedural limitations and administrative functions due to these changing parameters affect compliance with GL 88-17 commitments as follows:

1. Personnel training:

EPU does not impact personnel training requirements pertaining to reduced inventory or mid-loop operations. The degree of compliance with this licensing commitment is not affected by EPU.

2. Availability of instrumentation to verify the state of RCS and cooling systems performance:

There are no modifications associated with the EPU that will impact the operability of the core exit thermocouples, refueling level indicators, or shutdown cooling temperature indication. Operating procedures will continue to require their operability prior to and during reduced inventory and mid-loop operations. Therefore, the degree of compliance with this licensing commitment is not affected by EPU.

3. Procedures for normal and off-normal reduced inventory SDC operation and administrative controls for containment closure prior to core uncover. Refer to Item 5. below.

4. HPSI pump and charging pump availability to maintain RCS in stable and controlled condition:

The higher EPU decay heat generation rate requires higher makeup water flow rates to maintain the core covered during postulated core boiling conditions. GL 88-17 requires at least two independent means of adding inventory to the RCS. The independent means of adding inventory are the HPSI pump and one or two charging pumps. Operating procedures require at least one operable HPSI flow path during reduced inventory or mid-loop operation. Hence, a loss of the operable HPSI flow path requires restoration in order to maintain procedural compliance. Additionally, either one or two charging pumps are also required to be operable depending on the predicted steaming rate, which in turn depends on the length of time after shutdown. The minimum allowable time after shutdown until entry into reduced inventory or mid-loop is not a nuclear safety parameter (i.e., there are no nuclear safety parameters that require entry into these conditions). Plant procedures governing entry into reduced inventory or mid-loop will be revised as necessary to reflect the increased decay heat associated with the EPU.

Given these provisions, FPL has adequately addressed the increased makeup water requirement for EPU and will continue to be in compliance with this element of the GL 88-17 licensing commitments.

5. The performance of time to RCS boil-off, core uncover, and vent area analyses to supplement design information and support procedures/instrumentation:

The increased decay heat generation following EPU will impact the underlying calculations that support the applicable procedural limitations as follows:

- Minimum required shutdown time prior to reduced inventory or mid-loop operation based on the available RCS vent area:

The RCS hot legs must remain adequately vented during mid-loop operations to avoid pressurizing the reactor vessel upper plenum during core boiling if the cold leg is open to atmosphere. Under these conditions, pressurizing the vessel to greater than 3.0 psig could result in loss of coolant inventory through the cold leg opening and subsequent core uncover. Current analyses show that an unobstructed vent area of at least 0.56 ft² in the pressurizer manway foreign material exclusion (FME) cover provides sufficient steam flow to preclude pressurizing the reactor vessel to greater than 3.0 psig at 106.5 hrs after shutdown. If at least six seal carrier assemblies have been removed from the reactor vessel head Quickloc flanges to provide additional vent area, the minimum shutdown time may be reduced to 73 hrs. Minimum shutdown time may be further reduced if an engineering evaluation documents acceptably low decay heat generation based on the condition-specific reactor power history. Following EPU, operating procedures will be revised to require additional shutdown time prior to reduced inventory or mid-loop operation to ensure the existing vent paths can accommodate steam flow to avoid reactor vessel head pressurization.

- Required number of charging pumps as a function of time since shutdown:

The higher decay heat generation rate requires higher makeup water flow rates to maintain the core covered during postulated core boiling conditions. Currently, two charging pumps are required to be operable in reduced inventory or mid-loop conditions if the reactor has been shut down for 14 or fewer days. One charging pump is required beyond 14 days. As a result of the analyses developed for EPU, reduced inventory or mid-loop operating procedures will be revised to require two charging pumps to remain operable for a longer duration after shutdown than the current 14 day period.

- Containment closure requirements associated with the calculated time to core boil:

The time to core boil is calculated to determine the minimum time in which containment penetrations must be closed following a loss of decay heat removal in reduced inventory or mid-loop conditions. Procedures stipulate that operators calculate time to core boil at least once per shift. In the event that a containment penetration cannot be closed using normal means within the required time, Administrative procedures identify backup means of closure that may be employed, such as pre-staged potting materials. Logs are maintained to track the personnel responsible for containment closure and the means of communication with the control room that must remain operable while the penetration is open.

Containment penetrations must be capable of closure within the calculated time to boil. The containment equipment hatch is further restricted in that it cannot be opened during

mid-loop or reduced inventory conditions unless the refueling shuffle or core offload is complete, or the condition-specific time to core boil exceeds 30 minutes.

The normal and off-normal procedures that calculate time to core boil are based on decay heat generation, RCS inventory, initial RCS temperature, and time since shutdown. For EPU, the procedures will be revised to reflect the increased decay heat generation after shutdown and the shorter calculated times to the onset of core boiling. The administrative requirement to determine the time to core boil at least once per shift will continue to apply. Results of time to boil calculations for certain initial conditions are shown in LR

Table 2.8.7.1-3.

Off-normal procedures also document the minimum required flow to makeup for RCS boil-off and the minimum required flow to prevent boiling, both as a function of time since shutdown. These procedures will also be revised to reflect the higher flow requirements.

- Required secondary water level in a steam generator to maintain additional heat sink capacity before primary manways are removed:

Procedures require operators to maintain a minimum of 10 percent indicated narrow range level in at least one steam generator before entering reduced inventory conditions and as long as the primary side steam generator manways are installed. Although the analyses do not credit the steam generators with any decay heat removal capacity when calculating time to boil, this action provides an additional heat sink to mitigate the effects of a loss of decay heat removal.

For EPU, the analyses will continue not to credit the steam generators as potential heat sinks. The procedural requirement to maintain 10 percent narrow range secondary water level will be maintained.

Given the results of these analyses, and the incorporation of their results into operating procedures, FPL has adequately addressed the increased decay heat generation for EPU as it affects calculations supporting mid-loop and reduced inventory operations. St. Lucie Unit 2 will continue to be in compliance with this element of the GL 88-17 licensing commitments.

6. Guidelines to ensure perturbation-causing operations are minimized:

Perturbation-causing operations are minimized by the procedural limitations identified in LR Section 2.8.7.1.2.1, **item 6.**, above. The administrative and procedural limitations related to concurrent maintenance and operations, personnel access restrictions, and shutdown cooling operability are not affected by EPU. Additionally, since EPU does not affect the physical configuration of the RCS or shutdown cooling piping, there are no effects on the maximum allowable shutdown cooling or RCS draindown flow or the minimum RCS water level for LPSI pump operation. Therefore, St. Lucie Unit 2 will continue to be in compliance with this element of the GL 88-17 licensing commitments.

7. Controls to avoid RCS pressurization when hot leg nozzle dams are in place simultaneously:

The installation and removal of manways and nozzle dams are sequenced to avoid pressurization in the reactor vessel upper plenum. Since there are no changes to the physical configuration of the RCS, EPU does not impact the required sequencing of these evolutions.

Therefore, St. Lucie Unit 2 will continue to be in compliance with this element of the GL 88-17 licensing commitments.

2.8.7.1.4 Conclusion

FPL has reviewed the assessment of the effects of the EPU on the loss of decay heat removal at mid-loop operation and concludes that it has adequately identified the changes required for the EPU to ensure that St. Lucie Unit 2 maintains its ability to prevent or mitigate the consequences of loss of decay heat removal during mid-loop operation. FPL further concludes that systems, components, procedures, administrative controls and operator training meet the requirements of GL 88-17. Therefore, FPL finds the proposed EPU acceptable with respect to the loss of decay heat removal at mid-loop operation.

2.8.7.1.5 References

1. NRC Generic Letter 88-17, Loss of Decay Heat Removal, October 17, 1988.
2. FPL Letter to NRC, L-88-552, from W.F. Conway (FPL), Loss of Decay Heat Removal, dated January 1, 1989.
3. Letter from Jan A. Norris (NRC) to J. H. Goldberg (FPL), St. Lucie Units 1 and 2 – Programmed Enhancements For Generic Letter 88-17, Loss of Decay Heat Removal, (TAC Nos. 69780 and 69781), dated July 21, 1990.
4. FPL Letter to NRC from D.A. Sager (FPL), Programmed Enhancements for Generic Letter 88-17, dated November 17, 1990.
5. NRC Generic Letter 88-17, Loss of Decay Heat Removal, October 17, 1988.
6. FPL Letter to NRC, L-88-552, from W.F. Conway (FPL), Loss of Decay Heat Removal, dated January 1, 1989.
7. Letter from Jan A. Norris (NRC) to J. H. Goldberg (FPL), St. Lucie Units 1 and 2 – Programmed Enhancements For Generic Letter 88-17, Loss of Decay Heat Removal, (TAC Nos. 69780 and 69781), dated July 21, 1990.
8. FPL Letter to NRC from D.A. Sager (FPL), Programmed Enhancements for Generic Letter 88-17, dated November 17, 1990.

Table 2.8.7.1-1
Input Parameters for Loss of RHR at Mid-loop Evaluation

Name	Units	Pre EPU Values	/	EPU Values	Comments
Power Level	MWt	2700	/	3020	
Times After Shutdown	hours	0 to 1440	/	0 to 1440	
Operating Cycle Length	EFPH	9500, 11000, 13500, 16000, 25000	/	9500, 11000, 13500, 16000, 25000	These values correspond to 3, 6, 12, 18, and 24 months of continuous full-power operation.
Initial RCS Temperatures	°F	60, 80, 90, 100, 110, 120, 130, 140, 200	/	60, 80, 90, 100, 110, 120, 130, 140, 200	Time to boil cases are evaluated from these initial RCS temperatures.
RCS Heatup Volume	ft ³	1308.3	/	1308.3	This includes water within and above the active fuel region plus the upper plenum and outlet nozzle / hot leg volumes up to mid-loop elevation.
RCS Boil-off Volume	ft ³	1178.3	/	1178.3	This includes all of the above "RCS Heatup Volume" except the active fuel region. It also includes reactor vessel downcomer and cold-leg volumes up to mid-loop elevation.
Maximum allowable reactor vessel pressurization to avoid core uncover	psig	3.0	/	3.0	No additional vent area will be provided for EPU, so steam flow and venting characteristics during core boiling are unchanged.

Table 2.8.7.1-2
Assumptions for Loss of RHR at Mid-loop Evaluation

Assumptions for decay heat and time to boil <u>at mid-loop</u>:	
1	The decay heat formulation used to calculate the decay heat of the fuel in the core is consistent with that of Branch Technical Position ASB 9-2, Standard Review Plan, NUREG-0800
2	For 'time to boil' calculations, the volume of water considered is the volume above the bottom of the active core up to mid-loop, including the volume of hot legs and half the volume of active core region bypass. The cold legs and the downcomer are assumed not to participate in the convective heating process. This assumption is conservative as some conduction will result in heating the down comer water mass.
3	No credit is taken for the thermal mass of the metal in the vessel and the loops.
4	The pressure in the RCS is assumed to be 15 psia. This is a reasonable and conservative assumption for 'time to boil' calculations. The conservatism in the 'time to core uncover' calculation covers conditions where RCS pressure may remain higher than 15 psia.
5	Density variation in the RCS due to temperature changes is neglected in the 'time to core uncover' calculations. This assumption has an insignificant effect on calculated results.
Assumptions for time to boil <u>above mid-loop</u>:	
1	Reactor head/temporary reactor head are not installed.
2	Water below the lower reactor cavity "boot" is assumed to be inactive as convection currents stirring this inventory cannot be relied on. Likewise, SDC flow is assumed stopped, and natural convection currents involving steam generators or RCS loop inventories are not considered. Heat transfer to air or metal or concrete structures is not considered.
3	50 percent of the reactor vessel volume is assumed to be displaced by reactor vessel internals.
4	Calculation of additional water within the reactor cavity is not significantly affected by the displacement of the UGS lift rig.
5	Elevation above the core is not credited for an increase in saturation pressure.
Note: These assumptions apply to both the pre-EPU and EPU calculations for decay heat and time to boil.	

Table 2.8.7.1-3
Analysis Results for Loss of RHR at Mid-loop Evaluation

Result	Units	Pre EPU Values/ EPU Values	Comment
Time after shutdown when one charging pump provides sufficient makeup flow to compensate for core boil-off	Days	14 / 19	estimated based on pre-EPU vs. EPU decay heat calculation results
Time after shutdown when pressurizer manway alone provides sufficient vent area to avoid pressurizing the reactor vessel upper plenum	Hours	106.5 / 138	estimated based on pre-EPU vs. EPU decay heat calculation results
Time after shutdown when manway and all eight Quickloc flanges provide sufficient vent area to avoid pressurizing the reactor vessel upper plenum	Hours	73 / 96	estimated based on pre-EPU vs. EPU decay heat calculation results
Approximate Time to core boil at 73 hrs / 96 hrs (pre-EPU / EPU) after shutdown (assumed 120 °F initial RCS temperature)	Minutes	10 / 10	73 hrs after shutdown (pre-EPU) and 96 hrs after shutdown (estimated for EPU) correspond to the same decay heat generation rate, and thus, the same time to boil, since RCS configuration does not change.
Time after shutdown during which equipment hatch must remain closed	Hours	See comment	Operating procedures prevent the equipment hatch from being opened during reduced inventory or mid-loop conditions unless core offload or the refuel shuffle is complete, or maintenance has demonstrated that the equipment hatch can be closed within the time to boil as determined by a condition-specific calculation.

2.8.7.2 Natural Circulation Cooldown

2.8.7.2.1 Regulatory Evaluation

NRC Review Standard RS-001, Rev. 0 does not explicitly call out Standard Review Plans (SRPs) or other guidance documentation for current or post-uprate license basis reviews for natural circulation cooldown.

While there are no explicit criteria for this evaluation, the following criteria show acceptable natural circulation cooldown behavior:

1. The natural circulation ΔT s and temperatures are reasonable (that is, bounded by full-power conditions). This helps to avoid any concerns with thermal stresses and also helps to ensure adequate reactor coolant system (RCS) subcooling;
2. The RCS pressure is reduced to 275 psia for shutdown cooling initiation. Consequently to prevent the formation of voids the upper head fluid must be cooled to a value less than the corresponding saturation temperature of 409.5°F; and
3. Availability of adequate condensate supply necessary to achieve natural circulation cooldown conditions.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies, and is in compliance with, the GDC as discussed in UFSAR Section 3.1.

On June 11, 1980, an event occurred at St. Lucie Unit 1 which resulted in steam formation within the upper head of the reactor vessel while undergoing primary system cooldown under natural circulation conditions. The steam formation within the reactor vessel resulted from excessive plant depressurization, in turn leading to saturated fluid conditions within the upper head. As discussed in St. Lucie Unit 2 UFSAR Appendix 5.2B, an analytical evaluation of natural circulation to shutdown cooling system entry conditions without void formation was performed for St. Lucie Unit 1. Since St. Lucie Unit 2 “is essentially the same design as St. Lucie Unit 1” (see UFSAR Section 1.3.1), the St. Lucie Unit 1 analysis is applicable to St. Lucie Unit 2.

Hot leg temperature cooldown rates of 30°F/hr and 50°F/hr to 325°F were investigated to determine the cooldown time required for the fluid temperature in the reactor vessel upper head to reach shutdown cooling entry conditions without void formation. In order to determine a bounding cooldown time for operating guidelines, a conservative analysis assuming a hot leg temperature cooldown rate of 50°F/hr to 325°F was performed. The results demonstrate that the reactor vessel upper head cools to 409.5°F (the saturation temperature corresponding to shutdown cooling entry conditions) in 25.7 hours. The condensate supply required for this cooldown is 270,500 gallons.

Additional information pertaining to the St. Lucie Unit 1 natural cooldown analysis is provided in St. Lucie Unit 2 UFSAR Appendices 5.2B and 5.2C.

The NRC staff indicated that the St. Lucie Unit 1 natural circulation cooldown event would not, by itself, provide sufficient basis to satisfy the boron mixing and natural circulation cooldown test requirements associated with Reactor System Branch, Branch Technical Position 5-1. Therefore, St. Lucie Unit 2 was required to:

1. Provide a report on the San Onofre Unit 2 Natural Circulation Cooldown and Mixing Test, and
2. Justify that the test data is applicable to St. Lucie Unit 2.

The information from the San Onofre report was used on a comparison basis for NRC approval and provides the similarities of the results and the applicability to St. Lucie Unit 2.

Based on San Onofre Nuclear Generating Station Report CEN-259, the estimated cooling water requirement for St. Lucie Unit 2 is 276,000 gallons. The Technical specification in the condensate storage tank (CST) is 307,000 gallons, therefore St. Lucie Unit 2 has a sufficient amount of water in the CST to meet the requirements of BTP RSB 5-1.

NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September, 2003, defines the scope of license renewal. The natural circulation cooldown analysis is not within the scope of License Renewal.

2.8.7.2.2 Technical Evaluation

2.8.7.2.2.1 Introduction

The purpose of the natural circulation cooldown evaluation is to show that the plant at extended power uprate (EPU) conditions exhibits expected natural circulation behavior, similar to that previously evaluated. The evaluation demonstrates the ability to cool down the plant on natural circulation to shutdown cooling entry conditions (approximately 275 psia, and less than 325°F in the RCS) within a reasonable period of time.

The analysis provided in [Reference 1](#) was performed by Florida Power and Light (FPL) in December 1980 in response to the June 11, 1980 St. Lucie Unit 1 natural circulation cooldown event which resulted in steam formation within the upper head of the reactor vessel. This analysis used the RETRAN code to show that cooling down at a 50°F/hr rate to 325°F and then maintaining the hot leg temperature at 325°F conservatively for 20.4 hours would allow shutdown cooling pressure to be reached without flashing of the upper head fluid in a total cooldown time of 25.7 hours. The condensate requirement for that cooldown, based on this conservative analysis, was 270,500 gallons.

2.8.7.2.2.2 Input Parameters, Assumptions, and Acceptance Criteria

Input Parameters

The input parameters for the EPU evaluation are given in LR [Table 2.8.7.2-1](#).

Assumptions

The following assumptions were made in the EPU evaluation:

- Following a loss of offsite power, the plant is maintained at hot standby conditions for four (4) hours before entering the cooldown.
- Decay heat rates are based on ANSI/ANS-5.1-1979.
- Nominal atmospheric dump valve (ADV) capacities are assumed for the cooldown portion of the transient. Of the four total ADVs only two were used (one per steam generator).
- Maximum auxiliary feedwater enthalpy is assumed, corresponding to maximum condensate storage tank temperature.

Acceptance Criteria

1. The natural circulation ΔT s and temperatures are bounded by full-power conditions. This helps to avoid any concerns with thermal stresses and also helps to ensure adequate RCS subcooling.
2. The RCS pressure is reduced to 275 psia for shutdown cooling initiation. Consequently to prevent the formation of voids the upper head fluid is cooled to a value less than the corresponding saturation temperature of 409.5°F.
3. Availability of adequate condensate supply necessary to achieve natural circulation cooldown conditions.

2.8.7.2.2.3 Description of Analyses and Evaluations

To evaluate the natural circulation capability for EPU, the CENTS computer code was used to simulate plant response to a loss of offsite power followed by a natural circulation cooldown from hot standby conditions to shutdown cooling system entry conditions using only safety grade equipment and assuming the worst single failure, loss of one emergency power train. The shutdown cooling portion of the cooldown is addressed in LR [Section 2.8.4.4](#), Residual Heat Removal System.

The cooldown simulation followed Branch Technical Position (BTP) 5-4 ([Reference 2](#)). The CENTS code is not a part of the CLB, but is an NRC approved code that is acceptable for referencing in licensing applications for Combustion Engineering designed pressurized water reactors ([Reference 3](#)).

Two separate scenarios were simulated with cooldown rates of 30°F/hour and 50°F/hour. After four (4) hours at hot standby conditions, the operators cool the plant down to the shutdown cooling entry conditions at the specified cooldown rate of either 30°F/hour or 50°F/hour. The resulting total cooldown time and condensate requirement were compared to the existing pre-EPU values.

2.8.7.2.2.4 Impact on Renewed Plant Operating License Evaluations and License Renewal

The natural circulation cooldown analysis is not within the scope of License Renewal. Systems and components that are credited in natural circulation cooldown analysis are evaluated as part of their system evaluation.

2.8.7.2.2.5 Results

The limiting case analyzed in the evaluation demonstrates that the plant can be cooled down to shutdown cooling entry conditions using the same equipment as the existing analysis of record while maintaining pressure control (no voids in the RCS) for a loss of offsite power event.

The results of the St. Lucie Unit 2 EPU natural circulation cooldown analysis demonstrate that the applicable acceptance criteria are satisfied, specifically:

- The maximum core ΔT during the 30°F/hr and the 50°F/hr cooldown is lower than the normal full power ΔT of 53°F.
- Acceptable results are found for natural circulation cooling during the hot standby period for expected residual heat rates immediately following reactor shutdown from EPU conditions.
- The ADVs at the EPU conditions are adequate to achieve cooldown to the shutdown cooling entry point in a reasonable time period. Shutdown cooling entry conditions can be achieved in approximately 13 hours at a cooldown rate of either 30°F/hr or 50°F/hr, which includes four (4) hours in hot standby conditions.
- The existing condensate requirement established conservatively in the existing pre-EPU evaluation is bounding for the EPU program.

The results are shown in LR [Table 2.8.7.2-2](#). The condensate inventory required for the EPU conditions is expected to be greater due to the increased decay heat resulting from the higher core power. The EPU analysis results are lower than the current analysis due to the use of a more sophisticated analysis using the CENTS computer code which does not require a soak time.

2.8.7.2.3 Conclusion

FPL has reviewed the analyses related to the natural circulation cooldown for St. Lucie Unit 2 and concludes that the analyses have adequately accounted for the effects of changes in plant conditions. The FPL staff concludes that it maintains the ability to perform natural circulation cooldown following a trip from full power to shutdown cooling entry conditions in a reasonable period of time without voiding in the RCS. Therefore, FPL finds the EPU acceptable with respect to safely using a natural circulation cooldown to cool the RCS to shutdown cooling entry conditions.

2.8.7.2.4 References

1. Letter L-80-431 from Robert E. Uhrig to Robert A. Clark, St. Lucie Unit #1 Docket No. 50-335 Natural Circulation Cooldown, December 30, 1980.
2. Branch Technical Position (BTP) 5-4, Design Requirements for the Residual Heat Removal System, Rev. 4, March 2007. (See NUREG-0800, Standard Review Plan, Section 5.4.7 Residual Heat Removal (RHR) System).
3. Westinghouse Owners Group Topical Report WCAP-15996-P-A, Revision 1, Technical Description Manual for the CENTS Code, March 2005.
4. NRC letter to FPL, St. Lucie Plant, Unit 2, Natural Circulation Cooldown and Boron Mixing (TAC No. 54485), April 12, 1988.

Table 2.8.7.2-1
Input Parameters for Natural Circulation Cooldown Evaluation

Name	Units	Value	Comment
Power Level	MWt	3035.1 ⁽¹⁾	Nominal
Tube Plugging	Percent	0	
Inlet Temperature	°F	551/554	Nominal
Cooldown Rate	°F/hour	30 and 50	
1. Power level used conservatively includes 0.5% uncertainty.			

Table 2.8.7.2-2
Calculated Loop ΔT , Cooldown Time, and Condensate Requirement for Natural Circulation

Cooldown Rate (°F/hr)		Calculated Loop ΔT (°F)	Time to Shutdown Cooling Entry (hr)⁽¹⁾	Condensate Requirement (gallons)
Pre-EPU ⁽²⁾	50°F/hr	-	-	276,000
EPU	30°F/hr	32	12.78	178,200
EPU	50°F/hr	35	11.03	169,500
1. The condensate inventory required for the EPU conditions is expected to be greater due to the increased decay heat resulting from the higher core power. The EPU analysis results are lower than the current analysis due to the use of a more sophisticated analysis using the CENTS computer code which does not require a soak time. 2. The Reference 4 Safety Evaluation Report states that the condensate requirement is 276,000 gallons assuming St. Lucie Unit 2 requires the same upper head cooling time as San Onofre Unit 2. FPL analysis estimated that 270,500 gallons of condensate is required to cool the RCS and the vessel upper head to shutdown cooling entry conditions in 25.7 hours using very conservative assumptions regarding fluid mixing in the upper head.				

2.9 Source Terms and Radiological Consequences Analyses

2.9.1 Source Terms for Radwaste Systems Analyses

2.9.1.1 Regulatory Evaluation

Florida Power and Light (FPL) reviewed the radioactive source term associated with the extended power uprate (EPU) to ensure the adequacy of the sources of radioactivity used 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 FPL review included the parameters used to determine the:

- Concentration of each radionuclide in the reactor coolant;
- Fraction of fission product activity released to the reactor coolant;
- Concentrations of all radionuclides other than fission products in the reactor coolant;
- Leakage rates and associated fluid activity of all potentially radioactive water and steam systems; and
- Potential sources of radioactive materials in effluents that are not considered in the UFSAR, related to liquid waste management systems and gaseous waste management systems.

The NRC acceptance criteria for source terms are based on:

- 10 CFR 20, insofar as it establishes requirements for radioactivity in liquid and gaseous effluents released to unrestricted areas;
- 10 CFR 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
- General Design Criterion (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 Standard Review Plan (SRP) Section 11.1, and guidance provided in Matrix 9 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conform with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

Specifically, the adequacy of the radioactive source term is determined for the proposed EPU operating conditions relative to conformance to:

- GDC-60, Control of Releases of Radioactive Materials to the Environment, is described in UFSAR Section 3.1.60.

The nuclear power unit design shall include means to control suitably the release of radioactive materials in gaseous and liquid effluents and to handle radioactive solid wastes produced during normal reactor operation, including anticipated operational occurrences. Sufficient holdup capacity shall be provided for retention of gaseous and liquid effluents containing radioactive materials, particularly where unfavorable site environmental conditions can be expected to impose unusual operational limitations upon the release of such effluents to the environment.

The design for radioactivity control is based on the requirements of 10 CFR 20, 10 CFR 50, and Appendix I to 10 CFR 50 for normal operations and for any transient situation that might reasonably be anticipated to occur.

The licensing basis radioactivity concentrations in the liquid discharge are determined using models and assumptions contained in NUREG-0017. The estimated annual liquid effluent releases to the St. Lucie Plant discharge canal are given in UFSAR Table 11.2-1 for normal operation. Radiological liquid effluent releases for normal and design basis nuclide concentrations at the site boundary are presented in UFSAR Tables 11.2-3 and 11.2-4, respectively. The licensing basis annual radiation doses to the maximum individual from liquid pathways are presented in UFSAR Table 11.2-13. The licensing basis annual radiation doses are below the design objectives of 10 CFR 50, Appendix I.

UFSAR Sections 11.3.2 and 11.3.3 discuss the key parameters utilized to determine the radioactive source term for gaseous effluents. UFSAR Table 11.3-9 gives the estimated gaseous radiological effluent site boundary concentrations from normal operation. The design basis, gaseous radiological effluent annual release rates are listed in UFSAR Table 11.3-10. The licensing basis annual radiation doses to the maximum individual from gaseous pathways are presented in UFSAR Tables 11.3-11. The licensing basis annual radiation doses are below the design objectives of 10 CFR 50, Appendix I.

The St. Lucie Plant Offsite Dose Calculation Manual (ODCM) provides requirements for system operation, dose calculations, and monitoring requirements that ensure compliance with effluent limits. Actual measured concentrations of radioactivity released and real time dilution or dispersion estimates are required to verify compliance with effluent limits. Therefore, operation within the requirements of the ODCM ensures compliance with effluent limits.

The radioactivity effluent releases from St. Lucie Unit 2 and associated doses to the public are reported annually to the NRC in Annual Radioactive Effluent Release Reports. These reports serve to demonstrate continued compliance with the regulatory limits.

In addition to the licensing basis described in the UFSAR, the waste management system was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify

which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.3.16 of the SER identifies that components of the waste management system are within the scope of License Renewal. Programs used to manage the aging effects associated with the waste management system are discussed in SER Section 3.3.16 and Chapter 18 of the UFSAR.

The radiological source term is not within the scope of license renewal since it is an analytical product of the operational performance of plant systems and components in conjunction with regulatory limits that have been imposed on radiological releases. No changes in those applicable regulatory limits are proposed for plant operation at EPU conditions, which would change license renewal boundaries.

2.9.1.2 Technical Evaluation

2.9.1.2.1 Introduction

The plant normal operational radiation source terms establish the long-term concentrations of principal radionuclides in the plant fluid streams. The fluid streams that are the primary source of radioactivity in all process and effluent streams are the reactor coolant and the secondary steam generator (SG) water and steam. The radionuclide inventory in the reactor coolant system (RCS) results from two primary sources: the fission product release from failed or defective fuel pins, and the activation of corrosion products circulating in the RCS primary coolant loop. The secondary side radionuclide inventory is the result of primary coolant leakage to the SG secondary side steam and water. The normal operations radiation source terms in plant fluid streams, serve as input to assessments of the projected normal plant effluent released to the environment.

The core inventory of nuclides that are used to develop St. Lucie Unit 2 normal operations RCS equilibrium inventories are calculated with the ORIGEN 2.1 computer code ([Reference 1](#)), as described in LR [Section 2.9.2](#), Radiological Consequences Analyses Using Alternative Source Term (AST). The ORIGEN core inventory was developed using expected fuel management schemes that span the range of fuel enrichment from 1.5 weight percent (w/o) U-235 to 5.0 w/o U-235. The core inventory was modified by specific release fractions/escape rates from the fuel to yield an initial equilibrium RCS inventory. The initial RCS equilibrium 1% fuel defect inventory was processed through a production/cleanup model, based on the system inputs in LR [Tables 2.9.1-1](#), [2.9.1-2](#), and [2.9.1-3](#) to generate a final equilibrium 1% fuel defect based inventory.

The equilibrium corrosion product activities were calculated separately using the methodology outlined in ANSI Standard ANSI/ANS-18.1-1999, Radioactive Source Term for Normal Operation of Light Water Reactors ([Reference 2](#)). This method uses plant-specific conditions to develop adjustment factors to apply to a reference plant RCS corrosion product inventory. The plant-specific conditions for determining corrosion product inventories are based on the system inputs in LR [Tables 2.9.1-1](#) and [2.9.1-2](#).

The final EPU RCS equilibrium 1% fuel defect source term is given in LR [Table 2.9.1-3](#). The table shows the combined equilibrium fuel defect source and the equilibrium corrosion product source terms.

As stated in LR [Section 2.10.1](#), Occupational and Public Radiation Doses, there are no changes as a result of the EPU to existing radioactive waste systems (gaseous and liquid) 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 vs. EPU inventories/radioactivity concentrations in the reactor coolant and secondary coolant/steam. As a result, the impact of the EPU on radwaste releases and Appendix I doses can be estimated using scaling techniques.

The EPU evaluation of plant shielding adequacy focused on determining an EPU scaling factor based on the design basis fission and corrosion product activity concentrations in the reactor coolant used in the original plant shielding design versus that corresponding to the EPU, as controlled by the technical specifications (TS). The TS reactor coolant source terms are based on the 1% fuel defect reactor coolant isotopic mix developed using expected fuel management schemes that span the range of fuel enrichment from 1.5 w/o U-235 to 5.0 w/o U-235 presented in LR [Table 2.9.1-3](#). Plant shielding adequacy is presented in more detail in LR [Section 2.10.1](#).

Scaling techniques based on NUREG-0017, Revision 1 methodology were used to assess the impact of EPU on radioactive gaseous and liquid effluents. Use of the adjustment factors presented in NUREG-0017, Revision 1 allows development of coolant activity scaling factors to address EPU. These EPU coolant activity scaling factors are applicable to current, as measured, normal plant operation source terms, and are adequate for subsequently estimating the impact of EPU on offsite doses from normal plant liquid and gaseous effluents.

The EPU analysis utilized the plant core power operating history during the years 2003 to 2007, the reported gaseous and liquid effluent and dose 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 design objectives of 10 CFR 50 Appendix I, to demonstrate that the dose to the public, although increased, remain within regulatory guidance.

2.9.1.2.2 Analysis

LR [Section 2.10.1](#) defines the methodology utilized to define the source terms associated with radioactive waste systems (gaseous and liquid), and the resultant offsite doses.

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

As discussed above, the waste management system radiological source term and dose consequence analyses were determined to be outside the scope of License Renewal; therefore, with respect to the waste management system radiological source term and dose consequence analyses, the EPU does not impact any License Renewal evaluations.

2.9.1.2.4 Results

The conservatively performed EPU analysis utilized the plant core power operating history during the years 2003 to 2007, the reported gaseous and liquid effluent and dose data during that period, NUREG-0017 equations and assumptions, and conservative methodology, to estimate the impact of operation at the analyzed EPU core power level of 3030 MWt over that of current operation at a power level of 2700 MWt, on radioactive gaseous and liquid effluents. The application of this conservative methodology and EPU coolant activity scaling factors that are applicable to current, as measured, normal plant operation source terms, is adequate for subsequently estimating offsite doses from normal plant liquid and gaseous effluents at EPU conditions.

The impact of EPU on offsite doses is discussed in LR [Section 2.10.1](#).

2.9.1.3 Conclusion

FPL 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. FPL further concludes that the proposed radioactive source term will continue to meet its current licensing basis with respect to the requirements of 10 CFR 20, 10 CFR 50, Appendix I, and GDC-60. Therefore, FPL finds the proposed EPU acceptable with respect to source terms.

2.9.1.4 References

1. Oak Ridge National Laboratory, CCC-371, RSICC Computer Code Collection – ORIGEN 2.1, May 1999.
2. ANSI/ANS-18.1-1999, Radioactive Source Term for Normal Operation of Light Water Reactors, approved September 21, 1999; including Errata dated December 1, 2005.

**Table 2.9.1-1
RCS Equilibrium Activity Inputs
Considering EPU Conditions**

Input	Value	Units
Core thermal power (nominal for corrosion product determination)	3020	MWt
Core thermal power (with uncertainty for ORIGEN core inventory)	3030	MWt
Fuel defects	1	%
RCS volume/mass	9060	ft ³
	386,354 ⁽¹⁾	lbs
Volume control tank (VCT) pressure	15	psig
VCT temperature	120	°F
Letdown flow rate ⁽²⁾	40.0	gpm
Mixed bed demineralizer decontamination factors	2 for cesium	N/A
	10 for all other isotopes except Y, Mo and noble gases	
Lithium removal mixed bed demineralizer use and equivalent flow rate	In-service 20% of the time (neglected for corrosion product determination)	gpm
	8	
Lithium removal mixed bed demineralizer decontamination factors	2 for Cesium	N/A
	10 for all other isotopes except Y, Mo and noble gases	
Cation demineralizer flow rate	N/A	gpm
Primary makeup water (boron recovery flow)	200,000	gallons/year
Depleted zinc injection considered?	Yes	N/A
Notes: 1. A specific volume of 0.02345 ft ³ /lbm based upon RCS nominal conditions was used to obtain RCS mass 2. A conservative value of 29 gpm at 15 psig and 120°F was utilized for the letdown flow rate in the determination of corrosion product activities using Reference 2 .		

**Table 2.9.1-2
Gas Stripping Fractions**

Isotope	Stripping Fraction
Kr-83m	0.88
Kr-85m	0.74
Kr-85	0.00014
Kr-87	0.91
Kr-88	0.82
Xe-131m	0.03
Xe-133	0.07
Xe-133m	0.15
Xe-135m	0.97
Xe-135	0.50
Xe-138	0.975

**Table 2.9.1-3
RCS Source Term**

Nuclide	Half-Life (sec)	Core Inventory (Ci)	Core Inventory (Atoms)	Escape Coefficient (1/s)	1% Fuel Defect Source (Atoms/sec)	Results	
						Equilibrium Concentration ($\mu\text{Ci/gm}$)	Equilibrium Activity (μCi)
Co-58	-	-	-	-	-	4.600E-02 ⁽¹⁾	3.139E+04
Co-60	-	-	-	-	-	8.643E-02 ⁽¹⁾	5.899E+04
Cr-51	-	-	-	-	-	1.687E-01 ⁽¹⁾	1.151E+05
Fe-55	-	-	-	-	-	1.903E-01 ⁽¹⁾	1.299E+05
Fe-59	-	-	-	-	-	2.185E-02 ⁽¹⁾	1.491E+04
Mn-54	-	-	-	-	-	2.264E-01 ⁽¹⁾	1.545E+05
Zn-65	-	-	-	-	-	5.100E-03 ⁽¹⁾	3.481E+04
Kr-85	3.383E+08	1.221E+06	2.206E+25	6.50E-08	1.434E+16	4.295E+01	2.931E+07
Kr-85m	1.613E+04	1.939E+07	1.670E+22	6.50E-08	1.085E+13	1.298E+00	8.857E+05
Kr-87	4.578E+03	3.668E+07	8.966E+21	6.50E-08	5.828E+12	7.721E-01	5.269E+05
Kr-88	1.022E+04	5.154E+07	2.813E+22	6.50E-08	1.829E+13	2.290E+00	1.563E+06
Rb-86	1.612E+06	2.817E+05	2.425E+22	2.30E-08	5.576E+12	3.562E-02	2.431E+04
Sr-89	4.363E+06	7.059E+07	1.644E+25	1.00E-11	1.644E+12	5.792E-03	3.953E+03
Sr-90	9.190E+08	9.765E+06	4.791E+26	1.00E-11	4.791E+13	5.617E-04	3.834E+02
Sr-91	3.420E+04	8.810E+07	1.609E+23	1.00E-11	1.609E+10	1.562E-03	1.066E+03
Sr-92	9.756E+03	9.671E+07	5.037E+22	1.00E-11	5.037E+09	6.270E-04	4.279E+02
Y-90	2.304E+05	1.020E+07	1.255E+23	1.60E-12	2.008E+09	8.029E-04	5.480E+02
Y-91	5.055E+06	9.262E+07	2.500E+25	1.60E-12	4.000E+11	3.402E-02	2.322E+04
Y-92	1.274E+04	9.720E+07	6.613E+22	1.60E-12	1.058E+09	7.603E-04	5.189E+02
Y-93	3.636E+04	1.142E+08	2.216E+23	1.60E-12	3.546E+09	4.857E-04	3.315E+02

**Table 2.9.1-3
RCS Source Term**

Nuclide	Half-Life (sec)	Core Inventory (Ci)	Core Inventory (Atoms)	Escape Coefficient (1/s)	1% Fuel Defect Source (Atoms/sec)	Results	
						Equilibrium Concentration ($\mu\text{Ci/gm}$)	Equilibrium Activity (μCi)
Zr-95	5.528E+06	1.324E+08	3.909E+25	1.60E-12	6.254E+11	1.202E-03	8.204E+02
Zr-97	6.084E+04	1.327E+08	4.310E+23	1.60E-12	6.896E+09	5.400E-04	3.685E+02
Nb-95	3.037E+06	1.340E+08	2.172E+25	1.60E-12	3.475E+11	1.231E-03	8.402E+02
Mo-99	2.376E+05	1.558E+08	1.977E+24	2.00E-09	3.953E+13	5.273E+00	3.599E+06
Tc-99m	2.167E+04	1.364E+08	1.578E+23	2.00E-09	3.157E+12	4.008E+00	2.736E+06
Ru-103	3.394E+06	1.483E+08	2.687E+25	1.60E-12	4.300E+11	1.337E-03	9.122E+02
Ru-105	1.598E+04	1.152E+08	9.830E+22	1.60E-12	1.573E+09	1.826E-04	1.247E+02
Ru-106	3.181E+07	7.451E+07	1.266E+26	1.60E-12	2.025E+12	6.845E-04	4.672E+02
Rh-105	1.273E+05	1.047E+08	7.114E+23	1.60E-12	1.138E+10	6.705E-04	4.576E+02
Sb-127	3.326E+05	1.083E+07	1.924E+23	1.00E-09	1.924E+12	5.059E-02	3.453E+04
Sb-129	1.555E+04	2.998E+07	2.490E+22	1.00E-09	2.490E+11	2.904E-02	1.982E+04
Te-127	3.366E+04	1.076E+07	1.933E+22	1.00E-09	1.933E+11	5.351E-02	3.652E+04
Te-127m	9.418E+06	1.456E+06	7.323E+23	1.00E-09	7.323E+12	8.381E-03	5.720E+03
Te-129	4.176E+03	2.951E+07	6.579E+21	1.00E-09	6.579E+10	4.540E-02	3.099E+04
Te-129m	2.903E+06	4.396E+06	6.813E+23	1.00E-09	6.813E+12	2.483E-02	1.695E+04
Te-131m	1.080E+05	1.283E+07	7.398E+22	1.00E-09	7.398E+11	4.313E-02	2.944E+04
Te-132	2.815E+05	1.188E+08	1.785E+24	1.00E-09	1.785E+13	5.361E-01	3.659E+05
I-131	6.947E+05	8.522E+07	3.161E+24	2.30E-08	7.269E+14	1.015E+01	6.930E+06

**Table 2.9.1-3
RCS Source Term**

Nuclide	Half-Life (sec)	Core Inventory (Ci)	Core Inventory (Atoms)	Escape Coefficient (1/s)	1% Fuel Defect Source (Atoms/sec)	Results	
						Equilibrium Concentration (μ Ci/gm)	Equilibrium Activity (μ Ci)
I-132	8.280E+03	1.212E+08	5.357E+22	2.30E-08	1.232E+13	2.044E+00	1.395E+06
I-133	7.488E+04	1.637E+08	6.544E+23	2.30E-08	1.505E+14	1.070E+01	7.302E+06
I-134	3.156E+03	1.777E+08	2.994E+22	2.30E-08	6.886E+12	9.510E-01	6.490E+05
I-135	2.380E+04	1.538E+08	1.954E+23	2.30E-08	4.494E+13	4.813E+00	3.285E+06
Xe-133	4.532E+05	1.643E+08	3.975E+24	6.50E-08	2.584E+15	2.471E+02	1.686E+08
Xe-135	3.272E+04	4.310E+07	7.530E+22	6.50E-08	4.895E+13	9.513E+00	6.493E+06
Cs-134	6.507E+07	3.011E+07	1.046E+26	2.30E-08	2.406E+16	6.589E+00	4.497E+06
Cs-136	1.132E+06	7.995E+06	4.832E+23	2.30E-08	1.111E+14	1.577E+00	1.076E+06
Cs-137	9.467E+08	1.355E+07	6.850E+26	2.30E-08	1.575E+17	2.970E+00	2.027E+06
Ba-139	4.962E+03	1.435E+08	3.802E+22	1.00E-11	3.802E+09	5.012E-04	3.420E+02
Ba-140	1.101E+06	1.383E+08	8.125E+24	1.00E-11	8.125E+11	7.440E-03	5.078E+03
La-140	1.450E+05	1.446E+08	1.119E+24	1.60E-12	1.791E+10	3.446E-03	2.352E+03
La-141	1.415E+04	1.307E+08	9.871E+22	1.60E-12	1.579E+09	2.761E-04	1.884E+02
La-142	5.550E+03	1.257E+08	3.725E+22	1.60E-12	5.959E+08	7.798E-05	5.322E+01
Ce-141	2.808E+06	1.328E+08	1.991E+25	1.60E-12	3.185E+11	1.196E-03	8.164E+02
Ce-143	1.188E+05	1.199E+08	7.605E+23	1.60E-12	1.217E+10	6.744E-04	4.603E+02
Ce-144	2.456E+07	1.111E+08	1.458E+26	1.60E-12	2.332E+12	1.018E-03	6.950E+02
Pr-143	1.172E+06	1.192E+08	7.457E+24	1.60E-12	1.193E+11	1.073E-03	7.321E+02

**Table 2.9.1-3
RCS Source Term**

Nuclide	Half-Life (sec)	Core Inventory (Ci)	Core Inventory (Atoms)	Escape Coefficient (1/s)	1% Fuel Defect Source (Atoms/sec)	Results	
						Equilibrium Concentration (μ Ci/gm)	Equilibrium Activity (μ Ci)
Nd-147	9.487E+05	5.287E+07	2.678E+24	1.60E-12	4.284E+10	4.500E-04	3.071E+02
Np-239	2.035E+05	2.213E+09	2.404E+25	-	0.000E+00	-	-
Pu-238	2.769E+09	6.206E+05	9.175E+25	-	0.000E+00	-	-
Pu-239	7.594E+11	3.792E+04	1.538E+27	-	0.000E+00	-	-
Pu-240	2.063E+11	6.849E+04	7.544E+26	-	0.000E+00	-	-
Pu-241	4.544E+08	1.643E+07	3.986E+26	-	0.000E+00	-	-
Am-241	1.364E+10	1.930E+04	1.406E+25	-	0.000E+00	-	-
Cm-242	1.407E+07	7.300E+06	5.482E+24	-	0.000E+00	-	-
Cm-244	5.715E+08	1.481E+06	4.520E+25	-	0.000E+00	-	-
I-130	4.450E+04	5.738E+06	1.363E+22	2.30E-08	3.135E+12	2.785E-01	1.901E+05
Kr- 83m	6.588E+03	9.426E+06	3.315E+21	6.50E-08	2.155E+12	3.946E-01	2.693E+05
Xe-138	8.502E+02	1.314E+08	5.967E+21	6.50E-08	3.878E+12	5.385E-01	3.675E+05
Xe-131m	1.028E+06	9.535E+05	5.234E+22	6.50E-08	3.402E+13	3.071E+00	2.096E+06
Xe-133m	1.890E+05	5.268E+06	5.317E+22	6.50E-08	3.456E+13	3.583E+00	2.445E+06
Xe-135m	9.174E+02	3.419E+07	1.675E+21	6.50E-08	1.089E+12	8.829E-01	6.026E+05
Cs-138	1.932E+03	1.465E+08	1.511E+22	2.30E-08	3.475E+12	1.008E+00	6.880E+05
Cs-134m	1.044E+04	7.014E+06	3.909E+21	2.30E-08	8.992E+11	1.159E-01	7.908E+04
Rb- 88	1.068E+03	5.252E+07	2.995E+21	2.30E-08	6.888E+11	2.371E+00	1.618E+06

**Table 2.9.1-3
RCS Source Term**

Nuclide	Half-Life (sec)	Core Inventory (Ci)	Core Inventory (Atoms)	Escape Coefficient (1/s)	1% Fuel Defect Source (Atoms/sec)	Results	
						Equilibrium Concentration (μ Ci/gm)	Equilibrium Activity (μ Ci)
Rb- 89	9.120E+02	6.694E+07	3.260E+21	2.30E-08	7.497E+11	1.040E-01	7.101E+04
Sb-124	5.201E+06	2.690E+05	7.471E+22	1.00E-09	7.471E+11	1.526E-03	1.041E+03
Sb-125	8.741E+07	1.973E+06	9.210E+24	1.00E-09	9.210E+13	1.135E-02	7.743E+03
Sb-126	1.071E+06	1.506E+05	8.615E+21	1.00E-09	8.615E+10	8.095E-04	5.525E+02
Te-131	1.500E+03	7.505E+07	6.010E+21	1.00E-09	6.010E+10	1.767E-02	1.206E+04
Te-133	7.470E+02	9.701E+07	3.869E+21	1.00E-09	3.869E+10	7.154E-03	4.883E+03
Te-134	2.508E+03	1.301E+08	1.742E+22	1.00E-09	1.742E+11	2.368E-02	1.616E+04
Te-125m	5.011E+06	4.326E+05	1.157E+23	1.00E-09	1.157E+12	2.490E-03	1.699E+03
Te-133m	3.324E+03	5.770E+07	1.024E+22	1.00E-09	1.024E+11	1.378E-02	9.402E+03
Ba-141	1.096E+03	1.300E+08	7.611E+21	1.00E-11	7.611E+08	1.054E-04	7.191E+01
Ba-137m	1.531E+02	1.284E+07	1.050E+20	1.00E-11	1.050E+07	2.807E+00	1.915E+06
Pd-109	4.834E+04	4.489E+07	1.158E+23	-	0.000E+00	-	-
Rh-106	2.990E+01	8.175E+07	1.305E+20	1.60E-12	2.088E+06	6.846E-04	4.672E+02
Rh-103m	3.367E+03	1.336E+08	2.402E+22	1.60E-12	3.843E+08	1.328E-03	9.065E+02
Tc-101	8.520E+02	1.433E+08	6.520E+21	2.00E-09	1.304E+11	1.811E-02	1.236E+04
Eu-154	2.777E+08	1.795E+06	2.661E+25	-	0.000E+00	-	-
Eu-155	1.565E+08	1.225E+06	1.023E+25	-	0.000E+00	-	-
Eu-156	1.312E+06	3.731E+07	2.614E+24	-	0.000E+00	-	-

**Table 2.9.1-3
RCS Source Term**

Nuclide	Half-Life (sec)	Core Inventory (Ci)	Core Inventory (Atoms)	Escape Coefficient (1/s)	1% Fuel Defect Source (Atoms/sec)	Results	
						Equilibrium Concentration ($\mu\text{Ci/gm}$)	Equilibrium Activity (μCi)
La-143	8.538E+02	1.190E+08	5.424E+21	1.60E-12	8.678E+07	1.205E-05	8.226E+00
Nb-97	4.326E+03	1.339E+08	3.094E+22	1.60E-12	4.950E+08	9.285E-05	6.337E+01
Nb-95m	3.118E+05	9.476E+05	1.577E+22	1.60E-12	2.524E+08	8.658E-06	5.909E+00
Pm-147	8.279E+07	1.179E+07	5.209E+25	1.60E-12	8.335E+11	1.088E-04	7.425E+01
Pm-148	4.640E+05	2.459E+07	6.091E+23	1.60E-12	9.746E+09	1.944E-04	1.326E+02
Pm-149	1.911E+05	5.409E+07	5.518E+23	1.60E-12	8.829E+09	3.552E-04	2.424E+02
Pm-151	1.022E+05	1.899E+07	1.036E+23	1.60E-12	1.658E+09	9.992E-05	6.819E+01
Pm-148m	3.568E+06	2.904E+06	5.532E+23	1.60E-12	8.852E+09	2.616E-05	1.785E+01
Pr-144	1.037E+03	1.119E+08	6.195E+21	1.60E-12	9.912E+07	1.018E-03	6.950E+02
Pr-144m	4.320E+02	1.335E+06	3.079E+19	1.60E-12	4.927E+05	1.809E-05	1.235E+01
Sm-153	1.681E+05	6.060E+07	5.440E+23	-	0.000E+00	-	-
Y- 94	1.146E+03	1.161E+08	7.106E+21	1.60E-12	1.137E+08	1.581E-05	1.079E+01
Y- 95	6.420E+02	1.261E+08	4.324E+21	1.60E-12	6.918E+07	9.652E-06	6.587E+00
Y- 91m	2.983E+03	5.114E+07	8.143E+21	1.60E-12	1.303E+08	9.078E-04	6.196E+02
Br- 82	1.271E+05	7.573E+05	5.138E+21	2.30E-08	1.182E+12	6.249E-02	4.265E+04
Br- 83	8.604E+03	9.388E+06	4.313E+21	2.30E-08	9.919E+11	1.252E-01	8.542E+04
Br- 84	1.908E+03	1.599E+07	1.629E+21	2.30E-08	3.746E+11	5.131E-02	3.502E+04
Am- 242	5.767E+04	1.079E+07	3.323E+22	-	0.000E+00	-	-

**Table 2.9.1-3
RCS Source Term**

Nuclide	Half-Life (sec)	Core Inventory (Ci)	Core Inventory (Atoms)	Escape Coefficient (1/s)	1% Fuel Defect Source (Atoms/sec)	Results	
						Equilibrium Concentration ($\mu\text{Ci/gm}$)	Equilibrium Activity (μCi)
Np- 238	1.829E+05	6.601E+07	6.446E+23	-	0.000E+00	-	-
Pu - 243	1.784E+04	7.742E+07	7.375E+22	-	0.000E+00	-	-
Note: 1. The results for the seven corrosion product isotopes (Co-58, Co-60, Cr-51, Fe-55, Fe-59, Mn-54, and Zn-65) are determined via the methods described in Reference 2, and include the effects of zinc injection.							

2.9.2 Radiological Consequences Analyses Using Alternative Source Terms (AST)

2.9.2.1 Regulatory Evaluation

Florida Power and Light (FPL) performed design basis accident (DBA) radiological consequences analyses using the guidance in NRC Regulatory Guide (RG) 1.183, Alternative Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors. Clarification and additional guidance contained in Regulatory Issues Summary (RIS) documents 2001-19, Deficiencies in the Documentation of Design Basis Radiological Analyses submitted in Conjunction with License Amendment Requests, October 18, 2001 and 2006-04, Experience with Implementation of Alternative Source Terms, March 7, 2006 were also considered in performing these DBA consequence analyses. The radiological consequence analyses performed are for the following DBAs:

- Loss-of-coolant accident (LOCA),
- Fuel handling accident (FHA),
- Main steam line break accident (MSLB),
- Steam generator tube rupture (SGTR),
- Reactor coolant pump shaft seizure (Locked rotor),
- Control element assembly (CEA) ejection,
- Feedwater line break (FWLB), and
- Letdown line rupture (Letdown).

The analyses for each accident considered:

- The sequence of events; and
- Models, assumptions, and values of parameter inputs used for the calculation of the total effective dose equivalent (TEDE).

The NRC's acceptance criteria for radiological consequence analyses using an AST are based on:

- 10 CFR 50.67, insofar as it sets standards for radiological consequences of a postulated accident;
- General Design Criterion (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
- RG 1.183 insofar as it provides accident dose criteria.

Specific review criteria are contained in Standard Review Plan (SRP) Section 15.0.1.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conform with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The current licensing basis (CLB) with respect to radiation protection of plant personnel and the public includes the following:

- GDC-19 is described in UFSAR Section 3.1.19 Criterion 19 - Control Room.

A control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in safe condition under accident conditions, including loss-of-coolant accidents. Adequate radiation protection shall 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 for the duration of the accident.

- 10 CFR 50.67, insofar as it establishes requirements for an Alternative Source Term (AST) licensed plant that offsite and control room operator radiological doses from postulated accidents will be below established guidelines.
- Regulatory Guide 1.183 insofar as it provides accident dose criteria.

On September 29, 2008, the NRC approved Amendment 152 to the St. Lucie Unit 2 facility operating license, which adopts the AST as allowed in 10 CFR 50.67 and described in RG 1.183. The radiological consequences of a number of DBAs were reanalyzed using the AST methodology from RG 1.183 and the results were submitted for NRC review and approval.

NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Power Plant Units 1 and 2, dated September 2003, defines the scope of license renewal. Specific design transient analyses and radiological consequences are not within the scope of license renewal.

2.9.2.2 Technical Evaluation

The analyses performed for the extended power uprate (EPU) reflect the methodology of the prior AST licensing submittal and subsequent safety evaluation ([References 1 and 2](#)), and have all been updated, using input and assumptions consistent with the proposed EPU. For each accident, the TEDE is determined at the exclusion area boundary (EAB) for the limiting 2-hour period, at the low population zone (LPZ) outer boundary for 30 days, and in the control room for 30 days. These results, including direct shine dose contributions to control room personnel, are summarized in LR [Table 2.9.2-1](#) along with the dose acceptance criteria. The evaluation of the waste gas decay tank rupture event is provided in LR [Section 2.9.3](#), Radiological Consequences of Gas Decay Tank Ruptures.

2.9.2.2.1 Common Input Parameters and Assumptions

2.9.2.2.1.1 Source Terms

Consistent with [References 1](#) and [2](#), the full core isotopic inventory is determined in accordance with RG 1.183, Regulatory Position 3.1, using the ORIGEN-2.1 isotope generation and depletion computer code (part of the SCALE-4.3 system of codes) for the EPU specified burnup, enrichment, and burnup rates (power levels). For EPU, the following inputs are utilized to determine the bounding source term:

- An enrichment range of 1.5 weight percent (w/o) to 5.0 w/o 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 MWD/MTU.

A revised primary coolant source term is determined utilizing EPU conditions based upon maximum equilibrium concentrations of isotopes with small defects in 1 percent of the fuel rod cladding. Corrosion products are derived from ANSI/ANS-18.1-1999.

The primary coolant iodine activities are adjusted to achieve the Technical Specification (TS) 3.4.8 limit of 1.0 $\mu\text{Ci/gm}$ 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 proposed TS DE Xe-133 limit is derived 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.

Secondary coolant system activity is limited to a value of $\leq 0.10 \mu\text{Ci/gm}$ DE I-131 in accordance with TS 3.7.1.4. Noble gases entering the secondary coolant system are assumed to be immediately released; thus the noble gas activity concentration in the secondary coolant system is assumed to be 0.0 $\mu\text{Ci/gm}$. Thus, the secondary side iodine activity is 1/10 of the primary coolant iodine activity.

Consistent with [References 1](#) and [2](#), the FHA assumes the failure of one assembly; therefore, the FHA source term is based on a single “bounding” fuel assembly. As per the methodology of [References 1](#) and [2](#), the source term methodology for the FHA is similar to that used for developing the LOCA containment leakage source term, except that for DBA events that do not involve the entire core, the fission product inventory of each of the damaged fuel rods is determined by dividing the total core inventory by the number of fuel rods in the core. To account for differences in power level across the core, a radial peaking factor of 1.65 (total integrated peaking factor for St. Lucie Unit 2 with EPU), is applied in determining the inventory of the damaged rods. A maximum fuel assembly uranium (U-234, U-235, U-236, and U-238) loading of 410 kilograms is utilized.

The source term data used in performing EPU AST analyses are summarized in the following LR tables:

- [Table 2.9.2-2-](#) Primary Coolant Source Term,
- [Table 2.9.2-3-](#) Secondary Side Source Term,

- **Table 2.9.2-4** - LOCA Containment Leakage Source Term (compared with pre-EPU Source Term),
- **Table 2.9.2-5** - Fuel Handling Accident Source Term.

Consistent with the method of **Reference 1** accepted in **Reference 2** and the assumption of two high burnup assemblies, a high burnup adjustment/increase of 0.922 percent is applied to the release fractions for all non-LOCA events in which fuel damage causes the 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 assembly are assumed to be damaged, high burnup is addressed by increasing the gap release fraction of the entire assembly by a factor of two.

2.9.2.2.2 Iodine Spiking

A concurrent and a pre-accident iodine spike are modeled for the SGTR, as described in RG 1.183. Iodine spiking was not considered for the MSLLB, since it includes fuel damage. The EPU assumes that the initial primary coolant iodine concentrations are based on thyroid dose equivalent, as used in **References 1** and **2**. DE I-131 calculated using the thyroid DCFs results in higher primary coolant concentrations than the DE I-131 determined from effective DCFs.

2.9.2.2.3 Dose Conversion Factors

For the TEDE offsite and control room dose calculations, the DCFs are derived from FGR No. 11 and FGR No. 12. The DCFs are unchanged from those used in **References 1** and **2**.

2.9.2.2.4 Atmospheric Dispersion Factors (X/Q)

The X/Q values have been reevaluated utilizing more recent meteorological data and the methods described in **References 1** and **2**. The ARCON96 meteorological data that were utilized are from 2001 through 2004 and 2006, while the PAVAN joint frequency data that were utilized are from 2004 through 2007. LR **Figure 2.9.2-1** provides a sketch of the general layout of St. Lucie Unit 2 that has been annotated to highlight the release and receptor point locations. The following LR tables provide the utilized atmospheric dispersion factor information:

- **Table 2.9.2-6** - Release-Receptor Combination Parameters for Analysis Events - provides information related to the relative elevations of the release-receptor combinations, the straight-line horizontal distance between the release point and the receptor location, and the direction (azimuth) from the receptor location to the release point.
- **Table 2.9.2-7** - Onsite Atmospheric Dispersion Factors (X/Q) for Analysis Events - provides the control room X/Q values for the release-receptor combinations
- **Table 2.9.2-8** - Release-Receptor Point Pairs Assumed for Analysis Events - identifies the Release-Receptor pair and associated control room X/Q values from **Table 2.9.2-7** that are used in the event analyses during each of the modes of control room ventilation
- **Table 2.9.2-9** - Offsite Atmospheric Dispersion Factors (X/Q) – provides the EAB and LPZ atmospheric dispersion factors

2.9.2.2.5 Control Room Radiological Analysis Parameters

Control room radiological analysis parameters and assumptions are summarized in LR Table 2.9.2-10. The control room habitability and ventilation systems are described in LR Sections 2.7.1, Control Room Habitability Systems and 2.7.3, Control Room Ventilation System, respectively. The control room radiological analysis parameters and assumptions are the same as those from References 1 and 2 with the exception that conservative consideration of diesel generator under and over-frequency operation and surveillance test acceptance criteria impacts on control room ventilation flow rates was added (± 12 percent of design flow rates).

2.9.2.2.6 Direct Shine Dose to the Control Room

The direct shine dose to the control room is calculated using the methods of References 1 and 2 and EPU conditions. The total control room dose includes direct shine dose contributions from:

- The radioactive material on the control room filters,
- The radioactive plume in the environment, and
- The activity in the primary containment atmosphere.

LR Table 2.9.2-11 presents the components of the direct shine dose.

2.9.2.3 EPU LOCA Radiological Consequences

2.9.2.3.1 Description of Event

A major LOCA is defined as a break in the reactor coolant pressure boundary (RCPB) having an area greater than 0.5 ft^2 . Such a break and the consequent coolant loss would result in loss of the normal mechanism for removing heat from the reactor core. This sequence cannot occur unless there are multiple failures. Activity is released from the containment and from there, released to the environment by means of containment leakage and leakage from the emergency core cooling systems (ECCS).

2.9.2.3.2 Analysis Parameters and Assumptions

For this event, the control room ventilation system cycles through three modes of operation (the operational modes are summarized in LR Table 2.9.2-10). Inputs and assumptions are documented in LR Table 2.9.2-12, including a comparison to the inputs utilized in References 1 and 2. Inputs and assumptions fall into three main categories: radionuclide release inputs, radionuclide transport inputs, and radionuclide removal inputs.

Release Inputs

The core inventory of the radionuclide groups utilized for this event is based on RG 1.183, Regulatory Position 3.1, at 3030 MWt and is provided as LR Table 2.9.2-4. The source term represents end of cycle conditions assuming enveloping initial fuel enrichment and an average core burnup of 49,000 MWD/MTU.

From Table 6.5-7 of the UFSAR, the initial leakage rate from containment is 0.5 percent of the containment volume per day. Per RG 1.183, Regulatory Position 3.7, the primary containment leakage rate is reduced by 50 percent at 24 hours into the LOCA to 0.25 percent /day based on the post-LOCA primary containment pressure history.

The engineered safeguards feature (ESF) leakage to the reactor auxiliary building (RAB) is assumed to be 1.08 gal/hr, based upon two times the current licensing basis value of 0.54 gal/hr. The leakage is conservatively assumed to start at 20.3 minutes into the event and continue throughout the 30-day accident period. This portion of the analysis assumes that 10 percent of the total iodine is released from the leaked liquid. The form of the released iodine is 97 percent elemental iodine and 3 percent organic iodine. Dilution and holdup of the ECCS leakage in the RAB are not credited.

The ECCS backleakage to the refueling water tank (RWT) is initially assumed to be 2 gpm (based on doubling 1 gpm). This leakage is assumed to start at 20.3 minutes into the event when recirculation starts and continue throughout the 30-day accident period. Based on sump pH history, 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 elemental iodine. 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 which then enters the RWT air space is a function of the temperature-dependent iodine partition coefficient.

The time-dependent concentration of the total iodine in the RWT (including stable iodine) was determined from the tank liquid volume and leak rate. This iodine concentration ranged from a minimum value of 0 at the beginning of the event to a maximum value of 4.079E-05 gm-atom/liter at 30 days (see LR [Table 2.9.2-14](#)). Based upon the backleakage of sump water, the RWT pH slowly increases from an initial value of 4.5 to a maximum pH of 4.862 at 30 days (see LR [Table 2.9.2-13](#)). Using the time-dependent RWT pH and the total iodine concentration in the RWT liquid space, the amount of iodine converted to elemental iodine was determined using guidance provided in NUREG-5950. This RWT elemental iodine fraction ranged from 0 at the beginning of the event to a maximum of 0.1699 (see LR [Table 2.9.2-16](#)).

The elemental iodine in the liquid region of the RWT is assumed to become volatile and to partition between the liquid and vapor space in the RWT based upon the partition coefficient for elemental iodine as presented in NUREG-5950. A GOTHIC model was used to determine the RWT temperature and the peak temperature value from the model was conservatively applied for the full 30 days (see LR [Table 2.9.2-15](#)). This temperature was then used to calculate the partition coefficient shown in LR [Table 2.9.2-17](#), which was also constantly applied for 30 days. The RWT is a vented tank; therefore, there will be no pressure transient in the air region that would affect the partition coefficient. Since no boiling occurs in the RWT, the release of the activity from the vapor space within the RWT is calculated based upon the displacement of air by the incoming leakage and by conservative application of expansion of the gas volume by the diurnal heating and cooling cycles that may occur at the St. Lucie site. The elemental iodine flow rate from the RWT is equal to the air flow rate times the elemental iodine concentration in the RWT vapor space.

For the organic iodine flow, the same approach was used with an organic iodine fraction of 0.0015 from RG 1.183 in combination with a partition coefficient of 1.0. The particulates portion of the leakage is assumed to be retained in the liquid phase of the RWT. Therefore, the total iodine flow is the sum of the elemental iodine and organic iodine flow rates.

The time dependent iodine release rate presented in LR Table 2.9.2-18 is then applied to the entire iodine inventory (particulates, elemental iodine, and organic iodine) in the containment sump. The iodine released via the RWT air vent to the environment was effectively set to 100 percent elemental (the control room filters have the same efficiency for all forms of iodine).

Operation of the hydrogen purge system is also assumed coincident with the beginning of the LOCA. Since the purge is isolated prior to the initial release of fission products from the core at 30 seconds, only the initial RCS activity (at an assumed $1.0 \mu\text{Ci/gm}$ DE I-131 and $518.9 \mu\text{Ci/gm}$ DE Xe-133 gross activity) is available for release via this pathway. The release is modeled for 30 seconds at 425 cfm until isolation occurs.

The release point for each of the above sources is presented in LR Table 2.9.2-8.

Transport Inputs

During the LOCA event, the hydrogen purge system is assumed to be operating and releases prior to system isolation are through the plant stack with no filtration. Leakage into the secondary containment is assumed to be released directly to the environment (bypass leakage) as a ground level release prior to drawdown of the shield building annulus volume to negative pressure at 310 seconds. Activity is subsequently collected by the shield building ventilation system (SBVS). Effluents from the SBVS are assumed to be a filtered release from the plant stack with a filter efficiency of 99 percent for particulates and 95 percent for both elemental iodine and organic iodine. ECCS leakage into the RAB is modeled as a release via the RAB. For this release, the ECCS area ventilation system is credited with a particulates removal efficiency of 99 percent and elemental iodine and organic iodine efficiencies of 95 percent. The activity from the RWT is modeled as an unfiltered ground level release from the RWT.

For this event, the control room ventilation system cycles through three modes of operation:

- Initially the ventilation system is assumed to be operating in normal mode. The air flow distribution during this mode is 1000 cfm of unfiltered fresh air and an assumed value of 425 cfm of unfiltered inleakage.
- After the start of the event, the control room is isolated due to a containment isolation actuation signal (CIAS) as a result of a high containment pressure signal. A 30-second delay is applied to account for the time to reach the signal, the diesel generator start time, damper actuation time. After isolation, the air flow distribution consists of 0 cfm of makeup flow from the outside, 425 cfm of 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 to the control room. During this operational mode, the air flow distribution consists of up to 504 cfm of filtered makeup flow, 425 cfm of unfiltered inleakage, and 1256 cfm of filtered recirculation flow.

- The control room 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 iodine.

LOCA Removal Inputs

Reduction of the airborne radioactivity in the containment by natural deposition is credited. The natural deposition removal coefficient for elemental iodine is calculated per SRP Section 6.5.2 as 2.89 hr^{-1} . A natural deposition removal coefficient of 0.1 hr^{-1} is assumed for all aerosols in the unsprayed region and in the sprayed region after spray flow is secured at 8 hours. No removal of organic iodine by natural deposition is assumed.

Containment spray provides coverage to 85 percent of the containment. Therefore, the containment building atmosphere is not considered to be a single, well-mixed volume. A mixing rate of two turnovers of the unsprayed region per hour is assumed.

The elemental iodine spray coefficient is limited to 20 hr^{-1} per SRP Section 6.5.2. This coefficient is reduced to 0 when an elemental iodine decontamination factor (DF) of 200 is reached. Based upon the elemental iodine removal rate of 20 hr^{-1} , the DF of 200 is conservatively computed to occur at 3.07 hours.

The particulate iodine removal rate is reduced by a factor of 10 when a DF of 50 is reached. Based upon the calculated iodine aerosol removal rate of 6.52 hr^{-1} , the DF of 50 is conservatively computed to occur at 2.643 hours.

2.9.2.3.3 Comparison to References 1 and 2

The analysis of the LOCA radiological consequences is consistent with the analytical methods and assumptions presented in References 1 and 2, with changes made to reflect the increased power and as indicated in LR Table 2.9.2-12. Some of the changes include:

- Sump water temperatures and corresponding flashing fractions consistent with EPU conditions,
- RCS pressure and temperature conditions based on EPU conditions,
- Containment spray flow rate,
- RWT available and transfer volumes,
- 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,
- X/Q values consistent with more recent meteorological data, and
- Core radionuclide inventory consistent with EPU conditions.

2.9.2.3.4 Results

The post-accident doses are the result of five distinct activity releases:

- 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, and
- Hydrogen purge at event initiation.

The dose to the control room occupants includes terms for:

- Contamination of the control room atmosphere by intake and infiltration of radioactive material from the containment and ESF,
- External radioactive plume shine contribution from the containment and ESF leakage releases (this term takes credit for control room structural shielding),
- A direct shine dose contribution from the containment's contained accident activity (this term takes credit for both containment and control room structural shielding), and
- A direct shine dose contribution from the activity collected on the control room ventilation filters.

The calculated TEDE at the EAB, at the LPZ outer boundary, and in the control room for the DBA LOCA meet the exposure guideline values specified in 10 CFR 50.67, GDC-19, and the applicable acceptance criteria denoted in RG 1.183. The results of the LOCA dose calculations, and the applicable dose acceptance criteria, are presented in LR [Table 2.9.2-1](#).

2.9.2.4 FHA Radiological Consequences

2.9.2.4.1 Description of Event

This event consists of the drop of a single fuel assembly either in the fuel handling building (FHB) or inside of containment. All of the fuel rods in a single fuel assembly are damaged.

This analysis considers both a dropped fuel assembly inside the containment with the maintenance hatch open, and an assembly drop inside the FHB without credit for filtration of the FHB exhaust. The source term released from the overlying water pool is the same for both the FHB and the containment cases. RG 1.183 includes the same 2-hour guidance for the direct unfiltered release of the activity to the environment for either location.

A minimum water level of 23 feet is maintained above the damaged fuel assembly for both the containment and FHB release locations per TS. This water level ensures that an elemental iodine decontamination factor of 285 may be applied per the guidance provided in RIS 2006-04.

2.9.2.4.2 Analysis Parameters and Assumptions

Inputs and assumptions for the FHA are documented in LR [Table 2.9.2-19](#), including a comparison to the inputs utilized in [References 1 and 2](#). It is assumed that the FHA occurs at 72 hours after shutdown of the reactor per TS 3.9.3. 100 percent of the gap activity specified in Table 3 of RG 1.183 is assumed to be instantaneously released from a single fuel assembly into the fuel pool. A minimum water level of 23 feet is maintained above the damaged fuel for the duration of the event. 100 percent of the noble gas released from the damaged fuel assembly is assumed to escape from the pool. All of the non-iodine particulates released from the damaged fuel assembly are assumed to be retained by the pool. Iodine released from the damaged fuel assembly is assumed to be composed of 99.85 percent elemental iodine and 0.15 percent organic iodine. All activity released from the pool is assumed to leak to the environment over a two-hour period. No credit for dilution or holdup in the containment or FHB is taken.

The FHA source term is listed in LR [Table 2.9.2-5](#). The analysis includes a decay time of 72 hours before the beginning of fuel movement. Since the FHA source term presented in LR [Table 2.9.2-5](#) does not include this decay time, it is accounted for in the RADTRAD-NAI model. Gap release fractions are doubled to account for high burnup fuel rods.

For this event, the control room ventilation system cycles through three modes of operation:

- Initially, the ventilation system is assumed to be operating in normal mode. The air flow distribution during this mode is 1000 cfm of unfiltered fresh air and an assumed value of 425 cfm of unfiltered inleakage.
- After the start of the event, the control room is isolated due to a high radiation reading in the control room ventilation system. A 30-second delay is applied to account for diesel generator start time, damper actuation time, instrument delay, and detector response time. After isolation, the air flow distribution consists of 0 cfm of makeup flow from the outside, 425 cfm of 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 to the control room. During this operational mode, the air flow distribution consists of up to 504 cfm of filtered makeup flow, 425 cfm of unfiltered inleakage, and 1256 cfm of filtered recirculation flow.
- The control room 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 iodine.

2.9.2.4.3 Comparison to [References 1 and 2](#)

The analysis of the FHA radiological consequences is consistent with the analytical methods and assumptions presented in [References 1 and 2](#), with changes made to reflect the increased power as indicated in LR [Table 2.9.2-19](#). The only significant changes are:

- Assembly radionuclide inventory consistent with EPU conditions, and
- X/Q values consistent with more recent meteorological data.

2.9.2.4.4 Results

The calculated TEDE at the EAB, at the LPZ outer boundary, and in the control room for the DBA FHA meet the exposure guideline values specified in 10 CFR 50.67, GDC-19, and the applicable acceptance criteria denoted in RG 1.183. The results of the FHA dose calculations, and the applicable dose acceptance criteria, are presented in LR [Table 2.9.2-1](#).

2.9.2.5 MSLB Radiological Consequences

2.9.2.5.1 Description of Event

This event consists of a double-ended break of one main steam line either inside or outside of containment. Allowable fuel failure rates due to departure from nucleate boiling (DNB) and fuel centerline melt (FCM) are determined for both break locations based upon the dose limits specified in Table 6 of RG 1.183. The affected steam generator (SG) rapidly depressurizes and releases the initial contents of the SG to either the environment or the containment. Plant cool down is achieved via the remaining unaffected SG.

2.9.2.5.2 Analysis Parameters and Assumptions

Inputs and assumptions for the MSLB are documented in LR [Table 2.9.2-20](#), including a comparison to the inputs utilized in [References 1 and 2](#). The postulated accident consists of two cases; one case is based upon a double-ended break of one main steam line outside of containment, and the second case is based upon a double-ended break of one 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 steam generator. Upon a MSLB, the affected SG rapidly depressurizes. 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 SG secondary side due to primary-to-secondary leakage. The source term for this activity is presented in LR [Table 2.9.2-4](#) with subsequent adjustments for the fraction of damaged fuel, the non-LOCA fission product gap fractions from Table 3 of RG 1.183, high burnup fuel (increase of release fractions by 0.922 percent), and a radial peaking factor of 1.65. All noble gases associated with this leakage are assumed to be released directly to the environment. For the break outside containment, primary-to-secondary leakage into the affected SG is also assumed to directly enter the atmosphere. For the break inside containment, the affected SG leakage is released into containment. All primary-to-secondary leakage is assumed to continue until the RCS is cooled to 212°F at 12.4 hours.

Primary-to-secondary tube leakage is also postulated to occur in the unaffected SG for both cases. This activity is diluted by the contents of the steam generator and released via steaming from the atmospheric dump valves (ADVs) until the RCS is cooled to 212°F. In addition, the analysis of both cases assumes that the initial iodine activity of both SGs is released directly to the environment. The entire content of the faulted SG is released immediately, while the intact SG release occurs during the RCS cooldown. The secondary coolant iodine concentration is assumed to be the maximum value of 0.1 mCi/gm DE I-131 permitted by TS.

Allowable levels of fuel failure for DNB and FCM are determined for both the MSLB outside of containment and the MSLB inside of containment. These allowable fractions are based on the dose limits specified in Table 6 of RG 1.183. The activity released from the fuel that is assumed to experience DNB is based on Regulatory Positions 3.1, 3.2, and Table 3 of RG 1.183. The activity released from the fuel that is assumed to experience fuel centerline melt is based on Regulatory Position 1 of Appendix H to RG 1.183.

For this event, the control room ventilation system cycles through three modes of operation:

- Initially, the ventilation system is assumed to be operating in normal mode. The air flow distribution during this mode is 1000 cfm of unfiltered fresh air and an assumed value of 425 cfm of unfiltered inleakage.
- After the start of the event, the control room is isolated due to a high radiation reading in the control room ventilation system. A 30-second delay is applied to account for diesel generator start time, damper actuation time, instrument delay, and detector response time. After isolation, the air flow distribution consists of 0 cfm of makeup flow from the outside, 425 cfm of 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 to the control room. During this operational mode, the air flow distribution consists of up to 504 cfm of filtered makeup flow, 425 cfm of unfiltered inleakage, and 1256 cfm of filtered recirculation flow.
- The control room 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 iodine.

2.9.2.5.3 Comparison to References 1 and 2

The analysis of the MSLB radiological consequences is consistent with the analytical methods and assumptions presented in **References 1 and 2**, with changes made to reflect the increased power and as indicated in LR **Tables 2.9.2-20, 2.9.2-21, and 2.9.2-22**. Some of the changes made to be consistent with EPU conditions and site meteorology include:

- Assembly radionuclide inventories,
- Break flow rates,
- Steam releases,
- Primary fluid densities,
- Primary and secondary fluid inventories, and
- X/Q values consistent with more recent meteorological data.

2.9.2.5.4 Results

The calculated TEDE at the EAB, at the LPZ outer boundary, and in the control room for the DBA MSLB meet the exposure guideline values specified in 10 CFR 50.67, GDC-19, and the

applicable acceptance criteria denoted in RG 1.183. The results of the MSLB dose calculations, and the applicable dose acceptance criteria, are presented in LR [Table 2.9.2-1](#).

2.9.2.6 SGTR Radiological Consequences

2.9.2.6.1 Description of Event

This event is assumed to be caused by the instantaneous rupture of a SG tube that relieves to the lower pressure secondary system. No melt or clad breach is postulated for the SGTR event.

2.9.2.6.2 Analysis Parameters and Assumptions

Inputs and assumptions for the SGTR are documented in LR [Table 2.9.2-23](#), including a comparison to the inputs utilized in [References 1 and 2](#). This event is assumed to be caused by the instantaneous rupture of a SG tube releasing primary coolant to the lower pressure secondary system. In the unlikely event of a concurrent loss of power, the loss 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. This direct steam relief continues until the faulted SG is isolated at 45 minutes.

A thermal-hydraulic analysis is performed to determine a conservative break flow, break flashing flow, and steam release inventory through the faulted SG relief valves. Additional activity, based on the primary-to-secondary leakage limits, is released via steaming from the ADVs until the RCS is cooled to 212°F.

No fuel failure is postulated for the SGTR event. Consistent with RG 1.183 Appendix F, Regulatory Position 2, if no, or minimal, fuel damage is postulated for the limiting event, the activity release is assumed as the maximum allowed by TS for two cases of iodine spiking: (1) maximum pre-accident iodine spike, and (2) maximum accident-induced, or concurrent, iodine spike.

For the case of a pre-accident iodine spike, a reactor transient is assumed to have occurred prior to the postulated SGTR event. The primary coolant iodine concentration is increased to the maximum value of 60 $\mu\text{Ci/gm DE I-131}$ permitted by TS 3.4.8 (see LR [Table 2.9.2-25](#)). Primary coolant is released into the ruptured SG by the tube rupture and by a fraction of the total proposed allowable primary-to-secondary leakage. Activity is released to the environment from the ruptured SG via direct flashing of a fraction of the released primary coolant from the tube rupture and also via steaming from the ruptured SG ADVs until the ruptured SG is isolated at 45 minutes. The unaffected SG is used to cool down the plant during the SGTR event. Primary-to-secondary tube leakage is also postulated into the intact SG. Activity is released via steaming from the unaffected SG ADVs until the RCS is cooled below 212°F.

The assumption that steam is released from the ruptured SG ADV location is made to maximize the dose to control room operators via this release pathway. The assumed ADV release point conservatively bounds the dose consequences from other steam release points, such as the main steam safety valves and the turbine-driven auxiliary feedwater pump.

For the case of the accident-induced spike, the postulated STGR event induces an iodine spike. The RCS activity is initially assumed to be 1.0 $\mu\text{Ci/gm DE I-131}$ as allowed by TS 3.4.8. Iodine is

released from the fuel into the RCS at a rate of 335 times the iodine equilibrium release rate for a period of 8 hours. Parameters used in the determination of the iodine equilibrium release rate are provided in LR [Table 2.9.2-26](#). The iodine activities and the appearance rates for the accident-induced (concurrent) iodine spike case are presented in LR [Table 2.9.2-27](#). All other release assumptions for this case are identical to those for the pre-accident spike case.

For this event, the control room ventilation system cycles through three modes of operation:

- Initially, the ventilation system is assumed to be operating in normal mode. The air flow distribution during this mode is 1000 cfm of unfiltered fresh air and an assumed value of 425 cfm of unfiltered inleakage.
- After the start of the event, the control room is isolated due to a high radiation reading in the control room ventilation system. For this event, it is conservatively assumed that the control room isolation signal is delayed until the release from the ADVs is initiated at 284 seconds. A 30-second delay is applied to account for diesel generator start time, damper actuation time, instrument delay, and detector response time. After isolation, the air flow distribution consists of 0 cfm of makeup flow from the outside, 425 cfm of 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 to the control room. During this operational mode, the air flow distribution consists of up to 504 cfm of filtered makeup flow, 425 cfm of unfiltered inleakage, and 1256 cfm of filtered recirculation flow.
- The control room 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 iodine.

2.9.2.6.3 Comparison to [References 1 and 2](#)

The analysis of the SGTR radiological consequences is consistent with the analytical methods and assumptions presented in [References 1 and 2](#), with changes made to reflect the increased power and as indicated in LR [Tables 2.9.2-23 through 2.9.2-27](#). Some of the changes include using a conservative SG isolation time. Others were made to be consistent with EPU conditions, and site meteorology, including:

- Isolation of the ruptured SG is assumed to occur at 45 minutes,
- Broken tube flow rates,
- Steam releases,
- Primary fluid densities,
- Primary and secondary fluid inventories, and
- X/Q values consistent with more recent meteorological data.

2.9.2.6.4 Results

The calculated TEDE at the EAB, at the LPZ outer boundary, and in the control room for the DBA SGTR meet the exposure guideline values specified in 10 CFR 50.67, GDC-19, and the applicable acceptance criteria denoted in RG 1.183. The results of the SGTR dose calculations, and the applicable dose acceptance criteria, are presented in LR [Table 2.9.2-1](#).

2.9.2.7 Locked Rotor Radiological Consequences

2.9.2.7.1 Description of Event

This event is caused by an instantaneous seizure of a primary reactor coolant pump (RCP) rotor. Flow through the affected loop is rapidly reduced, causing a reactor trip due to a low primary loop flow signal. Fuel damage may be predicted to occur as a result of this accident. Due to the pressure differential between the primary and secondary systems and assumed SG tube leakage, fission products are discharged from the primary into the secondary system. A portion of this radioactivity is released to the outside atmosphere from the secondary coolant system through the SG via the ADVs and MSSVs. In addition, radioactivity is contained in the primary and secondary coolant before the accident and some of this activity is released to the atmosphere as a result of steaming from the steam generators following the accident.

2.9.2.7.2 Analysis Parameters and Assumptions

Inputs and assumptions for the locked rotor event are documented in LR [Table 2.9.2-28](#), including a comparison to the inputs utilized in [References 1 and 2](#). This event is caused by an instantaneous seizure of a primary RCP rotor. Flow through the affected loop is rapidly reduced, causing a reactor trip due to a low primary loop flow signal. Following the reactor trip, the heat stored in the fuel rods continues to be transferred to the reactor coolant. Because of the reduced core flow, the coolant temperatures will rise. The rapid rise in primary system temperatures during the initial phase of the transient results in a reduction in the initial DNB margin and fuel damage.

For the purpose of this dose assessment, a total of 19.7 percent of the fuel assemblies are assumed to experience DNB. The activity released from the fuel is assumed to be released instantaneously and homogeneously through the primary coolant. The source term is based upon release fractions from Appendix G of RG 1.183 with an adjustment for high burnup fuel (increase in the release fraction of 0.922 percent) and a radial peaking factor of 1.65. Primary coolant is released to the SGs as a result of postulated primary-to-secondary leakage. Activity is released to the atmosphere via steaming from the steam generator ADVs until the RCS is cooled to 212°F. These release assumptions are consistent with the guidance of RG 1.183.

For this event, the control room ventilation system cycles through three modes of operation:

- Initially, the ventilation system is assumed to be operating in normal mode. The air flow distribution during this mode is 1000 cfm of unfiltered fresh air and an assumed value of 425 cfm of unfiltered inleakage.

- After the start of the event, the control room is isolated due to a high radiation reading in the control room ventilation system. A 30-second delay is applied to account for diesel generator start time, damper actuation time, instrument delay, and detector response time. After isolation, the air flow distribution consists of 0 cfm of makeup flow from the outside, 425 cfm of 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 to the control room. During this operational mode, the air flow distribution consists of up to 504 cfm of filtered makeup flow, 425 cfm of unfiltered inleakage, and 1256 cfm of filtered recirculation flow.
- The control room 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 iodine.

2.9.2.7.3 Comparison to References 1 and 2

The analysis of the locked rotor event radiological consequences is consistent with the analytical methods and assumptions presented in References 1 and 2, with changes made to reflect the increased power and as indicated in LR Tables 2.9.2-28, 2.9.2-29, and 2.9.2-30. Some of the changes made to be consistent with EPU conditions and site meteorology include:

- Assembly radionuclide inventories,
- Steam releases,
- Primary fluid densities,
- Primary and secondary fluid inventories, and
- X/Q values consistent with more recent meteorological data.

2.9.2.7.4 Results

The calculated TEDE at the EAB, at the LPZ outer boundary, and in the control room for the DBA locked rotor meet the exposure guideline values specified in 10 CFR 50.67, GDC-19, and the applicable acceptance criteria denoted in RG 1.183. The results of the locked rotor dose calculations, and the applicable dose acceptance criteria, are presented in LR Table 2.9.2-1.

2.9.2.8 CEA Ejection Radiological Consequences

2.9.2.8.1 Description of Event

This event consists of an uncontrolled withdrawal of a single CEA. The CEA ejection results in a reactivity insertion that leads to a core power level increase and subsequent reactor trip. Following the reactor trip, plant cooldown is performed using steam release from the SG ADVs. Two CEA ejection cases are considered. The first case assumes that 100 percent of the activity released from the damaged fuel is instantaneously and homogeneously mixed throughout the containment atmosphere. The second case assumes that 100 percent of the activity released

from the damaged fuel is completely dissolved in the primary coolant and is available for release to the secondary system.

2.9.2.8.2 Analysis Parameters and Assumptions

Inputs and assumptions for the CEA ejection event are documented in LR [Table 2.9.2-31](#), including a comparison to the inputs utilized in [References 1 and 2](#). The postulated accident consists of two cases. One case assumes that 100 percent of the activity released from the damaged fuel is instantaneously and homogeneously mixed throughout the containment atmosphere, and the second case assumes that 100 percent of the activity released from the damaged fuel is completely dissolved in the primary coolant and is available for release to the secondary system.

For the containment release case, 100 percent of the activity is released instantaneously to the containment. The releases from the containment correspond to the same leakage points discussed for the LOCA in LR [Section 2.9.2.3.2](#). Natural deposition of the released activity inside of containment is credited. In addition, the SBVS is credited. Removal of activity via containment spray is not credited.

For the secondary release case, primary coolant activity is released into the SGs by leakage across the SG tubes. The activity on the secondary side is then released via steaming from the ADVs until the RCS is cooled to 212°F. All noble gases associated with this leakage are assumed to be released directly to the environment. The primary-to-secondary leakage is assumed to continue until the faulted SG is completely isolated at 12.4 hours. In addition, the analysis assumes that the initial iodine activity of both SGs is immediately released to the environment. The secondary coolant iodine concentration is assumed to be the maximum value of 0.1 mCi/gm DE I-131 permitted by TS. Thus, secondary side iodine activity is one-tenth of the primary coolant iodine activity. These release assumptions are consistent with the requirements of RG 1.183.

The CEA ejection is evaluated with the assumption that 0.5 percent of the fuel experiences FCM and 9.5 percent of the fuel experiences DNB. The activity released from the damaged fuel corresponds to the requirements set out in Regulatory Position 1 of Appendix H to RG 1.183 with an adjustment for high burnup fuel (increase in the release fraction of 0.922 percent) and a radial peaking factor of 1.65 applied in the development of the source terms.

For this event, the control room ventilation system cycles through three modes of operation:

- Initially, the ventilation system is assumed to be operating in normal mode. The air flow distribution during this mode is 1000 cfm of unfiltered fresh air and an assumed value of 425 cfm of unfiltered inleakage.
- After the start of the event, the control room is isolated due to a high radiation reading in the control room ventilation system. A 30-second delay is applied to account for diesel generator start time, damper actuation time, instrument delay, and detector response time. After isolation, the air flow distribution consists of 0 cfm of makeup flow from the outside, 425 cfm of 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 to the control room. During this operational mode, the air flow distribution consists of up to 504 cfm of filtered makeup flow, 425 cfm of unfiltered inleakage, and 1256 cfm of filtered recirculation flow.
- The control room 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 iodine.

2.9.2.8.3 Comparison to References 1 and 2

The analysis of the CEA ejection event radiological consequences is consistent with the analytical methods and assumptions presented in References 1 and 2, with changes made to reflect the increased power and as indicated in LR Tables 2.9.2-31, 2.9.2-32, and 2.9.2-33. Some of the changes made to be consistent with EPU conditions and site meteorology include:

- Assembly radionuclide inventories,
- Steam releases,
- Primary fluid densities,
- Primary and secondary fluid inventories, and
- X/Q values consistent with more recent meteorological data.

2.9.2.8.4 Results

The calculated TEDE at the EAB, at the LPZ outer boundary, and in the control room for the DBA CEA ejection meet the exposure guideline values specified in 10 CFR 50.67, GDC-19, and the applicable acceptance criteria denoted in RG 1.183. The results of the CEA ejection dose calculations, and the applicable dose acceptance criteria, are presented in LR Table 2.9.2-1.

2.9.2.9 Feedwater Line Break Radiological Consequences

2.9.2.9.1 Description of Event

This event involves a rupture of a main feedwater system pipe during plant operation. The rupture rapidly reduces the steam generator secondary inventory causing a partial loss of secondary heat sink, thereby allowing the heat-up of the Reactor Coolant System (RCS). A reactor trip is assumed to occur with a concurrent loss of offsite power. Plant cooldown is achieved via the remaining unaffected steam generator. No fuel failures are postulated to occur as a result of this event.

2.9.2.9.2 Analysis Parameters and Assumptions

Inputs and assumptions for the FWLB event are documented in LR Table 2.9.2-34, including a comparison to the inputs utilized in References 1 and 2. Primary coolant is released to the SGs as a result of postulated primary-to-secondary leakage. The activity on the secondary side of the intact SG is then released via steaming from the ADVs until the RCS is cooled to 212°F. All

noble gases associated with this leakage are assumed to be released directly to the environment. In addition, the entire secondary side inventory of the faulted steam generator is instantaneously released to the environment. The activity in the RCS tube leakage to the faulted SG is released directly to the environment until terminated at 12.4 hours. The initial secondary coolant iodine concentration is assumed to be the maximum value of 0.1 mCi/gm DE I-131 permitted by TS.

For this event, the control room ventilation system cycles through three modes of operation:

- Initially, the ventilation system is assumed to be operating in normal mode. The air flow distribution during this mode is 1000 cfm of unfiltered fresh air and an assumed value of 425 cfm of unfiltered inleakage.
- After the start of the event, the control room is isolated due to a high radiation reading in the control room ventilation system. A 30-second delay is applied to account for diesel generator start time, damper actuation time, instrument delay, and detector response time. After isolation, the air flow distribution consists of 0 cfm of makeup flow from the outside, 425 cfm of 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 to the control room. During this operational mode, the air flow distribution consists of up to 504 cfm of filtered makeup flow, 425 cfm of unfiltered inleakage, and 1256 cfm of filtered recirculation flow.
- The control room 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 iodine.

2.9.2.9.3 Comparison to [References 1 and 2](#)

The analysis of the FWLB radiological consequences is consistent with the analytical methods and assumptions presented in [References 1 and 2](#), with changes made to reflect the increased power and as indicated in LR [Tables 2.9.2-34, 2.9.2-35, and 2.9.2-36](#). Some of the changes made to be consistent with EPU conditions and site meteorology include:

- Primary coolant radionuclide inventories,
- Primary fluid densities,
- Primary and secondary fluid inventories, and
- X/Q values consistent with more recent meteorological data.

2.9.2.9.4 Results

The calculated TEDE at the EAB, at the LPZ outer boundary, and in the control room for the FWLB event meet the exposure guideline values specified in 10 CFR 50.67, GDC-19, and Section 15.8.2 of the Standard Review Plan. The results of the FWLB dose calculations, and the applicable dose acceptance criteria, are presented in LR [Table 2.9.2-1](#).

2.9.2.10 Letdown Line Rupture Radiological Consequences

2.9.2.10.1 Description of Event

This event is a rupture of a primary coolant letdown line outside of containment. The dose assessment for this event is comprised of a double ended rupture of the letdown line in the reactor auxiliary building.

2.9.2.10.2 Analysis Parameters and Assumptions

No fuel failure is postulated for the Letdown Line Rupture event. Consistent with Standard Review Plan Section 15.6.2, a concurrent iodine spike is assumed. The RCS activity is initially assumed to be 1.0 $\mu\text{Ci/gm}$ DE I-131 as allowed by TS 3.4.8. Iodine is released from the fuel into the RCS at a rate of 500 times the iodine equilibrium release rate for a period of 8 hours. Parameters used in the determination of the iodine equilibrium release rate are provided in LR Table 2.9.2-38. The iodine activities and the appearance rates for the accident-induced iodine spike case are presented in LR [Table 2.9.2-39](#).

Two activity release paths are considered in this event. Primary coolant is released into the SGs as a result of postulated primary-to-secondary leakage. The activity on the secondary side of the intact SG is then released via steaming from the ADVs until the RCS is cooled to 212°F at 12.4 hours. In addition, activity is released to the auxiliary building via direct flashing of the primary coolant from the broken letdown line. The broken tube flow isolated at 30 minutes. All noble gases associated with both release paths are assumed to be released directly to the environment.

For this event, the control room ventilation system cycles through three modes of operation:

- Initially, the ventilation system is assumed to be operating in normal mode. The air flow distribution during this mode is 1000 cfm of unfiltered fresh air and an assumed value of 425 cfm of unfiltered inleakage.
- After the start of the event, the control room is isolated due to a high radiation reading in the control room ventilation system. A 30-second delay is applied to account for diesel generator start time, damper actuation time, instrument delay, and detector response time. After isolation, the air flow distribution consists of 0 cfm of makeup flow from the outside, 425 cfm of 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 to the control room. During this operational mode, the air flow distribution consists of up to 504 cfm of filtered makeup flow, 425 cfm of unfiltered inleakage, and 1256 cfm of filtered recirculation flow.
- The control room 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 iodine.

2.9.2.10.3 Comparison to References 1 and 2

The analysis of the Letdown Line Rupture radiological consequences is consistent with the analytical methods and assumptions presented in References 1 and 2, with changes made to reflect the increased power and as indicated in LR Tables 2.9.2-37 through 2.9.2-42. Some of the changes made to be consistent with EPU conditions and site meteorology include:

- Primary coolant radionuclide inventories,
- Primary fluid densities,
- Primary and secondary fluid inventories, and
- X/Q values consistent with more recent meteorological data.

2.9.2.10.4 Results

The calculated TEDE at the EAB, at the LPZ outer boundary, and in the control room for the Letdown Line Rupture meet the exposure guideline values specified in 10 CFR 50.67, GDC-19, and Section 15.6.2 of the Standard Review Plan. The results of the Letdown Line Rupture dose calculations, and the applicable dose acceptance criteria, are presented in LR Table 2.9.2-1.

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

As discussed above, the design transient analyses and radiological consequences were determined to be outside the scope of License Renewal. Therefore, with respect to the DBAs and transients, the EPU does not impact any License Renewal evaluations.

2.9.2.12 Conclusion

FPL has reviewed the various DBA analyses performed in support of the EPU for their potential radiological consequences and concludes that the analyses adequately account for the effects of the proposed EPU. FPL further concludes that the plant site and the dose-mitigating ESFs continue to meet their current licensing basis with respect to the radiological consequences of postulated DBAs. The calculated TEDE at the EAB, at the LPZ outer boundary, and in the control room meet the exposure guideline values specified in 10CFR50.67, GDC-19, as well as applicable acceptance criteria denoted in RG 1.183. Therefore, FPL finds the EPU acceptable with respect to the radiological consequences of DBAs.

2.9.2.13 References

1. L-2007-087, Letter from Florida Power & Light Company to the USNRC, Subject: St. Lucie Unit 2, Docket No. 50-389, Proposed License Amendment, Alternative Source Term and Conforming Amendment, July 16, 2007 as supplemented by References 3 through 8.
2. Letter to Mr. J. A. Stall (Florida Power & Light Company) from Ms. Brenda L. Mozafari (NRC), St. Lucie Plant, Unit 2 – Issuance of Amendment Regarding Alternative Source Term (TAC No. MD6202), dated September 29, 2008.

3. L-2008-022, Letter from Florida Power & Light Company to the USNRC, Subject: St. Lucie Units 1 and 2, Docket Nos. 50-335 and 50-389, Proposed License Amendment, Request for Additional Information Response, Alternative Source Term Amendment – TAC No. MD6173, February 14, 2008.
4. L-2008-060, Letter from Florida Power & Light Company to the USNRC, Subject: St. Lucie Units 1 and 2, Docket Nos. 50-335 and 50-389, Proposed License Amendment, Request for Additional Information Response, Alternative Source Term Amendment – TAC Nos. MD6173 and MD6202, March 18, 2008.
5. L-2008-081, Letter from Florida Power & Light Company to the USNRC, Subject: St. Lucie Units 1 and 2, Docket Nos. 50-335 and 50-389, Proposed License Amendment, Request for Additional Information Response, Alternative Source Term Amendment – TAC Nos. MD6173 and MD6202, April 14, 2008.
6. L-2008-121, Letter from Florida Power & Light Company to the USNRC, Subject: St. Lucie Units 1 and 2, Docket Nos. 50-335 and 50-389, Proposed License Amendment, Request for Additional Information Response, Alternative Source Term Amendment – TAC Nos. MD6173 and MD6202, June 2, 2008.
7. L-2008-161, Letter from Florida Power & Light Company to the USNRC, Subject: St. Lucie Units 1 and 2, Docket Nos. 50-335 and 50-389, Proposed License Amendment, Request for Additional Information Response, Alternative Source Term Amendment – TAC Nos. MD6173 and MD6202, July 11, 2008.
8. L-2008-187, Letter from Florida Power & Light Company to the USNRC, Subject: St. Lucie Units 1 and 2, Docket Nos. 50-335 and 50-389, Proposed License Amendment, Request for Additional Information Response, Alternative Source Term Amendment – TAC Nos. MD6173 and MD6202, August 13, 2008.

Table 2.9.2-1
Summary of EPU Radiological Analysis Results

Case	Allowable Unfiltered Control Room Inleakage (cfm)	EAB Dose⁽¹⁾ (rem TEDE)	LPZ Dose⁽²⁾ (rem TEDE)	Control Room Dose⁽²⁾ (rem TEDE)	AOR Control Room Dose⁽⁵⁾ (rem TEDE)
LOCA	425	1.02	2.28	4.79	4.46
MSLB – Outside of Containment (1.2% DNB)	425	0.22	0.63	4.51	4.69
MSLB – Outside of Containment (0.29% FCM)	425	0.24	0.67	4.60	4.77
MSLB – Inside of Containment (21% DNB)	425	0.33	0.73	4.63	4.96
MSLB – Inside of Containment (4.5% FCM)	425	0.52	1.01	4.59	4.92
SGTR Pre-accident Iodine Spike	425	0.31	0.30	4.13	2.57
Acceptance Criteria		$\leq 25^{(3)}$	$\leq 25^{(3)}$	$\leq 5^{(4)}$	$\leq 5^{(4)}$
SGTR Concurrent Iodine Spike	425	0.15	0.15	1.54	0.66
Locked Rotor (19.7% DNB)	425	0.30	0.76	4.53	2.81
FWLB ⁽¹⁾	425	0.012	0.016	0.62	0.82
Letdown Line Rupture ⁽⁶⁾	425	0.26	0.26	2.97	2.57
Acceptance Criteria		$\leq 2.5^{(3)}$	$\leq 2.5^{(3)}$	$\leq 5^{(4)}$	$\leq 5^{(4)}$
FHA - Containment	425	0.49	0.47	1.33	0.81
FHA – Fuel Handling Building	425	0.49	0.47	3.40	1.63
CEA Ejection – Containment Release (9.5% DNB, 0.5% FCM)	425	0.23	0.47	2.98	2.78

Table 2.9.2-1
Summary of EPU Radiological Analysis Results

Case	Allowable Unfiltered Control Room Inleakage (cfm)	EAB Dose⁽¹⁾ (rem TEDE)	LPZ Dose⁽²⁾ (rem TEDE)	Control Room Dose⁽²⁾ (rem TEDE)	AOR Control Room Dose⁽⁵⁾ (rem TEDE)
CEA Ejection – Secondary Side Release (9.5% DNB, 0.5% FCM)	425	0.25	0.60	3.24	2.87
Acceptance Criteria		$\leq 6.3^{(3)}$	$\leq 6.3^{(3)}$	$\leq 5^{(4)}$	$\leq 5^{(4)}$
Notes: 1. Worst 2-hour dose 2. Integrated 30-day dose 3. RG 1.183, Table 6 4. 10 CFR 50.67 5. AOR control room dose from CLB AST results 6. Acceptance criteria from References 1 and 2					

Table 2.9.2-2
Primary Coolant Source Term

Nuclide	μCuries/gm		Nuclide	μCuries/gm
Co-58	4.394E-02		Cs-136	1.543E+00
Co-60	8.256E-02		Cs-137	2.899E+00
Cr-51	1.611E-01		Ba-139	4.800E-04
Fe-55	1.818E-01		Ba-140	7.124E-03
Fe-59	2.087E-02		La-140	3.299E-03
Mn-54	2.163E-01		La-141	2.646E-04
Zn-65	4.872E-03		La-142	7.483E-05
Kr-85	4.160E+01		Ce-141	1.147E-03
Kr-85m	1.268E+00		Ce-143	6.485E-04
Kr-87	7.574E-01		Ce-144	9.815E-04
Kr-88	2.247E+00		Pr-143	1.031E-03
Rb-86	3.403E-02		Nd-147	4.302E-04
Sr-89	5.691E-03		Kr-83m	3.826E-01
Sr-90	5.459E-04		Xe-138	5.168E-01
Sr-91	1.526E-03		Xe-131m	3.022E+00
Sr-92	6.105E-04		Xe-133m	3.479E+00
Y-90	7.799E-04		Xe-135m	8.553E-01
Y-91	3.327E-02		Cs-138	9.667E-01
Y-92	7.402E-04		Cs-134m	1.179E-01
Y-93	4.706E-04		Rb-88	2.326E+00
Zr-95	1.159E-03		Rb-89	1.022E-01
Zr-97	5.170E-04		Sb-124	1.910E-03
Nb-95	1.187E-03		Sb-125	1.277E-02
Mo-99	5.111E+00		Sb-126	9.173E-04
Tc-99m	3.885E+00		Te-131	1.741E-02
Ru-103	1.359E-03		-	-
Ru-105	1.934E-04		Te-134	2.280E-02
Ru-106	7.973E-04		Te-125m	2.828E-03
Rh-105	7.047E-04		Te-133m	1.326E-02
Sb-127	5.187E-02		Ba-141	1.009E-04
Sb-129	2.918E-02		Rh-103m	1.350E-03
Te-127	5.496E-02		Nb-97	8.889E-05

Table 2.9.2-2
Primary Coolant Source Term

Nuclide	μCuries/gm		Nuclide	μCuries/gm
Te-127m	8.677E-03		Nb-95m	8.343E-06
Te-129	4.558E-02		Pm-147	1.069E-04
Te-129m	2.486E-02		Pm-148	1.866E-04
Te-131m	4.273E-02		Pm-149	3.485E-04
Te-132	5.233E-01		Pm-151	1.021E-04
I-131	8.425E-01		Pm-148m	2.556E-05
I-132	1.689E-01		Pr-144	9.816E-04
I-133	8.713E-01		Y-94	1.528E-05
I-134	7.726E-02		Y-91m	8.872E-04
I-135	3.933E-01		Br-82	6.096E-02
Xe-133	2.381E+02		Br-83	1.214E-01
Xe-135	9.235E+00		Br-84	5.002E-02
Cs-134	6.972E+00		-----	-----

Table 2.9.2-3
Secondary Side Source Term

Isotope	iCi/gm
I-131	8.425E-02
I-132	1.689E-02
I-133	8.713E-02
I-134	7.726E-03
I-135	3.933E-02

**Table 2.9.2-4
LOCA Containment Leakage Source Term**

Nuclide	EPU Source	Pre-EPU Source from Reference 1	% Difference
	Core/Fuel Source (Curies)	Core/Fuel Source (Curies)	
Kr-85	1.238E+06	1.152E+06	7.5
Kr-85m	1.983E+07	1.784E+07	11.2
Kr-87	3.767E+07	3.383E+07	11.4
Kr-88	5.295E+07	4.752E+07	11.4
Rb-86	2.817E+05	2.348E+05	20.0
Sr-89	7.261E+07	6.480E+07	12.1
Sr-90	9.934E+06	9.253E+06	7.4
Sr-91	9.016E+07	8.105E+07	11.2
Sr-92	9.856E+07	8.882E+07	11.0
Y-90	1.036E+07	9.615E+06	7.7
Y-91	9.485E+07	8.483E+07	11.8
Y-92	9.904E+07	8.925E+07	11.0
Y-93	1.158E+08	1.046E+08	10.7
Zr-95	1.337E+08	1.206E+08	10.9
Zr-97	1.330E+08	1.207E+08	10.2
Nb-95	1.352E+08	1.220E+08	10.8
Mo-99	1.581E+08	1.405E+08	12.5
Tc-99m	1.384E+08	1.230E+08	12.5
Ru-103	1.578E+08	1.320E+08	19.5
Ru-105	1.277E+08	1.010E+08	26.4
Ru-106	9.086E+07	6.560E+07	38.5
Rh-105	1.150E+08	9.303E+07	23.6
Sb-127	1.163E+07	9.609E+06	21.0
Sb-129	3.155E+07	2.678E+07	17.8
Te-127	1.157E+07	9.546E+06	21.2
Te-127m	1.578E+06	1.294E+06	21.9
Te-129	3.105E+07	2.637E+07	17.7
Te-129m	4.607E+06	3.930E+06	17.2
Te-131m	1.330E+07	1.151E+07	15.6
Te-132	1.213E+08	1.073E+08	13.0

Table 2.9.2-4
LOCA Containment Leakage Source Term

Nuclide	EPU Source	Pre-EPU Source from Reference 1	% Difference
	Core/Fuel Source (Curies)	Core/Fuel Source (Curies)	
I-131	8.752E+07	7.686E+07	13.9
I-132	1.240E+08	1.094E+08	13.3
I-133	1.650E+08	1.486E+08	11.0
I-134	1.787E+08	1.616E+08	10.6
I-135	1.555E+08	1.396E+08	11.4
Xe-133	1.657E+08	1.492E+08	11.1
Xe-135	4.394E+07	4.333E+07	1.4
Cs-134	3.335E+07	2.606E+07	28.0
Cs-136	8.190E+06	7.018E+06	16.7
Cs-137	1.384E+07	1.284E+07	7.8
Ba-139	1.439E+08	1.307E+08	10.1
Ba-140	1.386E+08	1.258E+08	10.2
La-140	1.448E+08	1.310E+08	10.5
La-141	1.311E+08	1.190E+08	10.2
La-142	1.263E+08	1.146E+08	10.2
Ce-141	1.333E+08	1.208E+08	10.3
Ce-143	1.207E+08	1.094E+08	10.3
Ce-144	1.121E+08	1.014E+08	10.6
Pr-143	1.200E+08	1.088E+08	10.3
Nd-147	5.290E+07	4.809E+07	10.0
Np-239	2.435E+09	1.960E+09	24.2
Pu-238	6.206E+05	5.475E+05	13.4
Pu-239	3.828E+04	3.828E+04	0.0
Pu-240	7.207E+04	6.456E+04	11.6
Pu-241	1.785E+07	1.626E+07	9.8
Am-241	2.014E+04	2.152E+04	-6.4
Cm-242	8.940E+06	6.998E+06	27.8
Cm-244	3.272E+06	1.053E+06	210.7
I-130	6.937E+06	4.626E+06	50.0
Kr-83m	9.565E+06	8.634E+06	10.8

Table 2.9.2-4
LOCA Containment Leakage Source Term

Nuclide	EPU Source	Pre-EPU Source from Reference 1	% Difference
	Core/Fuel Source (Curies)	Core/Fuel Source (Curies)	
Xe-138	1.320E+08	1.198E+08	10.2
Xe-131m	9.824E+05	8.582E+05	14.5
Xe-133m	5.358E+06	4.765E+06	12.4
Xe-135m	3.513E+07	3.081E+07	14.0
Cs-138	1.470E+08	1.334E+08	10.2
Cs-134m	7.473E+06	5.846E+06	27.8
Rb-88	5.392E+07	4.841E+07	11.4
Rb-89	6.883E+07	6.176E+07	11.4
Sb-124	3.526E+05	2.157E+05	63.5
Sb-125	2.324E+06	1.797E+06	29.3
Sb-126	1.787E+05	1.244E+05	43.6
Te-131	7.697E+07	6.773E+07	13.6
Te-133	9.845E+07	8.797E+07	11.9
Te-134	1.312E+08	1.188E+08	10.4
Te-125m	5.143E+05	3.947E+05	30.3
Te-133m	5.818E+07	5.267E+07	10.5
Ba-141	1.304E+08	1.184E+08	10.1
Ba-137m	1.312E+07	1.216E+07	7.9
Pd-109	5.544E+07	3.771E+07	47.0
Rh-106	9.960E+07	7.109E+07	40.1
Rh-103m	1.422E+08	1.189E+08	19.6
Tc-101	1.470E+08	1.293E+08	13.7
Eu-154	2.086E+06	1.606E+06	29.9
Eu-155	1.446E+06	1.088E+06	32.9
Eu-156	4.763E+07	2.847E+07	67.3
La-143	1.198E+08	1.086E+08	10.3
Nb-97	1.342E+08	1.218E+08	10.2
Nb-95m	9.559E+05	8.606E+05	11.1
Pm-147	1.212E+07	1.187E+07	2.1
Pm-148	2.472E+07	2.220E+07	11.4

Table 2.9.2-4
LOCA Containment Leakage Source Term

Nuclide	EPU Source	Pre-EPU Source from Reference 1	% Difference
	Core/Fuel Source (Curies)	Core/Fuel Source (Curies)	
Pm-149	5.555E+07	4.726E+07	17.5
Pm-151	2.031E+07	1.686E+07	20.5
Pm-148m	2.971E+06	2.843E+06	4.5
Pr-144	1.129E+08	1.021E+08	10.6
Pr-144m	1.347E+06	1.218E+06	10.6
Sm-153	6.783E+07	5.086E+07	33.4
Y-94	1.175E+08	1.062E+08	10.6
Y-95	1.272E+08	1.152E+08	10.4
Y-91m	5.234E+07	4.705E+07	11.2
Br-82	7.734E+05	6.291E+05	22.9
Br-83	9.531E+06	8.606E+06	10.7
Br-84	1.632E+07	1.470E+07	11.0
Am-242	1.235E+07	1.041E+07	18.6
Np-238	6.601E+07	5.399E+07	22.3
Pu-243	1.146E+08	6.043E+07	89.6
Note that a positive % difference indicates that the EPU source inventory is higher than the pre-EPU source inventory. EPU evaluated a wider range of enrichments (1.5 – 5.0w/o U-235) and a higher burnup (49 GWD/MTU).			

**Table 2.9.2-5
Fuel Handling Accident Source Term**

Nuclide	Activity (Curies)	Nuclide	Activity (Curies)	Nuclide	Activity (Curies)
Co-58	0.000E+00	I-135	1.183E+06	Sb-126	1.359E+03
Co-60	0.000E+00	Xe-133	1.260E+06	Te-131	5.853E+05
Kr-85	9.417E+03	Xe-135	3.341E+05	Te-133	7.486E+05
Kr-85m	1.508E+05	Cs-134	2.536E+05	Te-134	9.973E+05
Kr-87	2.864E+05	Cs-136	6.227E+04	Te-125m	3.911E+03
Kr-88	4.026E+05	Cs-137	1.052E+05	Te-133m	4.424E+05
Rb-86	2.142E+03	Ba-139	1.094E+06	Ba-141	9.918E+05
Sr-89	5.521E+05	Ba-140	1.054E+06	Ba-137m	9.973E+04
Sr-90	7.554E+04	La-140	1.101E+06	Pd-109	4.216E+05
Sr-91	6.856E+05	La-141	9.966E+05	Rh-106	7.574E+05
Sr-92	7.494E+05	La-142	9.600E+05	Rh-103m	1.081E+06
Y-90	7.880E+04	Ce-141	1.014E+06	Tc-101	1.117E+06
Y-91	7.212E+05	Ce-143	9.179E+05	Eu-154	1.586E+04
Y-92	7.531E+05	Ce-144	8.526E+05	Eu-155	1.100E+04
Y-93	8.804E+05	Pr-143	9.128E+05	Eu-156	3.622E+05
Zr-95	1.016E+06	Nd-147	4.023E+05	La-143	9.110E+05
Zr-97	1.011E+06	Np-239	1.851E+07	Nb-97	1.021E+06
Nb-95	1.028E+06	Pu-238	4.719E+03	Nb-95m	7.268E+03
Mo-99	1.202E+06	Pu-239	2.911E+02	Pm-147	9.215E+04
Tc-99m	1.052E+06	Pu-240	5.480E+02	Pm-148	1.879E+05
Ru-103	1.200E+06	Pu-241	1.357E+05	Pm-149	4.224E+05
Ru-105	9.714E+05	Am-241	1.532E+02	Pm-151	1.544E+05
Ru-106	6.909E+05	Cm-242	6.798E+04	Pm-148m	2.259E+04
Rh-105	8.747E+05	Cm-244	2.488E+04	Pr-144	8.583E+05
Sb-127	8.842E+04	I-130	5.275E+04	Pr-144m	1.024E+04
Sb-129	2.399E+05	Kr-83m	7.273E+04	Sm-153	5.158E+05
Te-127	8.796E+04	Xe-138	1.004E+06	Y-94	8.931E+05
Te-127m	1.200E+04	Xe-131m	7.470E+03	Y-95	9.671E+05
Te-129	2.361E+05	Xe-133m	4.074E+04	Y-91m	3.980E+05
Te-129m	3.503E+04	Xe-135m	2.671E+05	Br-82	5.881E+03
Te-131m	1.012E+05	Cs-138	1.117E+06	Br-83	7.247E+04

Table 2.9.2-5
Fuel Handling Accident Source Term

Nuclide	Activity (Curies)	Nuclide	Activity (Curies)	Nuclide	Activity (Curies)
Te-132	9.227E+05	Cs-134m	5.683E+04	Br-84	1.241E+05
I-131	6.654E+05	Rb-88	4.100E+05	Am-242	9.393E+04
I-132	9.425E+05	Rb-89	5.234E+05	Np-238	5.019E+05
I-133	1.255E+06	Sb-124	2.681E+03	Pu-243	8.717E+05
I-134	1.358E+06	Sb-125	1.767E+04	-----	-----

Table 2.9.2-6
Release-Receptor Combination Parameters for Analysis Events

Release Point	Receptor Point	Release Height (m)	Receptor Height (m)	Distance (m)	Direction with respect to true North
Stack/Plant Vent	N CR intake	56.1	18.2	14.6	58
Stack/Plant Vent	S CR intake	56.1	17.6	38.6	1
Stack/Plant Vent	Midpoint between CR intakes	56.1	17.9	21.9	10
RWT	N CR intake	14.6	18.2	74.7	65
RWT	S CR intake	14.6	17.6	84.0	42
RWT	Midpoint between CR intakes	14.6	17.9	74.6	53
FHB Closest Point	N CR intake	13.1	18.2	36.9	48
FHB Closest Point	S CR intake	13.1	17.6	57.8	16
FHB Closest Point	Midpoint between CR intakes	13.1	17.9	42.9	26
Louver 2L-7B	N CR intake	11.6	18.2	37.4	47
Louver 2L-7B	S CR intake	11.6	17.6	37.7	72
Louver 2L-7B	Midpoint between CR intakes	11.6	17.9	49.1	30
Louver 2L-7A	N CR intake	11.6	18.2	40.4	85
Louver 2L-7A	S CR intake	11.6	17.6	45.0	40
Louver 2L-7A	Midpoint between CR intakes	11.6	17.9	36.2	61
Closest ADV	N CR intake	14.3	18.2	30.6	298

Table 2.9.2-6
Release-Receptor Combination Parameters for Analysis Events

Release Point	Receptor Point	Release Height (m)	Receptor Height (m)	Distance (m)	Direction with respect to true North
Closest ADV	S CR intake	14.3	17.6	59.6	320
Closest ADV	Midpoint between CR intakes	14.3	17.9	45.5	309
Closest Feedwater Line Point	N CR intake	5.2	18.2	25.3	306
Closest Feedwater Line Point	S CR intake	5.2	17.6	55.8	325
Closest Feedwater Line Point	Midpoint between CR intakes	5.2	17.9	40.9	315
Containment Maintenance Hatch	N CR intake	4.9	18.2	52.4	359
Containment Maintenance Hatch	S CR intake	4.9	17.6	84.3	351
Containment Maintenance Hatch	Midpoint between CR intakes	4.9	17.9	67.0	352

Table 2.9.2-6
Release-Receptor Combination Parameters for Analysis Events

Release Point	Receptor Point	Release Height (m)	Receptor Height (m)	Distance (m)	Direction with respect to true North
Steam Jet Air Ejector	N CR intake	16.0	18.2	45.6	266
Steam Jet Air Ejector	S CR intake	16.0	17.6	63.5	296
Notes: 1. Release heights represent the elevation above the plant grade elevation. 2. The FHB closest point release elevation is taken as the roof elevation since the SW corner of the roof is the closest building point to the intakes. 3. Release and receptor points are considered to be at the centerpoint or centerline of all openings. 4. The only release/receptor combinations which were credited as not having the intakes in the same wind direction window from the release point were the releases from the plant stack. All other release points were analyzed as having both control room intakes being in the same wind direction window. Therefore, credit was only taken for intake dilution for releases from the plant stack. 5. The receptor point for the "midpoint between intakes" is taken as being on the outside of the control room (and heating & ventilation room) east wall. The receptor elevation is taken as the average of the receptor elevations for the two outside air intakes. 6. For events where the limiting unfiltered inleakage location is through the control room intakes, atmospheric dispersion factors corresponding to the midpoint between the control room intakes are to be used during the time period when the control room intakes are isolated. 7. The closest containment/shield building penetration to the intakes that is directly exposed to the atmosphere is the closest feedwater line penetration.					

This table summarizes the X/Q values (sec/m^3) for the control room that apply to the various accident scenarios. For the intakes, values are presented for the unfavorable intake prior to control room isolation, the midpoint between the intakes during isolation, as well as values for the favorable intake following manual restoration of filtered control room make-up flow. These values are not corrected for control room occupancy factors but do include credit for dilution where allowed. Based on the layout of the site, the only cases that credited dilution are the releases from the plant vent stack. However, dilution is not credited during the time period when the control room intakes are isolated for these cases.

A comparison of EPU X/Q values to the pre-EPU X/Q values from [Reference 1](#) is presented in the shaded row below each release-receptor pair (positive values indicate that EPU X/Q values are higher).

* Indicates credit for dilution taken for this case.

The atmospheric dispersion factors corresponding to ADVs were determined to be more limiting than those from the MSSVs for all time periods. Therefore, the more limiting ADV values have been used throughout the analyses for all secondary releases. No distinction is made between automatic steam relief from the MSSVs and controlled releases from the ADVs for radiological purposes.

Table 2.9.2-7
Onsite Atmospheric Dispersion Factors (X/Q) for Analysis Events

Release Receptor Pair	Release Point	Receptor Point	0-2 hr X/Q	2-8 hr X/Q	8-24 hr X/Q	1-4 days X/Q	4-30 days X/Q
A*	Stack/Plant Vent	N CR intake	2.39E-03				
B*	Stack/Plant Vent	S CR intake	6.73E-04	4.55E-04	2.00E-04	1.43E-04	1.08E-04
C	Stack/Plant Vent	Midpoint between CR intakes	3.97E-03				
D	RWT	N CR intake	1.38E-03				
E	RWT	S CR intake	1.08E-03	8.64E-04	3.79E-04	2.96E-04	2.02E-04
F	RWT	Midpoint between CR intakes	1.37E-03				

Table 2.9.2-7
Onsite Atmospheric Dispersion Factors (X/Q) for Analysis Events

Release Receptor Pair	Release Point	Receptor Point	0-2 hr X/Q	2-8 hr X/Q	8-24 hr X/Q	1-4 days X/Q	4-30 days X/Q
G	FHB Closest Point	N CR intake	5.07E-03				
H	FHB Closest Point	S CR intake	1.92E-03	1.49E-03	6.51E-04	4.75E-04	3.18E-04
I	FHB Closest Point	Midpoint between CR intakes	3.57E-03				
J	Louver 2L-7B	N CR intake	4.81E-03				
K	Louver 2L-7A	S CR intake	3.37E-03	2.73E-03	1.19E-03	9.08E-04	6.22E-04
L	Louver 2L-7A	Midpoint between CR intakes	5.14E-03				
M#	Closest ADV	N CR intake	6.42E-03				
N#	Closest ADV	S CR intake	1.86E-03	1.51E-03	6.14E-04	4.77E-04	3.90E-04
O#	Closest ADV	Midpoint between CR intakes	3.02E-03				

Table 2.9.2-7
Onsite Atmospheric Dispersion Factors (X/Q) for Analysis Events

Release Receptor Pair	Release Point	Receptor Point	0-2 hr X/Q	2-8 hr X/Q	8-24 hr X/Q	1-4 days X/Q	4-30 days X/Q
P	Closest Feedwater Line Point	N CR intake	7.11E-03				
Q	Closest Feedwater Line Point	S CR intake	1.91E-03	1.56E-03	6.68E-04	5.03E-04	3.95E-04
R	Closest Feedwater Line Point	Midpoint between CR intakes	3.25E-03				
S	Containment Maintenance Hatch	N CR intake	1.91E-03				
T	Containment Maintenance Hatch	S CR intake	8.24E-04	6.50E-04	2.94E-04	2.03E-04	1.66E-04
U	Containment Maintenance Hatch	Midpoint between CR intakes	1.25E-03				
V	Steam Jet Air Ejector ⁽¹⁾	N CR intake	2.97E-03				
Notes:							
1. Based on recent meteorological and plant configuration data, the X/Q for the steam jet air ejector release point was determined to be higher than the X/Q for the condenser release point that was provided in Reference 1 .							

Table 2.9.2-8
Release-Receptor Point Pairs Assumed for Analysis Events
(Refer to Table 2.9.2-7 for Release/Receptor Pair Locations)

Event	Prior to Control Room Isolation	During Control Room Isolation	After Initiation of Filtered Air Makeup
LOCA:			
Containment Leakage (SBVS)	A	C	B
Containment (SBVS Bypass)	P	R	Q
ECCS Leakage	J	L	K
RWT Backleakage	D	F	E
Cont. Purge/H ₂ Purge	A	C	B
FHA:			
Containment Release	S	U	T
FHB Release	G	I	H
MSLB:			
Outside Containment	M	O	N
Inside Containment (SBVS)	A	C	B
Inside Containment (SBVS Bypass)	P	R	Q
SGTR	V (Prior to Reactor Trip) M (After Reactor Trip)	O	N
Locked Rotor	M	O	N
CEA Ejection:			
Secondary Release	M	O	N
Inside Containment (SBVS)	A	C	B
Inside Containment (SBVS Bypass)	P	R	Q
Letdown Line Break			
Letdown Line Release	J	L	K
Secondary Release	M	O	N
FWLB			
Intact SG	M	O	N
Faulted SG	P	R	Q

**Table 2.9.2-9
Offsite Atmospheric Dispersion Factors (X/Q) for Analysis Events**

Time Period	EAB X/Q (sec/m³)	LPZ X/Q (sec/m³)
0-2 hours	8.54E-05	8.24E-05
0-8 hours	4.96E-05	4.75E-05
8-24 hours	3.78E-05	3.61E-05
1-4 days	2.11E-05	2.00E-05
4-30 days	9.58E-06	8.99E-06
The above table summarizes the maximum X/Q values for the EAB and LPZ. Note that the 0-2 hour EAB X/Q value was used for the entire event.		

**Table 2.9.2-10
Control Room Ventilation System Parameters**

Parameter	EPU Value	Pre-EPU Value
Control Room Volume	97,215 ft ³	Same
Normal Operation		
Filtered Makeup Flow Rate	0 cfm	Same
Filtered Recirculation Flow Rate	0 cfm	Same
Unfiltered Makeup Flow Rate	1000 cfm	Same
Limiting Unfiltered Inleakage	425 cfm	435 cfm
Emergency Operation		
Isolation Mode:		
Filtered Makeup Flow Rate	0 cfm	Same
Filtered Recirculation Flow Rate	1760 cfm ⁽¹⁾	2000 cfm
Unfiltered Makeup Flow Rate	0 cfm	Same
Limiting Unfiltered Inleakage	425 cfm	435 cfm
Filtered Makeup Mode:		
Filtered Makeup Flow Rate	504 cfm ⁽¹⁾	450 cfm
Filtered Recirculation Flow Rate	1256 cfm ⁽¹⁾	1550 cfm
Unfiltered Makeup Flow Rate	0 cfm	Same
Limiting Unfiltered Inleakage	425 cfm	435 cfm
Filter Efficiencies:		
Particulates	99%	99%
Elemental iodine	95%	99%
Organic iodine	95%	99%
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 2.9.2-11
LOCA Direct Shine Dose

Source	Direct Shine Dose (rem)
Containment	0.029
Filters	0.033
External Cloud	0.083
Total	0.15

Table 2.9.2-12
Loss-of-Coolant Accident (LOCA) – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
Release Inputs:		
Core Power Level	3030 MWt (~3020 + 0.3%)	2754 MWt (2700 + 2%)
Core Average Fuel Burnup	49,000 MWD/MTU	45,000 MWD/MTU
Fuel Enrichment	1.5 – 5.0 w/o	3.0 – 4.5 w/o
Initial RCS Equilibrium Activity	1.0 mCi/gm DE I-131 and 518.9 mCi/gm DE Xe-133 (Table 2.9.2-2)	1.0 mCi/gm DE I-131 and 100/E-bar gross activity
Core Fission Product Inventory	Table 2.9.2-4	Different based on power, burnup and enrichment
Containment Leakage Rate 0 to 24 hours after 24 hours	0.5% (by volume)/day 0.25% (by volume)/day	Same Same
LOCA release phase timing and duration	RG 1.183, Table 4	Same
Core Inventory Release Fractions (gap release and early in-vessel damage phases)	RG 1.183, Sections 3.1 and 3.2	Same

Table 2.9.2-12
Loss-of-Coolant Accident (LOCA) – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
ECCS Systems Leakage		
Time of Recirculation	22.8 minutes	20 minutes
Sump Volume (minimum)	57,633 ft ³	55,739 ft ³
ECCS Leakage to RAB (2 times allowed value)	1.08 gph	1.28 gph
Flashing Fraction	Calculated – 5.7% Used for dose determination – 10%	Calculated – 3.4% Used for dose determination – 10%
Chemical form of the iodine in the sump water	0% aerosol, 97% elemental iodine, and 3.0% organic iodine	Same
Release ECCS Area Filtration Efficiency	Elemental iodine – 95% Organic iodine – 95% Particulates – 99% (100% of the particulates are retained in the ECCS fluid)	Same Same Same

Table 2.9.2-12
Loss-of-Coolant Accident (LOCA) – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
RWT Back-leakage		
Sump Volume (at time of recirculation)	57,633 ft ³	58,894 ft ³
ECCS Leakage to RWT (2 times allowed value)	2 gpm	Same
Flashing Fraction (elemental iodine assumed to be released into tank space based upon partition factor)	0% based on temperature of fluid reaching RWT	Same
RWT liquid/vapor Elemental Iodine partition factor	Table 2.9.2-17	Different based on RWT/sump conditions
Elemental Iodine fraction in RWT	Table 2.9.2-16	Different based on RWT/sump conditions
Initial RWT Liquid Inventory (minimum)	65,826 gallons	52,345 gallons
Release from Sump to RWT Vapor Space	Table 2.9.2-18	Different based on RWT/sump conditions
Release from RWT Vapor Space to Environment	0.98 cfm	Not explicitly used as model input; the vent flow concept was incorporated into effective sump to atmosphere iodine flow determination used in pre-EPU model.
Containment or Hydrogen Purge Release	2500 cfm for 30 sec (H ₂ purge)	Same
Removal Inputs:		
Containment Particulates/Aerosol Natural Deposition (only credited in unsprayed regions)	0.1/hour	Same
Containment Elemental Iodine Natural/Wall Deposition	2.89/hour	Same

Table 2.9.2-12
Loss-of-Coolant Accident (LOCA) – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
Containment Spray Region Volume	2,125,000 ft ³	Same
Containment Unsprayed Region Volume	375,000 ft ³	Same
Flow rate between sprayed and unsprayed containment volumes	12,500 cfm	Same
Spray Removal Rates: Elemental Iodine Time to reach DF of 200 Particulate Iodine Time to reach DF of 50	20/hour 3.07 hours 6.52/hour 2.643 hours	Same 3.06 hours 6.40/hour 2.65 hours
Spray Initiation Time Spray Termination Time	63.37 seconds (0.0176 hours) 8 hours	60 seconds (0.0167 hours) Same
Control Room Ventilation System Time of automatic control room isolation Time of manual control room air intake opening	(See Table 2.9.2-10) 30 seconds 1.5 hrs	Same Same
Secondary Containment Filter Efficiency	Particulates – 99% Elemental iodine – 95% Organic iodine – 95%	Same Same Same
Secondary Containment Drawdown Time	310 seconds	Same
Secondary Containment Bypass Fraction	9.6%	Same
Containment or Hydrogen Purge Filtration	0%	Same
Transport Inputs:		
Containment Release Secondary Containment release prior to drawdown	Nearest Containment penetration to CR ventilation intake	Same

Table 2.9.2-12
Loss-of-Coolant Accident (LOCA) – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
Containment Release Secondary Containment release after drawdown	Plant stack	Same
Containment Release Secondary Containment Bypass Leakage	Nearest Containment penetration to CR ventilation intake	Same
ECCS Leakage	ECCS exhaust louver	Same
RWT Backleakage	RWT	Same
Containment or Hydrogen Purge	Plant Stack	Same
Personnel Dose Conversion Inputs:		
Atmospheric Dispersion Factors Offsite Onsite	Table 2.9.2-9 Table 2.9.2-7	Different based on meteorological data Different based on meteorological data
Breathing Rates	RG 1.183 Sections 4.1.3 and 4.2.6	Same
Control Room Occupancy Factor	RG 1.183 Section 4.2.6	Same

Table 2.9.2-13
LOCA Time Dependent RWT pH

Time (hours)	RWT pH
0.00	4.500
0.38	4.500
0.50	4.500
1.0	4.500
5.0	4.504
10.0	4.508
15.0	4.511
25.0	4.519
50.0	4.537
75.0	4.555
100.0	4.572
125.0	4.589
150.0	4.604
200.0	4.634
250.0	4.662
300.0	4.689
350.0	4.713
400.0	4.737
450.0	4.759
500.0	4.780
550.0	4.800
600.0	4.819
650.0	4.838
700.0	4.855
720.0	4.862

Table 2.9.2-14
LOCA Time Dependent RWT Total and Elemental Iodine Concentration

Time (hours)	RWT Total Iodine Concentration⁽¹⁾ [I]aq (gm-atom/liter)	RWT Elemental Iodine Concentration [I₂]aq (gm-atom/liter)
0	0	0.000E+00
0.38	0.000E+00	0.000E+00
0.50	1.572E-08	2.784E-12
1.0	8.115E-08	7.386E-11
5.0	6.003E-07	3.910E-09
10.0	1.239E-06	1.601E-08
15.0	1.866E-06	3.499E-08
25.0	3.087E-06	8.941E-08
50.0	5.962E-06	2.878E-07
75.0	8.607E-06	5.310E-07
100.0	1.105E-05	7.885E-07
125.0	1.331E-05	1.045E-06
150.0	1.540E-05	1.291E-06
200.0	1.918E-05	1.740E-06
250.0	2.248E-05	2.123E-06
300.0	2.539E-05	2.441E-06
350.0	2.798E-05	2.702E-06
400.0	3.029E-05	2.912E-06
450.0	3.238E-05	3.078E-06
500.0	3.426E-05	3.207E-06
550.0	3.597E-05	3.305E-06
600.0	3.754E-05	3.377E-06
650.0	3.897E-05	3.427E-06
700.0	4.029E-05	3.458E-06
720.0	4.079E-05	3.466E-06
1. Includes radioactive and stable iodine isotopes		

Table 2.9.2-15
LOCA Time Dependent RWT Liquid Temperature

Time (hr)	Temperature (°F)
0	104.5
0.38	104.5
0.50	104.5
1.0	104.5
5.0	104.5
10.0	104.5
15.0	104.5
25.0	104.5
50.0	104.5
75.0	104.5
100.0	104.5
125.0	104.5
150.0	104.5
200.0	104.5
250.0	104.5
300.0	104.5
350.0	104.5
400.0	104.5
450.0	104.5
500.0	104.5
550.0	104.5
600.0	104.5
650.0	104.5
700.0	104.5
720.0	104.5

Table 2.9.2-16
LOCA Time Dependent RWT Elemental Iodine Fraction

Time (hr)	Elemental Iodine Fraction
0	0.000E+00
0.38	0.000E+00
0.50	3.542E-04
1.0	1.820E-03
5.0	1.303E-02
10.0	2.584E-02
15.0	3.750E-02
25.0	5.792E-02
50.0	9.654E-02
75.0	1.234E-01
100.0	1.427E-01
125.0	1.570E-01
150.0	1.676E-01
200.0	1.814E-01
250.0	1.889E-01
300.0	1.923E-01
350.0	1.931E-01
400.0	1.922E-01
450.0	1.901E-01
500.0	1.872E-01
550.0	1.838E-01
600.0	1.799E-01
650.0	1.759E-01
700.0	1.717E-01
720.0	1.699E-01

Table 2.9.2-17
LOCA Time Dependent RWT Partition Coefficient

Time (hr)	Elemental Iodine Partition Coefficient
0	41.88
0.38	41.88
0.50	41.88
1.0	41.88
5.0	41.88
10.0	41.88
15.0	41.88
25.0	41.88
50.0	41.88
75.0	41.88
100.0	41.88
125.0	41.88
150.0	41.88
200.0	41.88
250.0	41.88
300.0	41.88
350.0	41.88
400.0	41.88
450.0	41.88
500.0	41.88
550.0	41.88
600.0	41.88
650.0	41.88
700.0	41.88
720.0	41.88

Table 2.9.2-18
LOCA Release Rate from Sump to RWT Vapor Space

Time (hours)	Adjusted Iodine Release Rate (cfm)
0.0	0.0
0.38	5.433E-07
10.0	5.468E-06
25.0	3.205E-05
75.0	1.096E-04
125.0	2.013E-04
200.0	3.263E-04
300.0	4.645E-04
450.0	5.686E-04
600.0	6.221E-04

Table 2.9.2-19
Fuel Handling Accident (FHA) – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
Core Power Level Before Shutdown	3030 MWt (~3020 + 0.3%)	2754 MWt (2700 + 2%)
Core Average Fuel Burnup	49,000 MWD/MTU	45,000 MWD/MTU
Discharged Fuel Assembly Burnup	45,000 – 62,000 MWD/MTU	Same
Fuel Enrichment	1.5 – 5.0 w/o	3.0 – 4.5 w/o
Maximum Radial Peaking Factor	1.65	1.7
Number of Fuel Assemblies in the Core	217	Same
Number of Fuel Assemblies Damaged	1	Same
Delay Before Spent Fuel Movement	72 hours	Same
FHA Source Term for a Single Assembly	Table 2.9.2-5	Different based on power, burnup and enrichment
High Burnup Fuel Adjustment Factor	2.0	Same
Water Level Above Damaged Fuel Assembly	23 feet minimum	Same
Iodine Decontamination Factors	Elemental iodine – 285 Organic iodine – 1	Same Same
Noble Gas Decontamination Factor	1	Same
Chemical Form of Iodine In Pool	Elemental iodine – 99.85% Organic iodine – 0.15%	Same Same
Chemical Form of Iodine Above Pool	Elemental iodine – 57% Organic iodine – 43%	Same Same
Atmospheric Dispersion Factors Offsite Onsite	Table 2.9.2-9 Table 2.9.2-7	Different based on meteorological data Different based on meteorological data

Table 2.9.2-19
Fuel Handling Accident (FHA) – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
Control Room Ventilation System	(See Table 2.9.2-10)	
Time of Control Room Ventilation Isolation	30 seconds	Same
Time of Control Room Filtered Makeup Flow	1.5 hours	Same
Control Room Unfiltered Inleakage	425 cfm	500 cfm
Breathing Rates	RG 1.183 Sections 4.1.3 and 4.2.6	Same
Control Room Occupancy Factor	RG 1.183 Section 4.2.6	Same

Table 2.9.2-20
Main Steam Line Break (MSLB) – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
Core Power Level	3030 MWt (~3020 + 0.3%)	2754 MWt (2700 + 2%)
Core Average Fuel Burnup	49,000 MWD/MTU	45,000 MWD/MTU
Fuel Enrichment	1.5 – 5.0 w/o	3.0 – 4.5 w/o
Maximum Radial Peaking Factor	1.65	1.7
% DNB for MSLB Outside of Containment	1.2%	1.8%
% DNB for MSLB Inside of Containment	21%	29%
% Fuel Centerline Melt for MSLB Outside of Containment	0.29%	0.43%
% Fuel Centerline Melt for MSLB Inside of Containment	4.5%	6.1%
Core Fission Product Inventory	Table 2.9.2-4	Different based on power, burnup and enrichment
Initial RCS Equilibrium Activity	1.0 mCi/gm DE I-131 and 518.9 mCi/gm DE Xe-133 (Table 2.9.2-2)	1.0 mCi/gm DE I-131 and 100/E-bar gross activity
Initial Secondary Side Equilibrium Iodine Activity	0.1 mCi/gm DE I-131 (Table 2.9.2-3)	Same
Release Fraction from DNB Fuel Failures	RG 1.183, Section 3.2	Same
Release Fraction from Centerline Melt Fuel Failures	RG 1.183, Section 3.2, and Section 1 of Appendix H	Same
High Burnup Fuel Adjustment Factor	1.00922	None
Steam Generator Tube Leakage	0.25 gpm per SG (Table 2.9.2-22)	0.25 gpm per SG
Steam Release from Intact SGs	Table 2.9.2-21	Different based on different thermodynamic conditions.

Table 2.9.2-20
Main Steam Line Break (MSLB) – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
Intact SG Tube Uncovery Following Reactor Trip Time to tube recovery Flashing Fraction	1 hour 6%	1 hour 5%
Steam Generator Secondary Side Partition Coefficient	Unaffected SG - 100 Faulted SG - None	Same
Time to Terminate Steam Release	12.4 hours	10.32 hours
Time to Terminate SG Tube Leakage	12.4 hours	12 hours
Containment Volume Containment Leakage Rate 0 to 24 hours after 24 hours	2.50E+06 ft ³ 0.5% (by volume)/day 0.25% (by volume)/day	Same Same Same
Secondary Containment Filter Efficiency	Particulates – 99% Elemental iodine – 95% Organic iodine – 95%	Same Same Same
Secondary Containment Drawdown Time	310 seconds	Same
Secondary Containment Bypass Fraction	9.6%	Same
RCS Mass	420,090 lbm Minimum mass used for fuel failure dose contribution to maximize SG tube leakage activity.	423,700 lbm

Table 2.9.2-20
Main Steam Line Break (MSLB) – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
SG Secondary Side Mass	Minimum – 121,970.5 lbm (per SG) Maximum – 219,009 lbm (per SG) Maximum mass used for faulted SG to maximize secondary side dose contribution. Minimum mass used for intact SG to maximize steam release nuclide concentration.	Minimum – 105,000 lbm (per SG) Maximum – 260,000 lbm (per SG)
Chemical Form of Iodine Released from SGs	Particulates – 0% Elemental iodine – 97% Organic iodine – 3%	Same Same Same
Atmospheric Dispersion Factors Offsite Onsite	Table 2.9.2-9 Table 2.9.2-7	Different based on meteorological data Different based on meteorological data
Control Room Ventilation System Time of Control Room Ventilation Isolation Time of Control Room Filtered Makeup Flow Control Room Unfiltered Inleakage	(See Table 2.9.2-10) 30 seconds 1.5 hours 425 cfm	Same Same 435 cfm
Breathing Rates	RG 1.183 Sections 4.1.3 and 4.2.6	Same
Control Room Occupancy Factor	RG 1.183 Section 4.2.6	Same
Containment Natural Deposition Coefficients	Aerosols – 0.1 hr^{-1} Elemental Iodine – 2.89 hr^{-1} Organic Iodine – None	Same Same Same

Table 2.9.2-21
MSLB Intact Steam Release Rate

Time (hours)⁽¹⁾	Intact SG Steam Release Rate (lbm /min)
0.0	9081.1
0.5	5124.4
2.0	2690.3
8.0	2611.7
9.0	2478.3
10.0	2393.3
11.0	2301.7
12.0	2213.3
12.4	0.0
1. Flow rates are applied until the next time point.	

Table 2.9.2-22
MSLB Steam Generator Tube Leakage

Time (hours)⁽¹⁾	Intact SG Tube Leakage (lbm /min)	Faulted SG Tube Leakage (lbm /min)
0	1.58	2.00
0.50	1.67	2.00
1.00	1.75	2.00
1.50	1.83	2.00
2.00	1.86	2.00
4.00	1.90	2.00
6.00	1.94	2.00
9.00	1.98	2.00
11.00	2.00	2.00
12.40	0.00	0.000
1. Flow rates are applied until the next time point.		

Table 2.9.2-23
Steam Generator Tube Rupture Accident – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
Core Power Level	3030 MWt (~3020 + 0.3%)	2754 MWt (2700 + 2%)
Initial RCS Equilibrium Activity	1.0 mCi/gm DE I-131 and 518.9 mCi/gm DE Xe-133 (Table 2.9.2-2)	1.0 mCi/gm DE I-131 and 100/E-bar gross activity
Initial Secondary Side Equilibrium Iodine Activity	0.1 mCi/gm DE I-131 (Table 2.9.2-3)	0.1 mCi/gm DE I-131
Maximum Pre-Accident Spike Iodine Concentration	60 µCi/gm DE I-131	Same
Maximum Equilibrium Iodine Concentration	1.0 µCi/gm DE I-131	Same
Iodine Spike Appearance Rate	335 times	Same
Duration of Accident-Initiated Spike	8 hours	Same
Break Flow and Steam Releases	Table 2.9.2-24	Different based on different thermodynamic conditions and isolation time
Break Flow Flashing Fraction	Prior to Reactor Trip – 15.5% Following Reactor Trip – 7.5%	Prior to Reactor Trip - 17% Following Reactor Trip – 5%
Time to Terminate Break Flow	45 minutes	30 minutes
Steam Generator Tube Leakage Rate	0.25 gpm per SG	Same
Time to Terminate Tube Leakage	12 hours	Same
Time to Re-cover Unaffected SG Tubes	1 hour	Same
Steam Generator Secondary Side Partition Coefficients	Flashed tube flow – none Non-flashed tube flow – 100	Same Same
Time to Terminate Steam Release	12.4 hours	10.32 hours
Time to Terminate SG Tube Leakage	12.4 hours	12 hours

Table 2.9.2-23
Steam Generator Tube Rupture Accident – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
RCS Mass	Pre-accident Iodine Spike: 420,090 lbm Concurrent Iodine Spike: 386,354 lbm	Pre-accident Iodine spike – 423,700 lbm Concurrent Iodine spike – 452,000 lbm
SG Secondary Side Mass	Minimum -121,970.5 lbm (per SG) Minimum used for primary-to-secondary leakage to maximize secondary nuclide concentration.	Minimum – 105,000 lbm (per SG) Maximum – 260,000 lbm (per SG)
Atmospheric Dispersion Factors Offsite Onsite	Table 2.9.2-9 Table 2.9.2-7	Different based on meteorological data Different based on meteorological data
Control Room Ventilation System Time of Control Room Ventilation System Isolation Time of Control Room Filtered Makeup Flow Control Room Unfiltered Inleakage	(See Table 2.9.2-10) 314 seconds (Hot Leg Break Rx trip + 30 Sec) 1.5 hours 425 cfm	409.2 seconds 1.5 hours 500 cfm
Breathing Rates Offsite Control Room	RG 1.183, Section 4.1.3 RG 1.183, Section 4.2.6	Same Same
Control Room Occupancy Factor	RG 1.183 Section 4.2.6	Same

Table 2.9.2-24
SGTR Break Flow and Steam Releases

Time (hr)⁽¹⁾	Event Description	Ruptured SG Break Flow (lbm/min)	Ruptured SG Steam Release (lbm/min)	Unaffected SG Steam Release (lbm/min)
0	Event Initiation	3993.0	122133.8	121521.1
0.0789	Reactor Trip	2277.3	3658.1	3397.4
0.75	Ruptured SG Isolated	0.10	0.0	5028.0
1.25	Unaffected SG tubes Re-covered	0.0	0.0	5028.0
2.0		0.0	0.0	2698.9
8.0		0.0	0.0	2626.7
9.0		0.0	0.0	2491.7
10.0		0.0	0.0	2406.7
11.0		0.0	0.0	2313.3
12.0		0.0	0.0	2223.3
12.40	Termination of SG Releases at 212F	0.0	0.0	0.0
1. Flow rates are applied until the next time point.				

Table 2.9.2-25
SGTR 60 μ Ci/gm D.E. I-131 Activities

Isotope	Activity (μCi/gm)
I-131	50.6
I-132	10.1
I-133	52.3
I-134	4.6
I-135	23.6

Table 2.9.2-26
SGTR Iodine Equilibrium Appearance Assumptions

Input Assumption	Value
Maximum Letdown Flow	150 gpm at 120°F, 650 psig
Maximum Identified RCS Leakage	10 gpm
Maximum Unidentified RCS Leakage	1 gpm
RCS Mass	386,354 lbm
Total Removal Constants (min^{-1})	
I-131	0.003430
I-132	0.008393
I-133	0.003925
I-134	0.016548
I-135	0.005117

Table 2.9.2-27
SGTR Concurrent Iodine Spike (335 x) Activity Appearance Rate

Isotope	Activity Appearance Rate (Ci/min)	Total 8-hour Production (Ci)
I-131	169.6	81430
I-132	83.2	39950
I-133	200.8	96380
I-134	75.1	36030
I-135	118.2	56720

Table 2.9.2-28
Locked Rotor Accident – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
Core Power Level	3030 MWt (~3020+0.3%)	2754 MWt (2700 + 2%)
Core Average Fuel Burnup	49,000 MWD/MTU	45,000 MWD/MTU
Fuel Enrichment	1.5 – 5.0 w/o	3.0 – 4.5w/o
Maximum Radial Peaking Factor	1.65	1.7
Percent of Fuel Rods in DNB	19.7%	13.7%
High Burnup Fuel Adjustment Factor	1.00922	None
Core Fission Product Inventory	Table 2.9.2-4	Different based on power, burnup and enrichment
Initial RCS Equilibrium Activity	1.0 mCi/gm DE I-131 and 518.9 mCi/gm DE Xe-133 (Table 2.9.2-2)	1.0 mCi/gm DE I-131 and 100/E-bar gross activity
Initial Secondary Side Equilibrium Iodine Activity	0.1 mCi/gm DE I-131 (Table 2.9.2-3)	0.1 mCi/gm DE I-131
Release Fraction from Breached Fuel	RG 1.183, Section 3.2	Same
Steam Generator Tube Leakage	0.5 gpm (Table 2.9.2-30)	0.5 gpm
Secondary Side Mass Releases to Environment	Table 2.9.2-29	Different based on different thermodynamic conditions
SG Tube Uncovery Following Reactor Trip		
Time to tube recovery	1 hour	Same
Flashing Fraction	6%	5%
Steam Generator Secondary Side Partition Coefficient	Flashed tube flow – none Non-flashed tube flow – 100	Same Same
Time to Terminate Steam Release	12.4 hours	10.32 hours
Time to Terminate SG Tube Leakage	12.4 hours	12 hours

Table 2.9.2-28
Locked Rotor Accident – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
RCS Mass	Minimum - 420,090 lbm Minimum mass used for fuel failure dose contribution to maximize SG tube leakage activity.	Minimum - 423,700 lbm
SG Secondary Side Mass	Minimum – 243,941 lbm (Total) Minimum used for primary-to-secondary leakage to maximize secondary nuclide concentration.	Minimum – 105,000 lbm (per SG) Maximum – 260,000 lbm (per SG)
Atmospheric Dispersion Factors Offsite Onsite	Table 2.9.2-9 Table 2.9.2-7	Different based on meteorological data Different based on meteorological data
Control Room Ventilation System Time of Control Room Ventilation Isolation Time of Control Room Filtered Makeup Flow Control Room Unfiltered Inleakage	(See Table 2.9.2-10) 30 seconds 1.5 hours 425 cfm	Same Same 500 cfm
Breathing Rates Offsite Onsite	RG 1.183 Section 4.1.3 RG 1.183 Section 4.2.6	Same Same
Control Room Occupancy Factor	RG 1.183 Section 4.2.6	Same

Table 2.9.2-29
Locked Rotor Steam Release Rate

Time (hr)⁽¹⁾	Steam Release Rate (lbm/min)
0.0	11473.7
0.5	5124.4s
2.0	2690.3
8.0	2611.7
9.0	2478.3
10.0	2393.3
11.0	2301.7
12.0	2213.3
12.4	0.0
1. Flow rates are applied until the next time point.	

Table 2.9.2-30
Locked Rotor Steam Generator Tube Leakage

Time (hr)⁽¹⁾	SG Tube Leakage (lbm/min)
0	3.15
0.50	3.34
1.00	3.50
1.50	3.65
2.00	3.71
4.00	3.80
6.00	3.89
9.00	3.96
11.00	4.00
12.40	0.00
1. Flow rates are applied until the next time point.	

Table 2.9.2-31
CEA Ejection Accident – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
Core Power Level	3030 MWt (~3020 + 0.3%)	2754 MWt (2700 + 2%)
Core Average Fuel Burnup	49,000 MWD/MTU	45,000 MWD/MTU
Fuel Enrichment	1.5 – 5.0 w/o	3.0 – 4.5 w/o
Maximum Radial Peaking Factor	1.65	1.7
Percent of Fuel Rods in DNB	9.5%	Same
Percent of Fuel Rods with Centerline Melt	0.5%	Same
Core Fission Product Inventory	Table 2.9.2-4	Different based on power, burnup and enrichment
Initial RCS Equilibrium Activity	1.0 mCi/gm DE I-131 and 518.9 mCi/gm DE Xe-133 (Table 2.9.2-2)	1.0 mCi/gm DE I-131 and 100/E-bar gross activity
Initial Secondary Side Equilibrium Iodine Activity	0.1 mCi/gm DE I-131 (Table 2.9.2-3)	0.1 mCi/gm DE I-131
Release Fraction from DNB Fuel Failures	Section 1 of Appendix H to RG 1.183	Same
Release Fraction from Centerline Melt Fuel Failures	Section 1 of Appendix H to RG 1.183	Same
High Burnup Fuel Adjustment Factor	1.00922 2 fuel assemblies	None None
Steam Generator Tube Leakage	0.5 gpm (Table 2.9.2-33)	0.5 gpm
Secondary Side Mass Releases to Environment	Table 2.9.2-32	Different based on different thermodynamic conditions
SG Tube Uncovery Following Reactor Trip		
Time to tube recovery	1 hour	Same
Flashing Fraction	6%	5%

Table 2.9.2-31
CEA Ejection Accident – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
Steam Generator Secondary Side Partition Coefficient	Flashed tube flow – none Non-flashed tube flow – 100	Same Same
Time to Terminate Steam Release	12.4 hours	10.32 hours
Time to Terminate SG Tube Leakage	12.4 hours	12 hours
RCS Mass	Minimum - 420,090 lbm Minimum mass used for fuel failure dose contribution to maximum SG tube leakage activity.	Minimum – 423,700 lbm
SG Secondary Side Mass	Minimum – 243,941 lbm (Total) Minimum used for primary-to-secondary leakage to maximize secondary nuclide concentration.	Minimum – 105,000 lbm (per SG) Maximum – 260,000 lbm (per SG)
Chemical Form of Iodine Released to Containment	Particulates – 95% Elemental iodine – 4.85% Organic iodine – 0.15%	Same Same Same
Chemical Form of Iodine Released from SGs	Particulates – 0% Elemental iodine – 97% Organic iodine – 3%	Same Same Same
Atmospheric Dispersion Factors Offsite Onsite	Table 2.9.2-9 Table 2.9.2-7	Different based on meteorological data Different based on meteorological data
Control Room Ventilation System Time of Control Room Ventilation System Isolation Time of Control Room Filtered Makeup Flow Control Room Unfiltered Inleakage	(See Table 2.9.2-10) 30 seconds 1.5 hours 425 cfm	Same Same 500 cfm

Table 2.9.2-31
CEA Ejection Accident – Inputs and Assumptions

Input/Assumption	EPU Value	Pre-EPU Value
Breathing Rates	RG 1.183 Sections 4.1.3 and 4.2.6	Same
Control Room Occupancy Factor	RG 1.183 Section 4.2.6	Same
Containment Volume	2.500E+06 ft ³	Same
Containment Leakage Rate		
0 to 24 hours	0.5% (by volume)/day	Same
after 24 hours	0.25% (by volume)/day	Same
Secondary Containment Filter Efficiency	Particulates – 99%	Same
	Elemental iodine – 95%	Same
	Organic iodine – 95%	Same
Secondary Containment Drawdown Time	310 seconds	Same
Secondary Containment Bypass Fraction	9.6%	Same
Containment Natural Deposition Coefficients	Aerosols – 0.1 hr ⁻¹	Same
	Elemental Iodine – 2.89 hr ⁻¹	Same
	Organic Iodine – None	Same

Table 2.9.2-32
CEA Ejection Steam Release Rate

Time (hr)⁽¹⁾	Steam Release Rate (lbm/min)
0.0	11473.7
0.5	5124.4
2.0	2690.3
8.0	2611.7
9.0	2478.3
10.0	2393.3
11.0	2301.7
12.0	2213.3
12.4	0.0
1. Flow rates are applied until the next time point.	

Table 2.9.2-33
CEA Ejection Steam Generator Tube Leakage

Time (hr)⁽¹⁾	SG Tube Leakage (lbm/min)
0	3.15
0.50	3.34
1.00	3.50
1.50	3.65
2.00	3.71
4.00	3.80
6.00	3.89
9.00	3.96
11.00	4.00
12.40	0.00
1. Flow rates are applied until the next time point.	

**Table 2.9.2-34
FWLB Inputs and Assumptions**

Input/Assumption	EPU Value	Pre-EPU Value
Core Power Level	3030 MWt (3020 + 0.3%)	2754 MWt (2700 + 2%)
Initial RCS Equilibrium Activity	1.0 mCi/gm DE I-131 and 518.9 mCi/gm DE Xe-133 (Table 2.9.2-2)	1.0 mCi/gm DE I-131 and 100/E-bar gross activity
Initial Secondary Side Equilibrium Iodine Activity	0.1 mCi/gm DE I-131 (Table 2.9.2-3)	0.1 mCi/gm DE I-131
Steam Generator Tube Leakage	0.25 gpm per SG (Table 2.9.2-36)	0.25 gpm per SG
Time to Terminate Steam Release	12.4 hours	10.32 hours
Time to Terminate SG Tube Leakage	12.4 hours	12 hours
Steam Release from the Intact SG	Table 2.9.2-35	Different based on different thermodynamic conditions
Intact SG Tube Uncovery Following Reactor Trip Time to tube recovery Flashing Fraction	1 hour 6%	1 hour 5%
Steam Generator Secondary Side Partition Coefficient	Unaffected SG - 100 Faulted SG - None	Same
SG Secondary Side Mass	Minimum – 121,970.5 lbm Maximum - 219,009 lbm Maximum mass used for faulted SG to maximize secondary side dose contribution. Minimum mass used for intact SG to maximize steam release nuclide concentration.	Minimum – 105,000 lbm Maximum - 260,000 lbm

**Table 2.9.2-34
FWLB Inputs and Assumptions**

Input/Assumption	EPU Value	Pre-EPU Value
Atmospheric Dispersion Factors Offsite Onsite	Table 2.9.2-9 Table 2.9.2-7	Different based on meteorological data Different based on meteorological data
Control Room Ventilation System Time of Control Room Ventilation Isolation Time of Control Room Filtered Makeup Flow Control Room Unfiltered Inleakage	(See Table 2.9.2-10) 30 seconds 1.5 hours 425 cfm	Same Same 500 cfm
Breathing Rates: Offsite Onsite	RG 1.183 Section 4.1.3 RG 1.183 Section 4.2.6	Same Same
Control Room Occupancy Factor	RG 1.183 Section 4.2.6	Same

Table 2.9.2-35
FWLB Intact Steam Release Rate

Time (hours)⁽¹⁾	Intact SG Steam Release Rate (lbm /min)
0.0	9087.1
0.5	5124.4
2.0	2690.3
8.0	2611.7
9.0	2478.3
10.0	2393.3
11.0	2301.7
12.0	2213.3
12.4	0.0
1. Flow rates are applied until the next time point.	

Table 2.9.2-36
FWLB Steam Generator Tube Leakage

Time (hours)⁽¹⁾	Intact SG Tube Leakage (lbm /min)	Faulted SG Tube Leakage (lbm /min)
0	1.58	2.00
0.50	1.67	2.00
1.00	1.75	2.00
1.50	1.83	2.00
2.00	1.86	2.00
4.00	1.90	2.00
6.00	1.94	2.00
9.00	1.98	2.00
11.00	2.00	2.00
12.40	0.00	0.000
1. Flow rates are applied until the next time point.		

**Table 2.9.2-37
Letdown Line Rupture – Inputs and Assumptions**

Input/Assumption	EPU Value	Pre-EPU Value
Core Power Level	3030 MWt (~3020 + 0.3%)	2754 MWt (2700 + 2%)
Initial RCS Equilibrium Activity	1.0 mCi/gm DE I-131 and 518.9 mCi/gm DE Xe-133 (Table 2.9.2-2)	1.0 mCi/gm DE I-131 and 100/E-bar gross activity
Initial Secondary Side Equilibrium Iodine Activity	0.1 mCi/gm DE I-131 (Table 2.9.2-3)	0.1 mCi/gm DE I-131
Iodine Spike Appearance Rate	500 times	Same
Duration of Accident-Initiated Spike	8 hours	Same
Intact SG Tube Uncovery Following Reactor Trip Time to tube recovery Flashing Fraction	1 hour 6%	1 hour 5%
Steam Generator Tube Leakage Rate	0.5 gpm (Table 2.9.2-41)	0.5 gpm
Time to Terminate Steam Release	12.4 hours	10.32 hours
Time to Terminate SG Tube Leakage	12.4 hours	12 hours
Secondary Side Mass Releases to Environment	Table 2.9.2-40	Different based on different thermodynamic conditions
Broken Line Flashing Fraction	25.9%	Same
Time to Terminate Break Flow	1800 seconds	1920 seconds
Broken Line Flow Rate	Table 2.9.2-42	Different based on different thermodynamic conditions
RCS Mass	386,354 lbm	452,000 lbm
SG Secondary Side Mass	Minimum -243,941 lbm (Total) Minimum used for primary-to-secondary leakage to maximize secondary nuclide concentration.	Minimum – 210,000 lbm (Total)

**Table 2.9.2-37
Letdown Line Rupture – Inputs and Assumptions**

Input/Assumption	EPU Value	Pre-EPU Value
Atmospheric Dispersion Factors Offsite Onsite	Table 2.9.2-9 Table 2.9.2-7	Different based on meteorological data Different based on meteorological data
Control Room Ventilation System Time of Control Room Ventilation System Isolation Time of Control Room Filtered Makeup Flow Control Room Unfiltered Inleakage	(See Table 2.9.2-10) 30 seconds 1.5 hours 425 cfm	Same 1.5 hours 500 cfm
Breathing Rates Offsite Control Room	RG 1.183, Section 4.1.3 RG 1.183, Section 4.2.6	Same Same
Control Room Occupancy Factor	RG 1.183 Section 4.2.6	Same

Table 2.9.2-38
Letdown Line Rupture Iodine Equilibrium Appearance Assumptions

Input Assumption	Value
Maximum Letdown Flow	150 gpm at 120°F, 650 psig
Maximum Identified RCS Leakage	10 gpm
Maximum Unidentified RCS Leakage	1 gpm
RCS Mass	386,354 lbm
Total Removal Constants (min^{-1})	
I-131	0.003430
I-132	0.008393
I-133	0.003925
I-134	0.016548
I-135	0.005117

Table 2.9.2-39
Letdown Line Rupture Iodine Spike (500 x) Activity Appearance Rate

Isotope	Activity Appearance Rate (Ci/min)	Total 8-hour Production (Ci)
I-131	253.2	121500
I-132	124.2	59620
I-133	299.7	143900
I-134	112.0	53770
I-135	176.4	84650

Table 2.9.2-40
Letdown Line Rupture Steam Release Rate

Time (hr)⁽¹⁾	Steam Release Rate (lbm/min)
0.0	11473.7
0.5	5124.4
2.0	2690.3
8.0	2611.7
9.0	2478.3
10.0	2393.3
11.0	2301.7
12.0	2213.3
12.4	0.0
1. Flow rates are applied until the next time point.	

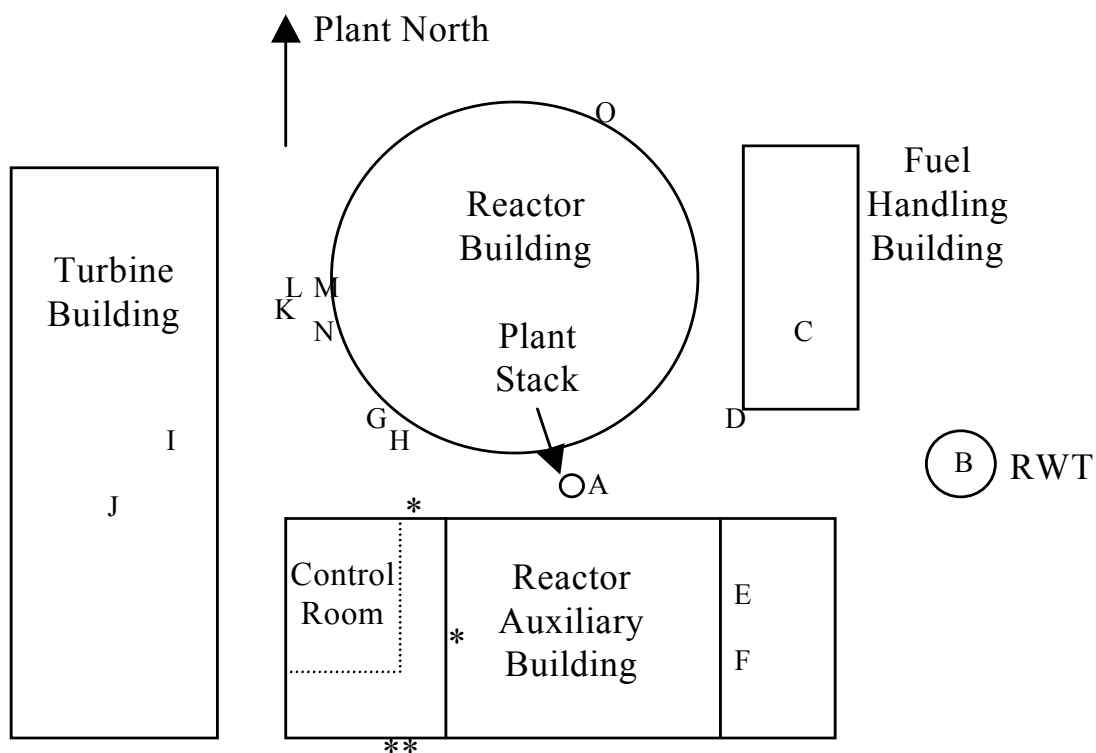
Table 2.9.2-41
Letdown Line Rupture Generator Tube Leakage

Time (hours)⁽¹⁾	SG Tube Leakage (lbm /min)
0	3.15
0.50	3.34
1.00	3.50
1.50	3.65
2.00	3.71
4.00	3.80
6.00	3.89
9.00	3.96
11.00	4.00
12.40	0.00
1. Flow rates are applied until the next time point.	

Table 2.9.2-42
Letdown Line Break Flow

Time (hours)⁽¹⁾	Total Break Flow (lbm /min)	Flashed Break Flow (lbm /min)
0	4329.2	1121.3
0.236	2082.3	539.3
0.50	0.0	0.0
1. Flow rates are applied until the next time point.		

**Figure 2.9.2-1
Onsite Release-Receptor Location Sketch**



(Not to scale)

- * – Control Room Intakes / Receptor Point
- A – Plant Stack
- B – RWT
- C – FHB Stack
- D – FHB Closest Point
- E – Louver 2L-7B
- F – Louver 2L-7A
- G – Containment Personnel Lock
- H – Containment Bulkhead Door
- I – Steam Jet Air Ejector
- J – Turbine Condenser
- K – Closest ADV
- L – Closest MSSV
- M – Closest Main Steam Line Point (containment penetration)
- N – Closest Feedwater Line Point (containment penetration)
- O – Containment Maintenance Hatch

2.9.3 Radiological Consequences of Gas Decay Tank Ruptures

2.9.3.1 Regulatory Evaluation

Florida Power and Light (FPL) 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 Nuclear Regulatory Commission (NRC) acceptance criteria for the radiological consequences of the waste gas decay rupture are based on:

- General Design Criterion (GDC-19), insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the control room (CR) under accident conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent (TEDE) for the duration of the accident;
- 10 CFR Part 100, insofar as it establishes requirements for assuring that offsite radiological doses from postulated accidents will be acceptably low;
- Branch Technical Position (BTP) 11-5, Rev. 3 from the Standard Review Plan, NUREG-0800 ([Reference 3](#)), insofar as it established specific analysis and acceptance criteria for licensee evaluations of this event.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to Title 10 of the Code of Federal Regulations (10 CFR) Part 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

- GDC-19 is described in UFSAR Section 3.1.19 Criterion 19 - Control Room.

A control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in safe condition under accident conditions, including loss of coolant accidents. Adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent for the duration of the accident.

On September 29, 2008, the NRC approved Amendment 152 to the St. Lucie Unit 2 operating license, which adopts the alternative source term (AST) as allowed in 10 CFR 50.67 and described in Regulatory Guide (RG) 1.183. The radiological consequences of a number of design basis accidents were reanalyzed using the AST methodology from RG 1.183 and the results were submitted for NRC review and approval. Consistent with Issue 11 of NRC Regulatory Issue Summary (RIS) 2006-04, the analysis of the WGDT rupture accident was excluded from the AST license amendment request. As such, St. Lucie Unit 2 licensing basis continues to include a WGDT analysis compliant with the 10 CFR Part 100 acceptance criteria.

In addition to the licensing basis described in the UFSAR, the WGDT was evaluated for License Renewal. For License Renewal, evaluation boundaries were established for mechanical systems to identify those systems or portions of systems that are in the scope of License Renewal. Those systems determined to be in scope were then screened to identify which components required an aging management review. This process is described in Section 2.1.2 of NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003. Section 2.3.3.16 of the SER identifies that components of the WGDT are within the scope of License Renewal. Programs used to manage the aging effects associated with the WGDT are discussed in SER Section 3.3.16 and Chapter 18 of the UFSAR.

The WGDT radiological source term and dose consequence analyses are not within the scope of license renewal since they are analytical products of the operational performance of plant systems and components in conjunction with regulatory limits that are imposed on accidental radiological releases. Changes proposed to regulatory limits applicable to the WGDT rupture accident for plant operation at EPU conditions will not change license renewal boundaries.

2.9.3.2 Technical Evaluation

2.9.3.2.1 Description of Event

The WGDT rupture accident for the current licensing basis is described in UFSAR Section 15.7.4. This new WGDT accident analysis replaces the current licensing basis source term and analysis methodology described in the UFSAR. In this reevaluation under EPU conditions, a single WGDT is assumed to fail, releasing the stored gaseous activity instantaneously to the environment at ground level.

Also, in this reevaluation under EPU conditions, conservative, bounding analysis inputs were selected such that a single WGDT accident dose consequence analysis will bound the consequences that may occur at either St. Lucie unit. To implement this single analysis, such inputs as limiting X/Q's and control room volume will be selected from between the set of Unit 1 and Unit 2 inputs, in order to maximize the single reported dose consequence.

2.9.3.2.2 Acceptance Criteria

The offsite dose acceptance criterion for a WGDT rupture accident of 0.1 rem TEDE, as specified in BTP 11-5, is chosen to apply to receptors located at the exclusion area boundary (EAB) and the low population zone (LPZ). As noted in UFSAR Section 11.3, the gaseous waste management system is designed to prevent an explosive gas mixture and the WGDTs are seismically designed. Per BTP11-5, a dose limit of 2.5 rem could be applied; however, FPL chose to adopt the more restrictive dose limit of 0.1 rem TEDE for systems not designed to withstand explosions and earthquakes as a conservative way to establish a restrictive technical specification limit for the contents of the WGDTs. The TEDE dose limit for the control room is given as 5.0 rem (TEDE) in 10 CFR 50.67 and GDC-19.

2.9.3.2.3 Applicable Regulatory Guidance

This revised analysis for EPU is performed using the AST consistent with RG 1.183 (Reference 1). In addition, recent NRC guidance given in Regulatory Issue Summary RIS-2006-04 (Reference 2) regarding application of the AST to WGD events is also followed. The RIS-2006-04 guidance specifically endorses BTP 11-5, Rev. 3 from the Standard Review Plan, NUREG-0800 (Reference 3).

2.9.3.2.4 Source Term and Dose Models, Assumptions, and Parameters

BTP 11-5 Position 1.B (Source Term) provides guidance on development of the source term for the pressurized water reactor (PWR) WGD event:

“The safety analysis on the radiological consequences of a single failure of an active component in the waste gas system should use a system design basis source term for light water cooled nuclear power plants. These assumptions are given below:

- i. For a PWR: 1 percent of the operating fission product inventory in the core being released to the coolant.”

The ORIGEN 2 2.1 computer code is used to calculate the EPU core inventory. 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 design basis reactor coolant system (RCS) inventory is based on the reactor core operating for an extended full power period with 1 percent failed fuel releasing fission product gases into the RCS. The entire RCS noble gas inventory is then assumed to be instantaneously transferred into one WGD following reactor shutdown. Upon failure, the entire WGD inventory of noble gases is then released to the environment at ground level with no credit for decay. Only noble gases are modeled in the source term, per Position 1.C of BTP 11-5. Transfer of iodine activity to the WGD is assumed to be insignificant. No credit is taken for isolation of the release path. LR Table 2.9.3-1 presents the activities of the noble gases in the RCS and the WGD.

Although when dealing with a source term consisting of 100 percent noble gases, consideration of filtered air intake is inconsequential, the following sequence of control room (CR) emergency heating, ventilation, and air conditioning systems (HVAC) operation is assumed, consistent with other design basis events. Unfiltered CR leakage is assumed to continue at 500 cubic feet per minute (cfm) throughout the 30-day event. Unfiltered makeup air (normal CR ventilation mode) continues for 50 seconds, until the CR isolation is assumed to occur. 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 RADTRAD-NAI (Reference 9) model developed for the WGD failure calculation consists of three compartments and four pathways (see LR Figure 2.9.3-1). Compartment inputs are described in LR Table 2.9.3-2. Pathway inputs are described in LR Table 2.9.3-3. RADTRAD-NAI plant and power modeling inputs are described in LR Table 2.9.3-4.

Breathing rates for offsite locations and the control room, and control room occupancy factors are given in LR Table 2.9.3-5. Atmospheric dilution factors (X/Q) are given in LR Table 2.9.3-6. The

offsite dose location X/Q data are based on PAVAN (References 4 and 5) analyses of St. Lucie site meteorological data. The control room X/Q data described in LR Table 2.9.3-6 are based on ARCON96 (Reference 10) analyses of St. Lucie site meteorological data.

Due to the close proximity of the control room complex to possible release points, the WGDT release from several candidate locations is considered in determining the control room X/Q data used in the analysis. In order to generate a single set of X/Qs which bound these possible release-receptor pairs (3 release points, 2 units, 2 HVAC intakes), the maximum X/Q is selected from among the possible release-receptor pairs. The result is shown in LR Table 2.9.3-6 as the “Bounding St. Lucie HVAC X/Q” to be used for the WGDT evaluation. The release-receptor pairs also include control room unfiltered inleakage pathways. The “intake” location for this inleakage is the St. Lucie Unit 2 louver 2L-11, instead of the north or south outside air intake. In order to generate a single set of X/Q’s which bounds these inleakage release-receptor pairs, the maximum X/Q is selected from among these cases. The result is shown in LR Table 2.9.3-6 as the “Bounding St. Lucie Inleakage X/Q” to be used for the WGDT evaluation.

The “Bounding St. Lucie Inleakage X/Q” is selected from among a compilation of worst-case X/Q’s that are associated with both St. Lucie Units. All release points, and all candidate CR receptor points were considered, and the worst case release-receptor pairs were selected as the WGDT dose analysis of record input. The X/Q input selected, therefore, conservatively maximizes the predicted St. Lucie Unit 2 CR dose for any WGDT event which may occur at the site. While St. Lucie Unit 1 X/Q candidates may have been considered in this St. Lucie Unit 2 WGDT dose analysis, the selection of the bounding, maximum X/Q’s creates no dependency on the St. Lucie Unit 1 EPU submittal or any planned Technical Specification changes for St. Lucie Unit 1.

The dose conversion factor file used in this analysis reflects dose conversion factors taken from Federal Guidance Reports 11 and 12 (References 7 and Reference 8) as endorsed for AST evaluations by RG 1.183 (Reference 1). The dose consequence analysis for the WGDT failure event is performed with the RADTRAD-NAI computer code (Reference 9). This code was used to perform the current licensing basis AST dose consequence analysis for several of the St. Lucie design basis events.

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

As discussed above, the WGDT radiological source term and dose consequence analyses were determined to be outside the scope of License Renewal; therefore, with respect to the WGDT radiological source term and dose consequence analyses, the EPU does not impact any License Renewal evaluations.

2.9.3.2.6 Results

Calculated radiological doses reported in LR Table 2.9.3-7 show that the EAB and LPZ 30-day doses are well within the BTP 11-5-specified limit of 0.1 rem TEDE. Similarly, the CR dose is a small fraction of the dose guidelines of GDC-19 for AST plants.

The WGDT failure dose consequence analysis source term provided in LR [Table 2.9.3-1](#) is equal to 90,921 dose equivalent (DE) curies Xe-133. Following the guidance of BTP 11-5, an additional EAB dose analysis was generated 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. All other inputs described for the design basis WGDT failure event remain the same. The WGDT inventory source term required to generate this dose is the basis for a proposed Technical Specification limit of 202,500 dose equivalent curies Xe-133 derived based on the definition given in Technical Specification Task Force (TSTF)-490 ([Reference 6](#)). LR [Table 2.9.3-8](#) summarizes the source terms and predicted dose consequences for these two WGDT analyses.

Technical Specification 3.11.2.6, Radioactive Effluents-Gas Storage Tanks, is revised to a Limiting Condition for Operation of less than or equal to 202,500 dose equivalent curies Xe-133. This limit will yield an EAB dose of 0.09 rem TEDE, or slightly less than the 0.1 rem TEDE limit of BTP 11-5.

2.9.3.3 Conclusion

FPL has reanalyzed the radiological consequences of releases from an accidental WGDT rupture to account for the effects of the proposed EPU. FPL has reviewed the results of the analysis and determined that the radiological consequences of a postulated WGDT rupture are acceptable, since the calculated total effective dose equivalents at the EAB and the LPZ outer boundary are below the dose guidelines of BTP 11-5. It is also demonstrated that the control room dose will continue to meet its current licensing basis with respect to the dose limits of GDC-19 for AST-licensed plants. Therefore, FPL finds the proposed EPU acceptable with respect to the radiological consequences of an accidental WGDT release.

2.9.3.4 References

1. USNRC, Regulatory Guide 1.183, Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Plants, July 2000.
2. USNRC, Regulatory Issue Summary RIS-2006-04, Experience with Implementation of Alternative Source Term, March 2006.
3. USNRC, NUREG-0800, Standard Review Plan, Branch Technical Position BTP 11-5, Postulated Radioactive Releases Due to a Waste Gas System Leak or Failure, Revision 3, March 2007.
4. USNRC, Regulatory Guide 1.145, Atmospheric Dispersion Models for Potential Accident Consequence Assessments at Nuclear Power Plants, Revision 1.
5. USNRC, NUREG/CR-2858, PAVAN: An Atmospheric Dispersion Program for Evaluating Design Basis Accidental Releases of Radioactive Materials from Nuclear Power Stations, November 1982.
6. TSTF-490, Revision 0, Deletion of E Bar Definition and Revision to RCS Specific Activity Tech Spec.

7. Federal Guidance Report 11, EPA-520/1-88-020, Limiting Values of Radionuclide Intake and Air Concentration and Dose Conversion Factors for Inhalation, Submersion, and Ingestion, 1988.
8. Federal Guidance Report 12, EPA-409-R-93-081, External Exposure to Radionuclides in Air, Water, and Soil, 1993.
9. Numerical Applications Inc., NAI-9912-04, Revision 4, RADTRAD-NAI Version 1.1a (QA) Documentation, October 2004.
10. USNRC, Regulatory Guide 1.194, Atmospheric Relative Concentrations for Control Room Radiological Habitability Assessments at Nuclear Power Plants, June, 2003.

**Table 2.9.3-1
WGDT Source Term – 1% Fuel Defects**

Nuclide	RCS 1% Defect Concentration ($\mu\text{Ci/gm}$)	EPA FGR 12, Table III.1 Effective DCF ($\text{Sv}/(\text{Bq}\cdot\text{s}\cdot\text{m}^{-3})$)	Tank Activity (Curies)	Activity⁽¹⁾ DCF
Kr-85	41.60	1.19E-16	7.290E+03	8.6752E-13
Kr-85m	1.268	7.48E-15	2.222E+02	1.6621E-12
Kr-87	0.7574	4.12E-14	1.327E+02	5.4684E-12
Kr-88	2.247	1.02E-13	3.938E+02	4.0164E-11
Xe-131m	3.022	3.89E-16	5.296E+02	2.0601E-13
Xe-133	238.1	1.56E-15	4.173E+04	6.5091E-11
Xe-133m	3.479	1.37E-15	6.097E+02	8.3524E-13
Xe-135	9.235	1.19E-14	1.618E+03	1.9259E-11
Xe-135m	0.8553	2.04E-14	1.499E+02	3.0576E-12
Xe-138	0.5168	5.77E-14	9.057E+01	5.2256E-12
			SUM	1.4184E-10
			DE Xe-133 ⁽¹⁾	90,921.0

NOTES:

1. In the DE Xe-133 calculation, the DCF units used are in $\text{Sv}/\text{Bq}\cdot\text{sec}\cdot\text{m}^3$, to be consistent with the given values in EPA FGR 12. By the nature of the arithmetic, the equation:

$$\text{DE} = \sum \frac{(\text{activity times DCF})}{\text{DCF}}$$

does not require that the DCFs be converted to Sv/Bq to Rem/Ci (or any other units) to remain correct. Any unit conversion factors would cancel out, and therefore, will not affect the calculated DE Xe-133 results.

Table 2.9.3-2
RADTRAD-NAI Compartment Description Tables

Compartment Description	Compartment Number	RADTRAD-NAI Compartment Type
WGDT Compartment	1	(3) Normal
Environment	2	(2) Environment
Control Room	3	(1) Control Room

Compartment 1 - WGDT

Volume	1000 ft ³	Arbitrary value assumed; an instantaneously release of the WGDT activity to the environment is modeled via rft file and high flow rate transfer pathway.
Source Fraction	1.0	100% of source term applied to WGDT volume
Recirculation Filters	No	
Natural Deposition	No	
Overlying Pool	No	

Compartment 3 – Control Room

Volume	96,228 ft ³	Minimum (Unit 1) CR volume used to maximize dose for this single analysis to generate a bounding result for either Unit 1 or Unit 2 dose consequence
Sprays	No	There are no sprays in this compartment
Recirculation Filters	No	Since the source term is 100% noble gas, control room filtration is not modeled
Natural Deposition	No	There is no deposition of particulates in this compartment

**Table 2.9.3-3
RADTRAD-NAI Pathway Description Tables**

Pathway Description	Pathway Number	Compartment Connections	RADTRAD-NAI Pathway Type
WGDT Leakage	1	1 to 2	Filtered
Control Room Unfiltered Inleakage	2	2 to 3	Filtered
Control Room Filtered Makeup	3	2 to 3	Filtered
Control Room Normal HVAC Intake	4	2 to 3	Filtered
Control Room Exhaust	5	3 to 2	Filtered

Pathway 1 - WGDT Leakage to Environment Pathway

Time (hours)	Flow Rate (cfm)	Filter Efficiency		
		Aerosol	Elemental	Organic
0.0	1E6	0	0	0
720.0	1E6	0	0	0

Pathway 2 - Control Room Unfiltered Inleakage Pathway

Time (hours)	Flow Rate (cfm)	Filter Efficiency		
		Aerosol	Elemental	Organic
0.0	500	0	0	0
720.0	500	0	0	0

Pathway 3 - Control Room Filtered Makeup Pathway

Time (hours)	Flow Rate (cfm)	Filter Efficiency		
		Aerosol	Elemental	Organic
0.0	0	0	0	0
0.01389	0	0	0	0
1.5	450.0 +12% ⁽¹⁾	0	0	0
720.0	450.0 +12% ⁽¹⁾	0	0	0
1. 12% is to account for the potential impact on ventilation flow rates of surveillance test tolerances and over/under frequency of the emergency diesel generators.				

Table 2.9.3-3 (Continued)
RADTRAD-NAI Pathway Description Tables
Pathway 4 – Control Room Unfiltered Normal Intake Pathway

Time (hours)	Flow Rate (cfm)	Filter Efficiency		
		Aerosol	Elemental	Organic
0.0	920.0	0	0	0
0.01389	0	0	0	0
1.5	0	0	0	0
720.0	0	0	0	0

Pathway 5 - Control Room Exhaust Pathway

Time (hours)	Flow Rate (cfm)	Filter Efficiency		
		Aerosol	Elemental	Organic
0.0	1420.0	0	0	0
0.01389	500.0	0	0	0
1.5	1004.0	0	0	0
720.0	1004.0	0	0	0

**Table 2.9.3-4
Dose Consequences Modeling Information**

Release Timing and Fractions	
Start of first release time (hours)	0.0
Calculate decay	yes
Calculate daughters	yes
Iodine Fraction – aerosol	1.0
Iodine Fraction – elemental	0.0
Iodine Fraction – organic	0.0
Instantaneous Release Time Step Controls	
Time (hours)	Time Step
0.0	1.0E-05
1.0E-04	2.0E-02
720.0	2.0E-02

**Table 2.9.3-5
Dose Location Information**

Breathing Rates

Time (hours)	EAB Breathing Rate (m³/sec)	LPZ Breathing Rate (m³/sec)	Control Room Breathing Rate (m³/sec)
0.0	3.5E-4	3.5E-4	3.5E-4
8.0	1.8E-4	1.8E-4	3.5E-4
24.0	2.3E-4	2.3E-4	3.5E-4
720.0	2.3E-4	2.3E-4	3.5E-4

Control Room Occupancy Factors

Time (hours)	Control Room Occupancy Factor
0.0	1.0
24.0	0.6
96.0	0.4
720.0	0.4

**Table 2.9.3-6
WGDT Failure X/Q Tables**

X/Q Table 1 – EAB

Time (hours)	Unit 1 X/Q (sec/m³)	Unit 2 X/Q (sec/m³)	St. Lucie Bounding EAB X/Q (sec/m³)
0.0	7.96E-05	8.54E-05	8.54E-05
720.0	7.96E-05	8.54E-05	8.54E-05

X/Q Table 2 – LPZ

Time (hours)	Unit 1 X/Q (sec/m³)	Unit 2 X/Q (sec/m³)	St. Lucie Bounding LPZ X/Q (sec/m³)
7.70E-05	8.24E-05	8.24E-05	7.70E-05
4.38E-05	4.75E-05	4.75E-05	4.38E-05
3.30E-05	3.61E-05	3.61E-05	3.30E-05
1.81E-05	2.00E-05	2.00E-05	1.81E-05
7.97E-06	8.99E-06	8.99E-06	7.97E-06
7.97E-06	8.99E-06	8.99E-06	7.97E-06

**X/Q Table 3 - Control Room HVAC Intake via N or S Fresh Air Intake
Summary – Bounding St. Lucie HVAC X/Q Table**

Time (hours)	Stack to HVAC X/Q (sec/m³)	L-7A/ 2L-7A to HVAC X/Q (sec/m³)	L-7B/ 2L-7B to HVAC X/Q (sec/m³)	St. Lucie Bounding HVAC X/Q (sec/m³)
0	2.390E-03	3.835E-03	3.785E-03	3.835E-03
0.01389	2.390E-03	3.835E-03	3.785E-03	3.835E-03
1.5	1.195E-03	3.835E-03	3.785E-03	3.835E-03
2	9.275E-04	3.195E-03	3.115E-03	3.195E-03
8	3.700E-04	1.365E-03	1.334E-03	1.365E-03
24	3.200E-04	1.104E-03	1.072E-03	1.104E-03
96	2.325E-04	7.870E-04	7.485E-04	7.870E-04
720	2.325E-04	7.870E-04	7.485E-04	7.870E-04

Table 2.9.3-6 (Continued)
WGDT Failure X/Q Tables

X/Q Table 4 - Control Room Unfiltered Inleakage X/Q via Louver L-11 or 2L-11

Time (hours)	Unit 1 Stack X/Q	Unit 2 Stack X/Q	Unit 1 L-7A X/Q	Unit 1 L-7B X/Q	Unit 2 L-7A X/Q	Unit 2 L-7B X/Q	St. Lucie Bounding Inleakage X/Q
	(Louver L-11)	(Louver 2L-11)	(Louver L-11)	(Louver L-11)	(Louver 2L-11)	(Louver 2L-11)	
	(sec/m ³)	(sec/m ³)	(sec/m ³)	(sec/m ³)	(sec/m ³)	(sec/m ³)	(sec/m ³)
0	2.55E-03	2.60E-03	3.70E-03	2.89E-03	3.75E-03	3.01E-03	3.75E-03
2	1.81E-03	1.84E-03	2.97E-03	2.30E-03	3.02E-03	2.39E-03	3.02E-03
8	7.94E-04	8.10E-04	1.29E-03	9.91E-04	1.32E-03	1.03E-03	1.32E-03
24	5.63E-04	5.75E-04	9.65E-04	7.51E-04	9.91E-04	7.81E-04	9.91E-04
96	4.30E-04	4.41E-04	6.73E-04	5.18E-04	6.84E-04	6.84E-04	6.84E-04
720	4.30E-04	4.41E-04	6.73E-04	5.18E-04	6.84E-04	6.84E-04	6.84E-04

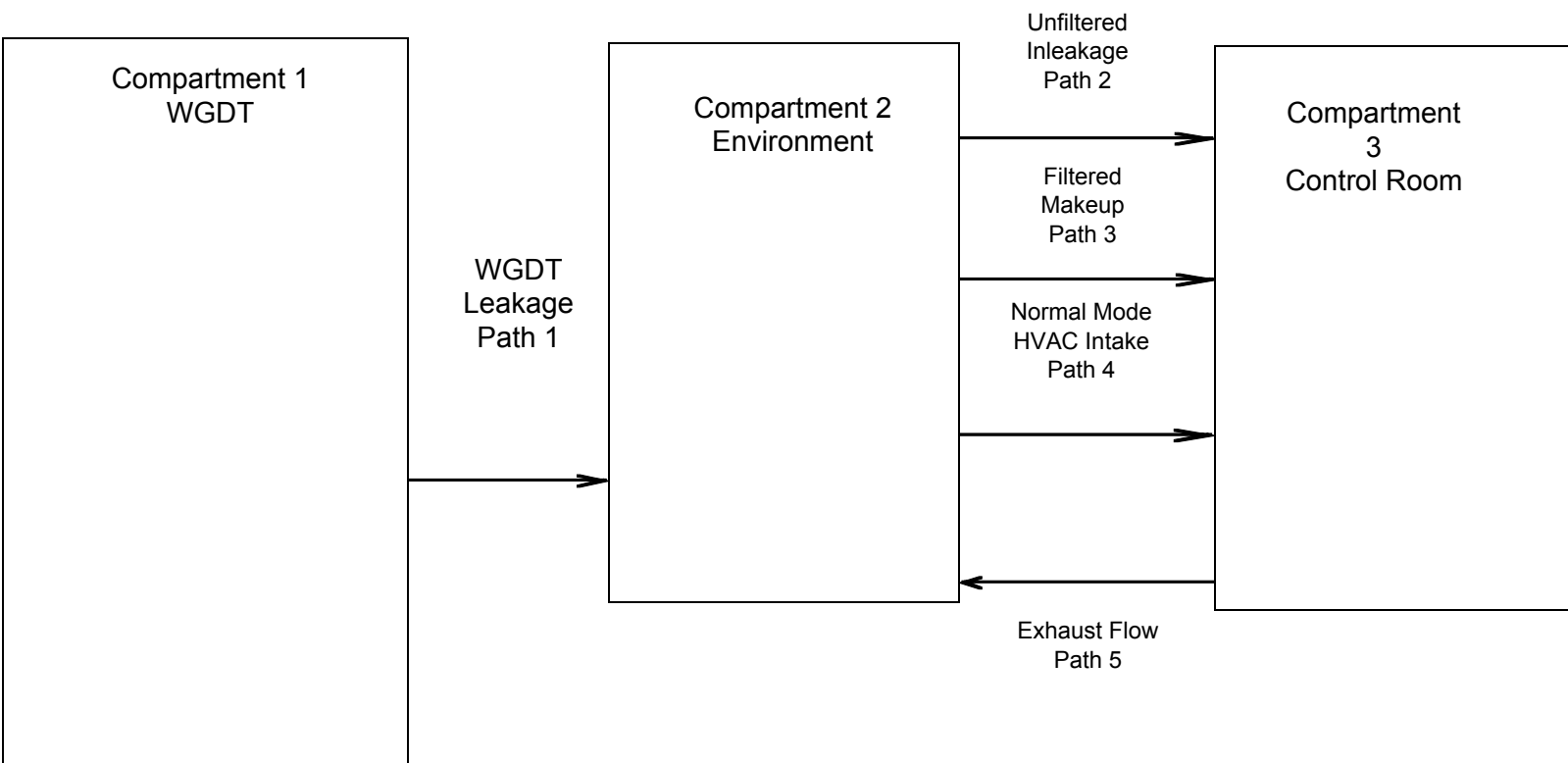
Table 2.9.3-7
Dose Consequences for Waste Gas Decay Tank Failure

Dose Contribution	TEDE Dose (rem)		
	EAB 30 Days	LPZ 30 Days	CR 30 Days
WGDT Failure	0.04	0.04	0.19
Acceptance Criteria	0.1 ⁽¹⁾	0.1 ⁽¹⁾	5 ⁽²⁾
Control Room Unfiltered Inleakage = 500 cfm			
1. The 0.1 REM (TEDE) 30 day dose limit is specified in NUREG-0800 (Reference 3), BTP-11-5 Rev 3 (March 2007) Position B.1.A for the EAB. The LPZ limit is assumed in this calculation to be the same value. 2. The 5.0 REM (TEDE) CR limit is not specified in either the BTP or RG 1.183 for this event, but is the specified Control Room limit for all other AST events.			

Table 2.9.3-8
WGDT Source Term – Technical Specification DE Xe-133 Curies

	DE Xe-133 WGDT Inventory (Ci)	EAB Dose (Limit = 0.1 Rem TEDE)
Design Basis	90,921	0.04
TS	202,500	0.09

**Figure 2.9.3-1
WGDT RADTRAD-NAI Model**



2.10 Health Physics

2.10.1 Occupational and Public Radiation Doses

2.10.1.1 Regulatory Evaluation

Florida Power and Light (FPL) conducted its review to ascertain the overall effects the extended power uprate (EPU) will have on both occupational and public radiation doses and to determine that FPL has taken the necessary steps to ensure that any dose increases will be maintained as low as reasonably achievable (ALARA). The FPL 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. FPL evaluated how personnel doses needed to access plant vital areas following an accident are affected. FPL 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 acceptance criteria for occupational and public radiation doses are based on 10 CFR 20 and General Design Criterion (GDC)-19. Specific review criteria utilized by NRC are contained in the Standard Review Plan (SRP) Sections 12.2, 12.3, 12.4, and 12.5, and other guidance provided in Matrix 10 of Review Standard (RS)-001.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to Title 10 of the Code of Federal Regulations (10 CFR) Part 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The current licensing basis (CLB) with respect to radiation protection (health physics) of plant personnel and the public includes the following:

- GDC-19 is described in UFSAR Section 3.1.1 Criterion 19 – Control Room.

A control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in safe condition under accident conditions, including loss-of-coolant accidents (LOCA). Adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent for the duration of the accident.

Equipment in appropriate locations outside the control room shall be provided (1) with a design capability for prompt hot shutdown of the reactor, including necessary instrumentation and controls to maintain the unit in a safe condition during hot shutdown, and (2) with a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

Control room design features that support safe occupancy during accident conditions are discussed in LR [Section 2.7.1](#), Control Room Habitability System. Demonstration of habitability

following design basis accidents is addressed in LR [Section 2.9.2](#), Radiological Consequences Analyses Using Alternative Source Terms (AST).

The CLB with respect to radiation protection of plant personnel and the public includes the following:

1. Normal Operation Radiation Levels and Shielding Adequacy

Radiation shielding is designed for continuous safe operation at a core power level of 2700 megawatts thermal (MWt) with system activity levels stemming from fuel cladding defects in the equivalent of one percent of the fuel rods.

Plant accessibility is facilitated by shielding and radiation monitoring and is controlled by procedures that take into account the requirements of 10 CFR 20. Plant shielding design and procedural controls ensure that exposure to plant personnel is maintained below the levels allowed for occupational exposure set by 10 CFR 20.

2. Radiation Monitoring

As discussed in UFSAR Sections 9.4, 11.5, 12.1, and 12.3 the radiation monitors can be classified into three categories: a) area, b) airborne, and c) process and effluent. Area and airborne radiation monitors are included as radiation protection features and provide radiation/radioactivity monitoring to support control of radiation exposure of plant personnel. Process and effluent radiation monitors are provided in support of radioactivity monitoring in gaseous or liquid process streams, or effluent release points to unrestricted areas, to support control of radiation exposure of both plant personnel and the public. The system operates in conjunction with regular and special radiation surveys and with chemical and radiochemical analyses performed by the plant staff to provide timely, adequate information for continued safe operation and for assurance that personnel exposure does not exceed 10 CFR 20 guidelines.

3. Post Accident Vital Area Accessibility

As discussed in UFSAR Appendix 12.3A, in response to NUREG 0737, Item II.B.2, Plant Shielding, a design review of the plant shielding was performed. This assures safe personnel access to the vital equipment or areas required for mitigation or monitoring of an accident.

In compliance with Item II.B.2 of NUREG-0737:

- Radiation source terms are specified,
- Systems assumed to contain high levels of radioactivity as a result of a postulated accident are listed,
- Vital areas requiring access are identified, and
- Dose rates and doses in vital areas are presented.

Source terms used are consistent with the requirements of Section II.B.2 of NUREG-0737, which are based on the guidelines of NRC Regulatory Guides (RG) 1.4 and 1.7 and SRP Section 15.6.5.

The systems identified as potentially containing high levels of radioactivity in a post-accident situation and which were considered in the shielding design review undertaken assure access to vital areas, are listed in UFSAR Table 12.3A-6.

A list of vital areas (with accompanying occupancy, dose rate, and dose information) is presented in UFSAR Table 12.3A-7. As indicated in UFSAR Table 12.3A-7, in cases where the review revealed that high dose rates or accumulated dose would preclude access, means for remote operation, additional shielding or plant modifications were provided.

As stated in UFSAR Section 12.3A.5 dose rate calculations were performed in areas identified as vital areas, and along potential access routes.

In a letter dated March 18, 2008 ([Reference 1](#)), and as part of the implementation of AST, FPL provided additional information describing the basis for maintaining the CLB radiological dose analyses for post-accident vital area access as described in NUREG-0737, Item II.B.2. FPL cited the resolution of NRC Generic Issue 187 as described for the justification of maintaining the CLB source term for environmental qualification, as applicable to the radiological dose analyses for post-accident vital area access as well. In the March 18, 2008 letter, the licensee asserted and in [Reference 2](#) the NRC staff concurred, that since the calculated post-accident vital area access dose rates are not expected to be significantly impacted by the AST during the first 30 days following a LOCA, the conclusions of the shielding study would not change significantly by expressing the mission dose in terms of total effective dose equivalent (TEDE).

Regarding post-accident sampling capability, as described in NUREG-0737, Item II.B.3, FPL cited technical specifications (TS) amendment No. 114, ([Reference 3](#)) which eliminated the requirements to have and maintain the post-accident sampling system (PASS).

FPL also cited the resolution of Generic Issue 187 as the basis for maintaining the CLB radiological dose analyses for the accident monitoring instrumentation as described in NUREG-0737, Item II.F.1. FPL asserted, and the NRC staff confirmed, that the leakage control requirements of NUREG-0737, III.D.1.1 and the CR habitability requirements of NUREG-0737, III.D.3.4 are incorporated into the revised AST radiological analyses.

4. Normal Operation Radwaste Effluents and Annual Dose to the Public

UFSAR Section 11.2.1 presents the liquid waste system design bases and addresses the systems ability to limit releases due to anticipated operational occurrences within 10 CFR 20. UFSAR Section 11.3.1 presents the gaseous radwaste systems design bases. The numerical design objective associated with the gaseous waste management system for releases during normal operation is to limit the site boundary noble gas dose to less than 10 mrem/year and Iodine-131 and particulate site boundary concentrations to 10^{-5} times 10 CFR 20 limits. Releases due to *normal operation and* anticipated operational occurrences are controlled by plant procedures to meet regulatory requirements.

Radiation exposure of the public due to normal operation radwaste effluents is determined by compliance with the Offsite Dose Calculation Manual (ODCM), which in turn invokes compliance with 10 CFR 20, 10 CFR 50 Appendix I and 40 CFR 190.

5. Ensuring that Occupational and Public Radiation Exposures are ALARA

As discussed in UFSAR Section 12.5.1, the health physics program objectives are:

- To implement a radiation protection program for protecting the health and safety of plant personnel and the public,
- To establish and maintain a comprehensive record system which will demonstrate the adequacy of the radiation protection program to ensure that occupational exposures are ALARA and which complies with all applicable federal and state regulations,
- To ensure that all radioactive effluent releases and waste shipments meet guidelines and established plant procedures, and
- To ensure that radioactive effluent releases are within TS requirements and maintained ALARA.

The radiation protection program ensures that radiation exposures to plant personnel and the public resulting from plant operation will be within applicable limits and will be ALARA, as described in UFSAR Section 12.5.1.

Implementation of the overall requirements of 10 CFR 50 Appendix I relative to utilization of radwaste treatment equipment to ensure that radioactive discharges and public exposure are ALARA are formalized in the ODCM.

In addition to the licensing basis described in the UFSAR, the radiation protection program (health physics) was evaluated for License Renewal. As documented in NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003, the radiation protection program was determined to be outside the scope of License Renewal.

2.10.1.2 Technical Evaluation

The technical evaluation is presented in five subsections as listed below:

1. Normal operation radiation levels and shielding adequacy,
2. Radiation monitoring setpoints,
3. Post-accident vital area accessibility,
4. Normal operation radioactive effluents and annual dose to the public, and
5. Ensuring that occupational and public radiation exposures are ALARA.

2.10.1.2.1 Normal Operation Radiation Levels and Shielding Adequacy

2.10.1.2.1.1 Introduction

Cubicle wall thickness is specified not only for structural and separation requirements, but also to provide radiation shielding in support of radiological equipment qualification, and to reduce exposure to plant personnel during all modes of plant operation, including maintenance and accidents.

Conservative estimates of the radiation sources in plant systems and personnel access requirements form the bases of normal operation plant shielding and radiation zoning. These radiation source terms are primarily derived from conservative estimates of the reactor core and reactor coolant isotopic activity inventory, and are referred to as design basis source terms.

The expected radiation source terms in the coolant are more realistic than design and are usually based on industry experience for normal plant operations scaled to reflect plant-specific parameters. Expected source terms are less than those allowable by the TS and are usually significantly less than the design basis source terms.

The impact of the EPU on the normal operation dose rates and the adequacy of existing shielding is evaluated to ensure safe operation within applicable regulatory limits. The assessment is broken into two parts – the impact of the EPU on (1) plant radiation levels during normal operation, and (2) adequacy of existing shielding for normal plant operation.

The shielding design basis summarized in UFSAR Sections 12.2.1 and 12.3.1 and UFSAR Tables 11.1-1 and 11.1-2 indicate that the pre-EPU plant shielding design was based on operation at a core power level of 2700 MWt and 1 percent fuel defects. Per the UFSAR Table 11.1-1, the fuel cycle length was one year. St. Lucie Unit 2 is currently operating at a core power level of 2700 MWt and an 18-month fuel cycle. The impact of the increase in core power level/fuel cycle length from pre-EPU design on plant radiation levels is monitored, and exposure to plant personnel controlled, by the radiation protection program. The pre-EPU design calculations supporting plant shielding remain adequate for current plant operations.

The EPU analysis is based on an analyzed core power level of 3030 MWt and an 18-month fuel cycle. An increase of fuel cycle length will increase the inventory of long-lived isotopes compared to the pre-EPU licensing basis core and reactor coolant. The activity inventory of a few isotopes that are produced primarily by neutron activation of stable or long-lived fission products will also increase due to longer accumulation time.

The EPU results in an increase of the nuclear fission rate, and consequently, an increase of neutron flux and the fission product generation rate. This leads to an increase of the fission product inventory in the core and spent fuel and an increase of neutron and gamma flux leaking out of the reactor vessel.

The increase in the neutron flux results in an increase of neutron activation and corrosion products in the reactor coolant system (RCS), and activation products in the control rod assemblies, reactor internals, and in the pressure vessel. The increase in the core inventory of fission products and actinides due to the EPU will also increase the activity concentrations in the reactor coolant due to fuel defects.

In the unlikely event that St. Lucie Unit 2 experiences primary-to-secondary leakage in the steam generators (SGs), the activity concentrations in the secondary system will increase. The radiation source in the downstream systems will undergo a corresponding increase. This increase in the radioactivity levels, and the associated increase in the radiation source strength, will result in an increase of radiation levels in the containment building, reactor auxiliary building, and other locations that are subject to direct shine from radiation sources contained in these buildings.

2.10.1.2.1.2 Description of Analyses and Evaluations

The EPU evaluation utilizes scaling techniques to determine the impact of the EPU on plant radiation levels. This evaluation takes credit for conservatism in existing shielding analyses and the radiation protection program to demonstrate adequacy of current plant shielding to support compliance with the plant personnel exposure limits of 10 CFR 20.

1. Normal Operation Radiation Levels

For the same facility configuration, the dose rate at a given location is directly proportional to the neutron/gamma flux leaking out of the source region or the volumetric gamma source strength in the source region. The impact of increasing the reactor power from the current licensed level of 2700 MWt to the conservatively analyzed core power level of 3030 MWt on the neutron flux and gamma flux in and around the core, fission product and actinide activity inventory in the core and spent fuels, N-16 source in the reactor coolant, neutron activation source in the vicinity of the reactor core, and fission/corrosion products activity in the reactor coolant and downstream systems, was examined, and the increase quantified. This flux or activity increase factor for a given radiation source was determined to be the EPU scaling factor for the estimated dose rate due to that source.

The EPU assessment with regard to normal operation radiation levels is divided into four areas:

a. Areas Near the Reactor Vessel

During normal operation, the radiation source in the reactor core is made up of the neutron and gamma flux that are approximately proportional to the core power level. The radiation sources during shutdown are the gamma flux in the core and the activation activities in the reactor internals, pressure vessel, and primary system piping walls, which also vary approximately in proportion to the reactor power.

The radiation dose rate near the reactor vessel is determined by the leakage flux from the reactor vessel. Therefore, an uprate from the current licensed core power of 2700 MWt to an analyzed core power of 3030 MWt is estimated to increase the normal operation radiation levels in areas near the reactor vessel by a factor of approximately 1.122, (i.e., $3030 \text{ MWt} / 2700 \text{ MWt}$).

b. In-Containment Areas Adjacent to the Reactor Coolant System (RCS)

During normal operation, the major radiation source in the RCS located within containment is N-16. With the core power increase from 2700 MWt to the analyzed core power of 3030 MWt, the fast neutron flux is estimated to increase by approximately 12.2 percent. The coolant residence time in the core and the transit time are not expected to change significantly due to the uprate. Therefore, the EPU scaling factor for the areas subjected to the N-16 source is 1.122.

The deposited corrosion material depends primarily on the RCS water chemistry and the cobalt impurity in the RCS and SG components. It is expected that a) the RCS water chemistry which is controlled by plant procedures will remain unchanged and b) the increase in corrosion due to any minor increase in RCS temperature and flow due to the

EPU will be minimal, and remain within the typical variation within a fuel cycle and between fuel cycles. The uprate will increase the neutron flux by approximately 12.2 percent; therefore, the corrosion product activity deposits and the associated shutdown dose rate are also expected to increase by approximately 12.2 percent.

c. Areas Near Irradiated Fuels and Other Irradiated Objects

These areas include the refueling canal, spent fuel pool, and other areas housing neutron irradiated materials. The radiation source is the gamma rays from the fission products and activation products, which are determined by the fission rate, neutron flux level, and the irradiation time.

Since both the fission products and the activation products are estimated to increase by approximately 12.2 percent for a core power increase from 2700 MWt to the analyzed core power level of 3030 MWt, the EPU scaling factor for the areas subjected to irradiated fuels and other irradiated sources is 1.122.

d. Areas Outside Containment where the Radiation Source Is Derived from the Primary Coolant Activity

In most areas outside the reactor containment, the radiation sources are either the primary coolant itself or down-stream sources originating from the primary coolant activity. Following the EPU, both the fission products and the activated corrosion products in the primary coolant, and thus the down-stream sources, are estimated to increase by approximately 12.2 percent for a core power increase from 2700 MWt to the analyzed power level of 3030 MWt. The EPU scaling factor for the areas outside containment where the radiation source is derived from the primary coolant activity is, in general, 1.122.

2. Plant Shielding Adequacy

Shielding is used to reduce radiation dose rates in various parts of the station to acceptable levels consistent with operational and maintenance requirements and to maintain the dose rates at the site boundary to below those allowed for continuous non-occupational exposure.

The pre-EPU shielding design was based on plant operation at a core power level of 2700 MWt / 12-month fuel cycle, upon generalized occupancy requirements in various radiation zones of the station, and upon conservative reactor coolant source terms assuming 1 percent fuel defects.

The EPU evaluation takes into consideration that the occupancy requirements are not affected by the EPU. Similarly, the layout/configuration of systems containing radioactivity are unchanged by the EPU. Consequently, the EPU evaluation focused on determining an EPU scaling factor based on the design basis fission and corrosion product activity concentrations in the reactor coolant used in the pre-EPU plant shielding design versus the corresponding EPU design basis reactor coolant activity concentrations presented in LR [Table 2.9.1-3](#), which reflects an analyzed core power level of 3030 MWt, an 18-month fuel cycle length, and 1 percent fuel defects.

The source terms at the analyzed power level are compared to the source terms used in the pre-EPU shielding design to evaluate the adequacy of the shielding design. The EPU evaluation takes into consideration a) the conservative analytical techniques used to establish plant shielding design, b) the TS limits on the reactor coolant activity concentrations, and c) the station radiation protection program that minimizes the radiation exposure to plant personnel.

a. Reactor Primary Shield

UFSAR Section 12.3.1.1 discusses the primary shield design which consists of a reinforced concrete structure that surrounds the reactor vessel. The primary function of the primary shield is to attenuate the neutron and gamma fluxes leaking out of the reactor vessel. Fuel cycle length has insignificant impact on the maximum dose rates around the reactor vessel which are based on the neutron and gamma flux during power operation.

The EPU evaluation confirmed that there was considerable conservatism included in pre-EPU design flux calculations. Applying present-day calculation methodologies and consideration for the current, as well as future use of low leakage fuel management, it has been determined that pre-EPU design calculations remain bounding for EPU conditions. Therefore, the existing primary shielding remains adequate, and the estimated dose rates adjacent to the reactor vessel/primary wall remain within pre-EPU design calculations.

b. Reactor Secondary Shields

UFSAR Sections 12.3.1.2 and 12.3.1.3 discuss the reactor building secondary shield and shield building surrounding the reactor coolant loops and the primary shield. The primary function of these secondary shields is to attenuate the N-16 source, which emits high-energy gammas. These shields were designed to limit the full-power with 1-percent fuel defects dose rate outside the shield building to < 0.25 mrem/hr.

The N-16 source is estimated to increase by approximately 12.2 percent (3030/2700) compared to pre-EPU design. The N-16 activity level is not impacted by fuel cycle length. The impact of the estimated 12.2 percent increase in source terms is bounded by the conservative analytical techniques typically used to establish plant shielding design (such as, ignoring the steel rebar in the concrete structures, shadow shielding effect of the neighboring sources, and rounding up the calculated shield thickness to the next higher whole number, etc.). In addition, current survey dose rates outside the containment wall at 100 percent power indicate radiation levels of <25 μ rem/hr. Consequently, the reactor building secondary shield and shield building are determined to be adequate for safe operation following the EPU.

c. Fuel Handling Building Shielding

UFSAR Section 12.3.1.6 discusses the shielding provided for radiation protection of plant personnel during all phases of spent fuel removal, storage and preparation for offsite shipment. The fuel transfer shielding is designed to alleviate radiation from spent fuel during transfer and storage, such that the dose rates at the refueling cavity water surface

and the outer surface of the fuel pool structure are < 2.5 mrem/hr and 0.5 mrem/hr, respectively.

With the analyzed core power increase from 2700 to 3030 MWt, the gamma source from the irradiated fuel is estimated to increase by approximately 12.2 percent. The 18-month fuel cycle will also increase the inventory of long-lived isotopes in the irradiated fuel. However, this is not a concern as the estimated maximum dose rates near the refueling canal and the spent fuel pool are dominated by the shorter half-life isotopes in the freshly discharged spent fuel assemblies. The impact of the estimated 12.2-percent increase in source terms used in the EPU analysis versus the pre-EPU shielding analysis is bounded by the conservative analytical techniques discussed earlier in item b, which were used to establish plant shielding design. In addition, the current survey dose rates in the spent fuel pool system areas and around the edges of the spent fuel pool at 100 percent power indicate radiation levels of < 1 mrem/hr. Based on the above, the current spent fuel shielding is determined adequate for safe operation following the EPU.

d. All Other Shielding Outside Containment

UFSAR Section 12.3.1.7 discusses the shielding provided outside the containment where the radiation sources are either the reactor coolant itself or down-stream sources originating from coolant activity. A review was performed of the EPU design primary coolant source terms (fission and activation products) versus the pre-EPU design basis primary coolant source terms. It is noted that the analyzed design primary coolant source term utilized for the EPU reflects a core power level of 3030 MWt, operation with an 18-month fuel cycle, 1 percent fuel defects, and more advanced fuel burnup modeling/libraries as compared to the computer codes used in the pre-EPU design analyses that addressed a core power level of 2700 MWt and a one-year fuel cycle length.

The EPU assessment concluded that the estimated increase in the dose rate for shielded configurations based on the design basis EPU reactor coolant versus the pre-EPU design basis coolant is compensated by the plant TS that will limit the EPU reactor coolant, degassed reactor coolant, and reactor coolant noble gas source terms and associated dose rates to less than the pre-EPU design basis values. It is, therefore, concluded that the shielding design based on the pre-EPU design basis primary coolant activity remains acceptable for the EPU condition.

2.10.1.2.1.3 Results

The normal operation radiation levels in most of the plant areas are estimated to increase by approximately 12.2 percent, i.e., the percentage increase between the current licensed power level of 2700 MWt, and the conservatively analyzed core power level of 3030 MWt used for the EPU assessment. The exposure to plant personnel and to the offsite public is also estimated to increase by the same percentage.

The increase in radiation levels will not affect radiation zoning or shielding requirements in the various areas of the plant. This is because the increase is offset by the:

1. Conservative analytical techniques typically used to establish shielding requirements,

2. Conservatism in the pre-EPU design basis reactor coolant source terms used to establish the radiation zones, and
3. TS Section 3.4.8 which limits the reactor coolant concentrations to levels significantly below the pre-EPU design basis source terms.

As indicated in UFSAR Section 12.1, individual worker exposures will be maintained within the regulatory limits of 10 CFR 20 for occupational exposure by the site radiation protection program that controls access to radiation areas. In addition, the ODCM ensures that the radiation levels at the site boundary due to direct shine from radiation sources in the plant will be maintained within the regulatory limits of 10 CFR 20 and 40 CFR 190 for continuous non-occupational exposure.

The EPU assessment also demonstrates compliance with GDC-19 with regard to radiation protection, insofar that actions can be taken in the Control Room to operate the nuclear power unit safely during normal operation.

2.10.1.2.2 Radiation Monitoring Setpoints

2.10.1.2.2.1 Introduction

The installed radiation monitoring system at a nuclear power plant includes (a) area monitors, (b) airborne monitors, (c) process and effluent monitors.

Area radiation monitors are provided as a radiation protection feature to monitor the direct radiation levels in general areas of the plant. Airborne radiation monitors are installed to detect the airborne particulate, iodine and gaseous activity concentrations in the various buildings and to alarm if there are any abnormal increases in the airborne activity levels. Process and effluent radiation monitors are provided in support of radioactivity monitoring in gaseous or liquid process streams, or effluent release streams, to facilitate detection of component leakages, monitor system performance, and support the safety of plant personnel and the public.

Radiation monitor alarm setpoints are used to warn plant personnel of any unusual increase in the radioactivity levels that may require operator actions. The function of area monitor alarm setpoints is to provide an early warning of changing radiological conditions in a specified area. The function of alarm setpoints for airborne/process/effluent monitors is to a) annunciate an unusual airborne concentration in a building or the potential of an activity release that may exceed the release limit, or b) indicate leakage or malfunction of equipment, or c) prevent inadvertent release of radioactivity to the environment. The high alarm setpoint for some area and airborne monitors are used to generate isolation functions, e.g., containment and control room isolation. The high alarm setpoint of selected effluent and process monitors will initiate interlocks that terminate activity release to the environment. The function of the post-accident radiation monitors is to give notice of significant radiation levels within plant areas or in environmental releases from the plant.

Power uprate will increase the activity level of radioactive isotopes in the reactor core, spent fuel, reactor primary and secondary coolant systems, and the process/waste systems containing radioactive materials. This increase in radioactivity levels will also result in an increase in the radiation levels in various plant areas, and will potentially increase the radioactive environmental releases from the station. The increase of the radioactivity levels in the monitored streams

(normal and accident) and areas, and the increase in background radiation levels have the potential of impacting the current radiation monitor setpoint basis or its value.

2.10.1.2.2.2 Description of Analyses and Evaluations

The installed radiation monitoring system is discussed in UFSAR Sections 11.5 and 12.3.4.

The bases of the radiation monitor setpoints were examined for the impact of the EPU. It was determined that the setpoints bases are either a) a regulatory commitment (i.e., at an effluent concentration level that will result in a fraction or a multiple of allowed site boundary dose rate limits, and are intended to give notice of releases approaching the limits of 10 CFR 20), b) a multiple of the background, or c) a high value indicating an unusual event (such as, leakage or malfunction of systems), that leads to a sudden increase of the activity level in the monitored stream. The setpoint values are based on background levels/process fluids source terms that reflect plant operating data and are reviewed frequently and adjusted as required.

Although EPU will increase the radioactivity levels in the monitored stream by approximately the percentage of power uprate, the relative nuclide mix is expected to remain unchanged. The small increase of the background count rate due to external plant sources following the EPU will not significantly increase the potential of spurious alarms. The setpoint bases and the parameters are not power level dependent and will not be impacted by EPU. It is concluded that all setpoint bases and methods of setpoint determination remain valid for the EPU.

2.10.1.2.2.3 Results

Impact of EPU on radiation monitor setpoints is expected to be minimal. Regardless, update of the setpoints, if deemed necessary, will be performed in accordance with existing plant procedures.

The EPU will not impact the radiation monitor setpoints values provided in TS Tables 3.3-4 and 3.3-6.

2.10.1.2.3 Post Accident Vital Area Accessibility

2.10.1.2.3.1 Introduction

In accordance with NUREG-0737, II.B.2, vital areas are those areas within the station that will or may require access/occupancy to support accident mitigation following a LOCA. All vital areas and access routes to vital areas must be designed such that exposure to plant personnel while performing vital access functions remain within regulatory limits.

This section focuses on areas that may require short-term, one-time, or infrequent access following a LOCA. Onsite locations that require continuous occupancy and a demonstration of 30-day habitability, such as the Control Room, are addressed in LR [Section 2.9.2](#), Radiological Consequences Analyses Using Alternative Source Terms (AST).

The pre-EPU licensing basis vital area access review is discussed earlier in LR [Section 2.10.1.1](#), item No. 3 and summarized below.

UFSAR Section 12.3A.1 indicates that a design review of the shielding design was performed in compliance with NUREG 0737, II.B.2. UFSAR Section 12.3A.5 indicates that dose rate calculations were performed in areas identified as vital areas, and along potential access routes. The systems identified as potentially containing high levels of radioactivity in a post-accident situation are listed in UFSAR Table 12.3A-6. A list of vital areas requiring short term access evaluated during the shielding design review (with accompanying occupancy, dose rate, and dose information) is presented in UFSAR Table 12.3A-7. As indicated in UFSAR Table 12.3A-7, per the initial review, some of the areas that needed short term access (i.e., target areas 3 through 8), revealed high dose rates and associated accumulated dose at T=1hr which would preclude access at that time. As noted in Table 12.3A-7, means for remote operation, additional shielding, plant modifications or alternate locations were provided such that a) access was no longer required to Target Areas 3, 4 and 7, or b) the dose was reduced to below regulatory requirements to Target Areas 5 and 8. In addition, as indicated in LR [Section 2.10.1.1](#) and UFSAR Table 12.3A-7, the post-accident sampling system (PASS), is no longer used and thus, access to the PASS (target area 6) is no longer required. Thus, and as noted in UFSAR Table 12.3A-7, of the six (6) areas identified in the shielding review as requiring short-term accessibility following a LOCA, only two (2) require access for current operation.

UFSAR Section 12.3A.5 indicates that as a result of the vital area access evaluation, radiation dose rate maps were prepared (from the dose rate data developed) that showed dose rate ranges throughout the auxiliary building at T=1 hr, 10 hr, 100 hrs and 1000 hrs following a LOCA. Radiation levels in the various areas around contaminated systems (for the referenced times) can be found on these maps. These maps, superimposed on the general arrangement drawings are included as UFSAR Figures 12.3A-1 through 12.3A-4. As noted in the referenced figures, zone boundaries encompass dose rates over several decades: < 0.015 R/hr, 0.015-0.10 R/hr, 0.10-1 R/hr, 1-10 R/hr, 10-100 R/hr, and > 100 R/hr.

UFSAR Section 12.3A.5 indicates that these maps reflect the time dependent post-LOCA radiation sources discussed earlier, and that appropriate geometry factors were applied to estimate dose rates from pipes and equipment carrying post-accident fluids. The shielding effect of the equipment, fluid, and shield wall arrangement were considered. The effect of reinforcement bars, imbedded plates, or any structural steel was neglected, which when combined with the very conservative "worst case" source terms, resulted in conservative calculated dose rates.

As noted previously in LR [Section 2.10.1.1](#), and in accordance with the CLB, the EPU assessment for vital area access is based on TID-14844 source terms. This approach is acceptable based on the AST benchmarking study reported in SECY-98-154 which concluded that results of analyses based on TID-14844 would be more limiting earlier on in the event, after which time the AST results would be more limiting.

A review of current emergency operating procedures (EOPs) was performed, including the potential impact of the EPU on vital access requirements. This review confirmed that the CLB post-LOCA operator mission requirements (including the task description and required time/duration for access), remain valid for the EPU, and that there are no additional access requirements due to the EPU. Thus, for EPU operations, required operator access is limited to

target areas 5 (hydrogen analyzer cubicle) and 8 (emergency core cooling system (ECCS) vent monitors).

2.10.1.2.3.2 Description of Analyses and Evaluations

The CLB source terms used to develop vital area access dose estimates were based on a power level of 2700 MWt, a 12-month fuel cycle length.

The proposed EPU core power level is 3020 MWt. Radiological safety analyses supporting the EPU are performed at a reactor power level of 3030 MWt (i.e., the core power level of 3020 MWt with a 0.3 percent margin for power uncertainty) and an 18-month fuel cycle. The containment sump water volume and reactor coolant volume applicable to the EPU application were slightly greater than the values utilized in the CLB analyses, whereas the containment atmosphere volume remained unchanged. Thus volume correction factors were not required to estimate the EPU doses.

EPU will typically increase the activity level in the core by the percentage of the uprate. The radiation source terms in equipment/structures containing post-accident fluids, and the corresponding environmental radiation levels, will increase proportionately to the uprate. In addition, factors that impact the equilibrium core inventory (and consequently the estimated radiation environment), are fuel enrichment and burnup.

The methodology utilized in the EPU evaluation is to demonstrate, using scaling techniques, compliance with the operator exposure dose limits provided in NUREG-0737, II.B.2, i.e., 5 rem whole body.

The impact of the EPU on the post-LOCA gamma radiation dose rates utilized to determine exposure to plant personnel during vital area access, is evaluated by comparing the gamma source terms, based on the pre-EPU core inventory utilized to develop the post-LOCA dose rates, to the gamma source terms, based on the EPU core inventory. This approach takes into consideration that: a) the post-LOCA operator mission requirements, including the task description and required time for access is not impacted by the EPU, and b) EPU does not impact the operation and layout/arrangement of plant radioactive systems.

The EPU equilibrium core inventory utilized for this assessment reflects expected fuel management schemes at EPU conditions that span a range of fuel enrichment from 1.5 weight percent (w/o) to 5.0 w/o U-235, and utilizes a more realistic prediction of the mix of assemblies relative to enrichment than that assumed for the dose consequence analyses discussed in LR [Section 2.9.2](#), Radiological Consequences Analyses Using Alternative Source Terms (AST). A sub-set of the core inventory of dose significant nuclides developed using ORIGEN 2.1 is presented in LR [Table 2.9.1-3](#). Note that the EPU vital area access assessment uses the entire complement of isotopes from the ORIGEN 2.1 output.

Theoretically, following the EPU, the post-LOCA environmental gamma dose rates and the operator dose per identified mission should increase by approximately 12.2-percent (3030 MWt/2700 MWt). However, because the EPU analyzed core reflects: a) operation with an 18-month fuel cycle and b) more advanced fuel burnup modeling/libraries than used in the pre-EPU analyses, the calculated EPU scaling factor values will deviate from the core power ratio.

The EPU assessment is essentially a two-step process. The first develops a bounding EPU dose rate scaling factor versus time, and the second multiplies the personnel dose/dose rates at target areas identified in the licensing basis by the bounding EPU scaling factor(s).

The pre-EPU and the EPU core inventories are utilized to develop the post-LOCA gamma energy release rates (Mev/sec) per energy group vs. time for the post accident sources addressed in the licensing basis.

For the unshielded case, the factor impact on post-accident integrated gamma dose rates is estimated by ratioing the gamma energy release rates weighted by the flux to dose rate conversion factors, as a function of time, for the core power level analyzed for the EPU, to the corresponding weighted source terms based on the CLB core. To address the fact that the vital access locations are outside containment and sump fluid is contained in equipment / piping, the unshielded values include the shielding effect of a pipe wall thickness associated with standard small bore pipe or a standard large bore pipe. This insures that the results are not impacted by photons at low energies, especially those less than 25 kev which are substantially attenuated by any piping sources or self-attenuation.

To evaluate the factor impact of EPU on post-LOCA gamma doses (versus time) in areas that are shielded, the pre-EPU as well as EPU source terms discussed above were weighted by the concrete reduction factors for each energy group. The concrete reduction factors for 1ft, 2ft, and 3ft of concrete were used to provide a basis for comparison of the post-LOCA spectrum hardness with respect to time, for lightly shielded and heavily shielded cases.

Since the EPU gamma dose rate scaling factors for the sump fluid vary with time, as well as shielding, to cover all types of analysis models/assessments, the maximum T=1hr dose rate scaling factor is used to estimate the impact of the EPU on the operator dose at T=1 hr for the remaining vital areas (i.e., target areas 5 and 8), that are deemed to require access following a LOCA.

In summary, a dose scaling factor of 1.32 is utilized to estimate the operator mission dose to the above target area.

Thus the estimated EPU operator mission dose at T=1 hr to personnel performing necessary functions in target area 5 (hydrogen analyzer cubicle) and target area 8 (ECCS vent monitors) is 1.72 rem and < 150 mrem, respectively, both of which remain below the regulatory limit of 5 rem whole body.

Impact of EPU on Post-LOCA Radiation Dose Rate Maps

In general, radiation dose rate maps are developed for purposes of post-accident mitigation planning, to provide a general idea of radiation levels at plant vital areas and areas essential to access those vital areas. Operators may refer to the maps to apprise themselves of the locations of potentially high radiation areas at any time following the accident. To that end, each zone in dose rate maps usually represents a range of estimated dose rates that cover a decade. As noted earlier, zone boundaries encompass dose rates over several decades: < 0.015 R/hr, 0.015-0.10 R/hr, 0.10-1 R/hr, 1-10 R/hr, 10-100 R/hr, and > 100 R/hr.

Note that the only impact the EPU increase can have on the radiation dose rate zone maps is in the zone boundary definition. Based on engineering judgment, it can be concluded that the

impact of the EPU will be well within the conservatism of the radiation dose rate zone boundaries depicted on the maps. This conclusion is based on the conservative modeling techniques utilized to establish the estimated dose rate range applicable to a zone, and the typical conservative approach utilized when establishing the approximate location of zone boundaries.

As stated earlier, operators refer to such maps to apprise themselves of the locations of potentially high radiation areas for any time following the accident. This function will still be met following the EPU. Thus, it is concluded that the zone maps presented in UFSAR Figures 12.3A-1 through 12.3A-4 will not be impacted by the EPU

2.10.1.2.3.3 Results

The EPU operator mission dose while accessing vital areas post accident remains compliant with the regulatory limit of 5 rem whole body listed in NUREG-0737, II.B.2.

The zone maps presented in UFSAR Figures 12.3A-1 through 12.3A-4 will not be impacted by the EPU

2.10.1.2.4 Normal Operation Radwaste Effluents and Annual Dose to the Public

2.10.1.2.4.1 Introduction

Liquid and gaseous effluents released to the environment during normal plant operations contain small quantities of radioactive materials.

Liquid, gaseous, and solid radwaste systems are designed such that the plant is capable of maintaining normal operation offsite gaseous and liquid releases and doses within regulatory limits. The actual performance and operation of installed equipment, as well as reporting of actual offsite releases and doses, are controlled by the requirements of the ODCM.

There are no specific regulatory limits associated with generation of solid radwaste other than those associated with transportation. However, onsite storage of solid radwaste may result in increased public exposure at the site boundary which is controlled by federal regulations.

EPU will increase the activity level of radioactive isotopes in the reactor and potentially increase the activity in the secondary coolant and steam. Due to leakage or process operations, fractions of these fluids are transported to the liquid and gaseous radwaste systems where they are stored/processed prior to discharge. As the activity levels in the coolants and steam are increased, the activity level of radwaste inputs, and subsequent environmental releases, are proportionately increased.

2.10.1.2.4.2 Description of Analyses and Evaluations

The methodology used in the EPU evaluation is to demonstrate, using scaling techniques, compliance with the annual dose limits to an individual in an unrestricted area set by 10 CFR 20, 10 CFR 50 Appendix I, and 40 CFR 190 resulting from radioactive gaseous and liquid effluents released to the environment following an EPU at both St. Lucie Units 1 & 2.

Note that limits on dose to the public resulting from normal operation are addressed in 10 CFR 20, 10 CFR 50 Appendix I, as well as 40 CFR 190. However, 10 CFR 50 Appendix I (which is based on the concept of ALARA) is the most limiting. 10 CFR 20 does have a release rate criterion that does not exist in 10 CFR 50 Appendix I, but the ODCM controls actual performance and operation of installed equipment and releases, thus maintaining compliance with that aspect of 10 CFR 20. In addition, if the projected increase in offsite doses due to radioactive gaseous and liquid effluents either approach or exceed 10 CFR 50 Appendix I guidelines, then the methodology in the ODCM is utilized to determine compliance with 40 CFR 190. Per Section 3/4.11.4 of the ODCM, compliance with the provisions 10 CFR 50 Appendix I is adequate demonstration of conformance to the standards set forth in 40 CFR 190 regarding the dose commitment to individuals from the uranium fuel cycle. Per the ODCM, if the quarterly doses from the release of radioactive materials in liquid or gaseous effluents exceed twice the design objectives of 10 CFR 50 Appendix I, to ensure 40 CFR 190 compliance, the quarterly dose calculations shall include exposures from effluent pathways and direct radiation contributions from the reactor units and from any outside storage tanks.

There are no changes as a result of the EPU to existing radioactive waste systems (gaseous and liquid) 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/radioactivity concentrations in the reactor coolant and secondary coolant/steam. As a result, the impact of the EPU on radwaste releases and 10 CFR 50 Appendix I doses can be estimated using scaling techniques.

Scaling techniques based on NUREG-0017, Revision 1 methodology were utilized to assess the impact of the EPU on radioactive gaseous and liquid effluents at St. Lucie Units 1 and 2. Use of the adjustment factors presented in NUREG-0017, Revision 1 allows development of coolant activity scaling factors to address the EPU.

The EPU analysis utilized the core power operating history during the years 2003 to 2007 for St. Lucie Units 1 and 2, the reported gaseous and liquid effluent and dose data during that period, NUREG-0017 Revision 1 equations, 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 consequent normal operation offsite doses.

For the current condition, the evaluation utilized offsite doses based on an average 5-year set of organ and whole body doses calculated from effluent reports for the years 2003 through 2007.

For the EPU condition, the system parameters utilized in the EPU analysis reflected the flow rates and coolant masses at an analyzed NSSS power level of 3034 MWt (3034 MWt is the sum of 3020 MWt and 14 MWt for thermal power from the reactor coolant pumps) and a conservative core power level of 3030 MWt. This is consistent with the guidance provided in NUREG-0017 which requires that the core power level utilized in the analysis reflect a margin for power uncertainty.

The maximum potential percentage increase in coolant activity levels due to the EPU, for each chemical group identified in NUREG-0017, was estimated using the methodology and equations found in NUREG-0017, Revision 1, and a comparison of the change in power level and in plant

coolant system parameters (such as reactor coolant mass, SG liquid mass, steam flow rate, reactor coolant letdown flow rate, flow rate to the cation demineralizer, letdown flow rate for boron control, SG blowdown flow rate, or SG moisture carryover) for both current and EPU conditions. To estimate an upper bound impact on offsite doses, the highest factor found for representative isotopes in any chemical group (including corrosion products) in either unit, pertinent to the release pathway was applied to the average doses previously determined as representative of operation at current conditions. This approach was utilized to estimate the maximum potential increase in effluent doses due to the EPU and to demonstrate that the estimated offsite doses following the EPU, although increased, will remain below the regulatory limits.

The impact of the EPU on solid radwaste generation was qualitatively addressed based on NUREG-0017, Revision 1 methodology, engineering judgment and the understanding of radwaste and affected plant system operation on the generation of solid radwaste.

The analysis concluded the following:

1. Expected Reactor Coolant Source Terms

Based on a comparison of current versus EPU input parameters, and the methodology outlined in NUREG-0017, Revision 1, the maximum expected increase in the reactor coolant source is approximately 12.9 percent for noble gases, 12.3 percent for I-131, and 12.2 percent for other long half-life activity. The above change is primarily due to the increase in effective core power level (~12.2 percent, i.e., 3030 MWt [power level conservatively analyzed for the uprate] / 2700 MWt [pre-uprate licensed power level]) and a minor reduction in reactor coolant mass (<1 percent) between current and EPU conditions.

2. Liquid Effluents

There is a maximum 12.2 percent increase in the radioactivity content of the liquid releases since input activities are based on long-term reactor coolant activity that is proportional to the core power uprate percentage increase, and on radwaste volumes that are essentially independent of power level within the applicability range of NUREG-0017. In the secondary coolant, halogens increased by a maximum of approximately 12.3 percent; thus this value is used to represent the halogen chemical class in the liquid releases and conservatively applied to the organ dose. It is noted however that halogens are a small contributor to liquid radwaste releases.

Tritium and non-halogen releases in liquid effluents are assumed to increase approximately 12.2 percent (corresponding to the effective core power uprate percentage) since the analysis is based on changes in an existing facility's power rating without changing its mode of operation. Thus, a 12.2 percent increase is applied to the whole body dose.

3. Gaseous Effluents

For all noble gases, there will be a bounding maximum 12.9 percent increase of radioactivity content in effluent releases due to the effective core power uprate percentage increase and a very slight decrease in primary coolant mass. Gaseous releases of isotopes with long half-lives such as Kr-85 will increase by approximately the percentage of power increase (~12.2 percent). Gaseous isotopes with shorter half-lives will have increases slightly more than the effective percentage increase in power level up to a bounding value of 13.2 percent.

Tritium releases in the gaseous effluents increase in proportion to their increased production (12.2 percent), which is directly related to core power and is allocated in this analysis in the same ratio as current releases.

The impact of the EPU on iodine releases is approximated by the effective core power level increase with the calculated increase in the I-131 concentration in the reactor coolant and secondary steam (includes the impact of EPU increase in the moisture carryover fraction), of 12.3 and 22.2 percent, respectively. The 22.2 percent would have been used as the limiting increase in thyroid doses due to iodine releases, but tritium is the controlling organ dose isotope (>70 percent) at the St. Lucie station.

For particulates, the methodology of NUREG-0017 specifies the release rate per year per unit per building ventilation system. This is not dependent on power level within the range of applicability. Particulates released via the turbine building due to leakage of main steam and air ejector exhaust are generally considered to be a small fraction of total particulate releases. Therefore, minimal change would be expected for the EPU operations. However, a conservative approach is dictated by the fact that the annual effluent release reports do not delineate the source of particulates or iodines released. In addition, at St. Lucie station, tritium is included in the category with iodines and particulates (radionuclides with half-lives greater than 8 days).

Particulates (Cs and Sr) released from the turbine building due to main steam leaks and air ejector exhaust, have been very conservatively estimated using a bounding multiplier. This multiplier of 9.89 is derived by using the SG design moisture carry over (MCO) fraction of 0.1 percent as the EPU value, and a previously measured MCO for the replacement SGs coupled with the 12.2 percent increase in reactor coolant inventory concentration. This creates the potential for a shift in the critical organ from thyroid (in which tritium and iodine are the principal contributors) to bone. While it is unlikely that the release from steam leakage is the controlling contributor, a bounding scaling factor approach is utilized to estimate the impact of the EPU.

4. Estimated Impact on Effluent Doses - Compliance with 10 CFR 50 Appendix I

LR **Table 2.10.1-1** shows that, based on operating history, the maximum estimated dose due to liquid and gaseous radwaste effluents following the EPU is significantly below the 10 CFR 50 Appendix I limits.

5. Solid Radioactive Waste

The volume of solid waste would not be expected to increase proportionally because the EPU neither appreciably impacts installed equipment performance, nor does it require significant changes in system operation or maintenance. The higher concentrations of radioactive species in process liquids and in the liquid radwaste system are an insignificant portion of the ionic or particulate load found in normal system fluids and therefore would not necessitate replacement of demineralizers or filters due to radioactive species loading. Any criteria related to surface dose rates on demineralizers or filters are not usually approached and, hence, again would not necessitate additional resin or filter changes in normal operation. Thus, only minor, if any, changes in waste generation volume are expected. However, it is estimated that the activity levels for most of the solid waste would increase

proportionately to the increase in long half-life coolant activity bounded by the 12.2 percent maximum increase.

Taking into consideration the average capacity factor during the 5-year evaluation period of 86.1 percent, and conservatively assuming a capacity factor of 1.0 following the EPU, the total long-lived activity contained in the waste following EPU is estimated to be bounded by approximately 14.2 percent (that is, 12.2 percent/0.861) over that currently stored on site. The direct shine dose from stored solid radwaste is discussed below under item 6.

6. Impact of EPU on Direct Shine

As noted in the St. Lucie Units 1 and 2 Annual Radioactive Effluent Report for 2007, "The results of direct radiation monitoring are consistent with past measurements for the specified locations. The exposure rate data show no indication of any trends attributed to effluents from the plant. The measured exposure rates are consistent with exposure rates that were observed during the pre-operational surveillance program," Thus, the annual direct shine dose due to plant operation during the pre-EPU 5-year period evaluated was deemed negligible.

For the EPU, the direct shine dose due to plant operation would increase by the increase percentage of the power level, that is, 12.2 percent. In addition, and in the long term, the direct shine dose contribution due to accumulation of stored solid radwaste, could increase by approximately 14.2 percent. A conservative bounding scaling factor of 14.2 percent would not change the estimated EPU direct shine dose, which would remain negligible.

7. Compliance with 40 CFR 190

The discussion that follows regarding compliance with 40 CFR 190 is provided for completeness even though, per the ODCM, compliance with the provisions of 10 CFR 50 Appendix I is adequate demonstration of conformance to the standards set forth in 40 CFR 190 regarding the dose commitment to individuals from the uranium fuel cycle.

The 40 CFR 190 whole body dose limit of 25 mrem to any member of the public includes: a) contributions from direct radiation (including sky shine) from contained radioactive sources within the facility, b) the whole body dose from liquid release pathways, and c) the whole body dose to an individual via airborne pathways.

Taking into consideration the estimated annual EPU doses and the negligible direct shine dose contribution, it is concluded that the 40 CFR 190 whole body dose limit of 25 mrem/yr, will not be exceeded by EPU.

2.10.1.2.4.3 Results

St. Lucie Unit 2 is required to meet the annual dose limits to an individual in an unrestricted area set by 40 CFR 190, 10 CFR 20 and 10 CFR 50 Appendix I. However, 10 CFR 50 Appendix I is the most limiting.

10 CFR 20 does have a release rate criterion that does not exist in 10 CFR 50 Appendix I, but the ODCM control actual performance and operation of installed equipment and releases thus maintaining compliance with that aspect of 10 CFR 20.

If the normal operation doses due to radioactive gaseous and liquid effluents either approach or exceed 10 CFR 50 Appendix I guidelines, the ODCM will ensure compliance with 40 CFR 190.

The EPU analysis demonstrates that the estimated doses will remain a small percentage of the allowable doses per 10 CFR 50 Appendix I (see LR [Table 2.10.1-1](#)). It is therefore concluded that following EPU, the liquid and gaseous radwaste effluent treatment systems, in conjunction with the procedures and controls provided by the ODCM, will remain capable of maintaining normal operation offsite doses within the regulatory requirements.

2.10.1.2.5 Ensuring that Occupational and Public Radiation Exposures Are ALARA

2.10.1.2.5.1 Introduction

As discussed in UFSAR Section 12.1.1, the health physics program complies with all federal and state regulations and ensures that the occupational radiation exposures are kept ALARA.

Implementation of the overall requirements of 10 CFR 50 Appendix I relative to utilization of radwaste treatment equipment to ensure that radioactive discharges and public exposure are ALARA is formalized via controls imposed by the ODCM.

2.10.1.2.5.2 Description of Analyses and Evaluations

As noted in UFSAR Sections 12.1.1 and 12.5.1, procedures and control within the radiation protection program govern all activities in restricted areas. Management commitment to the policy is reflected in the design of the plant, and the plant operation and maintenance procedures. As noted in UFSAR Section 12.5.2, the design of facilities including restricted areas is periodically reviewed by the health physics staff to ensure that provisions have been included to achieve as low as practicable exposures during maintenance, inservice inspection, refueling, and non-routine operations. The specific provisions are listed in UFSAR Section 12.1.2. In general, design features credited to support the commitment to ALARA exposure to plant personnel include shielding, which is provided to reduce levels of radiation; ventilation, which is arranged to control the flow of potentially contaminated air; an installed radiation monitoring system, which is used to measure levels of radiation in potentially occupied areas and measure airborne radioactivity throughout the plant; and respiratory protective equipment, which is used as prescribed by the radiation protection program.

Compliance with the requirements of the ODCM ensures that radioactive discharges and public exposure are ALARA.

The EPU assessments documented in LR [Sections 2.10.1.2.1](#) through [2.10.1.2.4](#) demonstrate that the dose limits imposed by regulatory requirements are met following the EPU. The EPU does not impact the effectiveness of the design features credited to support FPL's commitment to ALARA exposure to plant personnel. The intent of the ALARA procedures remain unchanged,

specifically, a) the allowable limits on plant personnel and public exposure and b) the intent to keep plant personnel and public exposure at a minimum.

2.10.1.2.5.3 Results

The review of the radiation protection program reveals that after EPU, the program will continue to be governed by the ALARA principle, as implemented by the ODCM, and as dictated by FPL management policy. As such, occupational and radiation doses to the public will continue to be maintained below regulatory guidelines after EPU and no additional steps are necessary to ensure that the dose increases are maintained ALARA.

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

As discussed above, health physics was determined to be outside the scope of License Renewal; therefore, with respect to the radiation protection program (health physics), the EPU does not impact any License Renewal evaluations.

2.10.1.4 Conclusion

FPL has assessed the effects of the proposed EPU on radiation source terms and plant radiation levels, the associated impact on shielding adequacy, radiation monitoring setpoints, post-accident vital area accessibility and normal operation radwaste effluents. FPL concludes that the evaluation adequately accounts for the effects of the proposed EPU on occupational and public radiation doses such that no additional steps are required to ensure that radiation doses will be maintained ALARA. Based on this, FPL concludes that the occupational and public radiation dose controls will continue to meet its current licensing basis with respect to the requirements of GDC-19; 10 CFR 20; 10 CFR 50 Appendix I; 40 CFR 190, and NUREG-0737 II.B.2. Therefore, FPL finds the proposed EPU acceptable with respect to radiation protection and ensuring that occupational and public radiation exposures will be maintained ALARA.

2.10.1.5 References

1. Letter from G. L. Johnston (FPL), Request for Additional Information Response Alternative Source Term Amendment – TAC Nos. MD6173 and MD6202, to NRC Document Control Desk dated March 18, 2008.
2. Letter from B. L. Mozifari (NRC), St. Lucie Unit 2 – Issuance of Amendment Regarding Alternative Source Term, Amendment No. 152 (TAC No. MD6202), to J. A. Stall (FPL) dated September 29, 2008.
3. Letter from K. N. Jabbour (NRC), St. Lucie Units 1 and 2 Re: Issuance of Amendments Regarding Elimination of Requirements for Post-Accident Sampling Systems, Amendment Nos. 174/114 (TAC Nos. MB0613 and MB0614), to T. F. Plunkett (FPL) dated March 27, 2001.

Table 2.10.1-1
Estimated Annual EPU Doses to the Public Due to Normal Operation Gaseous and Liquid Radwaste Effluents

Type of Dose	Appendix I Design Objectives (2 units)	Base Case @ 100% Capacity Factor Pre-EPU case	Scaled Doses EPU Case	Percentage of Appendix I Design Objectives Post-EPU
Liquid Effluents				
Dose to total body from all pathways	6 mrem/yr	2.89E-02 mrem/yr	3.24E-02 mrem/yr	0.54%
Dose to any organ from all pathways	20 mrem/yr	1.21E-01 mrem/yr (Lung)	1.36E-01 mrem/yr (Lung)	0.68%
Gaseous Effluents				
Gamma dose in air	20 mrad/yr	2.99E-03 mrad/yr	3.37E-03 mrad/yr	0.017%
Beta dose in air	40 mrad/yr	1.66E-03 mrad/yr	1.87E-03 mrad/yr	0.0047%
Dose to total body of an individual	10 mrem/yr	ODCM Control (1)	-	-
Dose to skin of an individual	30 mrem/yr	ODCM Control (1)	-	-
Radioiodines and Particulates Released to the Atmosphere				
Dose to any organ from all pathways	30 mrem/yr	2.45E-03 mrem/yr (Thyroid) (2)	6.94E-03 mrem/yr (Bone) (2)	0.023%
Notes: 1. Calculated doses do not apply to any ODCM Control. 2. For further explanation relative to the potential for a shift in the critical organ from thyroid to bone see explanation in LR Section 2.10.1.2.4 , item No. 3.				

2.11 Human Performance

2.11.1 Human Factors

2.11.1.1 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 Florida Power & Light (FPL) 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 extended power rate (EPU). FPL'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:

- General Design Criteria (GDC)-19,
- 10 CFR 50.120,
- 10 CFR 55, and
- Generic Letter (GL) 82-33.

Specific review criteria are contained in NRC Standard Review Plant (SRP) Sections 13.2.1, 13.2.2, 13.5.2.1, and 18.0.

St. Lucie Unit 2 Current Licensing Basis

As noted in UFSAR Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC GDC for Nuclear Power Plants as specified in Appendix A to 10 CFR 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The specific GDC for human factors is as follows:

- GDC-19 is described in UFSAR Section 3.1.19 Criterion 19 – Control Room.

A control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in safe condition under accident conditions, including loss of coolant accidents. Adequate radiation protection shall be provided to permit access and occupancy of the control room under accident conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent for the duration of the accident.

Equipment in appropriate locations outside the control room shall be provided (1) with a design capability for prompt hot shutdown of the reactor, including necessary instrumentations and controls to maintain the unit in a safe condition during hot shutdown, and (2) with a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

The control stations, switches, controllers and indicators necessary to operate or shut down the unit and maintain safe control of the facility are located in the control room.

The design of the control room permits safe occupancy during design basis accident conditions. The control room is isolated from the outside atmosphere during the initial period following the occurrence of an accident. The control room ventilation system recirculates control room air through HEPA and charcoal filters as discussed in UFSAR Sections 9.4.1 and 6.4. Radiation detectors and alarms are provided. Emergency lighting is provided as discussed in UFSAR Section 9.5.3.

Alternate local controls and local instruments are available for equipment required to bring the plant to and maintain a hot standby condition. It is also possible to attain a cold shutdown condition from locations outside of the control room through the use of suitable procedures.

The St. Lucie facility training program, which is maintained under the direction of the training manager, meets or exceeds the requirements and recommendations of Section 5.5 of ANSI/ANS 3.1-1978 and 10 CFR Part 55 and the supplemental requirements specified in Sections A and C of enclosure 1 of the March 28, 1980 NRC letter to all licensees, as outlined in Technical Specifications (TS) Section 6.4, Training.

NRC GL 82-33, Supplement 1 to NUREG-0737 Requirements for Emergency Response Capability, is discussed in UFSAR Section 1.9A.

Applicable procedures provide guidance on how FPL meets the requirements for training and qualification of nuclear power plant personnel as outlined in 10 CFR 50.120.

In addition to the UFSAR sections detailed above, human performance and human factors related elements are discussed in UFSAR Sections 7.7.3.1, HFE [Human Factors Engineering] Program; and 7.7.3.2, Detail Control Room Design Review Implementation.

As documented in NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, published September 2003, specific human factors are not within the scope of License Renewal.

2.11.1.2 Technical Evaluation

2.11.1.2.1 Introduction

Human factors engineering and human performance initiatives are foundational characteristics that help ensure that the plant operators can effectively and safely operate the facility as well as mitigate emergency conditions. When initiating a plant change, the modification process prompts completion of a human factors review checklist for changes that may impact the control room layout (alarms, indication, appearance or performance). In addition, plant operations staff has been represented and participated in EPU planning and modification development studies. To ensure changes associated with EPU do not introduce any unanticipated consequences, a review of the effects of those changes on human performance will be performed as part of the modification process.

A review of the emergency operating procedures (EOPs) and abnormal operating procedures (which are referred to as off-normal operating procedures (ONPs)) was conducted to determine the impact of EPU on EOP and ONP setpoints and identify any changes that are required. In

addition, a review was conducted of the EOP operator actions and times credited in the UFSAR Chapter 15 safety analyses, to determine if there is any impact as a result of EPU.

2.11.1.2.2 Description of Analysis and Evaluations

The NRC has developed a standard set of questions for the review of the human factors area. FPL has addressed these questions. The following are the NRC staff's questions and the FPL responses.

1. Changes in Emergency and Abnormal Operating Procedures

Describe how the proposed EPU will change the plant emergency and abnormal operating procedures.

Response

The existing EOPs and ONPs will continue to provide adequate guidance to cover the spectrum of anticipated events. The following procedure changes are intended to enhance operator response times and to incorporate physical plant changes resulting from EPU. In addition to the more significant items listed below, minor changes (typically setpoints) have been identified, and listed below, for several EOPs, ONPs, and other operating procedures.

Changes in EOPs and ONPs

The existing procedures provide adequate guidance to cover the spectrum of anticipated plant events. The EPU will result in changes to EOPs and ONPs to address changes in setpoints, alarm response setpoints and physical plant changes as a result of the EPU.

- Boric acid makeup tank requirements are changing due to increased boron concentration requirements for EPU. The combination of volume and boron concentration changes results in changes to the curves. This affects various ONPs.
- Although the TS minimum required condensate storage tank (CST) contained volume is unchanged for EPU, the allocation of the contained volume is changing. As a result, the CST level requirements are changing for cooling down to shutdown cooling (SDC) entry conditions
- Various I&C EPU modifications will affect the ONP load list. Procedure changes are required to include the new electrical loads.
- Main feedwater pump suction pressure alarm and automatic trip setpoints are changing as a result of the replacement of the main feedwater pumps to support EPU.
- Turbine drain valves cycle on cross over steam pressure (from high pressure (HP) to low pressure (LP) turbines). Due to changes in MWt power level and condenser backpressure values, this setpoint is changing.
- The existing setpoint for loop ΔT is increasing. This setpoint is used in conjunction with other indications, to assess the status of single phase liquid natural circulation flow in at least one reactor coolant system (RCS) loop.

- 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 EOP and ONP safety injection delivery curves require revision to reflect the high pressure safety injection (HPSI) accident analysis pressure reference point. The associated flow delivery curves will be revised consistent with the assumptions of the accident analysis.
- The time to boil is decreasing as a result of the EPU. This is due to an increase in decay heat in the core following a trip from a higher rated thermal power (RTP) associated with the EPU.
- The RCS makeup flow for boiloff versus time after shutdown will increase as a result of the EPU. This is due to the increased decay heat in the core as a result of the higher RTP from the EPU and leads to decreased time to boiling.

Fire protection actions will remain unchanged. For discussion, see LR [Section 2.5.1.4](#), Fire Protection.

Conclusion

The changes to EOPs and ONPs as a result of the EPU do not significantly impact operator actions and mitigation strategies. The changes will be appropriately proceduralized and the operators will receive appropriate classroom and/or simulator training for implementation.

2. Changes to Operator Actions Sensitive to Power Uprate

Describe any new operator actions needed as a result of the proposed EPU. Describe changes to any current operator actions related to emergency or abnormal operating procedures that will occur as a result of the proposed EPU.

Identify and describe operator actions that will involve additional response time or will have reduced time available. The response should address any operator workarounds that might affect existing response times. Identify any operator actions that are being automated or being changed from automatic to manual as a result of the power uprate. Provide justification for the acceptability of these changes.

Response

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. Any newly installed instruments or components required to support the EPU will be implemented in accordance with approved plant procedures and processes. Applicable procedures 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 ensure that each change is fully reviewed and approved by station and operations personnel prior to implementation.

The UFSAR Chapter 15 safety analyses were reviewed to identify potential changes to credited EOP operator action times. Changes identified include the following.

- In the event of a total loss of feedwater (TLOFW); a new step sequence is being implemented for securing all four reactor coolant pumps (RCPs). The step to secure all four RCPs in a TLOFW is being moved to earlier in the event to conserve steam generator (SG) inventory. 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.
- In the event of a steam generator tube rupture (SGTR); the current analysis requires isolation of the affected SG and opening of the atmospheric dump valve associated with the affected SG within 30 minutes. The EPU analysis supports a revised action time of 45 minutes.

There are no changes to operator workarounds or operator actions that are being automated or changed from automatic to manual, as a result of EPU.

Conclusion

The changes in operator actions related to EPU are not significant, and established change processes will provide an adequate implementation strategy. The changes do not significantly impact normal operator actions or off-normal event mitigation strategies. The changes will be appropriately proceduralized and the operators will receive formal classroom and simulator training for their implementation.

3. Changes to Control Room Controls, Displays and Alarms

Describe any changes the proposed EPU will have on the operator interfaces for control room controls, displays, and alarms. For example, what zone markings (e.g. normal, marginal and out-of-tolerance ranges) on meters will change? What set points will change? How will the operators know of the change? Describe any controls, displays, alarms that will be upgraded from analog to digital instruments as a result of the proposed EPU and how operators will be tested to determine they could use the instruments reliably.

Response

Changes resulting from the proposed EPU on operator interfaces for control room controls, displays, setpoints, and alarms will be implemented in accordance with approved plant procedures and processes, such as the modification process, including the human factors engineering review. These processes ensure that training affected or augmented by the EPU is addressed, including how operators will be tested to determine that they could use the instruments reliably.

Changes to control room controls and displays will not be extensive and will generally include calibration and/or rescaling loops for identified instrumentation. There will also be changes to several control board and computer alarms and limited changes to plant control systems.

Modifications discussed in this section have a significant impact on human factors; see LR [Section 2.12](#) for a complete list of planned modifications.

Below is a summary of the changes identified (refer to LR [Section 2.4.1](#), Reactor Protection, Safety Features Actuation and Control Systems):

a. Leading Edge Flowmeter (LEFM)

- The Cameron LEFM CheckPlus™ system will be installed as part of the EPU to provide accurate determination of main feedwater flow. Top level LEFM output data (i.e., calculated feedwater flow, feedwater temperature, and system status) will be integrated into existing computer system secondary calorimetric displays and calorimetric power calculations to provide a primary operator interface that meets applicable human factors design criteria. The installed LEFM system will include redundant touch screen displays providing ready access to the LEFM data. These displays will be located in the control room (behind the main control boards) and will support a more detailed periodic investigation of LEFM system status and review of system diagnostic parameters.

b. The following instrument loops are affected by the EPU (calibration range, setpoint transmitter changes and/or scaling):

- Feedwater flow – The range of the various feedwater flow channels will be increased to accommodate the higher EPU flow rates. Those instrument channels with an existing 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.
- Main steam flow – 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.
- Turbine steam chest pressure –The HP turbine is being replaced and turbine steam chest pressure is changing. Pressure sensing lines are being modified for the replacement turbine. Associated control systems (digital electro-hydraulic (DEH) and reactor regulating system) will be rescaled, as necessary.
- Feedwater 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 feedwater pumps.

c. Annunciator Response Procedures Will Require Revision as a Result of Setpoint Changes

- Annunciator response procedures will be revised as necessary to reflect new operating parameters and instrument channel rescaling as described above.

d. Plant Computer Setpoints Will Change

- Plant computer setpoints will be revised as necessary to reflect new operating parameters and instrument channel rescaling as described above.

e. Changes to Controls and Control Systems

Refer to LR [Section 2.4.1](#), Reactor Protection, Safety Features Actuation and Control Systems, for a more detailed description of control system changes.

- Feedwater Control System Changes
 - Range changes for main steam and feedwater flow, scaling changes to reflect replacement feedwater pump performance and feedwater control valve C_v curves, and improvements to transition logic between main feedwater control valves and low power control valves designed to minimize loss of SG inventory following a turbine trip.
- Steam Bypass Control System (SBCS)
 - 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.
- Leading Edge Flow Meter
 - The existing feedwater flow is measured using venturi differential pressure signals as part of the distributed control system (DCS). To support EPU, the existing DCS is being modified to use newly installed LEFMs, which provide alternate feedwater flow inputs. The LEFM system status will be communicated via dedicated alarms and displays, and it will provide alarms for degraded and/or inoperable modes.
- 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.
- Moisture Separator Reheater (MSR) and Feedwater Heater 5A/B Level Controls
 - The existing pneumatic controls for MSR and high pressure feedwater heater 5 level controls are being replaced with electronic instruments. The existing backup level switch control functions will not be changing.

Balance of Plant (BOP) Instrumentation and Controls Results

The changes to instrument ranges and/or setpoints for BOP instruments will not change any instrument loop design functions. Additionally, the quantity and types of process instrumentation provided, ensures a safe and orderly operation of the plant. The changes will not affect separation, redundancy, or diversity of the instrumentation and controls discussed above.

Conclusion

The operators will be provided detailed training related to the above EPU modifications and resulting control board and procedure changes. Additionally, EPU station modification packages are reviewed for impact on operations and classroom and simulator training is developed and implemented, where appropriate. The initial plant startup of the uprated plant will be implemented as an infrequently performed test or evolution and will be controlled by the power ascension testing plan described in LR [Section 2.12.1](#), Approach to EPU Power Level and Testing.

4. Changes on the Safety Parameter Display System

Describe any changes to the safety parameter display system resulting from the proposed EPU. How will the operators know of the changes?

Response

The plant computer emergency response data acquisition and display system (ERDADS), also referred to as the safety parameter display system (SPDS), and safety assessment system (SAS) is described in UFSAR Appendix 7.5A. Plant process computer system inputs that are affected by instrumentation scaling changes will be modified during the implementation phase of the EPU following station procedures and processes. However, the plant computer safety assessment functions as described in UFSAR Appendix 7.5A and Section 7.7.3 will not change as result of the EPU.

Changes identified for the SPDS will be captured through the normal procedure revision process, modification process, and operator training on plant modifications.

Range and/or setpoint changes to the SPDS parameters:

- Normal core full power ΔT , and
- T_{hot} minus T_{cold} .

Conclusion

These minor changes will be addressed by the normal processes with operations involvement in the modification process, procedure change reviews and operator training program modification training.

5. Changes to the Operator Training Program and the Control Room Simulator

Describe any changes to the operator training program and the plant referenced control room simulator resulting from the proposed EPU, and provide the implementation schedule for making the changes.

Response:

The existing licensed/non-licensed operator training programs ensure that adequate training is provided for significant plant modifications prior to implementation as appropriate. Training will focus on TS changes, procedure changes, EPU modifications, and power ascension testing. Training will be initiated during the training cycle associated with the EPU modifications prior to implementation. Prior to this time, licensed/non-licensed operator training will focus on a general overview of the uprate modifications and then training on specific topics such as the turbine upgrade and other topics. Comprehensive training of the modification scope will be performed and will include classroom and simulator training. The operators will be able to demonstrate understanding of the integrated plant response on the simulator. Just-In-Time Training (JITT) will be provided to the operators during the refueling outage prior to the EPU plant initial startup. This JITT will also cover the power ascension startup testing plan both in classroom and on the simulator, as appropriate.

Plant uprate modifications will be reviewed to determine impact on the simulator. Changes to the simulator modeling will be incorporated into the simulator, on a schedule established to meet the operator training program requirements. The current plant simulator configuration will remain unchanged and available for operator training. Status of the simulator configuration will be controlled through the established training process. The control board hardware changes and associated indications and replacement of indications with revised scaling, will also be scheduled to accommodate the training program requirements.

Additionally, operators will be involved in the continuing modification review process, providing operational input and gaining knowledge of the required plant changes. Changes, especially to the normal, emergency, and abnormal operating procedures as well as other off normal procedures, will be reviewed and validated. These activities will help provide a solid foundation for operator understanding and interaction during the formal EPU training sessions.

Conclusion:

EPU results in a significant number of plant modifications which will generate changes to TS, operations, maintenance, and testing procedures, as well as training simulator and training lesson plans. Training for implementation of the EPU modifications will be accomplished in accordance with the FPL training program.

Results

The results of the EPU human factors review show that changes to plant procedures, when prepared in accordance with the current procedure change control process, will not alter the

basic mitigation strategies with which the operators are familiar. Changes associated with instrument scaling and setpoints, if any, will not introduce a level of complexity that would lead to misunderstanding the parameter. Operator training will provide effective reinforcement of procedure and plant physical changes as well as build proficiency with the required operator action changes.

2.11.1.3 Conclusion

FPL has reviewed the changes to operator actions, human-system interfaces, procedures, and training required for the proposed EPU and concludes that FPL 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. FPL further concludes that St. Lucie Unit 2 will continue to meet its current licensing basis with respect to the requirements of GDC-19, 10 CFR 50.120, and 10 CFR Part 55 following implementation of the proposed EPU. Therefore, FPL finds the 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

2.12.1.1 Regulatory Evaluation

The purpose of the extended power uprate (EPU) test program is to demonstrate that systems, structures, and components (SSCs) will perform satisfactorily in service at the proposed EPU power level. The test program provides additional assurance that the plant will continue to operate in accordance with design criteria at EPU conditions. The Florida Power and Light (FPL) review included an evaluation of:

- plans for the initial approach to the proposed maximum licensed thermal power level, including verification of adequate plant performance,
- 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 NRC's acceptance criteria for the proposed EPU test program are based on 10 CFR 50, Appendix B, Criterion XI, which requires establishment of a test program to demonstrate that SSCs will perform satisfactorily in service.

Specific review criteria are contained in Standard Review Plan (SRP) Section 14.2.1.

St. Lucie Unit 2 Current Licensing Basis

As noted in Updated Final Safety Analysis Report (UFSAR) Section 3.1, the design bases of St. Lucie Unit 2 conforms with the NRC General Design Criteria (GDC) for Nuclear Power Plants as specified in Appendix A to Title 10 of the Code of Federal Regulations (10 CFR) Part 50 effective May 21, 1971 and subsequently amended July 7, 1971 and February 12, 1976. St. Lucie Unit 2 fully satisfies and is in compliance with the GDC as discussed in UFSAR Section 3.1.

The St. Lucie Unit 2 initial startup test program was described in the original FSAR Chapter 14. The initial startup test program was found to be acceptable by the NRC, as documented in Section 14 of the St. Lucie Unit 2 Safety Evaluation Report (SER) ([Reference 1](#)) and Section 14 of SER Supplement 4 ([Reference 2](#)).

After the operating characteristics of the reactor and plant had been verified by low power tests, a program of power escalation in successive stages was undertaken to bring the plant to its full rated power level (2560 megawatts thermal (MWt)). Both reactor and plant operational characteristics were closely examined at each stage before escalation to the next programmed level was affected. The first escalation was to approximately 20 percent reactor thermal power. Succeeding levels were at approximately 50 percent, 80 percent, and 100 percent reactor thermal power.

The results of the startup and power ascension testing program were reported to the NRC in the St. Lucie Unit 2 Startup Report dated November 1, 1983 ([Reference 3](#)). The NRC reviewed the

report and found the testing to be acceptable when issuing License Amendment 34 in the letter dated September 13, 1988 ([Reference 4](#)).

Amendment 9 to the operating license ([Reference 5](#)) was issued on March 1, 1985, which authorized an increase in the plant output from 2560 to 2700 MWt.

In addition to the licensing basis described in the UFSAR, the power ascension testing was evaluated for St. Lucie Unit 2 License Renewal. As documented in NUREG-1779, Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2, dated September 2003, the power ascension testing was determined to be outside the scope of License Renewal.

2.12.1.2 Technical Evaluation

2.12.1.2.1 Introduction

FPL is proposing an EPU to increase the licensed core thermal power to 3020 MWt. This uprate involves changes to the plant configuration to accommodate the higher reactor power limit, as well as the larger steam and feedwater (FW) flows commensurate with the power increase. As a result of these changes, testing is required to ensure that the plant will be operated safely in its uprated condition.

2.12.1.2.2 Background

The proposed EPU will result in the reactor operating at a new core thermal power of 3020 MWt. The current licensed core thermal power is 2700 MWt. St. Lucie Unit 2 has significant operating experience at its current operating conditions. St. Lucie Unit 2 is a Combustion Engineering (CE) design with two steam generators (SGs) and four reactor coolant pumps (RCPs). A power nearly identical to the proposed EPU level has been successfully achieved through an EPU by a similar CE design plant, Arkansas Nuclear One, Unit No. 2 (ANO-2), with no adverse effects. Additionally, a power higher than the proposed EPU level has been successfully achieved through an EPU by another CE design plant, Waterford 3, also with no adverse effects. For both St. Lucie Unit 2 and Waterford 3, Siemens is the supplier for the upgraded turbine to accommodate the increased steam flow.

In a pressurized-water reactor (PWR), the biggest change in system operating parameters due to an EPU occurs in the secondary side where mass flow is increased commensurate with the uprate. Minor changes occur in primary side temperatures to provide additional heat transfer in the SGs. The main steam and condensate/FW flows will increase by approximately 12 percent. Both reactor coolant operating cold leg best-estimate temperature and hot leg best-estimate temperature will be increased from 548.5°F to 551°F and 595°F to 602.6°F, respectively. SG outlet nozzle best-estimate pressure is 882 psia for EPU which is very close to current operation.

In order to accommodate this new thermal power, changes in plant operating parameters will occur. However, it has been found that the fundamental operating characteristics of an uprated plant remain consistent with the operating characteristics prior to the uprate. This is consistent with other similar units that have been uprated. Pre-uprate plant operating experience and industry operating experience provide valuable insight to the viability of a plant uprate. This

operating experience will be incorporated into the implementation details of the proposed test plan and into the controlling procedures.

Several plant modifications are required to support power operation at the proposed uprated core thermal power. Post-modification testing will be performed to ensure proper installation. A list of the significant plant modifications and the post-modification testing planned for these modifications is provided in LR [Table 2.12-3](#). Analyses and evaluations were performed for the Condition I operating transients and Condition II trip transients. (See LR [Section 2.12.1.2.6](#) for definitions of these conditions.) The results of these analyses are used, in part, in lieu of large transient testing to verify that the plant systems are capable of performing safely in the uprated condition.

The EPU power ascension test plan will 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. Comparison will be made between past operating data and the data that will be gathered during the uprate testing to ensure that the results are acceptable. Additionally, St. Lucie Unit 2 has extensive years of operating experience at the current licensed power level such that system interactions are well known. ANO 2 has uprated to a core thermal power (a 7.5 percent uprate to 3026 MWt) that is nearly identical to the St. Lucie Unit 2 EPU power level (3020 MWt) and has operated successfully at the new power for over seven years. Waterford 3 has uprated to a core thermal power (an 8.0 percent uprate to 3716 MWt) that is higher than the St. Lucie Unit 2 EPU power level (3020 MWt) and has operated successfully at the new power for over four years.

The test plan is based on industry operating experience pertaining to power uprate and has used this experience 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. As one example, FPL has learned valuable lessons from the industry regarding vibration and vibration monitoring.

In summary, the proposed EPU power ascension test plan is comprised of a mixture of power ascension monitoring, post-modification testing, and analytical evaluation to ensure that the plant can operate safely at its new uprated core thermal power. The following sections describe how the proposed EPU test program provides adequate assurance that the plant will operate in accordance with design criteria and that SSCs affected by the proposed EPU, or modified to support the proposed EPU, will perform satisfactorily in service.

2.12.1.2.3 Power Ascension Test Plan

2.12.1.2.3.1 General Discussion

The development of the power ascension test plan was based on the review of information from various sources, including:

- Chapter 14 sections 14.2.12.2, 14.2.12.3, and 14.2.12.4 of the original FSAR,
- St. Lucie Unit 2 Startup Report ([Reference 3](#)),
- Outputs of various system and integrated plant analyses performed in support of the EPU,

- Testing normally performed during power ascension following refueling,
- EPU test programs proposed and performed at other plants, with emphasis on recent PWR EPU implementations, and
- Planned EPU modifications.

The primary focus of the power ascension test plan includes:

- Technical Specification (TS) surveillance testing - An example is nuclear and ΔT power calibration,
- Normal startup testing - An example is power distribution monitoring,
- Additional power ascension testing judged necessary to support acceptance of the proposed EPU. An example is vibration monitoring, and
- Post-modification testing of required plant modifications.

The EPU power ascension test plan was developed to verify the following:

- Plant systems and equipment affected by EPU are operating within design limits,
- Nuclear fuel thermal limits are maintained within expected margins and the core is operating as designed,
- Control systems maintain stability and operation within acceptable limits,
- Instrument adjustments, including cases where at-power data is required, are consistent with EPU operating conditions,
- System radiation levels are acceptable and stable, and
- Flow induced piping vibration is within acceptable limits.

2.12.1.2.3.2 EPU Power Ascension Test Plan and Test Plateaus

During the EPU start-up, power will be increased in a slow and deliberate manner, stopping at pre-determined power levels for steady-state data gathering and formal parameter evaluation. These pre-determined power levels are referred to as test plateaus. The typical post-refueling power plateaus will be used until the current licensed full power condition (2700 MWt) is attained at approximately 89 percent of the EPU full power level (3020 MWt). Above this power level, smaller intervals between test plateaus will be established, with a concurrent higher frequency of data acquisition. A summary of the power ascension test plan is provided in LR [Table 2.12-1](#).

Prior to exceeding the current licensed core thermal power of 2700 MWt, the data gathered at the pre-determined power plateaus, as well as observations of the slow, but dynamic power increases between the power plateaus, will allow verification of the performance of the EPU modifications. The steady-state data collected at approximately 89 percent power is especially significant because this test plateau corresponds to the current full power level of 2700 MWt. Data collected at this plateau will form a basis of comparison for data collected at higher plateaus.

Once testing is complete at approximately 89 percent of EPU power (2700 MWt), power will be slowly and deliberately increased through four additional test plateaus, each differing by approximately 3 percent of the EPU rated thermal power. 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. LR

[Section 2.12.1.2.3.3](#) provides additional discussion of acceptance criteria.

Following each increase in power level, test data will be evaluated against its performance acceptance criteria and expected values (i.e., design predictions or limits). If the test data satisfies the acceptance criteria and expected values then system and component performance will be considered to have complied with their design requirements.

In addition to the steady-state parameter data gathered and evaluated at each test condition, the dynamic parameter response data gathered during the ascension between test plateaus will also be evaluated. This will demonstrate overall stability of the plant.

Hydraulic interactions between the new main FW pumps and SG flow control valves, as well as the impact of the higher main FW flow, will be monitored and evaluated. Individual control systems, such as SG level control and FW heater drain level control, will be optimized for the new conditions as required. The tests will adequately identify any unanticipated adverse system interactions and allow them to be corrected in a timely fashion prior to full power operation at the uprated conditions.

The EPU power ascension test plan 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. LR [Table 2.12-1](#) provides a summary of the power ascension test plan.

2.12.1.2.3.3 Acceptance Criteria

The acceptance criteria for the power ascension test plan will be established as discussed in Regulatory Guide (RG) 1.68, Initial Test Programs for Water-Cooled Nuclear Power Plants. Criteria will be provided against which the success or failure of the test will be judged. In some cases, the criteria will be qualitative. Where applicable, quantitative criteria will have appropriate tolerances.

If an acceptance criterion is not satisfied, the power ascension will be stopped and the plant will be placed in a condition that is judged to be safe based upon prior testing. The power ascension test procedure and TS, where applicable, will provide direction for actions to be taken to assure the plant is safe and stable. Resolution of the issue that resulted in criterion failure will be resolved by equipment changes or through engineering evaluation, as appropriate. Following resolution, the applicable test portion may need to be repeated to verify that the criterion is satisfied.

Although not strictly acceptance criteria as discussed above, expected values will be provided for various plant functions and parameters that are not safety significant. If expected value tolerances are not met, the power ascension test plan may continue. Investigation of the issue that resulted in exceeding the expected value tolerance may continue in parallel with the power ascension. These investigations will be handled by existing plant processes and procedures.

Specific acceptance criteria and expected values will be established and incorporated into the power ascension test procedures.

2.12.1.2.3.4 Vibration Monitoring

A piping and equipment vibration monitoring program, including plant walkdowns and monitoring of plant equipment, will be established to ensure that any steady-state flow induced piping vibrations following EPU implementation are not detrimental to the plant, piping, pipe supports, or connected equipment.

Observed piping vibrations will be evaluated to ensure that vibration-induced damage will not occur. The predominant way of assessing these vibrations is to monitor the piping during the plant heat up and power ascension. The methodology to be used for monitoring and evaluating this vibration will be in accordance with ASME OM-S/G-2007, Standards and Guides for Operation and Maintenance of Nuclear Power Plants, Part 3, Requirements for Preoperational and Initial Startup Vibration Testing of Nuclear Power Plant Piping Systems ([Reference 6](#)).

The scope of the piping and equipment vibration monitoring program includes any accessible lines that will experience an increase in their process flow rates. Any branch lines attached to these lines (experiencing increased process flows) will also be monitored as experience has shown that branch lines are susceptible to vibration-induced damage. The scope of the program includes the following systems:

- Main steam (outside of containment),
- Feedwater (outside of containment),
- Condensate,
- Heater drain and vent, and
- Extraction steam (and turbine generator gland seal and exhaust).

The main steam and FW piping inside containment is not readily accessible for performing vibration monitoring during power ascension. This piping inside containment is not considered to be a target area for the following reasons:

- The main steam and FW piping is well supported and seismically designed,
- The piping is large diameter, not overly flexible, with large diameter bends and few elbows,
- There are no long cantilever branch lines or branch lines with heavy unsupported valves,
- Operating experience from other PWRs for EPU and power uprate licensed power levels, which have similar piping and support designs, have not identified a history of vibration problems with these lines, and
- Review of operating experience at recent EPU and power uprate stations has not identified any significant vibration in these systems inside containment which would have been a safety or failure concern.

Reactor coolant system (RCS) piping is not included in the scope of this vibration monitoring program, as the system does not experience a significant change in flow due to the uprate. There

may be minor RCS mass and volumetric flow changes, depending on location, due to density distribution changes.

The program scope will include any lines or equipment within the monitored systems that have been modified or otherwise identified through the condition report system as having already experienced vibration issues.

The piping and equipment within the scope of the vibration monitoring program will be observed at several different plant operating conditions. The first observations will be conducted prior to the shutdown in which the EPU will be implemented. Data from these observations will be used to develop a list of priorities and baseline data for observation during the subsequent power escalation.

Subsequent observations will take place at each EPU test plateau, as described in LR [Section 2.12.1.2.3.2](#). By comparing the observed pipe vibrations / displacements at various power levels with previously established acceptance criteria, potentially adverse pipe vibrations will be identified, evaluated and resolved prior to the occurrence of detrimental effects.

2.12.1.2.3.5 Transient and Dynamic Tests

FPL has reviewed Section 14.2.1 of the Standard Review Plan. As a result of this review, and a review of the original startup test program, FPL concludes that no large load transient tests need to be performed as part of the EPU test program. LR [Section 2.12.1.2.7](#) provides the justification for not performing the large load transient tests.

The following transient or dynamic testing will support the proposed EPU. These evolutions will help verify that no new adverse system interactions have been introduced to plant systems as a result of the EPU or the associated modifications.

Turbine Overspeed Trip

Once a steady-state power of approximately 10 percent to 15 percent EPU rated power has been reached, a planned turbine overspeed trip will be performed. With the majority of power being routed to the main condenser via the steam bypass control system (SBCS), the turbine will be accelerated until its speed causes an actuation of an overspeed trip. This test will verify the proper performance of the turbine overspeed trip function. It will verify proper operation of the turbine valves and verify expected plant performance subsequent to the turbine trip. Performance of plant control systems, such as steam bypass control valves, will be monitored in response to the transient.

Main Feedwater System Transient Monitoring

The modifications associated with EPU include replacement of the main FW pumps and SG flow control valve trim. Main FW system response will be monitored during power ascension. This includes the transition from the 15 percent bypass valves to the SG flow control valves, the start of the second condensate pump, the start of the second main FW pump, closure of the recirc valve for the second main FW pump, and start of the heater drain pumps.

2.12.1.2.4 Comparison of EPU Power Ascension Test Plan to the Initial Plant Test Program

LR [Table 2.12-2](#) provides a comparison of the original plant start-up testing to the EPU power ascension test plan. The table lists tests performed during original power ascension, regardless of the power level at which they were performed. The table contains all items from original FSAR Sections 14.2.12.2, 14.2.12.3, and 14.2.12.4 as well as an additional at-power test documented in the St. Lucie Unit 2 Startup Report.

The first column of LR [Table 2.12-2](#) lists the original FSAR section item number or reference to the Startup Report. The second column of LR [Table 2.12-2](#) lists the test and conditions based on original FSAR sections 14.2.12.2, 14.2.12.3, and 14.2.12.4. Clarification for the test conditions is provided where necessary. For tests not included in the original FSAR, this column lists the test description, conditions, and section from the Startup Report.

The third column of LR [Table 2.12-2](#) specifies whether the testing activity will be replicated as part of the power ascension test plan. A 'Yes' indicates that testing should be performed to validate plant performance as a result of EPU. The testing performed may or may not be the original power ascension test, but will validate proper plant performance. A 'No' indicates testing need not be performed as a result of EPU, but does not necessarily mean that such testing will not be performed following the refueling outage (e.g., low power physics testing as discussed below).

The fourth column of LR [Table 2.12-2](#) lists the objective of the Initial Startup Test based on original FSAR sections 14.2.12.2, 14.2.12.3, and 14.2.12.4. For tests not included in the original FSAR, this column lists the objective based on the test purpose from the Startup Report.

The fifth column of LR [Table 2.12-2](#) provides explanations/justifications. Cross references are given where more details are needed for the justification. In some cases, clarification is provided for testing which will be performed. This table provides the justification for why the test activity is not performed (if it is not performed).

Reactor core physics testing was a significant portion of the original startup program. Since that time, physics testing has been required after every refueling because the reactor core has been modified. The purposes of this testing are to verify the core is consistent with design, to satisfy TS, and to adjust related instrumentation. This requirement is not changed by EPU. Physics testing has evolved since Cycle 1 for both low power and at-power conditions. Many of the original physics tests are not included today. Current testing methodology and scope are consistent with the industry standard ANS-19.6.1, Reload Startup Physics Tests for Pressurized Water Reactors ([Reference 7](#)). This standard specifies the minimum acceptable startup reactor physics test program to determine if the operating characteristics of the core are consistent with the design predictions, which provides assurance that the core can be operated as designed.

Low power physics testing (e.g., isothermal temperature coefficient, all-rods-out critical boron concentration) will be performed during startup from refueling prior to the EPU power ascension consistent with ANS-19.6.1 and normal FPL practices. This activity will be completed prior to exceeding 5 percent reactor power. No additional low power physics testing is required specifically for EPU. For those reasons, items related to low power physics testing are marked 'No' in the third column of LR [Table 2.12-2](#). This is true for low power physics tests performed

after every refueling, as well as original startup low power physics tests that are no longer performed.

At-power physics testing for the EPU power ascension will include the same tasks as a typical post-refueling power ascension. These tasks include:

- Core power distribution monitoring,
- Power indication calibration,
- Linear power range channel calibration,
- Shape annealing factor evaluation, and
- Critical boron check.

For this group of activities, monitoring, calibration checks, and the potential for adjustments are expanded for EPU due to the extra planned test plateaus and due to the fact that the plant is ascending to 3020 MWt for the first time. For those reasons, these activities are included in the test plan shown on LR [Table 2.12-1](#). Related activities from the original startup test program are marked 'Yes' in the third column of LR [Table 2.12-2](#).

Taken together, the planned low power and at-power physics testing program is adequate to verify the core is consistent with design, to satisfy TS, and to adjust related instrumentation as necessary. The following original at-power physics tests are not needed to achieve this goal, are marked 'No' in the third column of LR [Table 2.12-2](#), and will not be performed for EPU:

- At-power moderator temperature coefficient and power coefficient test, and
- Forced Xenon oscillation test.

2.12.1.2.5 Post-Modification Testing Requirements

Plant modifications will be implemented in order to achieve the EPU rated power and will comply with 10 CFR 50 Appendix B, Criterion XI. The paragraphs below address the following modification topics:

- Modification control,
- EPU planned modification status,
- EPU modification implementation schedule, and
- EPU modification testing.

Plant modifications are controlled by administrative procedures. These procedures provide configuration control, installation instructions, and testing requirements. Post-modification testing verifies satisfactory performance of the modification in accordance with the design documentation. The performance of post-modification testing is addressed by existing programmatic controls. Functional and operational post-modification testing will be performed as necessary for each modification to verify satisfactory installation and performance.

The modifications identified in LR [Table 2.12-3](#) constitute planned actions on the part of FPL. The final design of the modifications is not complete. As such, this list is not a formal commitment to implement the modifications and testing exactly as identified.

Implementation of EPU modifications is planned for refueling outage SL 2-19 (Fall 2010) and refueling outage SL 2-20 (Spring 2012). Power ascension to the EPU operating condition of 3020 MWt reactor power is planned to follow refueling outage SL 2-20. Post-modification testing will take place during the outage or during post-outage power ascension in which the modification is implemented. For modifications implemented in outage 2-19, additional monitoring or testing will be performed, where necessary, at the higher EPU power levels following the EPU implementation outage. Significant modifications are listed in LR [Table 2.12-3](#).

Construction, installation, and/or pre-operational testing for each modification will be performed in accordance with the plant design process procedures and much of this testing is not listed in LR [Table 2.12-3](#). In most cases, the tests listed are final acceptance tests that will demonstrate the modifications will perform their design function and integrate appropriately with the existing plant. Much of the at-power modification testing, particularly parameters monitored during power ascension, will be covered by the data collection and walkdown activities of LR [Table 2.12-1](#). For modifications with more extensive testing requirements, modification testing is shown explicitly on LR [Table 2.12-1](#).

2.12.1.2.6 Transient Analytical Methodology

The American Nuclear Society (ANS) classification of plant conditions divides plant conditions into four categories in accordance with anticipated frequency of occurrence and potential radiological consequences to the public. The conditions are:

- Condition I - Normal operation and operational transients,
- Condition II - Incidents of moderate frequency,
- Condition III - Infrequent faults, and
- Condition IV - Limiting faults.

Condition I Initiating Events and Condition II Trip Transients

Analyses were performed for EPU using the CENTS computer code for the Condition I operating transients and Condition II trip transients. The CENTS computer code is a system-level program that models the overall nuclear steam supply system (NSSS), including the detailed modeling of the control and protection systems. As discussed in LR [Section 2.4.2](#), the CENTS code was used for the analysis of design basis transients at EPU conditions. Since the analyses provide insights into plant response at EPU conditions, the results of the analyses were used, in part, as the basis for the justification of the elimination of certain transient testing included in the original at-power startup test program. The CENTS code is not a part of the current licensing basis, but is a NRC approved code that is acceptable for analyzing operational transients for CE designed PWRs. The CENTS computer code is described in Westinghouse Owners Group Topical Report WCAP-15996-P-A, Revision 1, Technical Description Manual for the CENTS Code, ([Reference 9](#)).

CENTS has been used on other CE designs. Waterford 3, a CE design similar to St. Lucie Unit 2, adopted the CENTS code for performance of transient analyses as part of EPU. As documented in the January 29, 2004 letter from Entergy to the NRC, W3F1-2004-0004 ([Reference 10](#)), CENTS has been used for transient evaluation on other CE designs including San Onofre Nuclear Generating Station Units 2 and 3, ANO-2, and Palo Verde Nuclear Generating Station Units 1, 2, and 3. As documented in the CENTS Topical Report CENPD-282-P-A, the NRC safety evaluation for the CENTS code concluded CENTS is “acceptable for referencing in licensing actions with respect to the calculation of non-LOCA transient behavior in PWRs.”

CENTS was benchmarked with operating data in order to refine the EPU model. The following St. Lucie transients were used in the benchmarking process:

- Unit 2 manual reactor trip from 100 percent power on June 4, 2008 following a loss of a main FW pump, and
- Unit 2 manual reactor trip from 100 percent power on June 7, 2008 following a condensate pump trip.

In addition, Unit 1 and Unit 2 are very similar with respect to overall plant design and behavior of NSSS control systems. The above Unit 2 events were used in the benchmarking process for the Unit 1 CENTS model with excellent results. The Unit 1 CENTS model was also benchmarked against specific Unit 1 events, including non-trip operational transients. Since the Unit 2 CENTS model is similar to the Unit 1 CENTS model, the Unit 1 CENTS benchmarking supports validation of the Unit 2 CENTS model.

A CENTS model base deck was developed at the EPU conditions. The model was built to incorporate the applicable EPU equipment modifications and setpoint changes as well as the EPU operating conditions. The specific EPU modifications modeled in the CENTS transient analyses are identified by the fifth column in LR [Table 2.12-3](#). In terms of transient response, the most significant hardware modifications are those for the SBCS and FW system. No significant NSSS hardware modifications are being implemented as part of EPU. LR [Sections 2.4.1](#) and [2.4.2](#) provide details with respect to the changes to the NSSS control system model for EPU. Since the CENTS model has been demonstrated to properly reflect plant response to operational transients and has been updated to reflect the applicable EPU modifications and setpoint changes, the aggregate impact of these changes on dynamic plant response can be addressed through CENTS analyses for Condition I initiating events and Condition II trip tests.

The CENTS computer code was used to analyze the Condition I initiating event and Condition II trip transient cases listed on LR [Table 2.12-4](#). This list of cases covers a wide range of transients and power levels. Based on a review of these CENTS cases and the planned modifications, no new thermal-hydraulic phenomena, new system dependencies, or system interactions are introduced.

The results of the analyses showed that the plant responses to Condition I initiating events and Condition II trip transients satisfied functional requirements and that the NSSS control system responses were stable. Plant responses to Condition I initiating events were shown to have acceptable margins to reactor trip and engineered safety features actuation. Specifically, the performance of the SBCS was acceptable during both steady-state and transient operating conditions.

Condition II, III, and IV Initiating Events

The results of the analyses performed for Condition II, III, and IV initiating events at EPU conditions are reported in the LR [Section 2.8.5.0](#), Accident and Transient Analyses. Condition II trip transients that were applicable to the original startup test program's significant large load transients were modeled and analyzed as described above.

Natural Circulation

Natural circulation capability for the proposed EPU was evaluated using the CENTS code to demonstrate that the plant exhibits acceptable natural circulation behavior. LR [Section 2.12.1.2.7](#) below and LR [Section 2.8.7.2](#), provide additional discussion of the EPU natural circulation analyses.

2.12.1.2.7 Justification for Exception to Transient Testing

FPL has reviewed Section 14.2.1 of the Standard Review Plan. As a result of this review, and a review of the original startup test program, FPL concludes that it is not necessary or prudent to perform large load transient tests as part of the EPU power ascension test plan. This section discusses the justification for not performing the large transient tests.

Justification for Exception - General

The original at-power startup test program was conducted in 1983. Significant differences exist between the original and EPU startups. Each of the following differences reduces the need to repeat the large load transient testing performed during the original startup:

- Advanced analytical tools, such as CENTS, and modeling techniques provide the ability to model plant response at a level not available for the original startup. The CENTS model is discussed in LR [Section 2.12.1.2.6](#),
- Code models can be benchmarked against existing plant data, whereas such data did not exist for the original startup. CENTS benchmarking is discussed in LR [Section 2.12.1.2.6](#),
- An analytical tool, such as CENTS, has the ability to simulate many transients under many conditions versus a test, applicable to one transient under one operating condition. The CENTS computer code was used to analyze Condition I initiating events and Condition II trip transients at EPU conditions as listed on LR [Table 2.12-4](#),
- Operating history since 1983 to the present has provided evidence of the plant's ability to respond to transients, whereas such history did not exist for the original startup,
- The original startup tests demonstrated that the systems and components could perform their intended function,
- The original startup test transients were envisioned as the first opportunity for operators to use various operating and emergency procedures. Such procedures have been refined through the many years of operation. Operator familiarization has been achieved through use of the procedures (e.g., unplanned trips) and regular simulator training, and
- Plant modifications have been installed that preclude repeating specific startup testing. The turbine runback feature has been deleted, automatic CEA withdrawal has been disabled, and

in accordance with station procedures the automatic mode of operation for CEA insertion is not used.

Any large load transient test has associated risks, whether the test initiates a reactor trip or increases the probability of a reactor trip. The risks associated with such a transient, while small, should not be incurred if the testing is not necessary. An additional drawback from inducing a large transient includes the potential to challenge the stability of the electric power grid, including the potential impact on St. Lucie Unit 1, due to the rapid loss of a large generation capacity.

A comparison of the original plant start-up testing to the EPU power ascension test plan is provided in LR [Table 2.12-2](#). For most of the tests listed in LR [Table 2.12-2](#), the table provides the justification for not performing the test at EPU conditions. For the following large load transients, the justification for not performing the test at EPU conditions is provided below:

- Automatic control system checkout and load swing test,
- Generator trip test, and
- Natural circulation test.

In summary, performing large load transient tests would not confirm any new or significant aspect of performance beyond those already demonstrated through analysis, by previous operating experience or routinely through plant operations. Furthermore, the NSSS control system functional design and hardware are not impacted. Therefore, large load transient tests will not be performed as part of the EPU Power Ascension Test Plan.

Justification for Exception - Specific

A description of the original startup test, the related CENTS analyses, plant operational data (when available), and concluding statements are provided for each test below.

Automatic Control System Checkout

The purpose of the automatic control system checkout transient test was to verify control system response for the SG level control system, the turbine control system, and the CEA regulating system. During the original startup test program, load transient testing was performed from the 50 percent test plateau as follows:

- A 10 percent load reduction at 5 percent/min from 50 percent power,
- A 10 percent step load reduction from 40 percent power,
- A 10 percent step load increase from 30 percent power, and
- A 10 percent load increase at 1 percent/min from 40 percent power.

The turbine runback feature, involving a rapid 10 percent load reduction, was verified from 75 percent power. Automatic control systems functioned as designed to facilitate the load changes and stabilize the plant.

Analyses were performed using the CENTS code for numerous load transients, as shown on LR [Table 2.12-4](#). Cases 8 - 11, 15 - 22, and 28 - 29, are more extensive, are bounding, and are enveloping relative to the load change testing done in the Automatic Control System Checkout.

Additionally, Cases 12 - 14 model 30 percent step load changes, which are considerably more severe transients than those performed in the automatic control system checkout. For each of these cases, the NSSS functional requirements applicable to the transient were met and all of the NSSS control systems performed adequately with the EPU setpoints, no reactor trip setpoints were challenged, and control system response was stable. Cases 8 and 9 provide a comparison of a 10 percent step load change from EPU operating conditions versus a 10 percent step load change from (approximately) current full power conditions. These two cases are discussed in more detail below.

Case 8 models a 10 percent step load change from full EPU power. No operator actions were assumed and CEA control was in manual. The reactor power decreased to about 96 percent. SBCS valves opened and limited the increase in steam pressure. The maximum pressurizer pressure was 2326 psia. The maximum pressurizer level was 68 percent. The pressurizer level was nearly back to the program level within 15 minutes. The maximum SG pressure was 956 psia.

Case 9 models a 10 percent step load change from 90 percent EPU power or 2718 MWt reactor power, which is close to the current full power level of 2700 MWt. No operator actions were assumed and CEA control was in manual. The reactor power decreased to about 87 percent. SBCS valves opened and limited the increase in steam pressure. The maximum pressurizer pressure was 2321 psia. The maximum pressurizer level was 72 percent. The pressurizer level was back to the program level within 15 minutes. The maximum steam generator pressure was 949 psia.

When Cases 8 and 9 are compared, the parameter responses are similar and the parameter trends are similar over the durations of the transients. This comparison demonstrates that EPU plant conditions do not result in a significant change in plant response to a 10 percent step load change.

Recent operational data demonstrates load change capability. On September 9, 2009, St. Lucie Unit 2 reduced power from 75 percent to 25 percent at a ramp rate of approximately 0.3 percent/min. On April 22 and 23, 2010, St. Lucie Unit 2 increased power from 25 percent to 94 percent. The ramp rate was approximately 0.3 percent/min during power escalations. Control systems performed adequately to allow smooth transients. Although not matching the load change and ramp rate of initial power ascension testing, these transients do demonstrate the ability to sustain an extended load change that is not typical of daily operation.

Waterford 3 provides related operating experience ([Reference 11](#)). Waterford 3 is a CE design plant that has been uprated to a core thermal power of 3716 MWt, which is higher than the proposed EPU power level. On August 28, 2005, Waterford commenced a plant shutdown from 100 percent power in anticipation of Hurricane Katrina. Load was reduced at a rate of approximately 0.8 percent/min. All systems responded as expected during the plant shutdown and control systems operated satisfactorily in automatic. Subsequent plant startup and power ascension was performed two weeks later. Power increase was restricted to a rate of 0.33 percent/min due to fuel preconditioning guidelines. Control systems responded properly during power ascension. This event demonstrates load ramp capability over all power levels for an uprated plant similar to St. Lucie Unit 2. Furthermore, the ramp rates are comparable to the rates from the automatic control system checkout transient test discussed above.

In summary, acceptable results were obtained from the CENTS analyses and acceptable response was demonstrated in the operating history examples. More specifically, the CENTS cases showed the NSSS functional requirements applicable to each transient were met, all of the NSSS control systems performed adequately with the EPU setpoints, no reactor trip setpoints were challenged, and control system response was stable. Conducting a test to demonstrate this acceptability is unnecessary, particularly when including the avoided risk of an unnecessary plant transient. Therefore, an automatic control system transient test is not required in the EPU power ascension test plan.

Generator Trip Test

The purpose of the generator trip test was to verify that the plant systems and controls dynamic response was in accordance with design requirements. During the original startup test program, the generator trip test was performed from approximately 100 percent power. A generator trip was initiated, and then the turbine and reactor tripped. Control systems functioned as designed to bring the unit to hot standby conditions with minimum operator action. Key plant parameters stayed within expected limits.

When a generator trip is the initiating event, the turbine trips automatically. As discussed below, the CENTS code was used to analyze a turbine trip from full power. Redundant logic is utilized in the turbine-trip-on-generator-trip function. In the event that the generator trips and the turbine does not receive a trip signal, the turbine would trip on overspeed. A turbine overspeed trip test from low power will be performed as shown on LR [Table 2.12-1](#).

Analyses were performed using the CENTS code for numerous transients as shown on LR [Table 2.12-4](#). Cases 1 and 31 modeled turbine trips from full EPU power. Cases 2 through 5 modeled trips from reduced power levels. For each turbine trip case, the NSSS functional requirements applicable to the transient were met and all of the NSSS control systems performed adequately with the EPU setpoints. These analyses demonstrate that a turbine trip from full power EPU conditions results in acceptable plant response. Cases 1 and 2 provide a comparison of a turbine trip from EPU operating conditions verses a turbine trip from approximately current full power conditions. These two cases are discussed in more detail below.

Case 1 models a turbine trip from full EPU power. A reactor trip occurs on turbine trip. An SBCS quick open signal occurs on reactor trip. The maximum SG pressure was 999 psia. Following the SBCS quick open, the SBCS provides modulation control near the SBCS pressure setpoint. The minimum SG level was at 39 percent which is above the auxiliary feedwater actuation system (AFAS) low level setpoint. The minimum pressurizer pressure was 1795 psia. The pressurizer level dropped below the heater cutoff setpoint and the pressurizer heaters were de-energized. The minimum pressurizer level was about 17 percent.

Case 2 models a turbine trip from 90 percent EPU power, or 2718 MWt reactor power, which is close to the current full power level of 2700 MWt. A reactor trip occurs on turbine trip. An SBCS quick open signal occurs on reactor trip. The maximum SG pressure was 976 psia. Following the SBCS quick open, the SBCS provides modulation control near the SBCS pressure setpoint. The minimum SG level was at 28 percent which is above the AFAS low level setpoint. The minimum pressurizer pressure was 1850 psia. The pressurizer level dropped below the heater cutoff

setpoint and the pressurizer heaters were de-energized. The minimum pressurizer level was about 23 percent.

When Cases 1 and 2 are compared, the parameter responses are similar with the Case 1 responses being slightly greater, as expected. In addition, the parameter trends are similar over the durations of the transients. (SG level response varies slightly due to power specific tuning parameters used in the feedwater control system (FWCS) control logic associated with the post-trip transition from the main FW flow control valves to the low power FW flow control valves.) This comparison of Cases 1 and 2 shows that EPU plant conditions do not result in a marked change in plant response to a turbine trip.

Recent St. Lucie Unit 2 operational data includes several trips from full power in the past decade.

- On March 14, 2001, automatic turbine trip from 100 percent power following a 6.9 kv breaker transfer failure,
- On April 11, 2003, manual reactor trip from 100 percent power following high condenser back pressure,
- On December 20, 2003, automatic reactor trip from 100 percent power following a generator lockout/turbine trip,
- On August 11, 2005, manual reactor trip from 100 percent power following a rapid SG level drop caused by a main FW pump trip,
- On June 4, 2008, manual reactor trip from 100 percent power following a loss of a main FW pump, and
- On June 7, 2008, manual reactor trip from 100 percent power following a condensate pump trip.

In each case, safety equipment operated per design and the unit was safely brought to Mode 3. These events demonstrate the ability to sustain a trip from the current full power level of 2700 MWt, and as discussed above, the CENTS analyses showed similar results for trips from 2700 MWt and 3020 MWt.

Applicable operating experience comes from Waterford 3 ([Reference 11](#)). On November 11, 2005, a manual reactor trip from 100 percent power was performed due to a total loss of circulating water. The integrated plant control systems operated satisfactorily in automatic to stabilize the plant post trip. Safety systems responded as designed. This transient demonstrates acceptable response to a reactor trip for an uprated plant similar to St. Lucie Unit 2.

Another example of a post uprate trip is provided by ANO 2. On December 19, 2002, ANO 2 experienced an unplanned post EPU trip. A review of the data from the trip indicated that plant performance had been adequately predicted by the calculation method which had been used for control systems and integrated plant transient response evaluation for EPU. This event illustrates the successful use of calculational models for predicting transient response post power uprate at a plant similar to St. Lucie Unit 2.

The CENTS cases demonstrate that a generator trip from full power EPU conditions results in acceptable plant response. The NSSS functional requirements applicable to the transient were met and all of the NSSS control systems performed adequately with the EPU setpoints. Comparing CENTS cases from current and EPU full power conditions does not show a marked difference in plant response. When adding the avoided risk of an unnecessary plant transient, the performance of a generator trip test from a high power level is unnecessary. Therefore, an at-power generator trip test from a high power level is not required in the EPU power ascension test plan.

Natural Circulation Test

The purposes of natural circulation testing were to provide training for the plant operators and to monitor the transition to natural circulation conditions while maintaining NSSS parameters. Natural circulation testing was performed during the precritical, hot functional testing phase of the original startup test program. Running RCPs were tripped simultaneously and natural circulation conditions were established. Depressurization rates, cooldown rates, and subcooled margin were maintained without uncontrolled oscillations of NSSS parameters.

Natural circulation capability for EPU conditions was evaluated using the CENTS code. The evaluation involved a trip from full power, establishment of natural circulation cooling, maintenance of hot standby conditions, and cooldown to shutdown cooling entry conditions. Details are provided in LR [Section 2.8.7.2](#), Natural Circulation Cooldown.

The evaluation concluded that St. Lucie Unit 2 maintains the ability to perform natural circulation cooldown following a trip from full power to shutdown entry conditions in a reasonable period of time without voiding the RCS. No major hardware modifications to NSSS components that could affect loop flow resistance or steam generator heat transfer are part of the EPU scope. Based on this analysis and the avoided risk of an unnecessary plant transient, a natural circulation test is not required in the EPU Power Ascension Test Plan.

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

As discussed above, the power ascension testing was determined to be outside the scope of License Renewal; therefore, with respect to the power ascension testing, the EPU does not impact any License Renewal evaluations.

2.12.1.4 Conclusion

FPL has reviewed the EPU power ascension test plan, including plans for the initial approach to the proposed maximum licensed thermal power level and the test program's conformance with applicable regulations. FPL concludes that the EPU test program provides adequate assurance that the plant will operate in accordance with design criteria and that SSCs affected by the proposed EPU, or modified to support the proposed EPU, will perform satisfactorily in service. Further, FPL finds that there is reasonable assurance that the EPU testing program will continue to meet its current licensing basis with respect to the requirements of 10 CFR 50, Appendix B, Criterion XI. Therefore, FPL finds the EPU power ascension test plan acceptable.

2.12.1.5 References

1. Safety Evaluation of the St. Lucie Plant Unit No. 2, dated October 1981.
2. Supplement 4 to the Safety Evaluation of the St. Lucie Plant Unit No. 2, NRC letter to FPL dated June 10, 1983.
3. FPL Letter to NRC, L-83-542, St. Lucie Unit 2 Startup Report, dated November 1, 1983.
4. NRC Letter to FPL, dated September 13, 1988.
5. Amendment No. 9 to Facility Operating License No. NFP-16 for St. Lucie Unit No. 2, dated March 1, 1985.
6. ASME OM-S/G-2007, Standards and Guides for Operation and Maintenance of Nuclear Power Plants, Part 3, Requirements for Preoperational and Initial Startup Vibration Testing of Nuclear Power Plant Piping Systems.
7. ANS-19.6.1, Reload Startup Physics Tests for Pressurized Water Reactors.
8. NRC Regulatory Guide 1.70, Revision 2, Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants, September 1975.
9. Westinghouse Owners Group Topical Report WCAP-15996-P-A, Revision 1, Technical Description Manual for the CENTS Code, March 2005.
10. Letter from Entergy to the NRC, W3F1-2004-0004, dated January 29, 2004.
11. Letter from Entergy to the NRC, W3F1-2005-0083, dated December 8, 2005.

**Table 2.12-1
EPU Power Ascension Test Plan**

Test/Activity	Description	Pre-S/U	Rated Thermal Power - % of 3020 MWt									
			0-5	5-20	30	45	80	89	92	95	98	100
Nuclear & ΔT power calibration	Verify thermal power and adjust instrumentation	X			X	X	X	X	X	X	X	X
Linear power range channel calibration	Align linear excore power to calorimetric power. Modify axial power shape indication from incore flux instrumentation. (Final adjustment may precede 92% power.)				X				X			
Core power distribution monitoring	Monitor power distribution by incore flux map				X	X		X		X		X
Shape annealing factors	Data collection from excore and incore flux instrumentation during power ascension, starting at 30% power and ending at 92% (or sooner). Update of constants at full power.				X	X	X	X	X			X
Hot full power (HFP) boron check	Evaluation of critical boron concentration at HFP											X
RCS flow determination	Determine RCS flow by reactor power measurement							X				X
NSSS data collection	Data collection				X	X	X	X	X	X	X	X
Balance of plant (BOP) data collection	Data collection				X	X	X	X	X	X	X	X
BOP walkdown	Equipment monitoring				X	X	X	X	X	X	X	X
Turbine trip	Turbine over speed trip test			X								
Reheat stop, interceptor, governor, throttle valve testing	Standard turbine valve tests		X									
Vibration monitoring	Monitor vibration in plant piping and rotating equipment				X	X	X	X	X	X	X	X

Table 2.12-1 (Continued)
EPU Power Ascension Test Plan

Test/Activity	Description	Pre-S/U	Rated Thermal Power - % of 3020 MWt									
			0-5	5-20	30	45	80	89	92	95	98	100
Plant radiation surveys	Perform surveys and update survey results impacted by EPU. Areas will include portions of containment, reactor auxiliary building, fuel handling building, and the steam trestle, taking accessibility and ALARA into consideration.							X				X
Leading edge flowmeter (LEFM) mod	LEFM functional check, following vendor commissioning.									X	X	
High pressure (HP) and low pressure (LP) turbine mods	Measurement of EPU electrical output											X
FW mods: New SG flow control valve trim, New FW pumps New condensate pumps FWCS changes	FW monitoring during evolutions such as swap from FW bypass to SG flow control valves, start of second condensate pump, start of second FW pump, start of heater drain (HD) pumps			X		X	X	X				
Moisture separator reheater (MSR) replacement mod	Functional/performance verification.							X				X
HP feedwater heater No. 5 replacement	Functional/performance verification.							X				X
No. 5 FW heater/MSR control mods New level controls New control valves	Monitor and tune, as necessary, upgraded MSR level controls and drain control valves.							X	X	X	X	X
Digital electro-hydraulic (DEH) computer replacement mod	Monitor and tune, as necessary, new DEH turbine controls.			X	X	X	X	X	X	X	X	X
SBCS mods: Capacity increase Control system changes	Monitor SBCS at low power.		X	X								
HD system mods	Monitor and tune, as necessary, new HD valves.			X	X	X	X	X	X	X	X	X

Table 2.12-1 (Continued)
EPU Power Ascension Test Plan

Test/Activity	Description	Pre-S/U	Rated Thermal Power - % of 3020 MWt									
			0-5	5-20	30	45	80	89	92	95	98	100
HD pump mods	Monitor new HD pumps.						X	X	X	X	X	X
Note: The 89% plateau corresponds to the current licensed power level of 2700 MWt, approximately 89% of EPU power.												

**Table 2.12-2
Comparison of Proposed EPU Tests to Original Startup Tests**

FSAR Item No.	Test Description and Conditions	Test Plan For EPU (yes/no)	Initial Startup Test Objective	Evaluation/Justification
	FSAR Sections 14.2.12.2, 3, and 4 [or Startup Report]			
14.2.12.2A	Reactor Coolant System Flow and Flow Coastdown Test Hot standby conditions (RCS flow measurement also performed at 90% and 100% power)	Yes (in part)	a. To measure the reactor coolant system flowrate and core pressure drop. b. To obtain reactor coolant pump flow coastdown characteristics	EPU has no adverse affect on the RCS system and does not invalidate the flow and flow coastdown tests as originally performed. Specifically, RCS flow rate will change only by a negligible amount. Therefore, this original startup test, performed at hot shutdown conditions, is not necessary for EPU. An at-power RCS flow measurement is performed following every refueling and this measurement is not impacted by EPU. However, this at-power RCS flow measurement is included with the proposed EPU power ascension test program, as shown on Table 2.12-1 , as a verification of adequate flow at the uprated conditions.

Table 2.12-2 (Continued)
Comparison of Proposed EPU Tests to Original Startup Tests

FSAR Item No.	Test Description and Conditions	Test Plan For EPU (yes/no)	Initial Startup Test Objective	Evaluation/Justification
	FSAR Sections 14.2.12.2, 3, and 4 [or Startup Report]			
14.2.12.2B	Control Element Drive Mechanism Performance Test Hot standby conditions	No	a. To demonstrate the operation of the control element drive mechanism with extension shaft installed. b. To measure the control element assembly withdraw and insertion speeds c. To demonstrate the operation of the control element assembly position indication system. d. To demonstrate the operation of the control element drive mechanism control system protective interlocks and alarms associated with individual CEA motion. e. To measure the control element assembly drop times. f. To demonstrate the operation of the control element assembly decelerating devices. g. To demonstrate the operation of the manual trip function.	Rod drop testing and control element drive mechanism testing are performed as normal Technical Specification surveillances. There are no EPU modifications that will affect rod drop time or control element drive mechanism function; therefore this test is not required to be re-performed at the EPU condition.
14.2.12.2C	Incore Instrumentation Pre-Critical Test Various temperatures during system heatup at zero power	No	a. To obtain incore thermocouple comparison data. b. To measure fixed incore detector leakage resistance. c. To demonstrate the operation of the movable incore detector system.	Proper operation of the incore thermocouples is verified by channel checks. The EPU will marginally raise the reactor coolant temperature; but well within the range of the thermocouples. EPU will have no affect on the operation of the fixed incore detectors and does not invalidate the test as originally performed. The movable incore detector system has been deleted.

Table 2.12-2 (Continued)
Comparison of Proposed EPU Tests to Original Startup Tests

FSAR Item No.	Test Description and Conditions	Test Plan For EPU (yes/no)	Initial Startup Test Objective	Evaluation/Justification
	FSAR Sections 14.2.12.2, 3, and 4 [or Startup Report]			
14.2.12.2D	Pressurizer Spray Effectiveness Test Hot standby conditions with four reactor coolant pumps operating	No	a. To establish proper settings of the continuous spray valves. b. To evaluate the performance of the spray valves at full flow.	EPU will have no affect on the operation of the pressurizer spray valves and does not invalidate the test as originally performed.
14.2.12.2E	Reactor Coolant System Leak Tightness Hot standby conditions with four reactor coolant pumps operating	No	Final assembled test of the reactor coolant system to verify the system is leaktight.	RCS leak rate testing is performed as a normal Technical Specification surveillance. EPU will have no affect on RCS leak tightness.
14.2.12.2F	Plant Chemical and Radiochemical Analysis Test Sampling plateaus at 200 °F, 532 °F, start-up mode, 20% power, 50% power, 80% power, 100% power	No	a. To monitor and measure the water quality of the reactor coolant system and steam generators. b. To monitor the corrosion inhibiting effects of the reactor coolant and steam generator chemistry programs. c. To monitor the buildup of fission product and corrosion product activity in the reactor coolant system.	EPU will have no affect on the operation of the chemistry sampling equipment and does not invalidate the test as originally performed. Current chemistry controls are adequate and will remain in place to maintain chemistry and radiochemistry conditions at the uprated conditions in the primary and secondary systems.
14.2.12.2G	Wide Range Nuclear Instrumentation Readings Several temperature plateaus prior to initial criticality.	No	To collect information regarding the temperature effects of neutron monitoring of the core by the wide range nuclear instrumentation. This test provides information to relate core loading count-rates to critical approach count-rates.	EPU will have no affect on the pre-critical temperature effects of neutron monitoring and does not invalidate the test as originally performed.

Table 2.12-2 (Continued)
Comparison of Proposed EPU Tests to Original Startup Tests

FSAR Item No.	Test Description and Conditions	Test Plan For EPU (yes/no)	Initial Startup Test Objective	Evaluation/Justification
	FSAR Sections 14.2.12.2, 3, and 4 [or Startup Report]			
14.2.12.2H	Loose Parts Monitoring System Baseline Data and Trigger Calibration Hot standby conditions with desired reactor coolant pumps operating	No	This test provides a set of baseline data results which are used to set alarm setpoints; and are used in the future to analyze data provided by the Loose Parts Monitoring System during plant operation.	EPU will have no affect on loose parts monitoring baseline data collected at hot standby conditions and does not invalidate the test as originally performed. In addition, EPU will have no affect on the baseline data collected on the replacement loose parts monitoring system and does not invalidate the testing of that replacement.
14.2.12.2I	Reactor Protection System (Pre-Critical Test) Pre-critical conditions	No	a. To verify trip and pre-trip setpoint settings are in accordance with Chapter 16 (Technical Specifications). b. To demonstrate operability of the by-pass logic and the trip logic circuitry. c. To demonstrate operability of the manual reactor trip initiation circuit.	Routine Technical Specification surveillances verify the operation and function of the reactor protection system. EPU will have no affect on required pre-critical reactor protection system checks. Those same checks will be used for the RPS SG low level trip setpoint, which will be changed to 35% as shown on Table 2.12-3 .
14.2.12.2J	Temporary Incore Instrument Channel Response Test Pre-core loading with temporary incore instrument channels in position	No	The two objectives of this test are to determine the background signal as measured by the temporary incore instrument channels prior to the introduction of a source and performance of a response check of these channels using a start-up source.	EPU will have no affect on temporary core load instrumentation and does not invalidate the test as originally performed. St. Lucie no longer uses temporary detectors for core load.
14.2.12.2K	Safety Channel Pre-critical Alignment and Calibration Pre-critical conditions	No	a. To perform final calibration and alignment of the safety channel drawers. b. To verify associated alarms, protective functions and by-passes occur at the correct setpoints.	Routine Technical Specification surveillances verify the operation and function of the safety channels. EPU will have no affect on these requirements.

Table 2.12-2 (Continued)
Comparison of Proposed EPU Tests to Original Startup Tests

FSAR Item No.	Test Description and Conditions	Test Plan For EPU (yes/no)	Initial Startup Test Objective	Evaluation/Justification
	FSAR Sections 14.2.12.2, 3, and 4 [or Startup Report]			
14.2.12.2L	Start-up/Control Channel Precritical Alignment and Calibration Pre-critical conditions	No	To perform final calibration and alignment of the safety channel drawers.	Routine Technical Specification surveillances verify the operation and function of the start-up/control channels. EPU will have no affect on the required pre-critical alignments and calibrations for these channels.
14.2.12.2M	Auxiliary Feedwater System Automatic Actuation System Test Hot standby conditions	No	a. Demonstrate auxiliary feedwater automatic actuation system operation. b. Demonstrate the absence of feedwater piping water hammer due to an initiation of auxiliary feedwater.	EPU will have no affect on the ability of the Auxiliary Feedwater System (AFW) to deliver auxiliary feedwater to the steam generators and does not invalidate the test as originally performed. The original Combustion Engineering steam generators (OSGs) have been replaced by Areva steam generators (RSGs). The water hammer concern was eliminated by the j nozzle design, which was added to OSGs and included with the RSGs. This design keeps the feed ring filled.
14.2.12.3A	Radiation Shielding Evaluation Test Pre-critical (background), 3-5%, 20%, 50%, 80%, 100% power	Yes	a. To measure the neutron and gamma radiation dose rates during start-up testing to evaluate the adequacy of the biological shielding. b. To obtain baseline radiation levels for comparison with future measurements.	Radiation surveys performed at lower power levels are not invalidated by EPU. However, plant surveys will be performed at the higher power levels shown in Table 2.12-1 , and survey results updated as necessary.
14.2.12.3B	Moderator Temperature Coefficient Test Reactor critical at zero power.	No	To measure the isothermal temperature coefficient (ITC) at zero power and derive the moderator temperature coefficient from it.	This particular test, in part, is within the scope of the current PSL low power physics test program. Low power physics testing will be performed in Mode 2 prior to the EPU power ascension, but no low power physics testing is required specifically for EPU. See LR Section 2.12.1.2.4 for further discussion.

Table 2.12-2 (Continued)
Comparison of Proposed EPU Tests to Original Startup Tests

FSAR Item No.	Test Description and Conditions	Test Plan For EPU (yes/no)	Initial Startup Test Objective	Evaluation/Justification
	FSAR Sections 14.2.12.2, 3, and 4 [or Startup Report]			
14.2.12.3C	Differential Boron Worth Test Reactor critical at zero power	No	To measure the differential boron reactivity worth for various CEA configurations.	Differential boron worth measurement is within the scope of the current PSL low power physics test program. Low power physics testing will be performed in Mode 2 prior to the EPU power ascension, but no low power physics testing is required specifically for EPU. See LR Section 2.12.1.2.4 for further discussion.
14.2.12.3D	Shutdown and Regulating CEA Group Worth Tests Reactor critical at zero power	No	Determine regulating and shutdown CEA group worths at zero power and verify that the CEA worths are adequate to assure the required shutdown margin and the CEA worths are in accordance with design prediction.	Rod worth measurements, using the rod swap method, are within the scope of the current PSL low power physics test program. Low power physics testing will be performed in Mode 2 prior to the EPU power ascension, but no low power physics testing is required specifically for EPU. See LR Section 2.12.1.2.4 for further discussion.
14.2.12.3E	Critical Boron Concentrations Test Reactor critical at zero power	No	To measure critical boron concentrations for various CEA configurations.	This particular test, in part, is within the scope of the current PSL low power physics test program. Low power physics testing will be performed in Mode 2 prior to the EPU power ascension, but no low power physics testing is required specifically for EPU. See LR Section 2.12.1.2.4 for further discussion.
14.2.12.3F	CEA Symmetry Test Reactor critical at zero power	No	To demonstrate proper coupling of each CEA to its CEDM and demonstrate that no gross radial power asymmetries are present.	This particular test is not part of the current PSL low power physics test program. See LR Section 2.12.1.2.4 for further discussion.
14.2.12.3G	Source and Intermediate Range Neutron Instrumentation Overlap Verification Reactor approaching or at criticality at zero power	No	Demonstration of adequate overlap of the source and intermediate neutron instrumentation.	EPU will have no affect on the overlap of the source and intermediate neutron instrumentation and does not invalidate the test as originally performed.

Table 2.12-2 (Continued)
Comparison of Proposed EPU Tests to Original Startup Tests

FSAR Item No.	Test Description and Conditions	Test Plan For EPU (yes/no)	Initial Startup Test Objective	Evaluation/Justification
	FSAR Sections 14.2.12.2, 3, and 4 [or Startup Report]			
14.2.12.3H	CEA Sequencing and Inhibit Test Hot standby conditions	No	a. To demonstrate the CEA withdrawal sequence while operating in sequential mode. b. To demonstrate the operation of CEA motion inhibits initiated by the analog display system.	CEA testing is performed as a normal Technical Specification surveillance. There are no EPU modifications that will affect CEA function; therefore this test is not required to be re-performed at the EPU condition.
14.2.12.4A	Automatic Control System Checkout and Load Swing Test 20%, 50%, 80%, 100% power, transient testing from 50% power	Yes (in part)	a. To demonstrate the operability of the CEA regulating system. b. To demonstrate the operability of the steam generator level control system during transient condition. c. To verify expected response of turbine control system during load swings.	System parameters will be monitored per NSSS and BOP data collection activities as shown in Table 2.12-1 . The load transient portion of the original testing is not necessary for EPU. See LR Section 2.12.1.2.7 for further discussion.
14.2.12.4B	Loss of Offsite Power Test From 20% power	No	To determine the plant's response during a load rejection and a loss of offsite power.	The original test demonstrated that the plant could lose off-site AC power, shutdown, and be maintained using power from the diesel generators. No changes with EPU impact the capability of the plant to handle a loss of off-site AC power. In addition, integrated safeguards testing, including loss-of-offsite-power, is performed during each refueling outage. This transient test is not necessary for EPU.
14.2.12.4C	10 Percent Load Reduction - Turbine Runback Test From 75% power	No	To determine the plant's response to a load reduction.	The turbine runback feature has been deleted. Similar testing for EPU is not necessary or possible. Also see discussion of Automatic Control System Checkout in LR Section 2.12.1.2.7 for further discussion related to plant transients.

Table 2.12-2 (Continued)
Comparison of Proposed EPU Tests to Original Startup Tests

FSAR Item No.	Test Description and Conditions	Test Plan For EPU (yes/no)	Initial Startup Test Objective	Evaluation/Justification
	FSAR Sections 14.2.12.2, 3, and 4 [or Startup Report]			
14.2.12.4D	Generator Trip with Shutdown Outside Control Room Test 10% power (performed from 20% power)	No	The objective of this test is to demonstrate that the plant can be shutdown and maintained in a hot standby condition from outside of the control room.	The original test demonstrated that the plant could be tripped from outside the control room and then maintained in hot shutdown conditions from remote locations. No changes with EPU impact the capability to remotely trip and maintain hot shutdown conditions. This transient test is not necessary for EPU.
14.2.12.4E	Generator Trip Test From 100% power	No	The objective of this test is to verify that the plant systems and controls dynamic response is in accordance with design requirements.	This transient test is not necessary for EPU. See LR Section 2.12.1.2.7 for further discussion.
14.2.12.4F	Evaluation of Core Performance 20%, 50%, 80%, 100% power	Yes	To verify the desired peaking factors, tilt annealing factors, and power distributions are within their allowable limits at various power levels.	Core power distribution measurements are included with the proposed EPU power ascension test program, as shown on Table 2.12-1 . Also see LR Section 2.12.1.2.4 for further discussion.
14.2.12.4G	At Power Moderator Temperature Coefficient and Power Coefficient Test From 50%, 80%, 100% power	No	To measure the power and isothermal temperature coefficients (ITC) and derive the moderator temperature coefficient at selected power levels.	This at-power physics test is not necessary for inclusion with the proposed EPU power ascension test program. See LR Section 2.12.1.2.4 for further discussion.
14.2.12.4H	Nuclear Power and Delta T Power Correlation 20%, 50%, 80%, 100% power	Yes	To provide a method to correlate the nuclear and delta T power to agree with the thermal energy balance calculations as calculated by the process computer.	Power indication monitoring and calibration are included with the proposed EPU power ascension test program, as shown on Table 2.12-1 .
14.2.12.4I	Natural Circulation Hot standby conditions	No	a. To provide licensed operators with actual natural circulation experience b. To collect plant data associated with natural circulation to better define plant transition into the natural circulation mode.	This transient test is not necessary for EPU. See LR Section 2.12.1.2.7 for further discussion related to natural circulation and reactor trip on low flow.

Table 2.12-2 (Continued)
Comparison of Proposed EPU Tests to Original Startup Tests

FSAR Item No.	Test Description and Conditions	Test Plan For EPU (yes/no)	Initial Startup Test Objective	Evaluation/Justification
	FSAR Sections 14.2.12.2, 3, and 4 [or Startup Report]			
14.2.12.4J	Digital Data Processor (DDPS) Instrument Correlation Test 0%, 20%, 50%, 80%, 100% power	No	To demonstrate the operation of the DDPS.	The DDPS functions have been incorporated into the distributed control system (DCS). Thermal power and core power distribution monitoring, through the use of the DCS, are included with the proposed EPU power ascension test program, as shown on Table 2.12-1 .
14.2.12.4K	Ventilation and Air Conditioning System Capabilities 50%, 100% power	Yes (in part)	To demonstrate that the heating, ventilating, and air conditioning (HVAC) systems for the containment, and areas housing Engineered Safety Features (ESF) maintain design temperatures.	EPU will not impact the ability to maintain temperatures below design temperatures (Ref. LR Sections 2.7.5, 2.7.6, and 2.7.7). In addition, the EPU will not modify the ventilation system and the testing that was performed during startup is still valid; therefore, specific testing of the ventilation system will not be performed, except for Control Room AC as shown on Table 2.12-3 . System parameters will be monitored per NSSS and BOP data collection activities shown in Table 2.12-1 . This data collection will include HVAC parameters such as containment temperatures.
N/A (from S/U Report)	Forced Xenon Oscillation Test [Startup Report - 6.I]	No	To obtain transient test data by inducing an axial xenon oscillation in the core at the 50% plateau in order to determine the Shape Annealing Factors (SAF) for each power range safety channel and power range control channel.	This at-power physics test is not necessary for inclusion with the proposed EPU power ascension test program. See LR Section 2.12.1.2.4 for further discussion. Note that Shape Annealing Factor monitoring and adjustment are included with the proposed EPU power ascension test program, as shown on Table 2.12-1 , although the test data is no longer collected during an induced axial xenon oscillation.

**Table 2.12-3
Post-Modification Testing**

Modification Title	Modification Description	Planned Outage	Potential Impact on Transient Response	Modeled in Transient Analysis	Post-Modification Test (during outage installed)	EPU Startup Testing (planned for EPU implementation outage 2-20)
Main feedwater pump replacement	Replace main FW pumps (no motor replacement required) to support full load FW flow at EPU conditions.	SL2-20	Yes	Yes	Pump performance verification. Vibration monitoring.	Parameters monitored during power ascension for FW system evolutions (e.g., swap from FW bypass to SG flow control valves, second condensate pump start, second FW pump start, closure of second FW pump recirc valve, HD pumps start).
SG flow control valve replacement	Replace SG flow control valve trim to increase Cv in order to support full load FW flow at EPU conditions.	SL2-20	Yes	Yes	Valve calibration. Post-maintenance air operated valve testing.	Parameters monitored during power ascension for FW system evolutions (e.g., swap from FW bypass to SG flow control valves, second condensate pump start, second FW pump start, closure of second FW pump recirc valve, HD pumps start). Valve position verification at full power.
HP FW heater No. 5 replacement	Replace the No. 5 FW heaters to meet the EPU conditions.	SL2-20	No	No	Functional/performance verification (performed during EPU startup testing).	Parameters monitored during power ascension. Functional/performance verification.
FW heater No. 4 modification	Modify the No. 4 FW heaters to meet the EPU conditions.	SL2-20	No	No	Standard post-maintenance testing.	Parameters monitored during power ascension.

**Table 2.12-3 (Continued)
Post-Modification Testing**

Modification Title	Modification Description	Planned Outage	Potential Impact on Transient Response	Modeled in Transient Analysis	Post-Modification Test (during outage installed)	EPU Startup Testing (planned for EPU implementation outage 2-20)
LEFM - measurement uncertainty recapture	Install LEFM for improved FW flow measurement accuracy. Note: The LEFM modification is also discussed in LR Section 2.4.4 , Measurement Uncertainty Recapture (MUR) Power Uprate.	SL2-20	No	No	Transducer testing. Software testing of plant computer and electronics unit. Vendor commissioning procedure. Functional checkout (performed during EPU startup testing). Pre-installation testing: Factory acceptance test (FAT) of electronics unit. Transducer cable testing. Hydrostatic testing of spool piece. Flow test of spool piece by third party.	Functional checkout at ~ 95% power, then monitoring up to 100% power.
Heater drain pump replacement	Replace the 2A and 2B HD pumps rotating elements (no motor replacement required).	SL2-20	Yes	Yes	Pump performance verification. Vibration monitoring.	Parameters monitored during power ascension.
Heater drain valves replacement	Replace specified FW HD valves to accommodate the increased flow demand for EPU conditions.	SL2-20	No	No	Calibration. Post-maintenance valve testing. Valves tuned, as necessary, during power ascension (performed during EPU startup testing).	Parameters monitored and valves tuned as necessary, during power ascension.
No. 5 FW heater / MSR system level control upgrades	Upgrade No. 5 FW heater / MSR level controls with modern instrumentation for improved reliability and accuracy.	SL2-20	No	No	Calibration. Input/output electrical checks. Controls tuned as necessary, during power ascension (performed during EPU startup testing).	Parameters monitored and controls tuned, as necessary, during power ascension.

**Table 2.12-3 (Continued)
Post-Modification Testing**

Modification Title	Modification Description	Planned Outage	Potential Impact on Transient Response	Modeled in Transient Analysis	Post-Modification Test (during outage installed)	EPU Startup Testing (planned for EPU implementation outage 2-20)
MSR replacement	Replace the MSRs due to the increased flow rates at the EPU conditions.	SL2-20	No	No	Functional/performance verification (performed during EPU startup testing).	Parameters monitored during power ascension. Functional/performance verification.
MSR drain control valves replacement	Replace the MSR normal drain control valves to meet the EPU conditions.	SL2-20	No	No	Calibration. Post-maintenance valve testing. Valves tuned, as necessary, during power ascension (performed during EPU startup testing).	Parameters monitored and valves tuned, as necessary, during power ascension.
Condenser upgrades	Upgrade condenser to ensure reliable and efficient operation at EPU conditions.	SL2-20	No	No	Standard post-maintenance testing.	Parameters monitored during power ascension.
Condensate pump replacement	Replace 2A, 2B, and 2C condensate pumps to meet the EPU conditions.	SL2-19 (2B) SL2-20 (2A, 2C)	Yes	Yes	Pre-operation motor electrical checks. Pump performance checks. Monitoring during power ascension, including pump discharge pressure and FW pump suction pressure.	Parameters monitored during power ascension, including pump discharge pressure and FW pump suction pressure.
Control Room AC Margin Improvement	Modify the Control Room Air Conditioning (CRAC) cooler to allow a higher Component Cooling Water (CCW) inlet temperature.	SL2-20	No	No	Cooler performance checks.	Temperatures monitored during power ascension.
SBCS capacity increase	Increase SBCS flow capacity to provide added relief capacity for higher EPU steam flow.	SL2-20	Yes	Yes	Channel calibrations, functional stroke testing, and dynamic testing prior to at-power operation.	SBCS operation verified at low power, where steam pressure is controlled by the SBCS prior to synchronization of the main generator.
Turbine cooling water (TCW) heat exchanger replacement	Provide additional heat removal capacity for the TCW system by replacing the existing TCW heat exchangers with larger heat exchangers.	SL2-20	No	No	Functional/performance verification.	Parameters monitored during power ascension.

**Table 2.12-3 (Continued)
Post-Modification Testing**

Modification Title	Modification Description	Planned Outage	Potential Impact on Transient Response	Modeled in Transient Analysis	Post-Modification Test (during outage installed)	EPU Startup Testing (planned for EPU implementation outage 2-20)
Iso phase bus duct cooling upgrade	Upgrade the capacity of the iso phase bus duct cooling system to meet higher heat load requirements.	SL2-20	No	No	Air flow performance test.	Iso phase bus duct temperatures monitored during power ascension.
Main transformer replacement	Replace the 2A and 2B main transformers to accommodate increased power at EPU conditions.	SL2-19 (2B) SL2-20 (2A)	No	No	Electrical testing following installation. Energized transformer checks. Winding and oil temperatures monitored during power ascension.	Winding and oil temperatures monitored during power ascension.
HP turbine steam path upgrade	Replace the HP turbine steam path to accommodate increased steam flow at EPU conditions.	SL2-20	No	No	Vendor commissioning. Turbine performance (electrical output) test at full power (performed during EPU startup testing).	Parameters monitored during power ascension. Overspeed test at low power. Turbine performance test at full power.
LP turbine steam path upgrade	Replace the LP turbine steam path to accommodate increased steam flow at EPU conditions.	SL2-19	No	No	Vendor commissioning. Turbine performance (electrical output) test at full power (performed during EPU startup testing).	Parameters monitored during power ascension. Overspeed test at low power. Turbine performance test at full power.
DEH computer replacement	Replace the turbine DEH computer.	SL2-20	No	No	Calibration. Input/output electrical checks. Controls tuned as necessary during power ascension (performed during EPU startup testing). Overspeed test at low power (performed during EPU startup testing).	Parameters monitored and controls tuned, as necessary, during power ascension. Overspeed test at low power.
Main generator upgrade	Replacement of the generator rotor and rewind of the stator to meet the increased generator electrical capability.	SL2-19	No	No	Pre-operation vendor electrical tests. Parameters monitored during power ascension.	Parameters monitored during power ascension.

**Table 2.12-3 (Continued)
Post-Modification Testing**

Modification Title	Modification Description	Planned Outage	Potential Impact on Transient Response	Modeled in Transient Analysis	Post-Modification Test (during outage installed)	EPU Startup Testing (planned for EPU implementation outage 2-20)
Generator current transformers (CTs), bushings and power system stabilizer (PSS)	Replace the generator bushings, CTs, and PSS to increase generator electrical capability.	SL2-19	No	No	For CTs and bushings, vendor mechanical and electrical tests. For PSS, vendor commissioning testing, including at-power testing.	Parameters monitored during power ascension. For PSS, additional vendor at-power commissioning testing, if required.
Generator hydrogen seal oil pressure increase	Increase generator Hydrogen pressure to 75 psig and Hydrogen seal oil pressure to 87 psig.	SL2-19	No	No	Standard post-maintenance testing.	Not required
Main generator hydrogen cooler replacement	Replace hydrogen coolers to meet the increased generator electrical capability.	SL2-19	No	No	Functional/performance testing. Parameters monitored during power ascension.	Parameters, such as temperatures, monitored during power ascension.
Exciter cooler replacement	Replace exciter cooler to meet the increased generator electrical capability.	SL2-19	No	No	Functional/performance testing. Parameters monitored during power ascension.	Parameters, such as temperatures, monitored during power ascension.
Electrical bus margin improvement	Increase margin on AC electrical busses. EPU increases electrical loading and this modification compensates for this increase for scenarios that include degraded grid voltage conditions. As a result, transient response problems will be avoided for components powered by the associated electrical buses.	SL2-20	No	No	Standard electrical post-modification testing. Integrated safeguards testing.	Not required.

**Table 2.12-3 (Continued)
Post-Modification Testing**

Modification Title	Modification Description	Planned Outage	Potential Impact on Transient Response	Modeled in Transient Analysis	Post-Modification Test (during outage installed)	EPU Startup Testing (planned for EPU implementation outage 2-20)
Setpoints and scaling: general	a. Replacement modifications will consist of compatible instrument replacements with increased operating ranges. b. Scaling changes, including: Main Steam instrumentation Heater Drain instrumentation c. Control systems setpoint changes (addressed below)	SL2-20	No, for most items Yes, as identified below	No, for most items Yes, as identified below	Calibration.	Physical instrument and setpoint changes will be validated as correct and functioning as expected prior to exceeding 2700 MWt. Performance of equipment affected by listed I&C changes will be monitored during power ascension.
Setpoints and scaling: specific instruments	Scaling and setpoint changes: a. Main steam header pressure transmitters respanned b. Steam flow transmitters respanned to accommodate higher steam flow c. FW flow transmitters respanned to accommodate higher FW flow d. FW pump pressure switches setpoints lowered. e. Turbine first stage pressure rescaled.	SL2-20	Yes	Yes	Calibration.	Parameters monitored during power ascension.
Setpoints and scaling: reactor regulating system (RRS)	RRS: The pressurizer level control program will maintain minimum and maximum setpoints, but the breakpoint temperatures will change slightly.	SL2-20	Yes	Yes	Calibration.	Parameters monitored during power ascension.

**Table 2.12-3 (Continued)
Post-Modification Testing**

Modification Title	Modification Description	Planned Outage	Potential Impact on Transient Response	Modeled in Transient Analysis	Post-Modification Test (during outage installed)	EPU Startup Testing (planned for EPU implementation outage 2-20)
Setpoints and Scaling: SBCS	The SBCS flow capacity will be increased. Control system changes will be made to linearize the system response based on the new valve characteristics. Additional changes will improve the quick-open mode of operation.	SL2-20	Yes	Yes	Channel calibrations, functional stroke testing, and dynamic testing prior to at-power operation.	SBCS monitored at low power. Parameters monitored during power ascension.
Setpoints and Scaling: FWCS	FWCS will be changed to accommodate the increased feedwater flow at EPU conditions and the replacement SG flow control valve trim, which have an increased Cv. Additional changes will be made to improve post-trip SG level control.	SL2-20	Yes	Yes	Calibration and functional test.	Parameters monitored during power ascension for FW system evolutions (e.g., swap from FW bypass to SG flow control valves, second condensate pump start, second FW pump start, closure of second FW pump recirc valve, heater drain pumps start).
Setpoints and Scaling: SG low level trip setpoint	RPS SG low level trip setpoint will be changed from 20.5% (narrow range) to 35%.	SL2-20	Yes	Yes	Channel checks, calibrations, and functional tests.	Not required.

Table 2.12-4
NSSS Transients Evaluated for EPU with the CENTS Code

Case	Power Level	Cycle Time	Transient
1	100%	BOC	Turbine Trip/Reactor Trip
2	90%	BOC	Turbine Trip/Reactor Trip
3	75%	BOC	Turbine Trip/Reactor Trip
4	50%	BOC	Turbine Trip/Reactor Trip
5	25%	BOC	Turbine Trip/Reactor Trip
6	100%	BOC	Reactor Trip
7	90%	BOC	Reactor Trip
8	100%	BOC	100% to 90% Step Change in Load
9	90%	BOC	90% to 80% Step Change in Load
10	50%	BOC	50% to 40% Step Change in Load
11	25%	BOC	25% to 15% Step Change in Load
12	100%	BOC	100% to 70% Step Change in Load
13	90%	BOC	90% to 60% Step Change in Load
14	75%	BOC	75% to 45% Step Change in Load
15	90%	BOC	90% to 100% Step Change in Load
16	80%	BOC	80% to 90% Step Change in Load
17	50%	BOC	50% to 60% Step Change in Load
18	25%	BOC	25% to 35% Step Change in Load
19	90%	EOC	90% to 100% Step Change in Load
20	80%	EOC	80% to 90% Step Change in Load
21	50%	EOC	50% to 60% Step Change in Load
22	25%	EOC	25% to 35% Step Change in Load
23	100%	BOC	Loss of a Main Feedwater Pump
24	90%	BOC	Loss of a Main Feedwater Pump
25	75%	BOC	Loss of a Main Feedwater Pump
26	100%	BOC	Loss of a Heater Drain Pump
27	90%	BOC	Loss of a Heater Drain Pump
28	100%	BOC	100% to 15% Ramp Change in Power at 5%/Min
29	15%	BOC	15% to 100% Ramp Change in Power at 5%/Min
30	100%	EOC	Reactor Trip
31	100%	EOC	Turbine Trip/Reactor Trip
32	90%	BOC	90% to 60% Step Change in Load (alternate input)

Table 2.12-4 (Continued)
NSSS Transients Evaluated for EPU with the CENTS Code

Case	Power Level	Cycle Time	Transient
33	100%	BOC	Turbine Trip/Reactor Trip with 1 MSSV lifting at 970 psia
34	100%	BOC	Reactor Trip with 1 MSSV lifting at 970 psia

2.13 Risk Evaluation

2.13.1 Regulatory Evaluation

Florida Power and Light (FPL) conducted an evaluation: (1) to determine if “special circumstances” are created by the proposed extended power uprate (EPU), (2) to demonstrate that the risks associated with the proposed EPU are acceptable, and (3) to assess the quality of the probabilistic risk assessment (PRA). As described in Appendix D of the Standard Review Plan (SRP) ([Reference 1](#)) Section 19, “special circumstances” are defined as “conditions or situations that would raise questions about whether there is adequate protection, and that could rebut the normal presumption of adequate protection from compliance with existing requirements.” FPL’s evaluation also addressed the impact of the proposed EPU on core damage frequency (CDF) and large early release frequency (LERF) for the plant due to changes in the risks associated with internal events, fire, external events, and shutdown operations. In addition, FPL improved the quality of the risk analyses used to support the application for the proposed EPU, by addressing issues raised in previous peer reviews of the individual plant examination (IPE) ([Reference 2](#)), and incorporating guidance from NRC Regulatory Guide (RG) 1.200 ([Reference 3](#)) with respect to Level 1 internal events PRA models. Resulting insights were integrated into the EPU risk evaluation.

The NRC’s risk acceptability guidelines are contained in RG 1.174 ([Reference 4](#)). Specific review guidance for EPUs is contained in Matrix 13 of Review Standard (RS)-001 ([Reference 5](#)) and its attachments.

St. Lucie Unit 2 Current Licensing Basis

The Level 1 and Level 2 models were initially developed in response to NRC Generic Letter (GL) 88-20, individual plant examination (IPE) for Severe Accident Vulnerabilities ([Reference 6](#)). Since the original IPE submittal, the PRA has undergone several model revisions to incorporate improvements and maintain consistency with the as-built, as-operated plant. The current PRA was developed as part of the RG 1.200 conformance project. This project resulted in improvements to the PRA model, data and associated documentation. The current PRA model also reflects the following:

- Facts & observations (F&Os) from the Combustion Engineering Owners Group (CEOG) industry peer review and subsequent focused peer review and self assessments.
- A gap analysis focused on the American Society of Mechanical Engineers (ASME) PRA standard supporting requirements (SRs) for Capability Category II, as endorsed by RG-1.200.

Specifically, the current Level 1 PRA incorporates extensive revision of the human reliability analysis, improved treatment of common cause data, enhancements to supporting thermal-hydraulic analysis, and an upgraded large early release model that significantly improved Interfacing Systems LOCA (ISLOCA) and containment isolation models.

Due to the low seismic hazard, St. Lucie Unit 2 has been designated as a reduced-scope plant in NUREG-1407 ([Reference 7](#)). As discussed in FPL letter L-95-58 ([Reference 8](#)), in response to GL 87-02 ([Reference 9](#)), Verification of Seismic Adequacy of Mechanical and Electrical

Equipment in Operating Reactors, FPL developed and implemented a site specific seismic program. In December 1991, in letter L-91-336, Response to Generic Letter 88-20 Supplement 4 (Reference 10), FPL committed to use this program as an alternative method to the seismic methodology proposed by the NRC as discussed in the December 15, 1988 SER for St. Lucie Unit 2. FPL found no seismic vulnerabilities to potential severe accidents. In June 1992, the NRC requested a description of the FPL site-specific program (Reference 18). A response was provided in August 1992 which referenced previous correspondence concerning the FPL site-specific seismic program and provided rationale why the program would meet the intent of the IPE for External Events (IPEEE) for seismic events (Reference 38). Additional information requested by the NRC was provided in September 1993 and May 1994 (Reference 39 and Reference 40).

The fire portion of the IPEEE (Reference 23) response was performed using the Electric Power Research Institute (EPRI) Fire Induced Vulnerability Evaluation Methodology (FIVE) (Reference 11). The FIVE approach includes progressive screening of fire areas and a PRA based quantitative approach for the analysis of non-screened areas.

The IPEEE concludes that St. Lucie Unit 2 conforms to the SRP criteria and there are no significant vulnerabilities to external events including external floods, high winds, and accidents related to nearby transportation routes, or nearby industrial or military facilities.

2.13.2 Technical Evaluation

2.13.2.1 Introduction

This section describes the risk analysis associated with the EPU. Specific equipment, operations and procedural changes are in process: (a) to accommodate the proposed EPU, and (b) to reduce plant risk and to support FPL's philosophy of a risk-beneficial EPU. Risk studies are used to provide insight and to illustrate how FPL has integrated risk insights into the EPU.

The implementation of the EPU consists of changes to plant equipment, operations and procedures such that the plant can accommodate the increase in power. In addition, these changes ensure that safe plant operating margins at EPU conditions are maintained and that the change in risk from current plant to EPU operation will not be adverse to risk. In addition to the power increase and associated plant operational changes, several plant modifications and procedure changes are also being made. A list of the plant changes being made to accommodate the EPU is presented in LR Section 1.0.

The risk evaluation addresses the impact of the EPU on:

- Initiating event frequencies,
- Component and system reliability,
- Operator response times (and human error probabilities),
- Success criteria (SC), and
- Core damage frequency and large early release frequency.

This section evaluates the impact of the EPU on plant risk. The risk evaluation includes a review of plant risks associated with plant internal events, turbine missile generation, external events (fire, seismic, external flood, high winds), and shutdown risks. The internal events evaluation provides a quantitative evaluation of the EPU-related plant changes, including their impact on the unit's CDF and LERF. The baseline model is applicable to the current plant and is used as the starting point for the EPU PRA model. The baseline PRA reflects resolutions of peer review technical observations and brings the model closer to conformance with the expectations of the ASME PRA Standard and RG 1.200 for a Level 1 and LERF internal events PRA. LR [Section 2.13.2.2](#) provides an overview of the PRA. The PRA internal events model excludes internal flooding and turbine missile risks, which are addressed in LR [Sections 2.13.2.3.5](#) and [2.13.2.3.6](#), respectively.

The remainder of the EPU evaluations involve a combination of qualitative assessments and bounding analyses to establish the impact of fire and external hazards. These evaluations relied on comparing and assessing the impact of the proposed EPU and associated plant modifications on results of the IPEEE.

LR [Section 2.13.2.11](#) discusses the PRA quality and provides status of resolving past peer reviews and their expected impact on EPU.

2.13.2.2 St. Lucie Unit 2 Level 1 PRA Model

The PRA model uses an integrated small event tree/large linked fault tree for the calculation of CDF (Level 1) and LERF (Level 2). Event trees are developed for each unique class of identified internal initiating events and top logic is developed to link functional failures to system-level failure criteria using the Computer Aided Fault Tree Analysis (CAFTA) code ([Reference 33](#)). Fault trees, comprised of component and human failure events, are developed for each of the systems identified in the top logic.

Plant initiating event grouping is based on standard industry PRA practices and is consistent with RG 1.200 ([Reference 3](#)). Initiating events are established based on industry experience. Fault tree hardware-related events are quantified with a mixture of generic data from throughout the nuclear industry in addition to site-specific data. Where sufficient plant data exists, plant data is used exclusively. In other instances, plant data is combined with generic data using a Bayesian process. Generic data is used for highly reliable components or low probability initiating events. With the exception of loss of offsite power (LOOP) initiating events, generic data is taken from NUREG/CR-5750 ([Reference 13](#)). LOOP initiating event frequencies were updated to include event data through 2008. In addition, the model was expanded from three LOOP categories (plant centered, grid related and weather) to four by adding a separate category to model the August 2003 grid blackout event ([Reference 14](#)). Common cause failure (CCF) analysis was updated to use INEL/NRC 2007 database which contains the latest compilation of CCF industry events. CCF update has received focus peer review in 2009 and found to meet ASME Standard Capability Category II ([Reference 37](#)).

Success criteria define the equipment set required to mitigate an event and avert core damage. In the context of PRA, core damage events are those that result in an uncontrolled core heatup or will result in the development of uncoolable core geometry. The PRA utilizes a combination of the Modular Accident Analysis Program (MAAP) code ([Reference 26](#)), design basis and other

analyses to support development of success criteria. MAAP analyses were conducted in accordance with guidance contained in [Reference 36](#). (This reference has been made available to the NRC for their use in evaluating the use of MAAP in PRA applications.) Note, as part of the accident sequence update for RG 1.200, several industry models have been integrated into the PRA model. Specifically, these include models for steam generator tube rupture (SGTR), LERF and reactor coolant pump (RCP) seals.

The human reliability analysis employed two separate, complementary approaches to quantify procedure-driven actions. The first approach was to use the human cognitive reliability (HCR) correlation developed by the EPRI, incorporating data from the operator reliability experiments (ORE), described in the EPRI reports NP-6560L ([Reference 15](#)) and TR-100259 ([Reference 16](#)). The second approach was to apply the cause-based decision tree methodology (CBDTM), also developed by EPRI and documented in [Reference 16](#). In both approaches, the probability of failure encompassed two contributions:

- The cognitive portion, which accounts for errors in detection, diagnosis, or decision-making, and
- The execution portion, in which possible errors in carrying out a decision might be made.

The HCR/ORE and CBDTM methodologies were applied to all of the human error events, and, for each event, where both methodologies were considered applicable; the greater of the calculated human error probabilities (HEPs) from the two methodologies was used in the PRA model.

Human failure events and associated probabilities are generated via the EPRI calculator ([Reference 27](#)). Quantification of human failure events is based on review of plant procedures, available operator cues, operator interviews and, where appropriate, analyses for estimating action time windows. Operator response times were developed based on observations of simulator exercises and operator interviews.

Solution of the CAFTA logic models, reflecting system and event success criteria requirements, component failure data and human actions, yields “cutsets,” which are the combinations of events that lead to core damage (and possibly large early release). As the precise impact of the EPU on plant operation and equipment performance can only be determined definitively after actual plant operation has determined plant-specific failure rates, selected sensitivity and importance analyses of the final results were also performed to help identify the risk impact of the EPU.

2.13.2.3 Internal Events

This section evaluates the impact of the EPU with respect to various initiating events. All classes of internal event initiators important to plant risk are considered. For the internal event initiators considered, the underlying contributors to these initiating events are reviewed to determine the potential effects of the EPU on the initiating event frequencies, event progression and success criteria and event mitigation.

To illustrate the risk impact of selected modifications and aid in the understanding of the EPU impact, results of sensitivity studies have been integrated into the discussion.

2.13.2.3.1 Loss-of-Coolant Accidents (LOCAs)

This section assesses the impact of the EPU on all LOCA events. The primary contributors to LOCA events arise from passive pipe failures. LOCAs may also arise from spurious opening failures of power-operated relief valves/safety relief valves (PORVs/SRVs), spurious failures of RCP seals, or transient-induced challenges to the PORVs or RCP seals.

2.13.2.3.1.1 LOCAs Arising from Passive Failure of Reactor Coolant System or Connected Piping

LOCAs are characterized by reactor coolant system (RCS) leakages in excess of that which may be made up from charging flow. LOCA events are considered rare events whose frequencies are obtained from a combination of engineering judgment and industry-wide operating history.

The frequency of LOCAs caused by pipe failures are determined by the potential for passive pipe failures and are not related to reactor power level. The EPU does not involve changes to the RCS or interfacing system piping, nor are there any changes to the RCS operating pressure or flowrates. Consequently, no changes in the LOCA initiating event frequencies are expected as a result of the EPU.

2.13.2.3.1.2 PORV/SRV LOCAs

A LOCA can occur as a result of either a spurious signal to open the PORV, or a mechanical failure of the SRV. Stuck open SRV scenarios cannot be terminated. EPU design changes will not impact PORV or SRV mechanical or electrical design characteristics and therefore, do not influence the initiating event frequency. However, the increased power operation potentially increases the plant vulnerability to a consequential PORV challenge following a variety of reactor transients. Transient events with the potential of challenging PORVs were identified by reviewing the EPRI transient event category list ([Reference 17](#)).

The PORV challenge frequency resulting from a reactor trip initiator is conservatively estimated at 8.81E-03 per year. As a result of improvements to the plant feedwater control system, the EPU PORV challenge frequency is expected to remain unchanged. Therefore, use of the same challenge frequency for both current and EPU conditions are considered conservative in both applications.

A sensitivity study was performed assuming that the expected EPU performance improvements do not actualize. This study concluded that increasing the transient induced PORV challenge frequency by 50 percent resulted in a CDF increase of 1E-09 per year. LERF values remained unchanged.

The current PORV LOCA is classified as a medium LOCA, which means feedwater is not required to remove decay heat.

2.13.2.3.1.3 RCP Seal LOCAs

EPU RCS operation will be only marginally different from current conditions, with only minor differences in RCP inlet temperature and pressure. As there will be no physical changes to the

RCP seal or seal operation, random and induced seal failure rates will be unchanged. No changes in EPU success criteria were identified.

2.13.2.3.1.4 Summary

In summary, for EPU operation, no changes are anticipated to the LOCA initiating event frequencies.

2.13.2.3.2 Steam Generator Tube Rupture (SGTR)

FPL installed replacement steam generators (SGs) in 2007. The SG tubes are constructed using Alloy 690 material which is less susceptible to stress corrosion cracking effects. Core exit temperature changes from current to EPU conditions are relatively small and are within the design range for Alloy 690. As changes to SG operating conditions following the EPU are minimal, the existing PRA modeling for SGTR events is considered applicable to EPU conditions.

2.13.2.3.3 Interfacing System LOCA (ISLOCA)

The ISLOCA event is a LOCA outside of containment. Such events, if not terminated, will ultimately deplete the inventory of the RCS and the refueling water tank (RWT). The ISLOCA event arises as a result of a combination of equipment (typically valve) failures and a rupture of piping outside of containment. A small ISLOCA is a possibility from a failure of the RCP seal cooler tubing. Large ISLOCAs may emerge from multiple valve failures on lines connected to the RCS (e.g. shutdown cooling line). As RCS pressures and temperatures are to be essentially the same for current and EPU conditions, failure rates of isolation valves and the RCP seal cooler tubes are expected to be the same. The EPU is not expected to have an impact on the frequency of occurrence or mitigation of ISLOCA scenarios.

2.13.2.3.4 Transients

The PRA model considers approximately 40 event groups. Transient events arise from a wide range of causes. The most frequent transient events are associated with a reactor or turbine trip. Plant design modifications to the feedwater and electrical systems will increase plant operational margin. While no increase in the initiating event frequency for these events is expected, the EPU PRA calculation presented in LR [Section 2.13.2.9](#) conservatively assumes a doubling of the current plant reactor trip frequency following the EPU.

Transient event groups included in the PRA also include LOOP, failures of an electrical or instrumentation bus, secondary side breaks, spurious valve challenges, and component cooling and intake canal cooling failures, among others. As discussed in LR [Section 2.13.2.3.1.2](#) above, transient events that challenge the PORVs or result in loss of cooling to the RCP seals can progress into LOCAs.

Potential contributors to increases in initiating event frequency are primarily a result of increased flow accelerated corrosion (FAC) mechanisms. The actual impact of these changes is uncertain; however, it is assumed that FAC will increase. The FAC Monitoring Program will be available to

ensure the piping is adequately maintained. Potential impacts of the EPU design changes are addressed via sensitivity studies in LR [Section 2.13.2.9](#).

2.13.2.3.4.1 Loss of Offsite Power (LOOP) Transients

LOOP frequency is correlated with the switchyard and grid reliability. The EPU does not necessitate replacement or modification of any switchyard breakers, but does require upgrade of switchyard disconnects. In a normal operational switchyard/plant configuration, all switchyard circuits and equipment will operate within design limits. As a consequence, increases in switchyard, plant centered or grid LOOP frequency are not expected. Furthermore, several plant (and system) modifications are to be undertaken to ensure the plant, at EPU conditions, is more robust to external LOOPS. As discussed in LR [Section 2.3.2](#), plant modifications to make the plant more resistant to LOOP events include the addition of a power system stabilizer. Conditional LOOP likelihood may decrease as a result of a modification to rearrange post trip safety injection actuation signal (SIAS) non-safety loads. As there is no correlation between the EPU and the occurrence of weather induced LOOP events, no change in the weather induced LOOP frequency is expected.

While no increases in LOOP frequency are expected, insights from the impact of potential LOOP frequency increases are provided by sensitivity studies which are discussed in LR [Section 2.13.2.9](#).

2.13.2.3.4.2 Anticipated Transients Without Scram (ATWS)

ATWS sequences arise when a plant transient occurs and the reactor does not trip as a result of a condition in which the rod drop signal is not generated, relayed, or multiple control element assemblies (CEAs) mechanically bind prior to significant insertion. As a consequence of the inability to shutdown, the reactor continues to produce power resulting in the SG emptying, pressurizing the RCS to the SRV setpoint and beyond. Without CEA insertion actualization, the charging pumps are required to borate the RCS, which will, over time, decrease the RCS pressure.

Detailed analyses of the integrity of systems post-ATWS indicate that for representative CE designed plants, attached systems will remain functional above RCS pressures of 4300 psia (Reference 19). Reference 19 states the following:

“All active valves in the CE Reactor Coolant Pressure Boundary scope of supply for the ...St. Lucie 1 plant[s] have been evaluated for the hypothetical ATWS pressure loading of 4300 psi (Component Catalogue 3-39 through 3-65). ...The Level C stress limits of the ASME Code are satisfied when these valves are subjected to the hypothetical ATWS pressures. Since there are no cases where membrane stresses exceed Level C, there is no permanent deformation of the valve assemblies. Operability of these active valves is therefore not impaired by an ATWS.”

The above conclusion is also considered applicable to St. Lucie Unit 2. For purposes of PRA, analyses conservatively assume that should the RCS pressurize increase to above 3700 psia, valves will begin to bind and further injection of safety injection (SI) fluid after the system has depressurized is uncertain, and core damage results. The above scenario is governed by two

factors, the plant time in cycle (as measured by the plant moderator temperature coefficient (MTC)) and the plant power. The significance of the ATWS event is evaluated in terms of unfavorable exposure times (UETs), which reflect the fraction of cycle the plant, would have to wait before MTC is sufficiently negative such that ATWS events could be mitigated with charging pumps and other resources. St. Lucie Unit 2 analyses indicate that the EPU ATWS frequency is approximately $4.69\text{E-}07$ per year. If MTC increased from 0.22 to 0.25, this would result in a ΔCDF from the baseline (current) plant of $3.6\text{E-}08$ per year. This would also reduce ΔLERF to be $1.6\text{E-}08$ per year over baseline. While EPU ATWS events do increase slightly, their significance is low due to the conservative nature of the analysis and low frequency of failure of rods to insert.

2.13.2.3.5 Internal Flooding

Other than the pipe break initiators discussed above, there are no substantive changes to other systems that might induce internal flooding. Therefore, the flooding impacts and initiator frequencies remain unchanged.

2.13.2.3.6 Turbine Missile Generation

Turbine missile threats are not explicitly included in the PRA. A separate evaluation (Reference 20) of turbine missile generation has been performed for the BB281-13.9m² retrofit design low pressure (LP) turbines that are being installed for the EPU. Results of the analysis show that the missile generation frequencies remain below the NRC limit of $1\text{E-}5$ per year for an unfavorably oriented unit for up to 100,000 operating hours between disk inspections, providing that no cracks are detected in the disks (Reference 21). As the high pressure (HP) turbine blades are housed in a stronger enclosure, the HP turbine missile generation risks are bounded by the LP turbine missile generation assessment.

This assessment does not consider the additional beneficial impact of the EPU digital electro hydraulic (DEH) computer upgrade (see LR Table 1.0-1) which would further help control turbine missile frequency following loss of load events. Because of its low occurrence frequency, this event is considered to be an insignificant contributor to overall EPU plant risk.

2.13.2.4 External Events and Shutdown Risk

Generic Letter No. 88-20, Supplement No. 4 (Reference 22), requested each licensee to conduct an individual plant examination of external events for severe accident vulnerabilities. The following discussion provides a brief description of the PRA external events modeling and the associated EPU impacts.

2.13.2.4.1 Seismic Events

To evaluate the potential impact of the EPU on plant systems risk due to seismic events, each specific plant modification was considered for its potential for introducing vulnerabilities during seismic events. Section 2.1.2 of the St. Lucie Unit 2 IPEEE (Reference 23) discusses the definition of success paths for seismic evaluation. Success was defined as the ability to achieve

and maintain a hot shutdown condition for 8 hours, while taking into account LOOP. The primary elements of the success path include:

- Supervisory and control function requirements,
- Requirements of decay heat removal via the auxiliary feedwater (AFW) system,
- Emergency electrical power requirements,
- Chemical and volume control requirements, and
- Equipment cooling (ultimate heat sink) requirements via the component cooling water (CCW) and intake cooling water (ICW) systems.

The 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 has any significant potential impact on seismic vulnerability. Therefore, the impact of the EPU plant modifications on safe shutdown and associated plant risk due to seismic events is judged to be negligible.

The EPU will not directly affect the plant's structural seismic capability. All structural plant modifications and the anchoring of all replacement components (safety and non-safety) for the EPU will have the same or greater seismic capability than the current design basis. Further, any additional loadings imposed by the component replacement will not adversely impact the seismic capability of attached and adjacent components. Lastly, no new seismic interactions are created by any modification or replacement.

While the EPU will not reduce seismic capability, increased decay heat levels will impact time available for operator response following a seismic event. Seismic events are likely to result in a LOOP and power recovery in the short term is not assured. In addition, some non-safety-related systems may be lost due to the seismic event. Given this, the risk increase due to these factors would be similar to a non-recovery grid loss event that involved a failure of non-seismically qualified systems, structures or components (SSCs).

Seismic risk has not been quantified either for the current plant or for EPU implementation. However, in order to provide additional insight with respect to the effect of the 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 characteristic seismic event. The analyzed event was a seismic initiated LOOP that occurs during ground accelerations with a magnitude between the operating basis earthquake (OBE) and the design basis earthquake (DBE). For St. Lucie Unit 2, the OBE is 0.05g and the DBE is assessed at 0.1g. Using NUREG-1488 (Reference 24) the frequency of a seismic event in the OBE to DBE range is 8.5×10^{-5} per year. During the seismic induced LOOP, it is assumed that non-seismically qualified SSCs are lost. For hazards with a magnitude above the DBE, events are expected to be driven primarily by equipment availability.

To establish an estimate of the expected EPU impact on seismic risk, a 1×10^{-4} per year seismic hazard (representing challenge between OBE and DBE) was evaluated. The hazard is assumed to cause an unrecoverable grid LOOP with concurrent failures of the instrument air system and turbine cooling water. This evaluation indicated that both current and EPU CDF estimates are very close to 4×10^{-9} per year. Similarly, LERF estimates were on the order of 6×10^{-10} per year. The

resultant net increases in CDF and LERF of $1.1\text{E-}09$ per year and $7.4\text{E-}11$ per year respectively, are considered negligible. While seismic events beyond the DBE will contribute to plant risk, there is little expectation that the small differences in operator response times will result in an incremental risk. Therefore, the impact of the EPU on seismic risk is considered negligible.

2.13.2.4.2 Fire

A qualitative evaluation of the EPU modifications was performed with respect to fire risk. The evaluation included an assessment of the impact of the EPU on the initial IPEEE fire screening, and a reassessment of the three non-screened fire areas: main control room, cable spreading room and the “B” switchgear room. The impact of the EPU changes on the FIVE screening was qualitatively evaluated. To better understand the impact of the planned EPU changes, NUREG/CR-6850 (Reference 34) modeling guidance was used. The evaluation concluded that the EPU changes would not impact the initial plant fire screening. It was further concluded that the combined CDF of the FIVE screened compartments was approximately $1.4\text{E-}06$ per year. Results of a fire risk assessment of the remaining non-screened fire compartments indicate the fire CDF contribution is approximately $7.8\text{E-}06$ per year.

An assessment of the impact of each of the planned EPU changes on the fire risk for these compartments indicates the impact to be negligible as either fire risk for these rooms did not credit operator actions, or human error probabilities for EPU-related operator actions were unchanged.

Therefore, the EPU and associated modifications will have, at most, a very small impact on the plant CDF and LERF due to fire. No new vulnerabilities or insights were noted.

2.13.2.4.3 High Winds, Floods, and Other External Events

The IPEEE other events analysis screening used the screening approach described in Generic Letter 88-20. The IPEEE submittal reviewed the plant design for consistency with the acceptance criteria in terms of high winds, onsite storage of hazardous materials, and offsite developments.

2.13.2.4.3.1 High Winds

The IPEEE evaluated the risk impact of high winds, including hurricanes and tornadoes, and concluded that the design conforms to the SRP criteria.

To evaluate the potential impact of the EPU on plant risk due to high winds, the relevant SRP criteria were compared with the planned plant modifications to determine if there is potential for the EPU to create a significant increase in plant risk due to high winds. It was concluded that the EPU does not affect the plant risk from high winds. However, these events are likely to result in a LOOP and power recovery in the short term is not likely. Given this, the risk increase due to these events would be similar to a non-recovery grid loss event. The sensitivity of LOOP initiating event frequencies for the EPU has been examined and is discussed in LR Section 2.13.2.4.5.

Therefore, it has been concluded that there is no significant threat of a severe accident as the result of high winds.

2.13.2.4.3.2 External Flooding

External flooding assessments involve the evaluation of potential threats and evaluating the plant against these hypothetical threats. For St. Lucie Unit 2, the major events of concern for external flooding event assessment are the probable maximum hurricane (PMH) and the probable maximum precipitation (PMP).

The IPEEE concludes that the current design meets the RG 1.59 ([Reference 25](#)) and SRP criteria, and thus poses no significant risk of severe accident as a result of external flooding. This is based on the NUREG-1407 statement that plants designed to the criteria in RG 1.59 and applicable SRP sections pose no significant threat of a severe accident.

To evaluate the potential impact of the EPU on plant risk due to external flooding, the relevant SRP criteria are compared with the planned plant modifications to determine if there is potential for the EPU leading to significant increase in plant risk due to external flooding. As a result of that review, it was concluded that the EPU does not affect the plant risk from external flooding.

2.13.2.4.3.3 Transportation and Industrial Facilities

The planned EPU plant modifications have been compared with the SRP descriptions and have been found to have no impact on the conclusion that St. Lucie Unit 2 meets the applicable SRP criteria.

2.13.2.4.4 Other Miscellaneous Challenges

The IPEEE reviewed other events with potential severe accident vulnerability. LR [Table 2.13-1](#) identifies potential hazards and concludes that no potential vulnerabilities are identified. An evaluation of the planned EPU modifications with IPEEE listed hazards in LR [Table 2.13-1](#), resulted in no new hazards identified as being impacted by the EPU.

Table 2.13-1
Impact of the EPU on Other External Event Risks

Hazard	Evaluation	Potential Impact of the EPU Modifications on “Other” Vulnerability Evaluation
Lightning	There is no unique vulnerability to lightning at St. Lucie and the impact on plant risk is bounded by the internal events analysis	None
River Diversion	Hazard is not applicable to St. Lucie Units 1 and 2	None
Sandstorm	Hazard is not applicable to St. Lucie Units 1 and 2	None
Seiche	Minimal plant impact	None

Table 2.13-1 (Continued)
Impact of the EPU on Other External Event Risks

Hazard	Evaluation	Potential Impact of the EPU Modifications on “Other” Vulnerability Evaluation
Snow	Hazard is not applicable to St. Lucie Units 1 and 2	None
Soil Shrink	Minimal impact	None
Volcanic Activity	Hazard is not applicable to St. Lucie Units 1 and 2	None

2.13.2.4.5 Quantitative Assessment for Non-Seismic External Events

The EPU does not affect high wind, flood, or offsite industrial accident frequencies; nor does it affect applicable protective features such as missile or flood barriers. However, these external events are likely to result in a LOOP where power recovery in the short term is unlikely. The sensitivity of LOOP initiating event frequencies for the EPU was examined as a part of the sensitivity analysis. This provides a gross estimate on the impact the EPU will have on “IPEEE events.”

The change in CDF associated with an unrecovered, weather induced LOOP is shown in LR [Table 2.13-2](#). In this assessment, external events are bounded by weather induced LOOP (frequency of 5.2E-03 per year) with off-site power not recoverable for an indefinite period. While recoverable weather induced LOOPS have been observed with some frequency, unrecoverable events are rare. Thus, use of weather induced initiating event frequency to bound the non-recovered external event frequency is considered appropriate. While the calculated external event risk was significant, the change in risk between the external event risk for the current and EPU plant was small. Note that the slight negative value reflects the implementation of an improved EPU-related surveillance program which reduces the potential for common cause failure (CCF) of safety related AFW valves as well as other components.

Table 2.13-2
Comparison of Pre- and Post-EPU External Event Risk

	CDF	ΔCDF $CDF_{EPU} - CDF_{current}$	LERF	ΔLERF $LERF_{EPU} - LERF_{current}$
Current (per yr)	1.73E-07	N/A	3.43E-08	N/A
EPU (per yr)	1.72E-07	-1.17E-09	3.41E-08	-2.4E-10

2.13.2.5 Shutdown Operations Risk

FPL has reviewed the effects of the EPU on the shutdown cooling (SDC) system (LR [Section 2.8.4.4](#)). The review adequately accounted for the effects of the EPU on the system and demonstrated that the SDC system will maintain its ability to cool the RCS following shutdown and to provide decay heat removal. With the exception of the EPU's impact on time available for operator actions, no further impact of the EPU is expected.

During shutdown, the main focus of the outage risk management process is to protect the functions of reactivity control, electrical power, RCS inventory control, core cooling, RCS pressure control, containment integrity and fuel pool cooling; with adequate redundancy and contingency. At the higher thermal power of the EPU, higher decay heat levels are expected to increase cooldown times and decrease operator action times during reduced inventory operation. However, the extended time to reach cold shutdown is not a safety concern since key safety functions remain protected. Reductions in available times for operators to take compensatory or mitigating actions could vary from several to ten or more minutes dependent on the shutdown condition. The safety evaluation demonstrates that the shorter available time window under the 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 the EPU. Thus existing processes will be adequate for EPU outage risk management.

A review of the spent fuel pool (LR [Section 2.5.4.1](#)) capabilities indicate that the EPU decay heat requires the need for increased time to transition from Mode 5 to Mode 6. The change in the spent fuel pool decay heat load will be within the capabilities of the existing spent fuel pool cooling system. In the event of a loss of spent fuel pool cooling, sufficient makeup water sources and systems are available to maintain fuel pool volume and remove decay heat.

In summary, based on the evaluation of the proposed plant EPU modifications, shutdown related normal and off-normal operating procedures and shutdown risk management procedures; there is no significant risk increase as a result of the EPU.

2.13.2.6 PRA Model Attributes

This section discusses several key PRA model attributes and how the EPU is expected to impact those attributes. This section discusses the impact of the EPU on the construction and use of the PRA model. Specific PRA areas discussed include the assignment of success criteria, operator actions, and component reliability.

2.13.2.6.1 Function/System Level Success Criteria

A detailed review was performed to identify the effect of the increase in thermal power on the system success criteria credited in the PRA model. These success criteria specify the requirements of the plant systems to address critical safety functions. These safety functions are reactivity control, RCS pressure control, RCS and core heat removal, and RCS inventory control.

2.13.2.6.1.1 Reactivity Control

There are no changes in reactivity control methods or effectiveness due to the 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. (See LR [Section 2.13.2.3.4.2](#)).

2.13.2.6.1.2 RCS Pressure Control

There are no changes in manner of operation, pressure, or components due to the EPU that affect pressure control success criteria. The EPU pressure control for total loss of feedwater events is impacted by the decay heat. To accommodate this increased heat removal requirement during once-through-cooling (OTC) operation, changes have been made to the SG low-level reactor trip setpoint and several operator actions.

2.13.2.6.1.3 RCS and Core Heat Removal

Increased decay heat due to the EPU results in a more rapid depletion of inventory in the SG. By increasing the SG low level reactor trip setpoint and other operational changes (see below) for the EPU, the time window for operator action following total loss of feedwater (TLOFW) events resulting from a trip on SG low level is increased. Specifically, the time available for re-establishing feedwater to avert core damage increases from 84 minutes for current plant operation, to 92 minutes for EPU operation (see [Table 2.13-3a](#)). For events related to a delayed loss of AFW (i.e., post reactor trip) or TLOFW events involving a reactor trip from nominal SG water level, the time to core damage is marginally decreased from 139 minutes to 136 minutes. (Note that much of the impact of the EPU is mitigated as a result of a change in plant emergency response strategy to include a step to trip all 4 RCPs early in the event following identification of a TLOFW event, see below. Without this change the anticipated time to core damage for that scenario would be 113 minutes).

Should feedwater not be recoverable, the increased core decay power and the associated decreased boil-off time impacts the timing and equipment set required for successful implementation of OTC. To address this potential loss of capability, a risk informed change to increase the SG low level reactor trip setpoint and make concurrent changes to the plant emergency operating procedures (EOPs) will be implemented. These changes are:

1. Increase in the narrow range (NR) SG low level reactor trip setpoint from 20.5 percent to 35 percent,
2. Modify emergency operating procedure (EOP) 2-EOP-01, "standard post trip actions" (SPTAs) procedures to trip all RCPs upon indication of a TLOFW (See LR [Section 2.11.1.2.2](#)).

Results from the MAAP analyses presented in LR [Table 2.13-3b](#) show that implementation of these actions following a TLOFW event with a reactor trip on steam generator low level will result in a decrease in the time to successfully implement OTC following the EPU. The impact of the EPU on timing available for operator actions depends upon the number of PORVs considered for event mitigation.

The time variations provided in **Table 2.13-3b** reflect various features of the EPU. First, all EPU analyses reflect the higher EPU power. However, analyses indicating ">" did not explicitly include consideration of the EOP changes as the resulting additional increase in time window was not significant to the HEP assessment, or would otherwise expand the time available time window. This treatment introduces a small conservatism into the EPU assessment. Second, while success criteria mainly involved one HPSI pump delivery and one or two PORVs in some instances success criteria included additional requirements on available injection points which impacts flow delivery, availability of charging pumps and timing of RCP shutdown. These factors have secondary impact on available action time windows. As OTC operator actions can be implemented within the control room in about seven minutes, the likelihood of successful operation is very high and the impact of any EPU-related plant changes on success criteria has a very small impact on plant risk.

Table 2.13-3a
Comparison of Current and EPU Plant Response to Total Loss of Feedwater Events
Time Available to Recover Feedwater to Steam Generator

Event Description	Current (Time to Restore FW Flow) Minutes	Current (Time to core uncovery) Minutes	EPU (Time to Restore FW Flow) Minutes	EPU (Time to core uncovery) Minutes
Loss of main feedwater (LOMFW) and AFW, Reactor Trip of SG Low Level (SG-LL) SG-LL: 20.5%(Current) SG-LL:35% (EPU)	84	56	92 all RCPs tripped while in 2-EOP-01)	66 (all RCPs tripped while in 2-EOP-01)
LOMFW resulting from a Reactor Trip (SG at nominal level) followed by loss of all AFW	139	103	136 (all RCPs tripped at 5 minutes)	105 (all RCPs tripped at 5 minutes)

Table 2.13-3b
Comparison of Current and EPU Plant Response to Total Loss of Feedwater Events
Time Available to Initiate Once Through Cooling

Event Description	Current (One PORV Available) Minutes	Current (Two PORVs Available) Minutes	EPU (One PORV Available) Minutes	EPU (Two PORVs Available) Minutes	Comments
LOMFW and AFW, Reactor Trip of SG Low Level (SG-LL) SG-LL: 20.5%(Current) SG-LL: 35% (EPU)	62 ⁽¹⁾	90	45 ⁽⁴⁾	>60	Without changes to the EOP, the EPU would result in response windows of 15 minutes (one PORV) and 60 minutes (two PORVs)
LOMFW resulting from a Reactor Trip (SG at nominal level) followed by loss of all AFW	45 ⁽²⁾	180	>45 ⁽³⁾	>125	Without changes to the EOP, the EPU would result in response windows of 45 minutes (one PORV) and 125 minutes (two PORVs)
Notes: 1. Timing credits one HPSI and availability of two charging pumps and injection into four cold legs. RCPs operated in accordance with trip two/leave two strategy. 2. Timing credits one HPSI injecting into one cold leg. No credit given for charging pumps. RCP trip delayed until PORV initiation. 3. The EPU timing estimate based on one HPSI and one charging pump (normally operating) injecting into one cold leg. RCP trip delayed until PORV initiation. 4. Credits post EPU EOP changes, one HPSI, two charging pumps and discharge into two cold legs.					

The EPU also impacts RCS core heat removal as a result of changes in boric acid concentrations and higher decay heat following loss of coolant accidents. RCS and core heat removal can be lost due to boron precipitation following a medium or large break LOCA. Anticipated changes in boron concentration have been considered in establishing time for operator to initiate hot leg injection. Changes in boron concentration have not resulted in changes to the long term cooling timing implementation requirements (See LR [Section 2.8.5.6.3.5.4](#)). Consequently, the risk impact of the above mentioned change is negligible.

The number of components required to support at-power RCS and core heat removal using main feedwater (MFW) will not change for the EPU. The heater drain pumps (HDPs) and MFW pumps are being replaced and/or modified to ensure that the current plant capability of the HDPs is maintained at EPU conditions.

2.13.2.6.1.4 RCS Inventory Control

The pressurizer level control setpoints will not change for the EPU; however, minor adjustments to the setpoint control breakpoints were made to represent 15 percent and 90 percent power, as a function of T_{avg} . To compensate for potential increases in PORV/SRV challenges, changes have been made to the quick response steam relief capacity. As a result of these changes, plant response analyses indicate that following the EPU, PORV challenges is not expected as a result of uncomplicated reactor or turbine trips. Additionally, RCS integrity will not be challenged by partial loss of reactor coolant flow (one RCP) or partial loss of feedwater (one MFW pump). Thus, any impact on the EPU RCS integrity is considered minimal.

2.13.2.6.2 Insights from Thermal-hydraulic Analysis

Success criteria assessments were primarily developed from plant specific MAAP (Reference 26) analyses. MAAP was also used to determine the available time for operator actions modeled in the PRA. For purposes of the MAAP analyses, it was assumed that core damage occurs once the peak fuel region temperature (TCRHOT) reaches 2200 °F or clad oxidation of a localized fuel region exceeds 1%. In some instances, lower core damage temperatures were conservatively applied. MAAP analyses confirm that one of the main impacts of the EPU is a reduction in the time available for operator response due to the increased decay heat. The PRA includes about 40 post-trip human actions; approximately half of these actions had reduced operator response times as a result of the EPU. However, as most actions have ample time for operator response, in addition to the actions being well defined and procedure driven, very few of these human actions resulted in human error probabilities that were impacted by the EPU. Furthermore, as a result of focused changes to EOPs and a plant reactor trip setpoint change, several risk-significant operator action times were actually extended for the EPU.

For transients that can not be adequately simulated by MAAP, results of design basis codes or extrapolation of representative analyses were used to establish success criteria and associated operator actions. Specifically, design basis input was used for success criteria for large LOCA injection and recirculation success criteria (including timing for simultaneous hot leg /cold leg injection). For the evaluation of ATWS peak pressures, success criteria for the EPU were based on a linear extrapolation of CEOG ATWS 2700 MWt peak pressure curves for a generic 2700 MWt pressurized water reactor (PWR) with two PORVs (each one half the capacity of a St. Lucie Unit 2 PORV) and two SRVs. St. Lucie Unit 2 analyses assume that both PORVs are available, although one PORV is blocked during power operation due to its large size. However, as the St. Lucie Unit 2 PORVs are twice the size of the PORV used in the generic evaluation the steam relief capability of a single St. Lucie 2 PORV is equivalent to that of the generic plant with two PORVs. Results of the EPU extrapolation are considered conservative in that conservative MTCs are used and the estimation of unfavorable exposure times (UETs) credits only two of three SRVs for steam relief.

2.13.2.6.2.1 Inventory Control

LOCA inventory losses are driven by RCS pressure. In the early moments of a LOCA event, the inventory losses are the same between the current plant and the EPU plant configurations. As the LOCA progresses with no injection, the EPU plant conditions will keep the RCS pressure slightly higher and experience core damage sooner than current conditions due to the higher decay heat. As recovery of equipment during inventory loss events was not credited, very few PRA operator actions are impacted by these changes. The operator actions that are potentially impacted were found either to not be time sensitive or performance of the action is independent of the event consequence. Therefore, the impact of the EPU on inventory loss events is considered small.

2.13.2.6.2.2 Decay Heat Removal

As discussed in LR [Section 2.8.4.4](#) Residual Heat Removal System, the EPU has direct effects on decay heat removal. The impact of decay heat removal primarily results in an increase in the requirements of equipment availability for event success and shortened times to implement operator actions. These issues are discussed below.

Decay Heat Removal via Recovery of Feedwater

Following TLOFW events, the time available to successfully recover feedwater to the steam generators prior to core damage is a direct function of the plant decay heat load. The impact of the EPU on the time for feedwater recovery following an instantaneous loss of all feedwater from full power is illustrated in [Table 2.13-3a](#). As discussed in [Section 2.13.2.6.1.3](#), depending on the details of the event initiation and whether the reactor trip occurs before the time of the SG low level trip, the net impact of the EPU would be to slightly increase or decrease the associated operator recovery window.

Decay Heat Removal via Once-Through-Cooling

To be effective, OTC must be initiated in advance of SG dryout to ensure that sufficient inventory is injected early in the transient to adequately cool the RCS and restore inventory such that the RCS pressure can be maintained at sufficiently low levels (typically around 1000 psia) as to accommodate long term high pressure safety injection (HPSI).

At St. Lucie Unit 2, following an ECCS actuation, RCS pressure must fall below the shutoff head of the HPSI pump (~1200 psia) for injection to initiate. To maintain RCS pressure low enough to initiate the HPSI pump injection, the plant relies on heat removal via the SGs. In the absence of an adequate SG secondary heat sink, reduction of RCS pressure below HPSI pump shutoff head is accomplished by opening the pressurizer PORVs which, when open, provide a flow path from the HPSI pumps through the core and out the top of the pressurizer through the PORVs. This flow path provides decay heat removal in the “once through cooling” alignment.

[Table 2.13-3b](#) provides OTC maximum available initiation times for an instantaneous TLOFW scenario for both current and EPU operation. The time to restore cooling on a total loss of decay heat removal varies considerably based on the time flow is lost to the steam generator, the amount of water in the steam generator at the time of the trip and the status of the RCPs. Extending the steam generator low level reactor trip setpoint to 35 percent NR results in an

earlier plant trip and provides for increased inventory in the Steam Generator early in the event, significantly mitigating the impact of the increased decay heat. Although the RCPs increase the rate of heat transfer to the steam generators, the RCPs become a liability later in the event when the additional heat added by the RCPs (approximately 14 MWt) become a significant fraction of the decay heat. Accordingly, the EOPs will be modified for the EPU to direct the operator to trip all RCPs early as a part of 2-EOP-01 SPTAs following initial identification of a TLOFW. This action extends SG inventory and provides for a further increase in the response window for operators to mitigate a TLOFW event via OTC.

Long Term Decay Heat Removal

Long term decay heat removal is slightly impacted by the increased decay heat load, which will lead to a delay of entry into shutdown cooling during a LOCA event. This reduction in available time is included in the plant human reliability analysis (HRA). As the operator actions to establish shutdown cooling are well proceduralized and well trained upon, the impact on the HEP and the PRA are judged negligible.

For large break LOCA scenarios, analyses indicate that the time window for the operator to complete switchover into the simultaneous hot leg/cold leg injection mode will be shortened, however, the actual limiting action time of 6 hours remains unchanged.

2.13.2.6.3 Operator Actions

The higher decay heat level associated with the EPU will reduce the total time available for the operators to complete recovery actions. For certain recovery actions, the reduced total response time will increase the human action failure likelihood. While several post-EPU actions were identified to have increased human error probability, no actions were considered failed for insufficient available time. For the most part, the impact on plant risk have been minimal as several offsetting compensatory changes will be implemented concurrently with the EPU (See [Section 2.13.2.6.3.3](#)).

Operator actions modeled in the PRA were reassessed using the EPRI HRA calculator. The reassessment was applied to both current and EPU PRA models. The resultant evaluation provides consistent and credible human action failure likelihoods with an added benefit of direct comparability between the current and EPU PRA results.

2.13.2.6.3.1 Human Reliability Analysis Methodology

As part of the EPU, the HRA was developed in a manner to conform to RG 1.200. All post-initiator human actions contained within the PRA were reviewed to address the impacts that are associated with adverse environmental conditions and accessibility limitations. Operator interviews and event simulations were conducted to gain a full understanding of the associated event environment, clarity and effectiveness of the procedures involved the extent of operator training on the scenarios and required operator actions. Using this gathered information in combination with the results of computer simulations of an accident sequence, each operator action was evaluated using the EPRI HRA Calculator ([Reference 27](#)).

Where appropriate, response time windows were evaluated using plant-specific MAAP 4.0.7 accident analysis simulations. As discussed in LR [Section 2.13.2.2](#), the HCR/ORE and CBDTM methodologies were applied to all of the human error events, and for each event, the greater of the calculated human error probabilities from the two methodologies was used in the PRA model.

2.13.2.6.3.2 Pre-Initiator Human Actions

In addition to post-initiator human actions, human performance actions prior to an event, such as those associated with maintenance and surveillance activities can be important contributors to risk. The methodology for evaluating pre-initiator human failure events was the accident sequence evaluation program (ASEP). Detailed ASEP calculations were performed on the non-screened human failure events that were judged to dominate systems risk based on systematic review of the surveillance procedures, per RG 1.200 requirements. Of particular importance is the surveillance testing on components of critical mitigating and support systems. A review of the EPU top 100 CDF and LERF CAFTA cutsets indicates many pre-initiator human failures are included in the top cutsets. As a result, the surveillance frequency will be increased on selected valves in the AFW system resulting in a risk-significant decrease in EPU CDF and EPU LERF. Changes to plant EOPs and surveillance procedures OSP-100.01 through OSP-100.13 will require weekly surveillance on selected risk-significant valves (AFW manual discharge valves) to ensure proper alignment. This action reduced the failure probability for these valves an order of magnitude from 1.3E-04 to 1.33E-05.

2.13.2.6.3.3 Results of Human Reliability Analysis

Results of the HRA assessment are provided in LR [Table 2.13-4](#). LR [Table 2.13-4](#) identifies the operator actions included in the PRA and the associated time to core damage and operator recovery times for both the current and EPU plant. Operator recovery times are defined as the time the operator has to perform an action, and is measured as time available from the action cue, less the time needed to respond to and complete the required action. Additionally, LR [Table 2.13-4](#) provides the associated calculated human error probabilities.

For most of the operator actions included in the PRA, the EPU has no impact on the estimated operator human recovery actions.

As discussed in LR [Section 2.13.2.6.2](#), human actions that are impacted by the EPU fall into two broad categories: inventory control and decay heat removal. Many involve changes to the time available to perform an action; however, for all but five of the actions, the reduction in the time available for operator action was not sufficient to cause an increase in the human error probability (HEP). All events that resulted in an increased HEP are associated with an initiator that resulted from a LOMFW. Three of the events (FHFP2RECMFW, FHFP2RECMFW-L, FHFP2RECMFW-N) are associated with restoration of MFW and the other events (GHFPOTCR, GHFPOTCS) are associated with implementing OTC following a SGTR and a small LOCA, respectively. As these values were obtained using a bounding HRA analysis where no credit is provided as a result of changing reactor trip setpoint and the early secure of RCPs during SPTA for TLOF scenarios, recovery timing leading to reduced HEP are expected to increase if such credit were to be considered. However, current HRA analysis using the same reactor trip setpoint for the EPU as that of pre-EPU is considered bounding. The credit for changes listed in

Section 2.13.2.6.1.3 has been implemented in the EPU model as reflected by the EPU success criteria analysis, but was not reflected in the bounding EPU HRA analysis.

Table 2.13-4
Comparison of St. Lucie Unit 2 Current (Baseline) and EPU Plant Human Error Probability (HEP)

Basic Event ID	Basic Event Description	Current HEP	EPU HEP	Current Recovery Time (Minutes)	EPU Recovery Time (Minutes)
AHFPMANUAL-L	Fail manually start AFW pump(s) (loss of auto start signal)	8.60E-05	8.60E-05	78	59
AHFPMANUAL-N	Fail start AFW pump(s) after loss of auto-start signal	8.60E-05	8.60E-05	133	107
AHFPMANUAL-R	Fail start AFW pump(s) to feed SGs & loss auto start signal	7.80E-05	7.80E-05	379	264
AHFPMANUAL-S	Fail start AFW pump(s) after sml LOCA & no auto-start signal	8.60E-05	8.60E-05	159	134
AHFPSGISO	Fail isolate faulted SG & realign AFW follow SGTR	2.20E-04	2.20E-04	171	131
AHFPXCON>4	Fail xtie AFW trains (trip@norm SG lev&FW avail for >=4hrs)	2.60E-03	2.60E-03	345	235
AHFPXCON-L<4	Fail xtie AFW trains (trip on lo-SG level & 1st 4hrs-no FW)	3.10E-03	3.10E-03	54	35
AHFPXCON-N<4	Fail xtie AFW trains (trip on norm-SG lev & 1st 4hrs-no FW)	2.60E-03	2.60E-03	109	83
AHFRCPUMP	Fail ctrl TD AFW pp during SBO & LODC	1.00E-01	1.00E-01	364	254
CHFPRCPTRP	Failure to trip RCPs loss of CCW	9.70E-04	9.70E-04	36	36
CHFPRCPTRP-L	Failure to locally trip RCPs loss of CCW and DC power	5.30E-03	5.30E-03	36	36
EHFP2XTIE	Failure to align blackout xtie to power Unit 2 from Unit 1	1.00E-03	1.00E-03	122	96
EHFPDC-2AB	Failure to realign 125vdc bus AB (not battery depletion)	2.30E-03	2.30E-03	78	59
EHFPEDGFO	Failure of manual MU to EDG day tank after auto MU fails	4.10E-02	4.10E-02	19	19
EHFRMANEDG	Failure to close EDG breaker w/loss of auto close permissive	9.70E-04	9.70E-04	124	98

Table 2.13-4
Comparison of St. Lucie Unit 2 Current (Baseline) and EPU Plant Human
Error Probability (HEP)

Basic Event ID	Basic Event Description	Current HEP	EPU HEP	Current Recovery Time (Minutes)	EPU Recovery Time (Minutes)
EHFRRESET	Failure to recover offsite power following failure of lockout relay	2.40E-04	2.40E-04	133	107
FHFP2RECMFW	Failure to restore MFW after transient (trip on low SG level)	1.10E-02	3.80E-02	54	35
FHFP2RECMFW-L	Failure to restore MFW after transient (trip on lo-SG level)	1.10E-02	3.80E-02	54	35
FHFP2RECMFW-N	Failure to restore MFW after transient (trip on normal SG level)	6.10E-04	2.00E-03	109	83
GHFP2HOTLEG	Failure to initiate hot-leg injection following large LOCA	5.90E-05	5.90E-05	335	335
GHFPOTCR	Failure to initiate OTC following SGTR	5.00E-04	7.60E-04	154	80
GHFPOTCS	Failure to initiate OTC following small LOCA	1.10E-03	4.70E-03	34	16
GHFPOTCTGT41	Fail to initiate OTC-FW for @least 4hrs (1 PORV)	5.00E-04	5.00E-04	126	86
GHFPOTCTLL	Fail initiate OTC follow LOFW -lo SG lvl & no FW (1st 4hrs)	5.00E-04	5.00E-04	77.7	49
GHFPOTCTNL1	Fail initiate OTC -norm SG lvl trip & no FW-1st 4hrs (1HPSI pp)	5.00E-04	5.00E-04	131	86
GHFPOTCTNL2	Fail initiate OTC -normSG lvl trip & no FW-1st 4hrs (2HPSI pp)	5.00E-04	5.00E-04	135	99
GHFPOTCTNLOG	Failure to initiate OTC (LOOP) -no FW 1st 4hrs	5.00E-04	5.00E-04	135	99
HHFPU1ALIGN	Failure to align IA compressor 1A/B after LOOP	1.40E-05	1.40E-05	915	915
HHFPU2ALIGN	Failure to align IA compressor 2A/B after LOOP	1.40E-05	1.40E-05	915	915
IHFP2ELEQ	Failure to restart elect equip room fans following LOOP	5.20E-03	5.20E-03	60	60
JHFPSDCR	Failure to establish SDC following SGTR	4.20E-06	4.20E-06	690	690

Table 2.13-4
Comparison of St. Lucie Unit 2 Current (Baseline) and EPU Plant Human
Error Probability (HEP)

Basic Event ID	Basic Event Description	Current HEP	EPU HEP	Current Recovery Time (Minutes)	EPU Recovery Time (Minutes)
JHFPSDCS	Failure to establish SDC following sml LOCA	4.20E-06	4.20E-06	705	705
KHFP2CISV	Failure to isolate containment isolation valve	8.90E-04	8.90E-04	73	73
LHFPMANUAL	Failure to initiate CS manually when auto actuation fails	1.90E-03	1.90E-03	54	54
MHFPEMBOR	Failure to perform emergency boration to shutdown reactor	1.40E-02	1.40E-02	7	7
NHFPMANTRIP	Failure to trip reactor when auto scram fails	2.50E-03	2.50E-03	0.67	0.67
NHFPMANUALR	Fail initiate sump recirc after LOCA & auto switchover fails	3.50E-02	3.50E-02	3.9	3.8
NHFPMANUALS	Failure to actuate SI manually after sml LOCA	1.90E-03	1.90E-03	34	31
OHFPPORVISO	Failure to isolate PORV relief path after PORV fails open	1.40E-03	1.40E-03	47	48

2.13.2.6.4 Component and System Reliability

Existing equipment monitoring techniques, preventive maintenance, and condition monitoring programs will identify any accelerated component wear that might result from the EPU. Additionally, through trending, these programs will also identify deviations or potential increases in component failure rates. In some instances, the EPU may require more frequent maintenance or replacement of components, to ensure proper system performance.

FPL utilizes an aggressive maintenance program that maintains operating margin. Therefore, decreases in component reliability are not expected and were not included in the base PRA assessment. However, sensitivity studies were performed on selected components or systems where changes due to the EPU had the potential to impact plant performance. These studies are presented in LR [Section 2.13.2.9](#).

2.13.2.7 Level 2 Analysis

The Level 2 model includes an explicit LERF model and provides an integrated interface with the Level 1 model. The simplified Level 2 evaluation calculates the LERF using the CDF accident sequences and bins results into LERF, intact containment, late containment failure and small early release end states. The calculations considered all relevant severe accident phenomenology.

2.13.2.8 IPE/IPEEE Vulnerabilities

All vulnerabilities identified in the IPE and IPEEE have been resolved. No new vulnerabilities are introduced as a result of the EPU.

2.13.2.9 EPU Risk Analysis and Sensitivity Studies

LR **Table 2.13-5** shows the current and EPU CDFs, as well as the change in CDF and LERF. The EPU risk assessment presented below conservatively doubles the EPU reactor trip frequency. As seen in LR **Table 2.13-5**, the EPU operation will be at a lower risk from the current plant conditions. This risk decrease is due to the following:

- FPL implemented requirements for weekly surveillance on selected risk-significant valves (AFW manual discharge valves) to ensure proper alignment.
- Increase in the SG low level reactor trip set point from 20.5 percent to 35 percent NR.
- Change in 2-EOP-01 to include a requirement that all RCPs be tripped upon identification of a total loss of feedwater event.

Table 2.13-5
Comparison of St. Lucie Unit 2 Current and EPU Internal Event Plant Risks

	CDF (per year)	ΔCDF (per year)	LERF (per year)	ΔLERF (per year)
Current	5.04E-06	N/A	2.77E-07	N/A
EPU	5.03E-06	-9.9E-09	2.60E-07	-1.71E-08

LR **Table 2.13-6** shows the top initiators that contribute to the increase in risk associated with the EPU. Although the initiating event frequency may not change, the time available to perform the required human actions, given the initiating event occurs, may change. This can cause an initiating event not directly impacted by the EPU to increase above its current risk contribution. Overall, the EPU has a small impact on the CDF risk profile.

Table 2.13-6
**Comparison of Initiating Event Contributions to CDF
from the Current and the EPU Plant**

Initiating Event (IE)	Current Plant (per year)		EPU (per year)	
	% Contribution	CDF per year Contribution	% Contribution	CDF per year Contribution
SMALL LOCA	31.11%	1.57E-06	31.17%	1.57E-06
STUCK-OPEN SRV	20.12%	1.01E-06	20.16%	1.01E-06
LOSS OF MFW	11.46%	5.78E-07	9.37%	4.71E-07
LARGE LOCA	10.21%	5.15E-07	10.23%	5.15E-07
REACTOR/TURBINE TRIP	6.63%	3.34E-07	8.85%	4.45E-07

Table 2.13-6
Comparison of Initiating Event Contributions to CDF
from the Current and the EPU Plant

Initiating Event (IE)	Current Plant (per year)		EPU (per year)	
	% Contribution	CDF per year Contribution	% Contribution	CDF per year Contribution
RX VESSEL RUPTURE	5.36%	2.70E-07	5.37%	2.70E-07
ISLOCA	2.90%	1.46E-07	2.91%	1.46E-07
SGTR	2.84%	1.43E-07	2.85%	1.43E-07
LOSS OF GRID	2.55%	1.28E-07	2.51%	1.26E-07
LOSS OF CCW/ICW	2.42%	1.22E-07	2.40%	1.21E-07
LOSS OF DC BUS	2.15%	1.08E-07	2.09%	1.05E-07
OTHER	0.89%	4.51E-08	0.73%	3.70E-08
MEDIUM LOCA	0.75%	3.79E-08	0.75%	3.79E-08
SEAL LOCA	0.61%	3.05E-08	0.61%	3.05E-08

The above CDF results reflect quantification of the PRA at a 9.0E-13 truncation limit. This value provides sufficient resolution for the risk calculations used for the EPU. The total LERF reflects quantification to a 1.0E-12 truncation limit.

Other plant changes are expected to further reduce risk as a result of actions to stabilize the grid and reduce the potential for the causes of known past reactor trips. While it is expected that these changes will reduce selected initiating event frequencies, these reductions were not credited in the EPU PRA. To better understand the impact of these changes on plant risk, sensitivity studies are provided below.

2.13.2.9.1 Initiating Events

The first sensitivity evaluation focused on initiating events that may be impacted by the EPU.

Increased Fluid Flow - Although it is the goal of the erosion control program to manage the impact of increased flows and maintain piping integrity, it is possible that certain piping segments will have increased wear and have a higher likelihood of failure. For this reason, the sensitivity of feedwater and steam line breaks was examined.

Electrical Stability - Although every prudent effort is made to ensure electrical stability at EPU conditions, the load on the lines from the generator to the switchyard and beyond will increase. For this reason, the sensitivity of line/grid losses were examined.

Increased Operational Margin for Electrical and Secondary components - Specific changes have been made to the electrical system to increase the cooling capacity and margin for the isophase bus (IPB). Additional changes have been made to the main feedwater system to increase operational margin and to reduce the susceptibility to reactor and turbine trips.

Regardless, for conservatism, the EPU model includes a doubling of the current reactor trip frequency post-EPU.

Increased Power – While increased power operation is not expected to result in an increase of plant trips, the EPU PRA model includes an EPU reactor trip frequency twice as large as the baseline value. Furthermore, even though the PORV challenge frequency was based on a conservative selection of events, the potential for an increase in the PORV frequency was considered a candidate for the sensitivity study and was therefore examined.

LR [Table 2.13-7](#) shows the sensitivity results for the initiating event frequencies discussed above. The table shows the initiating event description, the EPU frequency, and EPU CDF delta. The CDF increase is due to the assumption that the EPU initiating event frequencies increase. This assumption was made to support internal events analyses, as described in LR [Section 2.13.2.3](#).

Table 2.13-7
Sensitivity to Initiating Event Frequencies

Initiating Event (IE) Description	Base IE Frequency (per year)	IE Frequency Increase for the EPU	EPU Δ CDF (per year)	EPU Δ LERF (per year)
Loss of Offsite Power	3.11E-02	10%	1.24E-08	1.39E-09
Loss of 4Kv and 6.9 Kv Electrical Bus	(1)	10%	1.9E-09	1E-11
Reactor Trip (with concurrent PORV Challenge)	8.81E-03	50%	1.0E-09	unchanged
Loss of MFW due to Feedline Break	3.33E-03	10%	2.0E-10	4E-12
Main Steamline Break	1.47E-03	10%	4.0E-10	1E-11
Spurious MSIV Isolation Signal	2.09E-02	10%	9E-10	5E-11
1. Support system initiating event (SSIE): SSIE is modeled via use of fault trees.				

Note that in the above table, changes are referenced to the EPU condition with the lower frequency.

2.13.2.9.2 Impact of Reduced HRA Timing on the Baseline

In this sensitivity study, the CDF obtained by modifying only the EPU set of HEPs in the model was compared directly with the current plant CDF of 5.04E-06 per year. Results of using the EPU HRA in the current PRA model are illustrated in [Table 2.13-8](#). The HEPs used in the analysis can be found in LR [Table 2.13-4](#). Based on the results of [Table 2.13-8](#), the net impact of changes to HRA (including consideration of pre-initiator HRAs) is marginally risk beneficial.

Table 2.13-8
Sensitivity to Changes in Human Actions (Reduced HRA Timing)
Comparison of St. Lucie Unit 2 Current and EPU Plant Risks

	CDF	ΔCDF	LERF	ΔLERF
Current	5.04E-06	N/A	2.78E-07	N/A
EPU	5.03E-06	-9.9E-09	2.61E-07	-1.71E-08

The relatively small change is consistent with the observation noted in LR [Section 2.13.2.6.3.3](#) which notes that only 5 of the human action HEPs increased in value. The risk impact of these increased HEPs are offset by the order of magnitude reduction in pre-initiator HEP values resulting from increased surveillance of risk significant valves in the AFW system (See LR [Section 2.13.2.6.3.2](#)).

2.13.2.9.3 Hardware Failure Likelihood and Unavailability

For the purpose of this sensitivity study, system component unreliability is increased by 10 percent, which is in approximate proportionality to the EPU. LR [Table 2.13-9](#) provides a listing of Fussell Vesely (FV)-ranked SSC active elements whose failure probability was increased by 10 percent. These results indicate that a 10 percent increase in component unreliability will increase the EPU CDF by 3.76E-07 per year and the LERF by 2.27E-08 per year. When referenced to the current plant, the combined impact of the above sensitivities would result in a ΔCDF of 3.66E-07 per year and a ΔLERF of 5.64E-09 per year.

Table 2.13-9
Impact of System Component Unreliability Due to the EPU

Basic Event	Description	Probability	
		Pre-EPU	EPU (10% Inc)
NMM2CEDM	Mechanical Fault Preventing Rod Insertion	2.10E-06	2.31E-06
GMM2FTRCFI	Common Cause Failure of HPSI Pumps to Run During Injection	3.64E-05	4.00E-05
GMM2PAFTRI	Failure of HPSI Pump A to Run During Injection	1.23E-03	1.35E-03
GMM2PBFTRI	Failure of HPSI Pump B to Run During Injection	1.23E-03	1.35E-03
GMPA2PUMPA	HPSI Pump 2A Fails to Start	1.06E-03	1.17E-03
GMPA2PUMPB	HPSI Pump 2B Fails to Start	1.06E-03	1.17E-03
GMM2MNRCCA	Local Failures of Common ECCS Pump Train A Minimum Recirculation Valves	1.92E-03	2.11E-03
GMM2MNRCCB	Local Failures of Common ECCS Pump Train B Minimum Recirculation Valves	1.92E-03	2.11E-03
QMM2HDRA	ICW HDR A Strainer/Isolation Valve Failures	7.26E-04	7.98E-04
GMM2MPACCF	Common Cause Failure of HPSI Pumps to Start	1.97E-05	2.17E-05

Table 2.13-9
Impact of System Component Unreliability Due to the EPU

		Probability	
Basic Event	Description	Pre-EPU	EPU (10% Inc)
QMM2HDRB	ICW HDR B Strainer/Isolation Valve Failures	7.26E-04	7.98E-04
EDGR22BEDG	EDG 2B FTR	4.13E-02	4.54E-02
AMM2PCFTS	AFW Pump 2C Fails to Start	1.04E-02	1.14E-02
BMM22A1	SIT 2A1 Injection Path Fails	9.44E-04	1.04E-03
BMM22A2	SIT 2A2 Injection Path Fails	9.44E-04	1.04E-03
BMM22B1	SIT 2B1 Injection Path Fails	9.44E-04	1.04E-03
BMM22B2	SIT 2B2 Injection Path Fails	9.44E-04	1.04E-03
CMVC214-18	Motor-Operated Valve MV-14-18 Fails to Close Following SI	6.83E-04	7.51E-04
ECB4220302	AC Breaker 20302 Fails to Close - S/UP to 2B2	2.06E-03	2.27E-03
CMVC214-17	Motor-Operated Valve MV-14-17 Fails to Close Following SI	6.83E-04	7.51E-04
EDGR22AEDG	EDG 2A FTR	4.13E-02	4.54E-02
AMM2CCSVABCD	Common Cause Failure (4/4) OF SVS SE-09-2, SE-09-3, SE-09-4 & SE-09-5	4.12E-05	4.53E-05
ATPF2AFW2C	Turbine-Driven Pump 2C Fails to Run	1.09E-02	1.20E-02
JMFC23480I	Motor-Operated Valve 3480 Fails to Close	6.79E-04	7.47E-04
JMFC23651I	Motor-Operated Valve V3651 Fails to Close	6.79E-04	7.47E-04
JMFC23652I	Motor-Operated Valve 3652 Fails to Close	6.79E-04	7.47E-04
JMFC236651I	Motor-Operated Valve V3481 Fails to Close	6.79E-04	7.47E-04
GMM2ARWT	Local Faults of ECCS Pump A Suction Line from RWT	2.49E-04	2.73E-04
GMM2BRWT	Local Faults of ECCS Pump B Suction Line from RWT	2.49E-04	2.73E-04
EMM2BFOSS	Independent Failures of 2B EDG Fuel Oil Supply System	1.67E-02	1.83E-02
EMMDGRABCD	CCF (4/4) of EDG 1A,1B, 2A, and 2B to Run	9.00E-05	9.90E-05
ORYT2V1200	PZR Code Safety Valve SRV V-1200 Fails to Reclose	7.45E-03	8.20E-03
ORYT2V1201	PZR Code Safety Valve SRV V-1201 Fails to Reseat	7.45E-03	8.20E-03
ORYT2V1202	PZR Code Safety Valve SRV V-1202 Fails to Reseat	7.45E-03	8.20E-03

Table 2.13-9
Impact of System Component Unreliability Due to the EPU

		Probability	
Basic Event	Description	Pre-EPU	EPU (10% Inc)
FMM2ASVFTC	SG 2A Safety Valves Fail to Reseat Following SGTR	2.05E-02	2.25E-02
FMM2BSVFTC	SG 2B Safety Valves Fail to Reseat Following SGTR	2.05E-02	2.25E-02
FMM2ASVFTO	SG 2A Safety Valves Fail to Open Following ATWS	1.96E-02	2.15E-02
FMM2BSVFTO	SG 2B Safety Valves Fail to Open Following ATWS	1.96E-02	2.15E-02
EMM2AFOSS	Independent Failures of 2A EDG Fuel Oil Supply System	1.67E-02	1.83E-02
ECB4220102	AC Breaker 20102 Fails to Close - S/UP to 2A2 4KV	2.06E-03	2.27E-03
GMM2AMINRC	Local Faults of HPSI Pump A Min Recirc Line	2.75E-04	3.02E-04
GMM2BMINRC	Local Faults of HPSI Pump B Min Recirc Line	2.75E-04	3.02E-04
CXVK214126	Manual Valve 14126 Transfers Closed	1.34E-04	1.47E-04
GXVK23470S	Manual Valve V3470 Transfers Closed During Standby	1.34E-04	1.47E-04
CXVK214127	Manual Valve 14127 Transfers Closed	1.34E-04	1.47E-04
GXVK23411S	Manual Valve V3411 Transfers Closed During Standby	1.34E-04	1.47E-04
QMM2MPFCCF	ICW Pump Fails to Run Due to Common Cause Failure (3/3 ICWPs).	1.85E-06	2.04E-06
AMM2SGBP2C	Modular Event for Header Valves in Flow-Path from Turbine Pump to SG 2B	5.63E-03	6.20E-03
AMM2SGAP2C	Modular Event for Header Valves in Flow-Path from Turbine Pump to SG 2A	5.63E-03	6.20E-03
GMM2PCVCCF	Common Cause Failure OF HPSI Pump Discharge CV to Open	2.53E-06	2.78E-06
GMM2PAFTRR	Failure of HPSI Pump A to Run During Recirculation	1.23E-03	1.35E-03
GCVN23401	Check Valve V3401 Fails to Open	1.00E-04	1.10E-04
GCVN23427	Check Valve V3427 Fails to Open	1.00E-04	1.10E-04
OMM2CPORVO	CCF of 2/2 PORVS to Open	2.23E-04	2.46E-04
REPS2CA1RP	Case 1 – Plant Centered	1.65E-01	1.82E-01

Table 2.13-9
Impact of System Component Unreliability Due to the EPU

		Probability	
Basic Event	Description	Pre-EPU	EPU (10% Inc)
GCVN23410	Check Valve V3410 Fails to Open	1.00E-04	1.10E-04
GCVN23414	Check Valve V3414 Fails to Open	1.00E-04	1.10E-04
EDGR11AEDG	EDG 1A FTR	4.13E-02	4.54E-02
EDGR11BEDG	EDG 1B FTR	4.13E-02	4.54E-02
CMM2CCWA	Local Failures of CCW to Train A ECCS Pumps	8.93E-05	9.82E-05
CMM2CCWPA	Local Failures of CCW to HPSI Pump A	8.93E-05	9.82E-05
CMM2CCWB	Local Failures of CCW to Train B ECCS Pumps	8.93E-05	9.82E-05
CMM2CCWPB	Local Failures of CCW to HPSI Pump B	8.93E-05	9.82E-05
EDGL22BEDG	EDG 2B Fails to Load/Run	6.44E-03	7.08E-03
ECBR220402	AC Breaker 20402 Transfers Open - for 480V LC 2B2	2.40E-05	2.64E-05
GMM2ASUMP	Local Faults of ECCS Pump A Suction Line from Sump	8.04E-04	8.84E-04
JMM2MPACFI	Common Cause Failure OF LPSI Pumps to Start During Injection	1.31E-04	1.44E-04
GMM2PBFTRR	Failure of HPSI Pump B to Run During Recirculation	1.23E-03	1.35E-03
GMM2RCVCCF	Common Cause Failure OF RWT Outlet Check Valves to Open	1.38E-06	1.52E-06
GMM2FTRCFR	Common Cause Failure OF HPSI Pumps to Run During Recirculation	3.64E-05	4.00E-05
EDGL22AEDG	EDG 2A Fails to Load/Run	6.44E-03	7.08E-03
ECB4120501	Unit 1 Blackout Crosstie Breaker Fails on Demand	2.06E-03	2.27E-03
ECB4220501	Unit 2 Blackout Crosstie Breaker Fails on Demand	2.06E-03	2.27E-03
GCVN23217	Check Valve V3217 Fails to Open	1.00E-04	1.10E-04
GCVN23227	Check Valve V3227 Fails to Open	1.00E-04	1.10E-04
GCVN23237	Check Valve V3237 Fails to Open	1.00E-04	1.10E-04
GCVN23247	Check Valve V3247 Fails to Open	1.00E-04	1.10E-04
MMM2RWT	Local Faults in RWT Line	1.07E-03	1.17E-03
GMM2CVNSUCCJ	HPSI Pump Suction Check Valves V3401/3410 Fail to Open During Injection	1.28E-06	1.41E-06

Table 2.13-9
Impact of System Component Unreliability Due to the EPU

		Probability	
Basic Event	Description	Pre-EPU	EPU (10% Inc)
MMM2V2501	MOV V2501 Fails to Close Independent Failures	9.92E-04	1.09E-03
FMM2SGCVLV	Common Cause Failure of SG Check Valves - FTO	2.72E-06	2.99E-06
ECBR2B2AUE	2B AUX BKR to 2B2 4KV Bus Transfers Open (1 yr Exposure)	8.72E-03	9.59E-03
EMM2BFLVLV	Independent Failures of 2B EDG Day Tank Fuel Oil Fill Valves	4.74E-02	5.22E-02
EMM2SUBKR	CCF of SU TX BKRS to Close (2/2)	3.83E-05	4.22E-05
GMM2BSUMP	Local Faults of ECCS Pump B Suction Line from Sump	8.04E-04	8.84E-04
EMMDGSABCD	CCF (2/4) of EDG 1A,1B, 2A, and 2B to Start	8.59E-06	9.45E-06
EDGS22BEDG	EDG 2B FTS	3.60E-03	3.96E-03
CCVK2442E	Check Valve 14442 Transfers Closed (1 yr Exposure)	1.47E-02	1.62E-02
CCVK2443E	Check Valve 14443 Transfers Closed (1 yr Exposure)	1.47E-02	1.62E-02
CCVK2444E	Check Valve 14444 Transfers Closed (1 yr Exposure)	1.47E-02	1.62E-02
CCVK2445E	Check Valve 14445 Transfers Closed (1 yr Exposure)	1.47E-02	1.62E-02
CMM2MPFCCF	CCW Pump Fails to Run Due to Common Cause Failure	6.80E-07	7.48E-07
IMM2EERRABCD	HVS-5A, HVS-5B, HVE-11 and HVE-12 FTR CCF	1.80E-06	1.98E-06
EMM2AFLVLV	Independent Failures OF 2A EDG Day Tank Fuel Oil Fill Valves	4.74E-02	5.22E-02
GCVK23401I	Check Valve V3401 Transfers Closed During Injection	4.06E-05	4.46E-05
JMPA2PBINJ	LPSI Pump 2B Fails to Start During Injection	4.16E-03	4.58E-03
JMPA2PAINJ	LPSI Pump 2A Fails to Start During Injection	4.16E-03	4.58E-03
GCVK23410I	Check Valve V3410 Transfers Closed During Injection	4.06E-05	4.46E-05

2.13.2.9.4 Impact of Increased Secondary Side Feed and Steam Flows

In addition to the assumed increase in flow accelerated corrosion, as mentioned in LR [Section 2.13.2.3.4](#), there exists the additional potential of spurious closure of a main steam isolation valve (MSIV). Accordingly, in this sensitivity study all initiating event frequencies involving FW or steamline breaks, as well as spurious MSIV actuation were increased by 10 percent. Neither of these increases is in fact expected, but have been added for conservatism. As measured from the current plant risk, the potential for a main feedwater line break (MFLB) or a main steam line break (MSLB) will increase the plant CDF by 4E-10 and LERF by 1E-11 per year.

Similarly, spurious MSIV closure frequency is estimated to increase CDF by 9E-10 per year (and 5E-11 per year for LERF).

LR [Table 2.13-10](#) illustrates the potential impact of changes in steam and feedwater system flowrates on increased pipe failure frequency and plant risk.

Table 2.13-10
Impact of Potential Increases in Initiating Event Frequency Changes
on EPU CDF and LERF

Initiating Event (IE)	Description	Current IE Freq (per year)	% Increase for EPU	Delta EPU CDF (per year)	Delta EPU LERF (per year)
%ZZT3DU2	Loss of MFW due to Feedline Break Common to Both MFW Trains	1.11E-03	10%	2E-10	4E-12
%ZZT3DU2A	Loss of Main Feedwater due to Feedline Break on SG 1A	1.11E-03	10%		
%ZZT3DU2B	Loss of Main Feedwater due to Feedline Break on SG 1B	1.11E-03	10%		

Table 2.13-10
Impact of Potential Increases in Initiating Event Frequency Changes
on EPU CDF and LERF

Initiating Event (IE)	Description	Current IE Freq (per year)	% Increase for EPU	Delta EPU CDF (per year)	Delta EPU LERF (per year)
%ZZT5U2A	Steamline Break Upstream of SG 1A MSIV	3.15E-04	10%	4E-10	1E-11
%ZZT5U2B	Steamline Break Upstream of SG 1B MSIV	3.15E-04	10%		
%ZZT6U2	Steamline Break Downstream of the MSIVS	8.40E-04	10%		
%ZZT7MSU2	Spurious Main Steam Isolation Signal	2.09E-02	10%	9E-09	5E-11

2.13.2.9.5 Other Sensitivity Study Impacted Parameters

For further assurance of the EPU acceptability, the impacts of plant challenges to PORVs/main steam safety valves (MSSVs) and ATWS changes regarding PRA parameters were considered, as discussed below.

2.13.2.9.5.1 PORV/MSSV Challenge Parameters

A sensitivity study was performed to establish the impact of a 50 percent increase in pressurizer PORV challenge frequency. This magnitude of an increase is unlikely as several EPU improvements are being implemented to limit PORV/SRV challenges. Results of this sensitivity study are presented in [Table 2.13-5](#). Even with this 50 percent increase in challenge frequency the hypothetical risk impact would be limited to an increase in CDF of 1E-09 per year. Thus, any impact of the EPU on PORV challenge risks is judged to be negligible.

Increasing the size of the steam bypass control system (SBCS) from 29 percent to >45 percent of full steam flow and reducing the stroke time to 2 seconds is intended to limit potential MSSV challenges and improve operating margin. Based on the expected EPU system design, post trip MSSV challenges are expected to be less likely than for the current plant and therefore reduce the likelihood of stuck open MSSVs.

2.13.2.9.5.2 ATWS

As MSSV, PORV, and SRV capacities remain the same, the relative steam removal per megawatt thermal power is reduced causing the potential for a more severe ATWS event at EPU conditions. At St. Lucie Unit 2, FPL uses a conservative approach to assign UETs for an ATWS event.

The PRA defines ATWS success criteria with respect to a generic 2700 MWt CE plant analysis. The base plant for that analysis included two standard PORVs, two SRVs and a bounding MTC curve. In reality, St. Lucie Unit 2 utilizes three SRVs; however, modeling only two SRVs is more conservative for this analysis and therefore is acceptable. Only the most limiting condition associated with the concurrent loss of AFW without actuating a turbine trip is included in the PRA model.

The resulting UET identified in the current plant PRA is 0.22. Extrapolating the current pressure curve for increased power and using upper bound MTC curves, the EPU ATWS UET was increased to 0.255. To evaluate the risk impact of using the unfavorable MTC probability of 0.255, the basic event probability was changed from 0.22 to 0.255. The resulting increase in CDF becomes 4.61E-08 per year and a LERF increase of 1.11E-09 per year. Therefore, the risk impact of the EPU on ATWS is judged to be small.

2.13.2.9.6 Additional Sensitivity Study Discussion on Specific Plant Modifications

This section expands the discussion on four specific plant modifications. These are:

- Improved turbine cooling capacity,
- Improved electrical bus margin,
- Switchyard modifications, and
- Operational change to increase surveillance test frequency requirements for risk-significant AFW system valves.

2.13.2.9.6.1 Impact of Improved Cooling Capacity for Turbine Cooling Water

This plant modification includes replacement of turbine cooling water (TCW) heat exchangers (HXs) with larger HXs to provide additional heat removal capacity for the TCW system. This improvement is most beneficial during summer time. In this sensitivity case study, it is assumed that TCW system cooling reliability will be improved by 2.5 percent. In order to evaluate the risk impact of this improvement, failure probabilities of the dominant events associated with TCW system were reduced by 2.5 percent. LR [Table 2.13-11](#) provides a listing of the TCW events whose failure probability was reduced by 2.5 percent.

Table 2.13-11
EPU Sensitivity to Improved Cooling Capacity of TCW
(Failure Rates Reduced by 2.5%)

		Probability	
Basic Event		Current	2.5% EPU Reduction
TMM2AFLOWE	Faults in Pump "A" Flow Path (1 yr Exposure)	4.86E-02	4.74E-02
TMM2AFLOWL	Faults in Pump "A" Flow Path (MTTR)	4.09E-04	3.99E-04
TMM2AHX	Loss of 'A' TCW HX (1 yr Exposure)	1.98E-01	1.93E-01

Table 2.13-11
EPU Sensitivity to Improved Cooling Capacity of TCW
(Failure Rates Reduced by 2.5%)

		Probability	
Basic Event		Current	2.5% EPU Reduction
TMM2AHXL	Loss of 'A' TCW HX (MTTR)	1.81E-03	1.77E-03
TMM2AICWE	Loss of ICW Flow to 'A' TCW HX (1 yr EXPOSURE)	2.35E-01	2.30E-01
TMM2AICWL	Loss of ICW Flow to 'A' TCW HX (MTTR)	2.20E-03	2.15E-03
TMM2BFLOWE	FAULTS IN Pump "B" Flow Path (1 yr Exposure)	4.86E-02	4.74E-02
TMM2BFLOWL	Faults in Pump "B" Flow Path (MTTR)	4.09E-04	3.99E-04
TMM2BHX	Loss of 'B' TCW HX (1 yr Exposure)	1.98E-01	1.93E-01
TMM2BHXL	Loss of 'B' TCW HX (MTTR)	1.81E-03	1.77E-03
TMM2BICWE	Loss of ICW Flow to 'B' TCW HX (1 yr Exposure)	2.35E-01	2.30E-01
TMM2BICWL	Loss of ICW Flow to 'B' TCW HX (MTTR)	2.2E-03	2.15E-03

Results of the CAFTA evaluation indicate that the TCW system improvements result in a negligible decrease in EPU CDF of 1E-10 per year. LERF results are unchanged.

2.13.2.9.6.2 Impact of Electrical Bus Margin Improvement

Plant modifications include upgrades to the isophase bus cooling systems that increase the normal operating margin for the associated bus. Additionally, the modification includes the removal of several non-essential loads from the respective non-safety bus following generation of an SIAS. Expected loads to be stripped from the bus include condensate pumps, heater drain pumps, feedwater pump motors, and main transformer cooling and the isophase bus duct cooling fans. As a result of the improvements to the isophase bus cooling the loss of offsite power initiating event frequency related to plant-centered loads is judged to decrease. For the purpose of these sensitivity analyses it was assumed that the plant centered loss of offsite power initiating event frequency was reduced by 50 percent (from 1.64E-2 per year to 8.2E-3 per year) under EPU conditions.

Fault tree model changes were also included to reflect stripping of main feedwater components from the non-safety related AC buses upon SIAS. This feature was assumed to render the feedwater system unavailable for secondary heat removal for certain events including SGTRs and small LOCAs. The net impact of the aforementioned plant modifications is a decrease in the post-EPU CDF of approximately 2E-08 per year and a decrease in LERF of about 1.4E-08.

2.13.2.9.6.3 Impact of Increase in LOOP Due to Switchyard Modifications

Plant modifications proposed for the EPU to accommodate the power uprate include changes to the power block, and modifications to the switchyard. Power block modifications include the addition of a power system stabilizer and upgrades to the main generator and main transformer to achieve the increase in power. As discussed in LR [Section 2.13.2.3.4.1](#) the overall expectation is that plant changes will improve the resistance of St. Lucie Unit 2 to LOOP. However, it is possible that the unanticipated loss of some circuits may increase the load on the remaining circuits to unacceptable levels. To gain insight into the plant risk associated with such an occurrence, all LOOP initiating event frequencies were increased by 10 percent. The results of the sensitivity study are presented in [Table 2.13-12](#). Increasing all LOOP initiating event frequency values by 10 percent results in a plant EPU CDF increase of 1.24E-08 and EPU LERF increase of 1.39E-09 per year (see also LR [Table 2.13-7](#)).

Table 2.13-12
Comparison of Increased LOOP
For Switchyard Modification Sensitivity Evaluation

		LOOP Frequency (yr ⁻¹)		
CAFTA Basic Event		Pre-EPU	10% Increase	NUREG/CR-6890, Vol 1, (Table 3-5)
%ZZ2LOGP	Loss of Off-site Power (Plant-Centered)	1.64E-02	1.80E-02	1.31E-02
%ZZ2LOGG	Loss of Off-site Power (Grid-Related)	3.61E-03	3.97E-03	1.71E-03
%ZZ2LOGW	Loss of Off-site Power (Weather-Induced)	5.21E-03	5.73E-03	3.99E-03
%ZZ2LOGGBO	Loss of Off-site Power (Grid-Blackout)	5.84E-03	6.42E-03	Not Applicable

2.13.2.9.6.4 Change in Surveillance Frequency

Pre-initiator HFEs are contributors to dominant PRA scenarios. Pre-initiators are attributed to test and maintenance crews leaving risk significant valves in an undesirable state at the conclusion of their activity. These errors include instrument miscalibration and valves left in the wrong position. To reduce this risk for EPU operation, the plant procedures OSP-100.01 through OSP-100.13 will be modified to require weekly surveillances on selected risk significant valves. The impact of this procedural change is estimated to reduce the human failure event probability by one order of magnitude.

2.13.2.10 Summary of Current and EPU Level 1 and Level 2 Plant Risks

Level 1 and Level 2 LERF results for all models and external events are presented in LR **Table 2.13-13**. The implementation of the EPU is expected to be marginally risk-beneficial at St. Lucie Unit 2. Although there is risk increases associated with some aspects of the EPU, these increases are completely off-set through the risk-beneficial implementation of the following modifications/procedural changes:

- Increase in the SG Low-Level reactor trip setpoint from 20.5 percent to 35 percent NR,
- Change in EOPs to require that all RCPs are tripped upon identification of a TLOFW event in 2-EOP-01 SPTAs, and
- Increase in surveillance test frequency requirements for risk-significant AFW system valves.

Additionally, several other plant modifications that have not been credited by the EPU PRA further bolster the EPU's beneficial risk impact through reducing the likelihood of reactor and turbine trips, increasing resistance to LOOP events and reducing the frequency of main feedwater low suction pressure trips. A list of these items is provided below.

- Main feedwater pump replacement,
- Steam bypass control system capacity increase,
- DEH computer replacement,
- Turbine cooling water heat exchanger replacement,
- Electrical bus margin improvement,
- Iso-phase bus duct cooling upgrade, and
- Power system stabilizer.

While the EPU is not a risk-informed application, the risk evaluation of the EPU meets the rigorous standard of a risk-informed application. According to RG 1.174, for design basis plant risk changes to be considered "very small" (i.e., reside in Region III) they should not result in risk increases above $1.0\text{E-}06$ per year CDF and $1.0\text{E-}07$ per year LERF. Risks are considered "small" (i.e., reside in Region II) when they result in risk increases above Region III levels and remain below $1.0\text{E-}05$ per year CDF and $1.0\text{E-}06$ per year LERF. The present evaluation concludes that EPU operation will have, in aggregate, the same or a marginally lower risk of plant operation than does the current plant.

Table 2.13-13 summarizes the changes in CDF and LERF associated with the EPU for each evaluated plant hazard.

**Table 2.13-13
Current/EPU Summary Evaluation**

Model	Current		EPU		Change	
	CDF	LERF	CDF	LERF	CDF	LERF
Internal Events	5.04E-06	2.77E-07	5.03E-06	2.60E-07	-9.90E-09	-1.71E-08
Internal Flood	<5E-07	Not Available	<5E-07	Not available	<5 E-08	Very small
Fire (non-screened Compartments) ^{(1),(2)}	<1.4E-06	< 1.4E-07 ⁽¹⁾	< 1.4E-06	<1.4E-07 ⁽¹⁾	Small impact possible	Small impact possible
Fire (screened Compartments) ^{(1),(2)}	<7.8E-06	<7.8E-07 ⁽¹⁾	<7.8E-06	<7.8E-07 ⁽¹⁾	Small impact possible	Small impact possible
External events	1.73E-07	3.43E-08	1.72E-07	3.41E-08	-1.1E-09	-2.4E-10
Seismic	3.4E-09	5.7E-10	4.5E-09	6.5E-10	1.1E-09	7.4E-11
Turbine Missile	Not assessed	Not Assessed	<<2E-06 (IE Value, not CDF)	Not Available	Negligible	Negligible
Shutdown	Existing procedures and processes are adequate. EPU will be adequately controlled by existing process. Minor modifications to procedures are expected to accommodate boil-off curve changes.					
1. LERF results are established by extrapolating results of internal event LERF analyses which demonstrate LERF values to be below 10 percent of CDF. 2. IPEEE risks have been re-evaluated. Current risks consider severity factors below unity and credit potential actions of a fire brigade.						

2.13.2.11 Quality of PRA

The Level 1 and Level 2 PRA model was initially developed in response to NRC GL 88-20 Individual Plant Examination ([Reference 6](#)). Since the original IPE submittal, the PRA has undergone several model revisions to incorporate improvements and maintain consistency with the as-built, as-operated plant.

The PRA updates to meet Capability Category II requirements of the ASME standard ([Reference 37](#)) involved revision of the human reliability analysis, common cause analysis, ISLOCA analysis and LERF analysis, along with the development of plant-specific thermal-hydraulic analysis. Overall, the PRA is reviewed and updated with a goal of increased fidelity in areas related to the EPU.

2.13.2.11.1 Model Peer Review

In July 2002, CEOG performed a peer review of the St. Lucie Units 1 and 2, Level 1 and Level 2, 2002-PRA models update. The review followed a process that was adopted from industry

reference NEI-00-02, Rev A3 ([Reference 28](#)). The resulting peer review identified 9 A level F&Os and 30 B level F&Os.

Additionally, in July 2009, a focused peer review was conducted in accordance with RG-1.200 Revision 1 for LERF and common cause failure (CCF). 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 assessments. In 2009, focused peer review was developed for HRA by Scientech whose F&Os were addressed and closed. As a result, LERF, CDF, and HRA were found to meet ASME Standard Capability Category II as endorsed by RG-1.200 Revision 1.

The following is a list of 44 Level A and B observations from the NEI-00-02 PRA review.

2.13.2.11.2 Review Against NEI A and B Findings

For completeness, each F&O finding and comment includes the peer review summary and plant resolution.

1. Accident Sequence AS-1 Level of Significance A¹

Peer Review Observation: Cutset%ZZSU1*CMM1AVCCCF appears overly conservative. Each CCW header provides approximately 8000 gpm. The largest accident loads are the shutdown cooling heat exchangers (4500 gpm) and the fan coolers (1200 gpm each). The N-loads are the spent fuel pool (SFP) HXs (2900 gpm), [letdown] HX (less than 1400 gpm), the RCP cooling (250 gpm each), and the boric acid concentrators (775 gpm).

During a small break LOCA, the heat load on the containment fan coolers is significantly lower than a design basis accident. The load on the SDC HXs does not exist until re-circulation. Eventually, the LOCA will lead to the failure of the RCPs, even if the operators do not trip the pumps. When the RCPs are not running the heat load is further reduced. The SFP will act to moderate temperature changes due to the large volume of water.

Not only will the peak containment temperature and pressures be much lower during the small break LOCA, but also the decay heat removal will not solely be provided through the break. Secondary side heat removal is quite effective during the small break LOCA break sizes.

These issues combine to form a reasonable basis for not requiring N-header isolation during a small break LOCA. Considering the initial flow rates through the TCW HXs and the Open Blowdown HXs, it would be a more difficult argument to make to not require the closure of ICW motor operated valves (MOVs) 21-2 and 21-3.

Considering that most of the heat removal can still be provided by the SGs, it is probably reasonable to removal this closure as well.

This being said the failure both ICW isolation and N-header isolation should probably be considered failure unless a more detailed calculation is available.

1. The question, while explicitly referring to St. Lucie 1 also applies to Unit 2.

Resolution: The issues identified by the F&O were reviewed and resolved per St. Lucie 1&2 engineering calculations. PRA model changes were made accordingly.

2. Accident Sequence AS-2 Level of Significance A

Peer Review Observation: Considering the significance of aligning OTC and the high human action failure probability. It would be prudent to credit to develop multiple human action failure probabilities depending on the type of trip. Breaking out the trips based on SG water level would be a good start (low, normally, and high).

Resolution: This F&O was resolved as part of the PRA update. HRA events created for OTC following normal or low level trips with short term loss of FW, loss of FW after operating for at least 4 hrs, and loss of FW after condensate storage tank (CST) depletion. HRA analyses were further revised to be in accordance with capability category II of the ASME PRA standard.

3. Accident Sequence AS-3 Level of Significance A

Peer Review Observation: MFW is not credited post trip. This leads to quite a few high level cutsets that are overly conservative. If post SG level control is automatic, then only the control system hardware need be modeled. If not, then the human action to control SG water level need be modeled.

The availability of the TBVs post quick open prevents the need for hot well make-up. Crediting the atmospheric dump valves (ADV) for use with MFW would require the modeling of hotwell make-up.

Resolution: This F&O was resolved as part of the PRA update. Credit for MFW is included in the post trip.

4. Accident Sequence AS-8 Level of Significance A

Peer Review Observation: Check Valves V09294 and V09252 are common for AFW, MFW, and Low Pressure Feed. These check valves currently appear only in the AFW system. There may be some events (e.g., loss of load (LOL)) where the turbine trips and SG pressure rises enough to cause the closure of these check valves. Under these scenarios, the failure of both of these checks would fail all secondary side heat removal.

Currently, these check valves are modeled under FMM1SGCVLV. This event has a failure probability far lower than several three element check valve groups in the AFW system. There does not appear to be a basis for this difference. The failure likelihoods (independent and common cause) of the check valves in the AFW system should be consistent or the basis for the difference is documented.

Further, as the random failure of these check valves could cause a LOFW trip and eliminate all secondary side feed to a single SG, this is worthy of consideration as an initiating event.

Resolution: This F&O was resolved as part of the PRA update. Consistent failure mode and CCF data were updated for these components in the latest PRA update.

5. Accident Sequence AS-14 Level of Significance A

Peer Review Observation: The top core damage (CD) cutset is %ZZSU1*GMM1MRMOV. This cutset appear to be overly conservative. The base failure rate of a hand valve to transfer closed without a demand is in the 2E-7 range. The likelihood of a hand valve (HV) transferring closed should be 5 to 10 times lower. Further, the mission time for these MOVs is based on a 3-month test interval. As these MOVs are common to containment spray (CS), low pressure safety injection (LPSI), and high pressure safety injection (HPSI) (6 total pumps), it is highly doubtful that the MOVs will go more than a few weeks without passing flow.

Considering this, the likelihood of this event is between a factor of 20 to 50 lower than currently estimated.

Resolution: This F&O was resolved as part of the updated PRA model. Exposure time was changed to 2.5 months for recirculation valves transferring closed during standby. These additional changes were also implemented: Changed transfer closed (TC) rate for manual valve based on latest generic data calculation. Per discussion with the pump and valve test engineer, the ECCS pumps (HPSI, LPSI, and CS), and thus, recirculation flow paths, are tested within a week or so of each other. The 3-month exposure was reduced accordingly.

6. Initiating Event IE-8 Level of Significance A

Peer Review Observation: All of the PRA documentation are calculations covered by the FPL engineering calculation procedure. This procedure requires independent review and signoff of all calculations performed per this procedure. The latest PRA update was not fully completed at the time of the peer review so most documents had not been independently reviewed at the time of the peer review.

Resolution: All calculations generated in support of current update were independently reviewed/signed-off per FPL requirements.

7. Maintenance and Update MU-2 Level of Significance A

Peer Review Observation: FPL developed no criteria upon which to base the need for a model update. Impacts written against the model may remain pending for a long time. Incorporating into the model a pending impact is based only on judgment call.

In addition, a fixed periodic PRA model update schedule should be established. The update periodicity should be consistent with the principle of a living PRA.

Resolution: PRA internal guidance was revised to include suggested resolution.

8. System Analysis SY-8 Level of Significance A

Peer Review Observation: It appears that in general key control systems in the St. Lucie Plant are not modeled. AFW flow control is not modeled. The auxiliary feedwater actuation system (AFAS) system appears to be controlled based on the NR SG water level (opens at 19 percent decreasing) closes at 29 percent NR. There is no calculation available to determine the number

of cycles required for automatic flow control. Additionally the consequence of SG overfill is not modeled. It should be noted that increased cycles affect a wide array of components: the relays in the control circuitry, the check valves cycled as flow is interrupted to the SG, etc. This affects not only the independent failure rates, but the common cause failure likelihood as well.

Resolution: In consultation with operating staff, the AFW valve operation was reevaluated and an estimated number of valve cycles were established. This information was considered in the updated PRA.

9. System Analysis SY-12 Level of Significance A

Peer Review Observation: It appears that in general key control systems in the St. Lucie Plant are not modeled. In the fault tree the AFW flow control system is demanded 3 times, but the basis for using 3 demands is unclear. No analysis has been done to determine the number of cycles the AFW system will undergo. Further, the common cause MOV demand failure rate only considers a single demand.

The model does not differentiate between an overfill and underfill. Overfills in general could lead to the failure of the turbine driven AFW pumps.

Note: If the MOVs are demanded twice, it is doubtful that the failure likelihood would double. But it is also clear the failure likelihood will increase. Given the importance of the AFW MOVs, any increase to the failure rates can be quite significant.

Resolution: Discussions with operations personnel revealed that the AFAS would start pumps and open flow valves to provide AFW flow to SGs. Small adjustments to valve position over time would be performed by the operator to maintain desired SG level. There would not be a series of valve open and close cycles. Based on these results it was judged that the assumed 3 valve cycles would be adequate to capture or bound the total valve failure probability. No additional plant change was found to be necessary.

10. System Analysis Del2 Level of Significance A

Peer Review Observation: A majority of the documents used to support the model and evaluated as part of the Peer Review have not been independently tech reviewed. (The procedures and processes for calculations obviously have requirements for independent technical reviews and signoffs. The timing of the peer review, however, has the review team continually evaluating unreviewed documents.)

Resolution: All calculations supporting the current PRA updates have been independently reviewed and approved with proper signoffs as required by FPL procedures.

11. Accident Sequence AS-4 Level of Significance B

Peer Review Observation: RWT rupture is assumed to fail shutdown cooling. This seems overly conservative. Without make-up the level in the RCS would drop, but there is more than enough fluid in the boric acid tanks and the volume control tank (VCT) to restore this level. The level does not need to be fully restored to allow shutdown cooling. The level need only be above the hot leg.

Estimated Level Drop 2250 psia at 600°F (0.0217 ft³/lbm) to 100 psia at 300°F (0.01766 ft³/lbm). Given RCS liquid volume of 10,400 ft³, this means approximately 18,500 gallons are required to restore the PRZ level. Each Boric Acid Tank contains 9700 gallons the VCT contains 4000 gallons. Fully PRZ level is not required full shutdown cooling when core damage is the alternative.

Resolution: An assessment of the impact indicated that this has introduced a slight conservatism, as such, it was left as is. This model assumption will have a negligible impact on use of the PRA for the EPU risk assessment.

12. Accident Sequence AS-6 Level of Significance B*

Peer Review Observation: Consider adding low pressure feed (using Condensate pumps) to the model for accident sequences involving loss of all MFW/AFW.

Using condensate pumps to feed the SGs is in both EOP 6 'Total Loss of Feed' and EOP-15 'Functional Recovery Procedure'. Operations is directed to use low pressure feed in 1-EOP-06 (Step 8.B.3.1). Crediting low-pressure feed will eliminate those core damage sequences where the MFW pumps are lost, but the condensate pumps are available. If the TBVs are not available, then the hot well make-up control system (or an operation action) must be modeled to incorporate this alternative.

Adding low pressure fuel (LPF) could reduce dependency on once-through-cooling for a number of accident sequences.

Resolution: This action has not been credited. Upon loss of MFW, human action associated with recovery using condensate will be highly dependent on the human action to recover MFW, and thus, no gain will be achieved by having a combined human action unless the cause of the LOMFW was a hardware failure that would prevent its recovery. However, human failure to recover components usually overwhelms any associated hardware failure probability, and associated scenarios will be dominated by failure of human action to recover MFW.

13. Accident Sequence AS-11 Level of Significance B

Peer Review Observation: Documentation used to provide the basis of event tree structure is not adequately traceable to the underlying analysis.

Resolution: MAAP analyses have been explicitly defined and mapped within the Success Criteria and HRA Notebooks.

14. Accident Sequence AS-12 Level of Significance B

Peer Review Observation: Currently, shutdown cooling is credited as a long-term cooling method to eliminate the re-circulation requirement on certain ranges of LOCA breaks. A certain amount of water must be above the bottom of the hot leg to avoid drawing vapor into the SDC system. Some calculation must be done to ensure that the RCS will be above this critical point.

This calculation could be quite simple: determine the RCS water level at the point of shutdown cooling entry conditions, determine the leakage rate at the point, and verify the RCS level will be adequate for the remaining part of the 24 hr mission without re-circulation or RCS make-up.

If this is not true, then additional make-up must be modeled through the emergency sump or Chemical and Volume Control System (CVCS).

Resolution: Per 2-EOP-03 step 52, shutdown cooling would be initiated at pressurizer level greater than or equal to 30 percent, which is above the bottom of the hot leg.

15. Accident Sequence AS-13 Level of Significance B*

Peer Review Observation: The PORVs are only assumed to lift given total loss of secondary side heat removal or a loss of load with no anticipatory trip. This appears non-conservative. The only loss of load trips considered are TT and loss-of-offsite power trips. This is based on an informal calculation that shows the RCS pressure exceeds 2300 psia, but stays below the PORV open set point of 2400 psia. This does not consider variations in the time delay between the turbine trip and the reactor trip nor does it consider variations in the pressurizer (PZR) pressure set point. Consideration of these variables may lead the analyst to conclude that the likelihood of a PORV lift during this condition is much larger than analyzed.

Further, the portion of the tree (under Gate U1QT99) that models the circuitry associated with the anticipatory trip only contains a single basic event. No other support system dependencies appear. For example, does the status of pressurizer spray affect this calculation? Are there support system failures that could cause a loss of load and disable or degrade the anticipatory trip function?

Resolution: Input on trips likely to challenge PORVs were received from thermal-hydraulic (T/H) analyst and were incorporated in model updates under the appropriate logical gates. Potential PORV challenges were considered as PORV challenge initiators. Current model includes CEA withdrawal, boron dilution, turbine trips and partial loss of FW or RCP flow as PORV challenges. Associated initiating events were included in the model as point-estimates and not as fault tree-based initiating events with circuitry failures.

16. Accident Sequence Del1 Level of Significance B*

Peer Review Observation: Operations is directed to use low pressure feed in 1-EOP-06 (Step 8.B.3.1). Crediting low pressure feed will eliminate those core damage sequences where the MFW pumps are lost, but the condensate pumps are available. If the turbine bypass valves (TBVs) are not available, then the hot well make-up control system (or an operation action) must be modeled to incorporate this alternative.

Resolution: Credit for low pressure feed has been included in the current model. Additionally, this change has been reflected in Accident Sequence Notebook as well as model logic.

17. Accident Sequence Del2 Level of Significance B

Peer Review Observation: Documentation does not provide a basis for accident sequence definition that is traceable to underlying analysis.

Resolution: The accident sequence (AS) document has been updated to ensure that the accident sequence definitions are traceable to underlying analyses.

18. Data Analysis DA-4 Level of Significance B

Peer Review Observation: Generic data is ~13 years old and the failure rate sources are no longer industry standards.

Resolution: Generic database was updated to include data from NEI 99-02 Rev 5, and NUREG/CR 5750. LOOP database was further expanded to include events through 2008.

19. Dependencies DE-1 Level of Significance B

Peer Review Observation: The common cause analysis has very few electrical components (AC and DC) considered for common cause grouping. The EDG's, batteries, and reactor trip breakers appear to be the only electrical components in the common cause (CC) analysis.

An evaluation or analysis to justify the exclusion of other electrical components (breakers, relays, inverters, motor control centers (MCCs), etc.) could not be found in the references.

Resolution: The CCF analysis has been upgraded to meet Category II capability of the ASME PRA Standard and RG 1.200. The latest revision of CCF analysis update included use of the INEL methodology ([Reference 35](#)), the CCF guidance document for CE plants, and the most recent industry references (INEL-2007/NRC database), including the CCF guidance document for CE PWRs.

20. Human Reliability HR-1 Level of Significance B

Peer Review Observation: There is insufficient description of the process used to identify operator actions that need to be quantified and modeled in the PRA.

Resolution: The HRA evaluations have been updated to meet the ASME Category II capability. The update included improved documentation of the HRA methodology. The tool used for these evaluations has been changed to the EPRI HRA calculator. This tool includes provisions for the necessary documentation required to satisfy the documents requirements of this F&O.

21. Human Reliability HR-2 Level of Significance B

Peer Review Observation: Each post-initiator HRA should have pre-determined success criteria, assumed operator stress level, list of the manual actions with reference to EOP/AOP steps, performance shaping factors, and justified assumptions whenever assumptions are made to support the HRA. Also, the model fault tree where the HRA was used should be mentioned, and the MAAP 3B run or FSAR Calculation used to support the HRA timing should be quoted. The available EXCEL spreadsheet for HRAs provides the stress level selection and some

performance shaping forces (PSFs). By properly summarizing those details, the HRA documentation becomes stand alone, and helps to avoid misuse of the analyzed HRA at fault tree locations where the associated conditions are different from the analyzed ones.

Resolution: HRA was updated using EPRI HRA Calculator software which was developed in accordance with ASME PRA standard requirements for Category II capability. New document that described the use of MAAP was developed which included T/H analysis required to support HRA assumptions. This process and associated documentation resolved all aspects described in this F&O.

22. Human Reliability HR-3 Level of Significance B

Peer Review Observation: Section 1.1 stated that a multi-disciplinary team reviewed the HRA quantification. There should be a section added to the HRA report to describe the involvement of operations (or OPS training personnel). Operations personnel should validate various HRA sub-elements such as available timing, time to perform the manual actions, likely RO actions, etc. If there were no such reviews, they should be conducted in the near future.

The significance of this F&O was changed from A to B. Stuart Lewis (from SAROS) was contacted to request documented evidence that he had detailed discussions with OPS personnel related to the various HRAs (especially the non-proceduralized ones). Stuart produced the necessary document. That evidence, however, need to be incorporated in the HRA report.

Resolution: Current HRA updates were reviewed by a senior reactor operator (SRO)-licensed operator who is also qualified as an operations training instructor. The updated HRA document included results of discussions of operator actions with the operations staff. In several instances results of simulator experiences were used. The current update also used EPRI HRA calculator with detailed operator action description and evaluation. Detailed results of operator interviews are included in the HRA notebook.

23. Human Reliability HR-5 Level of Significance B

Peer Review Observation: The reported HRA probabilities are median values that were justified as being representative values. The combination of event probability and EF for HRA events FHFP1RECMFW and NHFPMANUALM would likely produce a 95 percent value above 1.0. 95 percent values above 1.0 would not be acceptable for uncertainty analyses. The best estimates for HRA quantification (pre- and post-initiators) should be based on the use of MEAN values for HEPS. A justification for using medians for pre-initiator values was provided for pre-initiator HRAs but not for post-initiator HRAs.

Resolution: The current HRA update with the EPRI HRA calculator used the mean values.

24. Human Reliability HR-6 Level of Significance B

Peer Review Observation: Section 2.3 discussed the modeling of non-proceduralized human interactions (Cr-type HRAs). A paragraph in that section stated that no Cr-type HRAs were included in the quantification of CDF. When the model was searched, three Cr-type HRAs were included (see Tables 11, 12): AFHRCPUMP, EFHPDC-2AB, and EFHPRESET.

Non-proceduralized human interactions must be reviewed by the operations staff to ensure they include the most likely operator actions and to validate the various assumptions made in support of their quantification. This is especially important because at least one of the Cr-type HRAs is among the top 5 risk-important HRAs. SEE F&O HR-03.

Resolution: The current HRA update uses the EPRI HRA calculator with detailed operator action description and evaluation. As part of this analysis, all of the relevant operator actions were reviewed against existing operating procedures, expected operator practices, operator experiences, and training. The analysis update was also reviewed by SRO-licensed operator who is also qualified as an operations training instructor.

25. Human Reliability HR-8 Level of Significance B

Peer Review Observation: The particular steps in EOPs or AOPs used as a basis for manual actions should be cited. This type of pinpointed reference would greatly facilitate the impacts on HRAs from changes in EOPs or AOPs. For example, the addition of a checkoff provision to a list of quantified manual actions would result in lower HEPs that need to be reflected in the affected HRA.

Resolution: St. Lucie Unit 2 operating procedures are event-based. Unlike symptom-based procedures, to be found in Westinghouse Owners Group (WOG) and Boiling Water Owners Group (BWROG) plants, event-based procedure cannot be used in sequential order. Major steps are marked with asterisk which allows the operator to skip to any other step based on the event being handled. Input for times taken by operations to perform a particular step, or to go through a particular scenario, is mainly influenced by operator interviews, observation of crews during training, and final cross check with SRO-qualified personnel. Review of procedures for potential impact of a specific scenario is performed by qualified personnel familiar with the referenced procedures and involved steps.

26. Human Reliability HR-9 Level of Significance B

Peer Review Observation: The best estimates for pre-initiator HRA quantification is based on the use of MEDIAN screening values for HEPs. No quantification was done. The screening values are very conservative values.

Resolution: The current HRA analysis update with the EPRI HRA calculator used the mean values. Pre-initiator HRA quantification is developed and documented.

27. Human Reliability HR-Del8 Level of Significance B

Peer Review Observation: See F&O-1 through 07 for weaknesses in documentation.

Resolution: PRA documentation has been improved to resolve all issues associated with this F&O.

28. Initiating Event IE-1 Level of Significance B

Peer Review Observation: LOSP Initiating Event was extracted from generic industry data going back 20 years or more. No data trending was applied to establish a downward trend in LOSP annual frequency. The latest biannual EPRI report on LOSP frequency concluded that: LOSP frequency has trended downward and has stabilized over the last few years. The non-trended derived St. Lucie Unit 2 LOSP frequency (Total value approximately $5.3E-02$ Table 6.1) is very conservative; and the probability of non-recovery of offsite power (shown in the Log-normal cumulative figures) is also too high.

This high degree of conservatism in LOSP frequency and associated non-recovery probabilities may lead a PRA practitioner to determine unnecessarily high risk for some applications that would otherwise be acceptable.

Resolution: The current LOOP (LOSP) analysis considers events from 1984 through 2008 and includes associated industry references such as NUREG/CR-6890 and EPRI published documentation on LOOP. The data selection includes a small conservative bias on the LOOP initiating event frequency. Use of the selected LOOP frequencies will provide bounding assessment of the EPU on LOOP-related plant risks.

29. Initiating Event IE-4 Level of Significance B

Peer Review Observation: St. Lucie includes loss of individual 120 VAC instrument buses as initiators, but does not address multiple bus failures as initiators. The 120 VAC buses power the reactor protection system (RPS)/engineered safety feature actuation system (ESFAS). Failure of 2 buses could result in spurious actuation of multiple safety systems given the 2 of 4 actuation logic. This type of initiator has not been addressed for the St. Lucie PRA. Multiple actuations could have unanticipated effects such as actuation of the Feed Only Good logic for both SGs at the same time that AFAS was actuated. This would result in no AFW being supplied to the SGs.

Note: Panels are co-located in pairs. Construction activity noted in area. Construction materials/debris could block cooling intakes and cause failure. This is one example of potential common cause mechanism.

Resolution: This F&O was evaluated by FPL staff. Multiple instrument bus failures were judged to be a low probability event and contribute an insignificant amount of risk. This assumption has a negligible impact of the calculation of the EPU risk.

30. Initiating Event IE-5 Level of Significance B

Peer Review Observation: St. Lucie Unit 2 PRA-2.P presents the ISLOCA calculation. It has not been updated since 1992. This calculation does not address the RCP seal cooler heat exchanger tube leak ISL path nor does it discuss treatment of common cause failure of valves for the other ISL paths.

Resolution: It was judged that the impact of the RCP seal cooler heat exchanger tube leaks and common cause failure of valves on risk is minimal.

31. Initiating Event IE-7 Level of Significance B

Peer Review Observation: The IE data documentation is scattered in different reports and in different revisions of the same report. Sometimes, inconsistent values are provided (see F&O IE-05).

Resolution: Updated IE data have been revised and documented in a stand alone data update report.

32. Containment Performance L2-1 Level of Significance B

Peer Review Observation: The St. Lucie level 2 analyses in the IPE submittal address thermally induced SGTR was originally quantified based on industry understanding of the issue at the time of the IPEs. More recent information indicates that thermally-induced SGTRs are more likely than previously thought. The latest requantification uses a higher value, but this is based on a Westinghouse plant. Due to the vessel lower head differences, CE plants are more susceptible to TI-SGTR. The value should reflect this.

Resolution: An upgraded Level 2 analysis was performed which explicitly considered the impact of the CE lower head design on the thermally induced (TI)-SGTR. This methodology has been peer reviewed and found to be in accordance with respect to the current ASME standard.

33. Containment Performance L2-2 Level of Significance B

Peer Review Observation: According to the St. Lucie Units 1 and 2 IPE submittal, the timing of radionuclide releases is divided into three categories: E = early < 2 hours, D= delayed (2 to 6 hours), and L = late > 6 hours.

Typically, Level-II PRAs define early release as core-damage accidents in which containment failure occurs within approximately 4 hours of vessel breach. This definition is consistent with the Emergency Evacuation Plans where any evacuation within 4 hours is considered as early. Also, this definition is consistent with the EPRI PRA Applications Guide. Late release is normally defined as > 24 hours from time of vessel breach.

Since St. Lucie's late release is defined as > 6 hours, this could underestimate the delayed release (D) category. Also, since St. Lucie Level-II PRA defines early release as < 2 hours, this could underestimate LERF and overestimate delayed releases.

In addition, it is not clear how the severity (magnitude) of releases is defined. Normally, as can be predicted by the MAAP code simulation of dominant core damage sequences, High release is defined as > 10 percent mass fraction of CsI (volatile) and Tellurium (non-volatile), Medium (or moderate) release is between 1 percent - 10 percent mass fraction of CsI and Tellurium, and Low as < 1 percent Cs and Tellurium releases.

Resolution: An upgraded level 2 analysis was developed. LERF events were defined consistently with plant emergency plans and expected evacuation timings. All events that would result in containment releases prior to evacuation of the low population zone were included in LERF contribution.

34. Containment Performance L2-3 Level of Significance B

Peer Review Observation: Containment capability is analyzed under severe accident conditions for its survivability: The containment fragility curve (a.k.a., St. Lucie Containment Survival Probability) is an adjusted curve from Turkey Point fragility curve, and is provided at one single temperature.

Typically the mechanical properties (e.g., yield stress, ultimate strength, and failure pressure) of the containment steel liner degrade as the temperature in the containment increases during ex-vessel severe accident progression.

Resolution: The calculation of containment strength is judged to be conservative. This assessment was confirmed by comparison with fragility curves of other steel shell containment designs. The calculation used design basis methods and did not credit plasticity. Actual containment tests conducted at Sandia Natural Laboratories indicated steel shells will significantly balloon prior to failure, indicating integrity is maintained into the “plastic” region.

35. Containment Performance L2-4 Level of Significance B

Peer Review Observation: The St. Lucie reactor cavity configuration allows the cavity to be flooded (i.e., St. Lucie’s Reactor Cavity is wet type). As a result, the likelihood of basemat melt-through should be smaller than what is assumed in Level-II PRA analysis (set at 0.175 and 0.50, respectively, for all PDSs per Table 17: “Summary of containment event time (CET) and Their Recommended Probabilities”).

Resolution: The revised calculation focuses on LERF and models a simplified conservative treatment of late large release events. This treatment credits the impact of a wet cavity retarding basemat melt through.

36. Quantification QU-2 Level of Significance B

Peer Review Observation: A lot of results sections in the quantification report are blank with a “later” in place of the table or results.

Resolution: Documentation was completed and peer reviewed.

37. Quantification QU-4 Level of Significance B

Peer Review Observation: No uncertainty analysis has been performed on the results from Unit 1 or Unit 2 quantification results.

Resolution: Uncertainty analysis has been included. Uncertainty analysis and associated sensitivity studies have also been explicitly included in the St. Lucie Unit 2 quantification report. Additional sensitivity studies are included in the LERF model notebook.

38. Structural Response ST-1 Level of Significance B

Peer Review Observation: FPL does not directly address reactor vessel capability. In the accident sequence analysis report, FPL dismisses reactor vessel rupture as being of low risk

significance because of a low generic failure probability and also dismissed PTS as being of low risk significance based on generic analyses. Therefore, reactor vessel failure is not included in the model at all.

Resolution: Reactor vessel failure is explicitly considered in the upgraded LERF evaluation. Pressurized thermal shock (PTS) is not explicitly treated in the LERF model.

39. Structural Response ST-2 Level of Significance B

Peer Review Observation: The containment capability analysis included in the IPE submittal is a simplified analysis based on the generic approach in NUREG/CR-2442 and NUREG/CR-3653 using St. Lucie specific information in the simplified equation. This analysis provided an estimate of containment ultimate pressure value that was used to generate a containment fragility curve based on containment fragility curves for other similar containment designs shifted so that the median was at the St. Lucie ultimate containment pressure. The analysis did not address temperature effects and only included a single failure mode, liner tear at the spring line. The analysis did not address other containment failure points such as liner tear at the containment hatches or penetrations.

The Level 2 analyses did consider release pathways including containment bypass, containment isolation and containment failure. Only the single failure mode of unspecified location was used for containment.

Resolution: Note that the containment capability analysis is based on a conservative assumption that shell failure occurs at the shell elastic limit. Consequently, the impact of this modeling assumption is to conservatively bias the shell failure potential to lower internal pressure. Note that tests of steel shells performed by Sandia indicate considerable plastic behavior prior to failure (see NUREG/CR-6906).

The containment structure has been reinforced according to the ASME requirements, thus ensuring a higher resistance than that of the un-penetrated shell. Failure in the vessel penetration intersection or in the penetration wall is possible, but is much less probable than failure in the basic shell modes. Hence, the shell modes were the only failure modes considered.

40. System Analysis SY-1 Level of Significance B

Peer Review Observation: There are no references to engineering calculations or analyses to support the system analysis success criteria, either in the system analysis documents or the accident sequence analysis. The basis for success criteria should be included in the system analysis documentation in order to facilitate review, update, and application of the model.

For example, for AFW, the success criteria section of the AFW system analysis document does not give a basis for the success criterion that is described (flow to 1 SG). The required flow rate to remove decay heat should be compared to the capacity of a single pump, including the effects of potential flow diversion through the recirc line (since failure of the recirc line is assumed to be subsumed in the injection failure) and blowdown (since isolation of blowdown is assumed not to be needed). This could be done using engineering analysis or thermal-hydraulic analysis, but the basis should be described in the AFW system analysis document.

Another example is the basis for the AFW success criterion for ATWS (flow to both SGs).

Resolution: A PRA notebook was developed for Success Criteria Analysis that included assumptions considered in the current PRA and associated engineering analyses where included, as appropriate. The basis for the success criteria are explicitly modeled in the revised notebooks.

41. System Analysis SY-14 Level of Significance B

Peer Review Observation: There is not a single event model that represents debris clogging the sump (i.e. both headers blocked).

Resolution: Sump debris clogging has been included as a failure mode and as a CCF in the current PRA update.

42. System Analysis SY-15 Level of Significance B

Peer Review Observation: The implementation of the Alpha Parameter methodology for common cause analysis has resulted in conditions that appear to be an over estimation of the contribution from common cause and results that do not make obvious sense (i.e. cutsets in which the common cause failure of three check valves [three AFW pump discharge check valves] is more likely than the common cause failure of two check valves [two MFW check valves to the SGs I-V09294 and I-V09252]). The implementation of the methodology includes an assumption in the development of the parameters of staggered testing. This assumption may be non-conservative. The common cause failure of the check valves in the pump recirculation lines was not considered and justification provided for not including them was not included. Some of the issues may be the result of the use of component specific and generic alpha parameter data.

Resolution: The CCF analysis was updated to meet ASME PRA Standard Capability Category II requirements. This was confirmed during the CCF notebook focused peer review.

Regarding AFW Pumps recirculation lines, valves in those lines are locked-open manual valves. AFW pumps may start at anytime with no concern of being dead-headed. Failure of the recirculation line is considered insignificant. As such, this F&O is considered resolved.

43. Thermal Hydraulic Analysis TH-2 Level of Significance B

Peer Review Observation: FPL uses a combination of UFSAR and best estimate analyses to support success criteria. There is a calculation which documents MAAP runs supporting success criteria evaluation. However, the accident sequence analysis report does not have any direct references to the cases within the MAAP analyses report linking specific success criteria assumptions to specific MAAP runs.

Resolution: Documentation has been improved as part of RG-1.200 conformance project. MAAP cases used to support HRA, accident sequence and success criteria analyses have been explicitly identified in their respective notebooks.

44. Thermal Hydraulic Analysis TH-Del3 Level of Significance B

Peer Review Observation: FPL did not model failure of HVAC for the control room. No room heat-up calculations were performed to justify this modeling assumption.

Resolution: It was judged that control room heat, ventilation, air conditioning (HVAC) does not have significant risk impact at St. Lucie Unit 2 and thus was not considered in its PRA model.

2.13.2.11.3 PRA Maintenance and Update

The PRA is a living document that is updated and maintained to adequately reflect the as-built, as-operated plant. Most recently the PRA has been extensively updated including documentation to more closely conform to the requirements of RG 1.200. Additional work is currently in progress. A procedurally controlled change impact evaluation process ensures that changes to the plant are reviewed for impact on the PRA. This process is integrated with the plant change process and setpoint change process such that the originator of the change and a PRA engineer determine if the change impacts the PRA. In performing the EPU, plant design and operation staff has worked closely with the PRA group so that risk benefits of proposed plant changes are maximized. Several risk informed changes driven by PRA insights have also been adopted. In addition, the procedure change process requires that any change, addition, or deletion of operator actions, or change to step sequence, is reviewed for impact on the PRA.

Changes to the PRA are also procedurally controlled. Changes to the fault trees, databases, and the final report require documentation and an independent review.

2.13.2.11.4 Other Relevant Open Items

There are no other known open items.

2.13.2.12 Software

2.13.2.12.1 Thermal Hydraulic Software

Several computer codes have been used for developing PRA thermal hydraulic success criteria. The timing changes for inventory control and decay heat removal losses are calculated using MAAP (Reference 26). MAAP is a graphical interface thermal-hydraulic code. MAAP has undergone extensive benchmarking by EPRI and the MAAP users group. MAAP analyses have been performed within the code capabilities and MAAP has not been used for Level 1 large break LOCA or ATWS success criteria.

Short term large break LOCA success criteria is based on results of Appendix K calculations. Long term cooling for medium and large LOCAs include the design basis results of the BORON (Reference 31) computer code. ATWS events are based on short term generic CE PWR CENTS (Reference 32) (CE Nuclear Transient Simulator) evaluations for similar CE PWRs.

2.13.2.12.1.1 MAAP

MAAP is generally used as a best estimate analysis tool for establishing PRA success criteria and event timing for PWRs. The code provides integrated responses of the RCS and containment and extends the calculation to beyond design basis and core damage events. Guidelines for applying MAAP for PRA applications are contained in [Reference 36](#). The MAAP version used for this evaluation is MAAP 4.0.7

MAAP is generally known to not properly model large break LOCA and ATWS events. MAAP lacks the dynamic detail to properly model the early portion of the reactor vessel blowdown and core uncover for large break LOCA. However, MAAP can calculate the containment energy balance during a large break LOCA. MAAP does not include reactor kinetics and therefore does not model ATWS events. In this evaluation MAAP is used to support containment performance success criteria and success criteria for transients, SGTR, and small, medium and long term heat removal for large break LOCAs (up to entry to long term cooling).

MAAP analyses use realistic inputs for injection sources, plant geometry and decay heat. Decay heat is based on the ANS 1979 Standard, with actinides, and does not include a two-sigma uncertainty.

2.13.2.12.1.2 CENTS

CENTS ([Reference 32](#)) models the transient simulation of a CE PWR. The code is not intended to be used in conditions of significant core uncover. CENTS is able to model reactor point kinetics. In this assessment, results of generic CENTS analyses for 2700 MWt CE designed PWRs are used as a basis for ATWS peak pressure estimates. Plant specific CENTS results were used to support the feedwater system design and the associated nominal pressurizer pressure responses following various plant upsets.

2.13.2.12.2 CAFTA

CAFTA, Version 5.1 tool is used to perform probabilistic risk analysis using a linked event tree/fault tree methodology. Details about CAFTA ([Reference 33](#)) are available on the EPRI website.

2.13.2.12.3 HRA Calculator

The HRA Calculator Software, Version 4.1: Human Reliability Analysis ([Reference 27](#)) is used to determine HRA failure likelihoods. The computer code includes multiple HRA calculation approaches and allows for direct comparisons among these approaches. Details about the HRA calculator are available on the EPRI website.

2.13.2.13 Results

Although this license amendment is not being requested as a risk-informed change, the risk due to internal and external events that result from plant changes implemented as part of the EPU were found to be acceptable as defined in RG 1.174.

While the EPU does place additional burdens on plant systems and the power increase will reduce the time available for operator recovery actions, FPL took several actions to limit adverse impacts. Many of the plant changes implemented for the EPU will ensure that current operating margins for key components are maintained or increased.

For internal events, these changes offset the additional risks posed by the EPU and are calculated to be slightly risk beneficial. For example, for total loss of feedwater events, focused risk-informed procedure changes will be made to increase the time available for the operator to implement once-through-cooling. These changes include increasing the inventory in the SGs by raising the SG low level reactor trip setpoint and revising steps in the standard post-trip procedure to require the operator to trip all four reactor coolant pumps. To ensure the availability of the AFW system, plant procedure changes will be made to confirm key valve alignments.

For external events, no new fire, seismic, wind, or external flooding vulnerabilities are introduced due to the EPU. Although no new vulnerabilities are introduced, the time available for operator actions has decreased slightly. A review of key operator actions credited during these challenges indicates that the impact on the plant risk will be very small.

A qualitative review of shutdown procedures indicates that the procedures will remain adequate for the control of shutdown operations during EPU operation. Thus, the risk impact from the EPU on shutdown risk was judged to be small.

Comparing current plant configuration and procedures with the EPU plant configuration, the internal events CDF is predicted to decrease by about $1\text{E-}08$ per year and LERF is also predicted to decrease by about $1\text{E-}08$ per year. When external events and shutdown risk are considered, the EPU is judged to have a small potential impact on CDF and LERF.

The risk assessment also shows that the EPU does not create the “special circumstances” described in Appendix D of the SRP Chapter 19 (2.13.2, Reference 1). The EPU does not:

- Substantially increase the likelihood of a risk-significant accident that is outside of the design basis of the plant,
- Degrade multiple levels of defense,
- Reduce the availability or reliability of risk-significant structures, systems, or components, and
- Introduce synergistic or cumulative changes that substantially increase CDF.

2.13.3 Conclusion

FPL has reviewed the assessment of the risk implications associated with the implementation of the proposed EPU and concludes that the potential impacts associated with the implementation of the proposed EPU are adequately modeled and/or addressed. FPL further concludes that the results of the risk analysis indicate that the risks associated with the proposed EPU are acceptable. The EPU does not create the “special circumstances” described in Appendix D of the Standard Review Plan, Chapter 19. Therefore, FPL finds the risk implications of the proposed EPU acceptable.

2.13.4 References

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4. NRC Regulatory Guide 1.174, An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis, Rev. 1, November 2002.
5. RS-001, Review Standard for Extended Power Uprates, USNRC, December 2003.
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9. GL 87-02, Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, Unresolved Safety Issue (USI) A-46, February 19, 1987.
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21. U.S. Nuclear Regulatory Commission NUREG-1048 Appendix U, Table U1.
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32. WCAP-15996-NP-A, Rev. 1, Technical Description Manual for the CENTS Code, March 2005.
33. EPRI, CAFTA: Fault Tree Analysis System, Version 5.4, January 2009.

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40. FPL letter to the NRC, L-94-107, Verification of Seismic Adequacy of Mechanical and Electrical Equipment in Operating Reactors, (USI) A-46, (GL) 87-02, May 5, 1994.

2.14 Impact of EPU on the Renewed Plant Operating License

A license renewal application (LRA) was prepared in accordance with the requirements of 10 CFR 54 for FPL's St. Lucie Unit 2 and was submitted to the NRC in November 2001. The NRC staff reviewed the LRA for compliance with 10 CFR 54. In September 2003, the Safety Evaluation Report Related to the License Renewal of St. Lucie Nuclear Plant, Units 1 and 2 (SER), was issued as NUREG-1779.

Although not specifically identified in the scope of NRC Review Standard (RS)-001, this LR section documents FPL's reviews on the effects of the EPU on evaluations performed for license renewal.

The LRA and SER were reviewed to determine the impact of the EPU on license renewal. Where appropriate, each section in this LR evaluates the effect of EPU on the structures, systems or components (SSCs) under review as well as evaluates the impact to the programs which manage the aging effects on those components. This section presents summary information of the results of the review, and discusses the effects of EPU on SSCs included in the LRA but not discussed in RS-001.

2.14.1 Impact of EPU on Aging Management

The LRA credited a number of existing, modified, and new aging management programs with managing the effects of aging on SSCs during the period of extended operation. In NUREG-1779, the NRC determined that, subject to license conditions to implement LRA commitments prior to the extended period of operation, these programs will provide reasonable assurance that aging effects will be managed such that the SSC intended functions will be maintained during the license renewal period.

LR Sections 2.1 through 2.13, summarize the impact of the EPU on plant accident response and safety, as well as discuss the impact on the license renewal regulated events (environmental qualification (EQ), anticipated transient without scram (ATWS), station blackout (SBO), pressurized thermal shock (PTS), and fire protection) that were the basis for license renewal scoping and screening. UFSAR Chapter 18 aging management programs that were credited for license renewal were reviewed with respect to the changes associated with the EPU as described in this LR. The review concluded that effects of the EPU have been adequately identified and addressed with respect to the plant's license renewal commitments for aging management.

2.14.2 Impact of EPU on Time-Limited Aging Analyses

The time-limited aging analyses (TLAAs) are presented in Section 4.0 of the LRA. The NRC concluded in Section 4.1.3 of NUREG-1779 that the LRA included the list of TLAAs as defined in 10 CFR 54.3. The staff also concluded on the basis of its evaluation of the application, the following:

- Actions have been identified and have been or will be taken with respect to managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require an aging management review under 10 CFR 54.21(a)(1); and

- Actions have been identified and have been or will be taken with respect to time-limited aging analyses that have been identified to require review under 10 CFR 54.21(c). Accordingly, the staff finds that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis.

The impacts of the EPU on the TLAA's are discussed in this LR. A summary of each TLAA in the LRA and the corresponding discussion for EPU is presented below.

Reactor Vessel Neutron Embrittlement

The evaluation of neutron fluence is summarized in the LRA. The NRC reviewed the evaluation and determined that the calculation of the neutron fluence values, as projected through the period of extended operation is acceptable to use in the evaluation of the TLAA's for the upper shelf energy (USE), PTS, and pressure-temperature (P-T) limit curves.

Upper Shelf Energy

Appendix G to 10 CFR Part 50 requires that reactor vessel (RV) beltline materials have C_vUSE values in the transverse direction for the base metal and along the weld for the weld material according to the ASME Code, of no less than 75 foot-pounds (ft-lb) (102 J) initially, and must maintain C_vUSE values throughout the life of the vessel of no less than 50 ft-lb (68 J).

As stated in Section 4.2.1.1 of NUREG 1779, FPL has calculated C_vUSE values through the period of extended operation.

The NRC performed an independent evaluation of C_vUSE for St. Lucie Unit 2. The NRC determined that the 60-year USE assessment for the RV beltline materials is bounded (limited) by the USE value for the lower shell plate M-4116-1. The staff calculated the projected USE value to be 71 ft-lb through the expiration of the extended period of operation for the unit. This material meets the staff's end-of-life 50 ft-lb acceptance criterion. Based on the staff's independent USE calculations, the staff concludes that the RV beltline materials will have adequate USE through the expiration of the extended period of operation for the unit.

The staff confirmed that all RV beltline materials will continue to satisfy the C_vUSE value requirements of 10 CFR Part 50, Appendix G, through the end-of-extended operating life. The staff, therefore, concludes that the TLAA for calculating the C_vUSE values of the RV beltline materials is acceptable because it meets the requirements of 10 CFR 54.21(c)(1)(ii) and will ensure that the RV materials will have adequate USE levels and fracture toughness through the end-of-extended period of operation.

Evaluations performed by FPL in support of EPU relative to the RV beltline materials document USE values in excess of the 50 ft-lb screening criteria. The intermediate-to-lower shell girth weld, 101-171, is predicted to have the most limiting USE value of 71 ft-lb at 60 years. Therefore, there is no impact upon the conclusions reached by the NRC in their evaluation of USE as part of their review of St. Lucie Unit 2 LRA. Refer to LR [Section 2.1.2](#), Pressure-Temperature Limits and Upper Shelf Energy, for additional information pertaining to USE.

Pressurized Thermal Shock

The requirements of 10 CFR 50.61 set forth the fracture toughness requirements associated with protecting the RVs of pressurized-water reactors (PWRs) against the consequences of PTS. The

rule requires each licensee to calculate the end-of-life reference temperature (RT_{PTS}) value for each material located within the beltline of the reactor pressure vessel. The requirements of 10 CFR 50.61 also provides screening criteria against which the calculated RT_{PTS} values are to be evaluated. For RV beltline base metal materials (forging or plate materials) and longitudinal (axial) weld materials, the materials are considered to provide adequate protection against PTS events if the calculated RT_{PTS} values are less than or equal to 270°F. For RV beltline circumferential weld materials, the materials are considered to provide adequate protection against PTS events if the calculated RT_{PTS} values are less than or equal to 300°F.

FPL performed an evaluation of RT_{PTS} over the period of extended operation which equates to 54 effective full power years (54 EFPY) the results of which demonstrates that the screening criteria described above are not violated.

As stated in Section 4.2.2.2 of NUREG-1779, the staff performed an independent calculation of the RT_{PTS} values for the beltline RV materials based on the projected end-of-extended operating term (54 EFPY) neutron fluences for the materials. The staff's calculated RT_{PTS} values for the RV beltline materials were within 2°F of the RT_{PTS} values calculated by FPL. Both the staff's and FPL's PTS analyses confirm that the RT_{PTS} values for beltline materials will remain under the PTS screening criteria of 10 CFR 50.61 through the extended operating period.

For the RV, the staff determined that the intermediate shell plate M-605-2 is the most limiting material and calculated the end-of-extended-operating-term RT_{PTS} value for this material to be 174°F. This material meets the 10 CFR 50.61 screening criteria for longitudinal weld and base metal materials of 270 °F.

Evaluations performed by FPL in support of the EPU, document that the RT_{PTS} values projected to 60 years for the intermediate shell plate M-605-1 is predicted to have the most limiting RT_{PTS} value of 175°F at 60 years. This value does not exceed the PTS screening criteria of 270°F for axial welds and therefore there is no impact upon the conclusions reached by the NRC in their evaluation of PTS as part of their review of the LRA. Refer to LR [Section 2.1.3](#), Pressurized Thermal Shock, for additional information pertaining to PTS.

Pressure-Temperature Limits

The requirements in 10 CFR Part 50, Appendix G, are designed to protect the integrity of the reactor coolant pressure boundary in nuclear power plants. Appendix G to 10 CFR Part 50 requires that P-T limit curves be at least as conservative as those obtained by applying the methodology of Appendix G to Section XI of the ASME Boiler and Pressure Vessel Code. Appendix G to 10 CFR Part 50 also provides minimum temperature requirements that must be considered in the development of the P-T limit curves.

Operation of the reactor coolant system (RCS) is also limited by the net positive suction curves for the reactor coolant pumps (RCPs). These curves specify the minimum pressure required to operate the RCPs. Therefore, in order to heat up and cool down, the reactor coolant temperature and pressure must be maintained within an operating window established between the Appendix G, P-T limits and the net positive suction curves of the RCPs.

As stated in Section 4.2.3.2 of NUREG 1779 the P-T limits have been established by calculations that utilize the materials and fluence data obtained through the unit-specific reactor surveillance capsule program (UFSAR Section 18.2.11.1).

10 CFR 50.90 requires licensees to submit new P-T limit curves to the NRC for review and have the curves approved and implemented into the TS prior to the expiration of the most current P-T limits curves approved in the TS.

Analyses performed by FPL demonstrate that the existing P-T limit curves are projected to remain valid for approximately 47 EFPY under EPU conditions. Refer to LR [Section 2.1.2](#), Pressure-Temperature Limits and Upper Shelf Energy, for additional information pertaining to the P-T limit curves.

Metal Fatigue

A metal component subjected to cyclic loads may fail at a load magnitude less than its ultimate load capacity due to metal fatigue. The fatigue life of a component is a function of its material, its environment, and the number and magnitude of the applied cyclic loads. Fatigue was a design consideration for plant mechanical components and, consequently, fatigue is part of the CLB for these components. The following sections address fatigue of ASME Section III, Class 1 components, ASME Section III, Class 2 and 3 and ANSI B31.1 components; and environmentally assisted fatigue.

ASME Section III, Class 1 Components

The LRA included a TLAA for metal fatigue. The RV, reactor vessel internals, pressurizers, steam generators (SGs), RCPs, and reactor coolant piping have been designed in accordance with the requirements of the ASME Code, Section III. FPL reanalyzed the pressurizer surge line in accordance with the requirements in Section III of the ASME Code in response to NRC Bulletin 88-11, Pressurizer Surge Line Thermal Stratification. FPL determined the fatigue usage factors for critical locations in Class 1 components using design cycles that were intended to be conservative and bounding for all foreseeable plant operations. FPL notes that a review of the plant operating history indicates that the number of cycles used in the design of these components bounds the number anticipated for the period of extended operation and, therefore, the analyses remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

In addition to the above, FPL employs a fatigue monitoring program (FMP) as a confirmatory program to assure that design cycle limits are not exceeded during the period of extended operation. If 80 percent of a design cycle limit is reached, this program will require plant management review to determine appropriate actions. The FMP is described in UFSAR Section 18.2.6.

As stated in NUREG 1779 Section 4.3.2, the staff finds FPL's criteria for selecting transients to be monitored by the FMP to be reasonable.

The conditions for surge line thermal stratification were evaluated relative to EPU. The results of this evaluation reveal that the surge line would not be affected by the EPU.

Operating characteristics of ASME Section III, Class 1 components will remain unchanged under EPU, thus, the number of design cycles that systems or components will be subjected to during 60 years of operation will not be exceeded. In addition, the EPU has not resulted in any change to 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.

Refer to LR [Section 2.2.6](#), NSSS Design Transients, for additional information pertaining to NSSS design transients.

ASME Section III, Class 2 and 3 and ANSI B31.1 Components

A review of ASME Section III, Class 2 and 3 and ANSI B31.1 piping within the scope of license renewal was undertaken in order to establish the cyclic operating practices of those systems that operate at elevated temperature. Based on the guidance from the Electric Power Research Institute (EPRI) and Babcock and Wilcox (B&W) any piping system with operating temperatures less than 220°F (carbon steel) or 270°F (stainless steel) may be conservatively excluded from further consideration of thermal fatigue.

Piping systems within the scope of license renewal are generally only occasionally subjected to cyclic operation. Typically these systems are subjected to continuous steady state operation and operating temperatures vary only during plant heatup and cooldown, during plant transients or for periodic testing. The results of the review determined that, except for the RCS hot leg sample piping on each unit, components will not exceed 7000 equivalent full temperature thermal cycles during the period of extended operation. ANSI B31.1 requires that a reduction factor be applied to the allowable bending stress range if the number of full range cycles exceeds 7000. Sample piping and tubing were reevaluated for the number of expected cycles and found acceptable for the period of extended operation.

Therefore, the ASME Section III, Class 2 and 3 and ANSI B31.1 piping fatigue TLAA that was performed in support of license renewal remains valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). The reactor coolant system hot leg sample lines fatigue analyses have been projected to the end of the period of extended operation in accordance with 10 CFR 54.21(c)(1)(ii). As stated in Section 4.3.3 of NUREG 1779 the staff finds the evaluations performed by FPL acceptable.

As noted above, systems were screened as part of license renewal in order to assess the potential for thermal fatigue. Threshold limits of 220°F for carbon steel and 270°F for stainless steel were used as the upper bound screening limit. Systems that operate below these threshold limits screened out as not being subject to thermal fatigue. Using EPU operating characteristics no new systems have been identified that exceed the threshold limits. Operating characteristics of these systems will remain unchanged under EPU, thus, the number of cycles that the system or component will be subjected to during 60 years of operation continues to be below 7,000 equivalent full temperature cycles. The evaluation of the RCS hot leg sampling piping conducted for license renewal is based on 365 samples per year for 60 years which is 21,900 however the piping system was evaluated for 22,000 cycles of operation. The sampling schedule will remain unchanged under EPU. Therefore, the TLAA related to thermal fatigue of ASME Section III,

Class 2 and 3 and ANSI B31.1 components will continue to be valid following implementation of the EPU.

Environmentally Assisted Fatigue

FPL evaluated the following fatigue sensitive component locations relative to the affects of environmentally assisted fatigue:

- RV shell and lower head,
- RV inlet and outlet nozzles,
- Pressurizer surge line,
- RCS piping charging nozzle,
- RCS piping safety injection nozzle,
- Shutdown cooling system Class 1 piping.

The results of FPL's evaluation indicates that the pressurizer surge line elbows required further evaluation for environmental fatigue during the period of extended operation. FPL will use an aging management program (AMP) to address fatigue of the surge line during the period of extended operation. As noted in UFSAR Section 18.2.2.1, the AMP will rely on the Inservice Inspection (ISI) Program to manage surge line fatigue during the period of extended operation. FPL notes that no indications have been identified as a result of the weld examinations performed to date. Furthermore FPL will perform additional surge line weld examinations prior to the period of extended operation. The results of the examinations will be used to develop the approach for addressing environmentally assisted fatigue of the surge lines prior to the period of extended operation. This approach could include one or more of the following:

- Further refinement of the fatigue analysis to lower the cumulative usage factors (CUF) to below 1.0,
- Repair of the affected locations,
- Replacement of the affected locations,
- Management of the effects of fatigue by an inspection program that has been reviewed and approved by the NRC (e.g., periodic nondestructive examination of the affected locations at inspection intervals to be determined by a method accepted by the NRC).

As stated in Section 4.3.2 of NUREG-1779, the staff finds FPL's proposed options provide acceptable plant-specific approaches to address environmentally assisted fatigue of the pressurizer surge lines during the period of extended operation in accordance with 10 CFR 54.21(c)(1).

As noted above, FPL will use an aging management program (AMP) to address fatigue of the surge line during the period of extended operation. The AMP will rely on the ISI Program to manage surge line fatigue during the period of extended operation. EPU has not resulted in any change to the AMP or ISI Program; therefore, the TLAA related to fatigue design will continue to be valid following implementation of EPU.

Environmental Qualification

As stated in Section 4.4 of NUREG 1779, the NRC has reviewed the information in the LRA regarding Environmental Qualification (EQ), and concluded that FPL has demonstrated the ability to manage the effects of aging during the period of extended operation for electrical components that meet the definition for TLAA as defined in 10 CFR 54.3. On the basis of this review, the NRC staff concludes that FPL (for electrical/I&C components that meet the definition for TLAA as defined in 10 CFR 54.3) has projected the TLAA (i.e., the 10 CFR 50.49 radiation, temperature, and wear cycle aging analyses) from the current 40 years to 60 years (i.e., to the end of the period of extended operation), as provided in 10 CFR 54.21(c)(1)(ii).

A review of the TLAA associated with EQ of electrical and I&C components was performed relative to EPU conditions. The aging mechanisms the TLAA addresses include thermal aging, wear and radiation aging. Peak post-accident pressures and temperatures remain bounded by the TLAA as does wear related aging. Post-accident radiation levels were calculated to increase. As a result localized areas, previously mild areas, on the 43 – foot elevation of the RAB in the vicinity of the shield building ventilation system HEPA and the charcoal filters could receive a total integrated dose greater than $1\text{E}+05$ rads.

The EPU impact on EQ of electrical equipment and the impact on component qualified life are discussed in LR [Section 2.3.1](#), Environmental Qualification of Electrical Equipment.

UFSAR Section 18.2.5 discusses the EQ program relative to AMPs and TLAA activities.

Containment Penetration Fatigue

The containment penetration bellows are specified to withstand a lifetime total of 7,000 cycles of expansion and compression as a result of maximum operating thermal expansion, and 200 cycles of seismic motion and differential settlement.

The containment penetration bellows are categorized as follows according to operating conditions:

- Type I Those which must accommodate considerable thermal movements (hot penetrations),
- Type II Those which are not required to accommodate thermal movements (cold penetrations),
- Type III Those which must accommodate moderate thermal movements (semi-hot penetrations),
- Type IV Containment sump recirculation suction lines, and
- Type V Fuel transfer tube penetration.

The designs of the Types I and III penetration bellows accommodate thermal movements, and are bounded by the thermal design limits of the associated piping systems. Bellows Types II and IV do not require a thermal fatigue analysis because they are associated with cold penetrations, penetrations used for post-accident scenarios, or penetrations that are not subject to high temperatures. For these bellows, the 200 cycles of differential settlement and seismic motion are also bounding for the period of extended operation. The Type V fuel transfer penetration is not

subject to elevated temperatures or thermal fatigue and thus meets the requirements for 7000 thermal cycles. The 200 cycles of differential settlement and seismic motion are also adequate for the period of extended operation since the fuel transfer penetration has already experienced differential settlement and has not been subjected to any seismic loading thus far.

Analyses associated with containment penetration bellows fatigue have been evaluated and determined to remain valid for the period of extended operation.

As stated in part in Section 4.5.4 of NUREG 1779, the NRC staff concludes that FPL has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1), that, for penetrations fatigue TLAA, the analyses remain valid and have been projected to the end of the period of extended operation.

Types I and III primary and secondary containment penetration bellows were evaluated for continued acceptability under EPU conditions. The bellows are similar in configuration to the Unit 1 bellows. The UFSAR and design specification requirements for the bellows are identical to the Unit 1 requirements. Therefore, the analysis contained in Appendix 3G of the St. Lucie Unit 1 UFSAR is applicable to the St. Lucie Unit 2 bellows. Unit 1 UFSAR Appendix 3G qualifies the bellows for 7,000 cycles maximum thermal expansion and 200 cycles differential settlement and seismic motion based on axial, lateral and vertical design movements which envelope both cases. Inputs utilized in the evaluation in addition to design movements include bellows material and dimensional properties (length, thickness, number of convolutions, number of plies, type), design pressure and temperature. These inputs do not change for EPU. Therefore, the bellows analysis contained in St. Lucie Unit 1 UFSAR Appendix 3G remains valid for EPU conditions.

Leak-Before Break

A generic Leak-Before-Break (LBB) analysis was performed for Combustion Engineering (CE) designed Nuclear Steam Supply Systems (NSSS) by the CE Owners Group (CEOG) which included St. Lucie Units 1 and 2. The results of this analysis are documented in report CEN-367-A. The NRC approved the generic application of the LBB methodology for CEOG plants on October 30, 1990. The specific application of the CEOG LBB methodology to St. Lucie Units 1 and 2 was approved by the NRC on March 5, 1993. A SG equivalency report prepared for the replacement SG concluded that the LBB evaluation which was conducted prior to the SG replacement remains valid following the replacement SG installation.

The LBB analysis is described in Section 4.6.1 of the LRA. The intent of the LBB analysis is to demonstrate through qualitative assessment that the plant-specific Fatigue Monitoring Program (FMP) is capable of programmatically managing the assumptions, including the fatigue cycles, for the period of extended operation. The NRC performed a review of this section in order to determine that the requirements contained in 10 CFR 54.21(c) related to the TLAA for LBB for Units 1 and 2 have been met.

As stated in part in Section 4.6.1.2 of NUREG 1779 the staff agrees with FPL's conclusion that the continued implementation of the Fatigue Monitoring Program, (UFSAR Section 18.2.6) provides reasonable assurance that thermal fatigue will be managed for the primary loop piping and components, and that therefore the analyses for this TLAA remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

Normal operation (NOP) + SSE for Group 1 plants were used in the CEOG report to demonstrate crack stability for LBB. Implementation of the EPU will affect NOP loads. SSE loads are not affected by EPU.

An analysis compared the NOP + SSE loads presented in the NRC approved CEOG report to the revised plant-specific loads for the EPU. The results of the analysis demonstrate that NOP+SSE loads for EPU are bounded by the loads presented in the CEOG report. Therefore, the leakage crack length and crack stability evaluation remain valid for EPU.

Refer to LR [Section 2.1.6](#), Leak Before Break, for additional information relative to LBB.

Therefore there are no impacts to the conclusions reached by the NRC in their evaluation of LBB as part of their review of St. Lucie Unit 2 LRA.

Crane Load Cycle Limit

The NRC states in Section 4.6.2.2 of NUREG 1779 that it finds the TLAA associated with crane load cycle limits acceptable and compliant with the requirements of 10 CFR 54.21(c)(1). The cranes that were evaluated for TLAA include the following:

- reactor building polar cranes, refueling machine and hoist,
- reactor containment building auxiliary telescoping jib cranes,
- fuel transfer machine,
- spent fuel handling machine,
- refueling canal bulkhead monorail,
- cask storage pool bulkhead monorail, and
- intake structure bridge cranes.

The cranes identified above, are designed in accordance with the criteria of the Crane Manufacturers Association of America (CMAA) Specification No. 70, "Specifications for Electric Overhead Traveling Cranes," and are acceptable for at least 20,000 to 200,000 load cycles.

The cranes are used primarily during refueling outages. Occasionally, cranes make lifts at or near their rated capacity. However, most crane lifts are substantially less than their rated capacity. A review of crane usage determined that the spent fuel handling machine is bounding for load cycle analysis.

The spent fuel handling machine is used primarily to move fuel assemblies during refueling cycles and is subject to the most loading cycles at or near its rated capacity. The number of spent fuel handling machine load cycles for 60 years of operation will not exceed the requirements of CMAA-70.

Since the number of spent fuel handling machine load cycles bounds that of the other cranes in the license renewal scope, all of the cranes identified above are considered adequate for expected load cycles over the period of extended operation. Furthermore, as stated in LR [Section 2.5.7.2.2.3](#), the structures, systems, and components (SSCs) associated with the Light Load Handling System (LLHS) related to refueling are not modified for EPU purposes, and will

continue to use the current Westinghouse design 16x16 fuel assemblies. Fuel assembly weight will therefore remain within the load bearing capacity of the LLHS and tooling, inclusive of seismic loads. Therefore the EPU has no impact on the crane load cycle limit TLAA which has been approved by the NRC as presented in Section 4.6.2.2 of NUREG 1779. In addition, because crane gearing and shafting fatigue life is related to load lifts (fatigue life design per CMAA-70), the crane gearing and shafting is also adequate for the period of extended operation.

Alloy 600 Instrument Nozzles

Small diameter Alloy 600 nozzles, such as pressurizer and RCS hot-leg instrumentation nozzles in CE designed PWRs, have developed leaks or partial through-wall cracks as a result of primary water stress corrosion cracking (PWSCC). The residual stresses imposed by the partial-penetration “J” welds between the nozzles and the low alloy or carbon steel pressure boundary components are the driving force for crack initiation and propagation.

A repair technique known as the “half nozzle” weld repair has been used to repair leaking Alloy 600 nozzles and as a preventative repair on nozzles that may leak in the future. In the half nozzle technique, the Alloy 600 nozzle is cut outboard of the partial-penetration weld and replaced with a short Alloy 690 nozzle section that is welded to the outside surface of the pressure boundary component. This repair leaves a short section of the original nozzle attached to the inside surface with the “J” weld and an area of the shell in the crevice region exposed to borated water. This repair technique is performed under ASME Section XI Article IWA-7000, Replacement. In Section 4.6.4 of the LRA, FPL summarizes the process and results of its TLAA related to half-nozzle repairs of leaking Alloy 600 instrumentation nozzles to the RCS hot-leg piping and original pressurizer. These TLAAs address: 1) the potential growth of the original flaw due to thermal or mechanical cycling, and 2) the potential wastage of the ferritic material that is adjacent to the half-nozzle configuration and exposed to borated reactor coolant.

A fracture mechanics analysis ([Reference 1](#)) was performed and submitted to the NRC to support the pressurizer steam space half nozzle repairs performed in 1994. This analysis was completed using plant-specific data. The analysis presented a bounding flaw evaluation for small diameter Alloy 600/690 nozzle replacements in accordance with ASME Section XI requirements. Postulated flaws in the original weldments associated with the nozzle locations where half-nozzle replacements would be utilized were evaluated. These postulated flaws were assessed for flaw growth and flaw stability as specified in the ASME Code, Section XI. The flaw growth analysis included in the report assumes the total number of design cycles, consistent with the UFSAR, adjusted for the 60 year plant life. This analysis bounds the Class 1 fatigue design requirements. A review of actual plant operation concluded that the existing design cycles and cycle frequencies are conservative and bounding for the period of extended operation. The minimum margin in the stress intensity associated with the end of life (60 year) crack for the hot leg nozzles is 20 percent. Thus, flaw growth analysis of the RCS Alloy 600 instrument nozzle replacement has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

Two mechanisms that can result in growth of the existing cracks are fatigue and stress corrosion cracking (SCC). Fatigue crack growth considers the transient cycles, including thermal cycles, that the piping or component will experience. In order for SCC and crack growth to occur three

factors must be present – high stress levels, the material must be susceptible to SCC and the right combination of environmental conditions must be present.

The key environmental factor affecting SCC and crack growth is the oxidizing potential of the coolant, which is primarily driven by the dissolved oxygen (DO) content. The hydrogen overpressure that is normally present in the coolant system tends to produce a low DO value.

While EPU will result in an increase in RCS temperature (T_{HOT} changes from 595°F to 604°F), the types and number of cycles included in the fatigue analysis of the hot leg piping is unchanged. The impact of EPU on the previously calculated thermal cycles and resulting fatigue stress is judged to be insignificant. The implementation of EPU will not exceed the limits for DO and hydrogen in the RCS as specified in the St. Lucie Chemistry Program, nor will it result in any material changes in the RCS or pressurizer. Since the conditions evaluated by WCAP-15973-P-A bound the conditions for St. Lucie Unit 2 after EPU, the conclusions of WCAP-15973-P-A remain valid after EPU.

Topical Report Nos. CE NPSD-1198-P and WCAP-15073-P developed corrosion rates for high temperature (normal operating) conditions, intermediate temperature (startup) conditions and low temperature aerated (shutdown) conditions. For this evaluation, the corrosion rates defined in the topical report are considered applicable. The overall corrosion rate is the sum of the corrosion for each condition, based on the percentage of time at that condition. The topical report assumed that CE plants would be operating at high temperature conditions for 88 percent of the time, at intermediate temperature startup conditions for 2 percent of the time, and at shutdown conditions for 10 percent of the time over the life of the plant.

The rate of corrosion is dependent on several environmental factors, including temperature and pH. Laboratory testing has demonstrated that the corrosion rate decreases as temperature increases. As temperature is reduced, dissociation of the boric acid increases and pH is depressed. The dissolved oxygen concentration in the liquid is also a factor in establishing the corrosion rate.

The greatest contribution to the overall corrosion rate is the corrosion occurring during shutdown conditions, which has the lowest RCS temperature and the highest dissolved oxygen content. Thus, any operation with capacity factors greater than 88 percent (time at shutdown of less than 10 percent) will be bounded by the corrosion rates defined in Topical Report CE NPSD-1198-P and WCAP-15073-P. Based on plant-specific operating experience and projected future operations and outage schedules, the assumptions of the topical report are conservative and will bound the actual corrosion rates over the life of the plant.

An evaluation was performed to determine the design lifetime of the Alloy 600 nozzle replacements based on the allowable corrosion rates. The evaluation concluded that the most limiting hot leg nozzle has a lifetime of 90.5 years. This lifetime is significantly longer than 60 years. Therefore, ASME Code requirements will not be exceeded prior to the end of the period of extended operation.

In addition, FPL has reviewed WCAP-15973-P Revision 00 (CE-NSPD-1198-P, Revision 01) dated November 2002 and determined that the conclusions of the plant specific evaluation are not changed.

The evaluations described above were conducted in accordance with the methods of Topical Report Nos. CE NPSD-1198-P and WCAP-15973-P. The evaluations demonstrate that the carbon and low alloy steel RCS components will not be unacceptably degraded by general corrosion as a result of the implementation of replacements of small diameter Alloy 600 nozzles. Although some minor corrosion may occur in the crevice region of the replaced nozzles, the degradation will not proceed to the point where ASME Code requirements will be exceeded before the end of plant life, including the period of extended operation.

When corrosion occurs, the crevice region will fill with corrosion products, which occupy a greater volume than the non-corroded based metal from which they originated. As the amount of corrosion product builds up, the crevice will be filled and eventually virtually eliminate any contact between the borated water and the carbon steel or low alloy steel material. Once this happens the rate of corrosion will essentially stop.

EPU will slightly increase RCS hot leg temperature, which will tend to reduce the corrosion rate. EPU will not affect the percentages of time at power operation, in startup/shutdown or refueling. EPU will not affect the size of the crevice. Therefore, the conclusions of the nozzle corrosion evaluation will continue to be valid after EPU, indicating that EPU will not affect the calculated lifetimes of the nozzle repairs.

Refer to LR [Section 2.2.6](#), for additional information pertaining to NSSS design transients and LR [Section 2.1.5](#) for additional information pertaining to reactor coolant pressure boundary materials.

2.14.3 Conclusion

FPL has reviewed the effect of EPU on the Renewed Plant Operating License for St. Lucie Unit 2. Based on this review, FPL concludes that the effects of EPU on the renewed operating license have been accounted for and the aging effects of the SSCs within the scope of license renewal will be adequately managed through the extended period of operation.

2.14.4 References

1. WCAP-15973-P, Low-Alloy Steel Component Corrosion Analysis Supporting Small-Diameter Alloy 600/690 Nozzle Repair/Replacement Programs (November 2002), which was submitted to the NRC for review and approval in Combustion Engineering Owners Group letter CEOG-02-243, dated November 11, 2002.